EXHIBIT A
GENERAL INFORMATION ABOUT THE APPLICANT
OAR 345-021-0010(1)(A)

CONTENTS

APPENDICES

1.0 INFORMATION ABOUT THE APPLICANT

OAR 345-021-0010(1)(a). *Exhibit A. Information about the applicant and participating persons, including:*

The applicant is Jordan Cove Energy Project, L.P. ("Applicant"), a Delaware limited partnership. As of the date of this application, Jordan Cove Energy Project, L.P. is owned by two limited partners and one general partner. The limited partners are: Energy Projects Development L.L.C and Jordan Cove LNG L.P. ("limited partners").[1] The general partner is Jordan Cove Energy Project L.L.C. ("general partner"). Both the general partner and Jordan Cove LNG L.P. are owned by Veresen, Inc. ("Veresen"). However, the Applicant anticipates that, prior to issuance of the Site Certificate, the interests of Energy Projects Development L.L.C. will be acquired by Jordan Cove Energy Project, L.P. and, as a result, the Applicant will become a wholly owned subsidiary of Veresen. Accordingly, information is included in Exhibit A for both the Applicant's ownership structure on the date hereof and its anticipated ownership structure upon issuance of the Site Certificate.[2]

[1] Jordan Cove LNG L.P. was formerly Fort Chicago LNG II U.S. L.P. See Appendix 4, Copy of Amendment to Certificate of Limited Partnership.
[2] The date hereof is July 21, 2014.

2.0 NAME AND ADDRESS OF APPLICANT AND CONTACT PERSON

OAR 345-021-0010(1)(a)(A). *The name and address of the applicant including all co-owners of the proposed facility, the name, mailing address, email address and telephone number of the contact person for the application, and if there is a contact person other than applicant, the name, title, mailing address and telephone number of that person.*

Applicant's name and address:
Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420

Contact Person, address, and phone number:
Mr. Robert Braddock
Vice President – Project Manager
Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420
Phone: (541) 266-7510
E-mail: bobbraddock@attglobal.net

3.0 PARTICIPANT INFORMATION

OAR 345-021-0010(1)(a)(B). *The contact name, mailing address, email address and telephone number of all participating persons, other than individuals, including but not limited to any parent corporation of the applicant, persons upon whom the applicant will rely for third-party permits or approvals related to the facility, and, if known, other persons upon whom the applicant will rely in meeting any facility standard adopted by the Council.*

Parent Corporation:
Veresen, Inc., a Canadian corporation
Suite 900, Livingston Place, South Tower
222 – 3rd Avenue Southwest
Calgary, Alberta
T2P 0B4
Attention: Kevan King, Senior Vice President, General Counsel and Secretary
Email: kking@vereseninc.com
Phone: (403) 213-3643

Third-party Permits:

Coos Bay North Bend Water Board
2305 Ocean Boulevard
PO Box 539
Coos Bay, Oregon 97420-0108
Attention: Ron A. Hoffine, P.E., Operations Director
Email: ron_hoffine@cbnbh2o.com
Phone: (541) 267-3128

At this time the Applicant is relying only upon the Coos Bay North Bend Water Board's state-issued water rights as a third-party permits. However, additional third-party permits may be obtained by the construction firm selected to build the facility. The Applicant anticipates that these third-party permits may include permits for obtaining aggregate and other construction materials, transporting materials to the site, and other building-related permits that are typically obtained immediately prior to or during construction activities. The Applicant will require that these permits meet the facility standards adopted by the Council.

4.0 CORPORATE INFORMATION

OAR 345-021-0010(1)(a)(C). *If the applicant is a corporation, it shall give*:
(i) The full name, official designation, mailing address, email address and telephone number of the officer responsible for submitting the application;

Although the Applicant is a limited partnership and not a corporation, the Applicant provides the following information because it is a wholly owned subsidiary, in compliance with OAR 345-021-0010(1)(a)(D).

Parent Company:
Veresen, Inc., a Canadian corporation ("Parent")

(ii) The date and place of its incorporation;

Parent is a Canadian corporation, and it filed its Certificate of Incorporation on October 1, 2010.

(iii) A copy of the articles of incorporation and its authorization for submitting the application;

See Appendix 1 for copy of Certificate of Incorporation for Parent

(iv) In the case of a corporation not incorporated in Oregon, the name and address of the resident attorney-in-fact in this state and proof of registration to do business in Oregon.

Parent is not registered to do business in the State of Oregon, and registration is not required under Oregon law. However, the Applicant is registered and authorized to do business in the State of Oregon.

5.0 MISCELLANEOUS INFORMATION

OAR 345-021-0010(1)(a)(D). *If Applicant is a wholly owned subsidiary of a company, corporation, or other business entity, in addition to the information required by OAR 345-021-0010(1)(a)(C), it shall give the full name and business address of each of the applicant's full or partial owners.*

The Applicant is made up of one general partner and two limited partners. The general partner and limited partner Jordan Cove LNG, LP are both currently owned by Veresen.[3] The information required for each entity is presented here:

Parent Corporation:
Veresen, Inc., a Canadian corporation
Suite 900, Livingston Place, South Tower
222 – 3rd Avenue Southwest
Calgary, Alberta
T2P 0B4
Attention: Kevan King, Senior Vice President, General Counsel and Secretary
Phone: (403) 213-3643
Email: kking@vereseninc.com

General Partner:
Jordan Cove Energy Project L.L.C., a Delaware limited liability company
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420
Phone: (541) 266-7510
Email: bobbraddock@attglobal.net

Limited Partner:
Jordan Cove LNG LP, a Delaware limited partnership
(fka Fort Chicago LNG II LP, see Appendix 4 for name change document)
Suite 900, Livingston Place, South Tower
222 – 3rd Avenue Southwest
Calgary, Alberta
T2P 0B4
Attn: Vivian Zipchian
Phone: (403) 718-2487
Email: vzipchian@vereseninc.com

[3] Currently Veresen owns 75% of Jordan Cove Energy Project, L.P.

Limited Partner:
Energy Projects Development, LLC, a Colorado limited liability company
1274 Silvertip Lane
Evergreen, Colorado 80439
Attn: Elliot Trepper
Phone: (303) 534-1842
Email: eltrepper@attglobal.net

OAR 345-021-0010(1)(a)(E). *If Applicant is an association of citizens, a joint venture or a partnership it shall give:*

Applicant is a limited partnership organized under the laws of the State of Delaware on July 12, 2005; and registered to do business in the State of Oregon on August 25, 2005.

(i) Full name, official designation, mailing address, email address and telephone number of the person submitting the application:

Mr. Robert Braddock
Vice President – Project Manager
Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420
Phone: (541) 266-7510
E-mail: bobbraddock@attglobal.net

(ii) The name, business address and telephone number of each person participating in the association, joint venture or partnership and the percentage interest held by each:

General Partner:
Jordan Cove Energy Project L.L.C., a Delaware limited liability company
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420
Phone: (541) 266-7510
Email: bobbraddock@attglobal.net
Owns 100% of Class C Series 1 Units

Limited Partner:
Jordan Cove LNG LP, a Delaware limited partnership
Suite 900, Livingston Place, South Tower
222 – 3rd Avenue Southwest
Calgary, Alberta
T2P 0B4
Attn: Vivian Zipchian
Phone: (403) 718-2487
Email: vzipchian@vereseninc.com

Owns 100% of Class A Units; comprising of a total 75% ownership in Applicant

Limited Partner:
Energy Projects Development, LLC, a Colorado limited liability company
1274 Silvertip Lane
Evergreen, Colorado 80439
Attn: Elliot Trepper
Phone: (303) 534-1842
Email: eltrepper@attglobal.net
Owns 100% of Class B Units; comprising a total 25% ownership in Applicant.

(iii) Proof of registration to do business in Oregon:

See Appendix 2 attached hereto.

(iv) A copy of its articles of association, joint venture agreement or partnership agreement and a list of members and their cities of residence:

See attached Appendix 3.

(v) If there is no articles of association, joint venture agreement or partnership agreement, the applicant shall state that fact over the signature of each member:

Not applicable.

Rules **OAR 345-021-0010(1)(a)(F-H)** have been determined not applicable because the Applicant is not a public or government entity, nor an individual, nor a limited liability company.

APPENDIX A-1

Certificate of Incorporation for Veresen

CORPORATE ACCESS NUMBER: 2015609411

BUSINESS CORPORATIONS ACT

CERTIFICATE

OF

AMENDMENT

1560941 ALBERTA LTD.
CHANGED ITS NAME TO **VERESEN INC.** ON 2010/10/15.

BUSINESS CORPORATIONS ACT

Alberta

ARTICLES OF AMENDMENT

1. Name of Corporation	2. Corporate Access Number
1560941 ALBERTA LTD.	**2015609411**

3. Pursuant to subsection 173(1)(a) of the *Business Corporations Act* (Alberta), the Articles of the Corporation be amended by changing the name of the Corporation from 1560941 Alberta Ltd. to **VERESEN INC.**

4. DATE	SIGNATURE	TITLE
October 15, 2010		Vice President, General Counsel and Secretary

REGISTERED ON
THE ALBERTA REGISTRIES
CORES SYSTEM
OCT 15 2010

Name Change Alberta Corporation - Registration Statement

Alberta Amendment Date: 2010/10/15

Service Request Number: 15390523
Corporate Access Number: 2015609411
Legal Entity Name: 1560941 ALBERTA LTD.
French Equivalent Name:
Legal Entity Status: Active

Alberta Corporation Type: Named Alberta Corporation
New Legal Entity Name: VERESEN INC.
New French Equivalent Name:
Nuans Number: 100775970
Nuans Date: 2010/10/12
French Nuans Number:
French Nuans Date:

Professional Endorsement Provided:
Future Dating Required:

Annual Return

No Records returned

Attachment

Attachment Type	Microfilm Bar Code	Date Recorded
Share Structure	ELECTRONIC	2010/10/01
Other Rules or Provisions	ELECTRONIC	2010/10/01

Registration Authorized By: RENEE RATKE
SOLICITOR

CORPORATE ACCESS NUMBER: 2015609411

Alberta

BUSINESS CORPORATIONS ACT

CERTIFICATE

OF

INCORPORATION

1560941 ALBERTA LTD.
WAS INCORPORATED IN ALBERTA ON 2010/10/01.

Alberta

Articles of Incorporation

1. **Name of Corporation**

1560941 Alberta Ltd.

2. **The classes of shares, and any maximum number of shares that the corporation is authorized to issue:**

The attached Schedule of Share Capital is incorporated into and forms part of this form.

3. **Restrictions on share transfers *(if any)*:**

None.

4. **Number, or minimum and maximum number, of directors that the corporation may have:**

Not less than Three (3) directors and not more than Fifteen (15) directors.

5. **If the corporation is restricted FROM carrying on a certain business, or restricted TO carrying on a certain business, specify the restriction(s):**

None.

6. **Other rules or provisions *(if any)*:**

The attached Schedule of Other Provisions is incorporated into and forms part of this form.

7. **Dated:** October 1, 2010

Incorporators

Name of Person Authorizing *(please print)*	Address: *(including postal code)*	Signature
Karen Keck	4500, 855 - 2nd Street SW Calgary, AB T2P 4K7	

REGISTERED ON
THE ALBERTA REGISTRIES
CORES SYSTEM
OCT 01 2010

SCHEDULE OF SHARE CAPITAL

The Corporation is authorized to issue:

(a) one class of shares, to be designated as "Common Shares", in an unlimited number; and

(b) one class of shares, to be designated as "Preferred Shares", issuable in series, to be limited in number to an amount equal to not more than one-half (1/2) of the Common Shares issued and outstanding at the time of issuance of such Preferred Shares;

such shares having attached thereto the following rights, privileges, restrictions and conditions:

A. Common Shares

The Common Shares shall have attached thereto the following rights, privileges, restrictions and conditions:

(i) the right to one vote at all meetings of shareholders of the Corporation, except meetings at which only holders of a specified class of shares are entitled to vote;

(ii) subject to the prior rights and privileges attaching to any other class of shares of the Corporation, the right to receive any dividend declared by the Corporation; and

(iii) subject to the prior rights and privileges attaching to any other class of shares of the Corporation, the right to receive the remaining property and assets of the Corporation upon dissolution.

B. Preferred Shares

The Preferred Shares shall have attached thereto the following rights, privileges, restrictions and conditions:

(i) the Preferred Shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be determined by resolution of the directors of the Corporation, provided that the number of Preferred Shares of all series shall not, in aggregate, exceed the number of Preferred Shares authorized above; and

(ii) subject to the provisions of the Business Corporations Act (Alberta), the directors of the Corporation may by resolution fix from time to time before the issue thereof the designation, rights, privileges, restrictions and conditions attaching to each series of the Preferred Shares.

REGISTERED ON
THE ALBERTA REGISTRIES
CORES SYSTEM
OCT 01 2010
cf

SCHEDULE OF OTHER PROVISIONS

1. The directors may, between annual meetings of shareholders, appoint one or more additional directors of the Corporation to serve until the next annual meeting of shareholders, but the number of additional directors shall not at any time exceed one-third (1/3) of the number of directors who held office at the expiration of the last meeting of the shareholders of the Corporation.

2. Any meeting of the shareholders of the Corporation may be held at any place within Canada or at any other place outside of Canada selected by the directors of the Corporation.

REGISTERED ON
THE ALBERTA REGISTRIES
CORES SYSTEM

OCT 0 1 2010

cP

Articles of Incorporation
For
1560941 ALBERTA LTD.

Share Structure:	THE ATTACHED SCHEDULE OF SHARE CAPITAL IS INCORPORATED INTO AND FORMS PART OF THIS FORM.
Share Transfers Restrictions:	NONE.
Number of Directors:	
Min Number of Directors:	3
Max Number of Directors:	15
Business Restricted To:	NONE.
Business Restricted From:	NONE.
Other Provisions:	THE ATTACHED SCHEDULE OF OTHER PROVISIONS IS INCORPORATED INTO AND FORMS PART OF THIS FORM.

Registration Authorized By: KAREN KECK
SOLICITOR

Incorporate Alberta Corporation - Registration Statement

Alberta Registration Date: 2010/10/01

Corporate Access Number: 2015609411

Service Request Number: 15301075
Alberta Corporation Type: Numbered Alberta Corporation
Legal Entity Name: 1560941 ALBERTA LTD.
French Equivalent Name:
Nuans Number:
Nuans Date:
French Nuans Number:
French Nuans Date:

REGISTERED ADDRESS
Street: 4500, 855 - 2ND STREET SW
Legal Description:
City: CALGARY
Province: ALBERTA
Postal Code: T2P 4K7

RECORDS ADDRESS
Street:
Legal Description:
City:
Province:
Postal Code:

ADDRESS FOR SERVICE BY MAIL
Post Office Box:
City:
Province:
Postal Code:
Internet Mail ID:

Share Structure: THE ATTACHED SCHEDULE OF SHARE CAPITAL IS INCORPORATED INTO AND FORMS PART OF THIS FORM.

Share Transfers

Restrictions:	NONE.
Number of Directors:	
Min Number Of Directors:	3
Max Number Of Directors:	15
Business Restricted To:	NONE.
Business Restricted From:	NONE.
Other Provisions:	THE ATTACHED SCHEDULE OF OTHER PROVISIONS IS INCORPORATED INTO AND FORMS PART OF THIS FORM.
Professional Endorsement Provided:	
Future Dating Required:	
Registration Date:	2010/10/01

Director

Last Name:	JANG
First Name:	THERESA
Middle Name:	
Street/Box Number:	440, 222 - 3RD AVENUE SW
City:	CALGARY
Province:	ALBERTA
Postal Code:	T2P 0B4
Country:	
Resident Canadian:	Y

Last Name:	KING
First Name:	KEVEN
Middle Name:	S.
Street/Box Number:	440, 222 - 3RD AVENUE SW
City:	CALGARY
Province:	ALBERTA
Postal Code:	T2P 0B4
Country:	
Resident Canadian:	Y

Last Name:	WHITE
First Name:	STEPHEN
Middle Name:	H.
Street/Box Number:	440, 222 - 3RD AVENUE SW

City: CALGARY
Province: ALBERTA
Postal Code: T2P 0B4
Country:
Resident Canadian: Y

Attachment

Attachment Type	Microfilm Bar Code	Date Recorded
Share Structure	ELECTRONIC	2010/10/01
Other Rules or Provisions	ELECTRONIC	2010/10/01

Registration Authorized By: KAREN KECK
SOLICITOR

APPENDIX A-2

Authority to Transact Business in Oregon Applicant

Phone: (503) 986-2200
Fax: (503) 378-4381

Application for Registration—Foreign Limited Partnership

Secretary of State
Corporation Division
255 Capitol St. NE, Suite 151
Salem, OR 97310-1327
FilinginOregon.com

FILED
AUG 2 5 2005
OREGON
SECRETARY OF STATE

REGISTRY NUMBER: 307661-90

In accordance with Oregon Revised Statute 192.410-192.490, the information on this application is public record. We must release this information to all parties upon request and it will be posted on our website.

For office use only

Please Type or Print Legibly in Black Ink. Attach Additional Sheet if Necessary.

1) NAME OF LIMITED PARTNERSHIP (Must contain the words "Limited Partnership" without abbreviation.)

Jordan Cove Energy Project L.P. Limited Partnership, a Limited Partnership of Delaware

2) STATE OR COUNTRY OF FORMATION

Delaware

3) CERTIFICATE OF EXISTENCE (This application must be accompanied by a certificate of existence, current within 60 days of delivery to the Division, authenticated by the official having custody of the corporate records in the jurisdiction of incorporation.)

☑ CERTIFICATE ATTACHED

4) DATE OF FORMATION

July 12, 2005

5) DURATION, IF NOT INDEFINITE

6) ADDRESS OF OFFICE (Street address where records of partnership are maintained.)

125 Central Avenue, Suite 380
Coos Bay, OR 97420

7) THE PARTNERSHIP AGREES TO KEEP THE RECORDS REFERRED TO IN ORS 70.050 UNTIL THE FOREIGN LIMITED PARTNERSHIP'S REGISTRATION IN OREGON IS CANCELLED.

☑ YES

8) NAME OF REGISTERED AGENT

Elliot Trepper

9) ADDRESS OF INITIAL REGISTERED AGENT (Must be an Oregon Street Address, which is identical to the registered agent's business office.)

125 Central Avenue, Suite 380
Coos Bay, OR 97420

10) ADDRESS WHERE DIVISION MAY MAIL NOTICES

125 Central Avenue, Suite 380
Coos Bay, OR 97420

11) NAME AND ADDRESS OF EACH GENERAL PARTNER

Jordan Cove Energy Project L.L.C.
125 Central Avenue, Suite 380
Coos Bay, OR 97420

12) EXECUTION (Signature of each General Partner.)

Signature: [signature]

Printed Name:
Jordan Cove Energy Project L.L.C.
It's General Partner
By Elliot Trepper, Vice President

13) CONTACT NAME (To resolve questions with this filing.)

Sheri L. Berndt-Smith

DAYTIME PHONE NUMBER (Include area code.)

(206) 903-2373

FEES

Required Processing Fee $50
Confirmation Copy (Optional) $5
Processing Fees are nonrefundable.
Please make check payable to "Corporation Division."

NOTE:
Fees may be paid with VISA or MasterCard. The card number and expiration date should be submitted on a separate sheet for your protection.

JF 8/25

147 (Rev. 7/04)

APPENDIX A-3

Limited Partnership Agreement for Applicant

JORDAN COVE ENERGY PROJECT L.P.

LIMITED PARTNERSHIP AGREEMENT

AMONG

JORDAN COVE ENERGY PROJECT L.L.C.

- AND -

FORT CHICAGO LNG II U.S. L.P.

- AND –

ENERGY PROJECTS DEVELOPMENT L.L.C.

- AND -

EACH PERSON WHO IS ADMITTED TO THE PARTNERSHIP AS A LIMITED PARTNER IN ACCORDANCE WITH THE TERMS HEREOF

July 12, 2005

TABLE OF CONTENTS

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CAPITAL CONTRIBUTIONS AND ACCOUNTS

ARTICLE 5
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ARTICLE 7
POWERS, DUTIES AND OBLIGATIONS OF GENERAL PARTNER

ARTICLE 8
FINANCIAL INFORMATION

ARTICLE 9
MEETINGS OF LIMITED PARTNERS

Schedules:

LIMITED PARTNERSHIP AGREEMENT

THIS AGREEMENT made as of the 12th day of July, 2005 among JORDAN COVE ENERGY PROJECT L.L.C., a limited liability company incorporated under the laws of the State of Delaware, as General Partner, FORT CHICAGO LNG II U.S. L.P., a limited partnership created under the laws of the State of Delaware, as Limited Partner, ENERGY PROJECTS DEVELOPMENT L.L.C., a limited liability company created under the laws of the state of Colorado, as Limited Partner and each Person who is admitted to the Partnership as a Limited Partner in accordance with the terms hereof.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT IN CONSIDERATION of the covenants and agreements contained in this Agreement, the Partners agree with each other as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, except where otherwise specifically provided, the following words have the following meanings:

"Act" means the *Delaware Revised Uniform Limited Partnership Act*, as amended or replaced from time to time;

"Affiliate" when used to indicate a relationship with a specified Person, means another Person that directly, or indirectly through one or more intermediaries or otherwise, Controls, or is Controlled by, or is under common Control with, such specified Person. A corporation shall be deemed to be an Affiliate of another corporation if one of them is the Subsidiary of the other or if both are Subsidiaries of the same Person or if each of them is directly or indirectly Controlled by the same Person;

"Agreement" means this Limited Partnership Agreement made as of the 12th day of July, 2005 among Jordan Cove Energy Project L.L.C., as General Partner of the Partnership, Fort Chicago LNG II U.S. L.P. as Limited Partner of the Partnership, Energy Projects Development L.L.C., as Limited Partner of the Partnership and those parties referred to as Limited Partners herein, as from time to time amended, supplemented or restated;

"Auditor" means PricewaterhouseCoopers LLP or such other member in good standing of the American Institute of Certified Public Accountants who is appointed from time to time as auditor of the Partnership by the General Partner;

"Book Depreciation" means for each Fiscal Year (or other period for which Book Depreciation must be computed), the depreciation, amortization or other cost recovery deduction allowable for federal income tax purposes with respect to an asset, except that, if the Book Value of an asset differs from it adjusted tax basis at the beginning of the year, Book Depreciation will be an amount which bears the same ratio to Book Value at the beginning of the year as the federal income tax depreciation, amortization, or other cost recovery deduction for the year bears to the beginning adjusted tax basis; provided, however, that if the adjusted tax basis of the asset at the beginning of the year is zero, Book Depreciation will be determined by an Extraordinary Resolution using any reasonable method;

"Book Value" with respect to any asset of the Partnership means the asset's adjusted tax basis for federal income tax purposes, except as follows:

(a) The initial Book Value of any asset contributed to the Partnership by a Partner shall be the fair market value of the asset as of the date of contribution;

(b) The Book Value of each asset shall be its respective fair market value, as of (i) the issuance of an interest in the Partnership to a new or existing Partner in exchange for a Capital Contribution, (ii) the distribution by the Partnership to a Partner in liquidation of the Partners' interest in the Partnership, and (iii) the liquidation of the Partnership within the meaning of Treasury Regulation Section 1.704-1(b)(2)(ii)(g). The determination of the fair market value of property when required shall be made by the General Partner unless an independent appraiser is selected pursuant to an Extraordinary Resolution;

(c) The Book Value of each asset distributed to any Partner will be the fair market value of the asset as of the date of distribution;

(d) The Book Value of each asset will be increased or decreased to reflect any adjustment to the adjusted basis of the asset under Code Section 734(b) or 743(b), but only to the extent that the adjustment is taken into account in determining Capital Accounts under Treasury Regulation Section 1.704-1(b)(2)(iv)(m), provided that the Book Value will not be adjusted under this clause (d) to the extent that an adjustment under clause(b) above is necessary or appropriate in connection with a transaction that would otherwise result in an adjustment under this clause; and

(e) Book Value will be adjusted by Book Depreciation, and gain or loss on a disposition of any asset shall be determined by reference to such asset's Book Value as adjusted herein;

"Capital Contribution" means with respect to any Partner, the amount of money and the initial Book Value of any property (other than money) contributed to the Partnership by the Partner;

"Certificate" means the certificate of limited partnership for the Partnership filed under the Act and all amendments thereto and renewals, replacements or restatements thereof;

"Class A Unit Preferred Distribution" has the meaning set forth in Schedule D;

"Class B Unit Preferred Distribution" has the meaning set forth in Schedule E;

"Class A Units" means Class A limited partnership units of the Partnership as authorized in Article 3;

"Class B Units" means Class B limited partnership units of the Partnership as authorized in Article 3;

"Class C Units" means units of any series of Class C limited partnership units of the Partnership as authorized in Article 3;

"Class C Unit, Series 1" means the first series of Class C Units, designated "Class C Unit, Series 1, as authorized in Article 3;

"Code" means the *Internal Revenue Code* (United States of America) and the regulations thereunder, as amended from time to time;

"Commercial Operations Date" means the first date upon which the Facilities first commence operations on a commercial basis (following testing and start-up operations) with respect to which there is a reasonable expectation of the General Partner that customers will be billed and revenue generated on an on-going basis;

"Confidential Information" has the meaning set forth in Section 13.2;

"Contribution Agreement" means that contribution agreement to be entered into by the Partnership and Energy Projects on the date hereof substantially in the form of Schedule A;

"Controlled": a Person is "Controlled" by another Person or two or more other Persons acting jointly or in concert if:

(a) in the case of a body corporate, securities entitled to vote in the election of directors of such body corporate carrying more than 50% of the votes for the election of directors are held, directly or indirectly, by or for the benefit of the other Person or Persons, and the votes carried by such securities are entitled, if exercised, to elect a majority of the board of directors of such body corporate; or

(b) in the case of a Person which is not a body corporate, more than 50% of the voting or equity interests of such entity are held, directly or indirectly, by or for the benefit of the other Person or Persons;

and "Controls", "Controlling" and "under common Control with" shall be interpreted accordingly;

"Customers" has the meaning set forth in Section 13.1(a)(ii);

"Departing Partner" has the meaning set forth in Section 7.6;

"Distributable Cash" means with respect to a particular period, the amount by which the Partnership's cash on hand at the end of such period (including any amounts borrowed by the General Partner on behalf of the Partnership and net proceeds received by the Partnership from the issuance of Units and any other securities of the Partnership) exceeds: (i) the amount of Tax Distributions made or to be in accordance with Section 5.4(a) with respect to such period; (ii) unpaid administration expenses of the Partnership for that and any previous period; (iii) amounts required for the business and operations of the Partnership during such period including anticipated repayments of amounts borrowed, payments of interest and fees related to amounts borrowed or available credit and debt reserve requirements of lenders; and (iv) any cash reserve which the board of directors of the General Partner in its discretion determines is necessary to satisfy the Partnership's current and anticipated obligations;

"Energy Projects" means Energy Projects Development L.L.C.;

"Extraordinary Resolution" means:

(a) prior to the Commercial Operations Date and on such date and thereafter with respect to the matters contemplated in Sections 9.17(c), 9.17(d) (with respect to Extraordinary Resolutions requiring a greater than 75% approval), 9.17(e), 9.17(h), 9.17(m) and 9.17(n);

  (i) a resolution approved by greater than 75% of the votes cast in person or by proxy by the Limited Partners who voted in respect of that resolution; or

  (ii) a written resolution in one or more counterparts signed by Limited Partners holding in the aggregate greater than 75% of the votes entitled to vote on that resolution; and

(b) on or after the Commercial Operations Date except with respect to the matters contemplated in Sections 9.17(c), 9.17(d) (with respect to Extraordinary Resolutions requiring a greater than 75% approval), 9.17(e), 9.17(h), 9.17(m) and 9.17(n);

  (i) a resolution approved by not less than 55% of the votes cast in person or by proxy by the Limited Partners who voted in respect of that resolution; or

  (ii) a written resolution in one or more counterparts signed by Limited Partners holding in the aggregate not less than 55% of the votes entitled to vote on that resolution;

"Facilities" means those facilities from time to time owned or leased by the Partnership and used in the operation of the Jordan Cove Energy Project;

"Fiscal Year" has the meaning set forth in Section 2.5;

"Fort Chicago" means Fort Chicago LNG II U.S. L.P.

"General Partner" means the general partner of the Partnership, currently Jordan Cove Energy Project L.L.C. or any other Person who may become the general partner of the Partnership in place of or in substitution for Jordan Cove Energy Project L.L.C., from time to time, in each case until such general partner ceases to be the general partner of the Partnership under the terms of this Agreement;

"Indemnitee" has the meaning set forth in Section 7.6;

"Interest Rate" has the meaning set forth in Section 4.11;

"Jordan Cove Energy Project" or "Project" means that project to be undertaken by the Partnership including the development, design, construction, ownership and/or leasing (or combination thereof) and operation of a liquid natural gas terminal, liquid natural gas storage tanks, a regassification facility, an integrated power facility, gas pipelines and related facilities near North Bend, Oregon;

"Limited Liability Company Agreement" means that limited liability company agreement of the General Partner;

"Limited Partner" means any Person who is or shall become a limited partner of the Partnership;

"L.L.C. Interests" means membership interests in the General Partner;

"Operating Agreement" means that Development and Construction Agreement to be entered into by the General Partner, on behalf of itself and the Partnership and Energy Projects on the date hereof substantially in the form of Schedule B;

"Ordinary Resolution" means:

(a) a resolution approved by more than 50% of the votes cast in person or by proxy by the Limited Partners who voted in respect of that resolution; or

(b) a written resolution in one or more counterparts signed by Limited Partners holding in the aggregate more than 50% of the votes entitled to vote on that resolution;

"Partners" means the General Partner and the Limited Partners and **"Partner"** means any one of them;

"Partnership" means Jordan Cove Energy Project L.P. formed under the laws of the State of Delaware as a limited partnership by the filing of the Certificate under the Act on July 12, 2005;

"Person" means any individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted;

"Project Interest" means, in respect of any Limited Partner, such Limited Partner's Units and such Limited Partner's L.L.C. Interests;

"**Reference Rate**" has the meaning set forth in Section 4.11;

"Register" means the register indicating the names and addresses of the Limited Partners and the number of Units held by them, to be kept by the General Partner;

"Requisitioning Partners" has the meaning set forth in Section 9.1(b);

"Restricted Area" has the meaning set forth in Section 13.1(a)(i);

"Sale", **"Sell"** or **"Sold"** have the meaning set forth in Section 3.11;

"Section 704(b) Amendments" has the meaning set forth in Section 5.8;

"Subscription Form" means a subscription agreement and power of attorney in such form as approved from time to time by the General Partner;

"Subsidiary" means any Person which another Person Controls;

"Transfer Form" means a transfer and power of attorney in the form or substantially in the form set forth in Schedule C or such other form as approved from time to time by the General Partner;

"Unit" means a limited partnership unit of the Partnership and includes a Class A Unit, a Class B Unit, and/or a Class C Unit, as the context requires;

"Unit Certificate" means a certificate for Units issued in accordance with Section 3.19 in such form or forms as approved by the General Partner from time to time; and

"**Unitholder**" means the holder of a Unit as indicated on the Register.

In addition to the foregoing, certain capitalized terms which are used in this Agreement and which are defined in the Schedules hereto, shall have the meanings set forth therein.

1.2 Headings

In this Agreement, the headings are for convenience of reference only, do not form a part of this Agreement and are not to be considered in the interpretation of this Agreement.

1.3 Interpretation

In this Agreement:

(a) words importing the masculine gender include the feminine and neuter genders, corporations, partnerships and other Persons, and words in the singular include the plural, and vice versa, wherever the context requires;

(b) all references to designated Articles, Sections and other subdivisions are to be designated Articles, Sections and other subdivisions of this Agreement;

(c) all accounting terms not otherwise defined will have the meanings assigned to them by, and all computations to be made will be made in accordance with, generally accepted accounting principles in the United States of America from time to time;

(d) any reference to a statute will include and will be deemed to be a reference to the regulations made pursuant to it, and to all amendments made to the statute and regulations in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute referred to or the relevant regulation;

(e) any reference to a Person will include and will be deemed to be a reference to any Person that is a successor to that Person;

(f) any reference to a business day will be deemed to be a reference to any day which is not a Saturday, Sunday or a day which is generally observed as a holiday in the United States of America; and

(g) "hereof", "hereto", "herein", and "hereunder" mean and refer to this Agreement and not to any particular Article, Section or other subdivision.

1.4 Currency

All references to currency herein are references to lawful money of the United States of America.

ARTICLE 2
RELATIONSHIP BETWEEN PARTNERS

2.1 Formation and Name of Partnership

The General Partner and the Limited Partners agree to and do hereby form a limited partnership in accordance with the laws of the State of Delaware and the provisions of this Agreement to carry on business in common with a view to profit under the firm name and style of **"Jordan Cove Energy Project L.P."** or any other name or names as the General Partner may determine from time to time. The General Partner shall have the right to change the name of the Partnership and to file an amendment to the Certificate recording the change of name of the Partnership. The Partnership shall be effective as a limited partnership from the date on which the Certificate is registered under the Act.

2.2 Business of the Partnership

(a) The business of the Partnership shall consist of activities relating directly or indirectly to the development, construction, ownership and operation of the Jordan Cove Energy Project. The Partnership may also engage in such other necessary or related activities as the General Partner deems advisable in order to carry on the business of the Partnership as aforesaid.

(b) The Partnership shall not carry on any business other than as described in this Section 2.2.

2.3 Business in Other Jurisdictions

(a) The Partnership shall not carry on business in any jurisdiction unless the General Partner has taken all steps which may be required by the laws of that jurisdiction for the Limited Partners to benefit from limited liability substantially to the same extent that such Limited Partners enjoy limited liability under the Act. The Partnership shall not carry on business in any jurisdiction in which the laws do not recognize the liability of the Limited Partners to be limited unless, in the opinion of the General Partner, the risks associated with the possible absence of limited liability in such jurisdiction are not significant considering the relevant circumstances.

(b) The Partnership shall carry on business in such a manner as to ensure, to the greatest extent commercially reasonable, the limited liability of the Limited Partners, and the General Partner shall register the Partnership in other jurisdictions where the General Partner considers it appropriate to do so.

2.4 Office of the Partnership

The principal place of business of the Partnership shall be 125 Central Avenue, Suite 380, Coos Bay, Oregon 97420, or such other address in the U.S. as the General Partner may designate in writing from time to time to the Limited Partners provided that the Partnership shall at all times maintain a principal office in Oregon.

2.5 Fiscal Year

Subject to the General Partner determining otherwise, the first fiscal period of the Partnership shall end on December 31, 2005 and thereafter each fiscal period shall commence on January 1 in each year and shall end on the earlier of December 31 in that year or on the date of dissolution or other termination of the Partnership. Each such fiscal period is herein referred to as a **"Fiscal Year"**.

2.6 Status of Partners

(a) The General Partner represents, warrants, covenants and agrees with each Limited Partner that:

(i) it is a limited liability company formed under the laws of the State of Delaware and is validly subsisting under such laws;

(ii) it has the capacity and the necessary corporate authority to act as the general partner of the Partnership and to enter into and perform its obligations under this Agreement, and such obligations do not conflict with nor do they result in a breach of the Limited Liability Company Agreement or any of its constituent documents or any agreement by which or to which it or any of its property is or may become bound or subject;

(iii) it will hold and continue to hold at least one Class C Unit, Series 1 while it is the general partner of the Partnership;

(iv) it will act in good faith in the best interests of the Partnership, subject to the provisions of this Agreement;

(v) it holds and shall maintain the registrations necessary for the conduct of its business and has and shall continue to have all licenses and permits necessary to carry on its business as the General Partner of the Partnership in all jurisdictions where the activities of the Partnership require such licensing or other form of registration of the General Partner;

(vi) it will devote all of its time for the conduct and prudent management of the business and affairs of the Partnership; and

(vii) it is and shall remain a "U.S. person" within the meaning of the Code.

(b) Each of the Limited Partners severally represents, warrants, covenants and agrees with each other Partner that:

(i) it is validly subsisting under the laws of the jurisdiction of its incorporation or creation;

(ii) it has the capacity and competence and the necessary corporate or other authority to enter into this Agreement;

(iii) it has and shall maintain the capacity and corporate, partnership or other necessary authority to be a Partner of the Partnership and to perform its obligations under this Agreement, and such obligations do not and will not conflict with or result in a breach of any of its constituent documents, or any agreement by which or to which it or any of its property is or may become bound or subject;

(iv) it shall provide the General Partner with such evidence regarding its ability to subscribe for Units without having received a prospectus therefor and without registration of such Units under applicable securities legislation as the General Partner may reasonably request;

(v) it is not relying on the experience, creditworthiness or continued involvement of any Person other than the General Partner in entering into this Agreement;

(vi) it is an "accredited investor" within the meaning of the United States *Securities Act of 1933*, as amended, and is acquiring and will hold the Units for its own account for investment purposes and not with a view to any public resale or distribution thereof;

(vii) it has received a copy of this Agreement, all schedules thereto and all other documents to be executed and delivered in connection therewith, and is fully familiar with the contents thereof;

(viii) it has made such investigations of the business carried on or proposed to be carried on by the Partnership as it has considered appropriate, has obtained such information with respect thereto as it has considered necessary, and has been, and will continue to be, solely responsible for making its own independent appraisal and assessment of the merits and risks of entering into this Agreement without relying on any other Person in respect thereof;

(ix) it acknowledges that an investment in the Partnership is speculative and involves a high degree of risk; and

(x) it acknowledges that Units in the Partnership have not been and will not be registered under the United States *Securities Act of 1933*, as amended, or under the securities or "blue sky" laws of any state, that Units may not be transferred except as provided in this Agreement, and that no such transfer may be made unless the Units are registered under the United States *Securities Act of 1933*, as amended, and any applicable state securities or "blue sky" laws or an exemption from such registration is available.

2.7 Survival of Representations, Warranties, Covenants and Agreements

The representations, warranties, covenants and agreements made pursuant to Section 2.6 above shall survive execution of this Agreement and each Partner covenants and agrees to ensure that each representation, warranty, covenant and agreement made pursuant to Section 2.6 remains true so long as such Partner remains a Partner.

2.8 Limitation on Authority of Limited Partners

A Limited Partner in its capacity as a Limited Partner may not:

(a) except for its rights to vote as provided in this Agreement, take part in the administration, control, management or operation of the business of the Partnership or exercise any power in connection therewith or transact business on behalf of the Partnership;

(b) execute any document which binds or purports to bind any other Partner or the Partnership;

(c) hold itself out as having the power or authority to bind any other Partner or the Partnership;

(d) have any authority or power to act for or undertake any obligation or responsibility on behalf of any other Partner or the Partnership;

(e) except as specifically provided for herein, bring any action for partition or sale or otherwise in connection with the Partnership, any interest in any property of the Partnership, whether real or personal, tangible or intangible, or file or register or permit to be filed, registered or remain undischarged any lien or charge in respect of any property of the Partnership; or

(f) except as specifically provided for herein, compel or seek a partition, judicial or otherwise, of any of the assets of the Partnership distributed or to be distributed to the Partners in kind in accordance with this Agreement.

Notwithstanding the foregoing, the General Partner, in respect of its ownership of Units, shall not be subject to the restrictions that otherwise apply to Limited Partners.

2.9 Power of Attorney

Each Limited Partner hereby irrevocably nominates, constitutes and appoints the General Partner, with full power of substitution, as its agent and true and lawful attorney to act on its behalf with full power and authority in its name, place and stead to execute and record or file as and where required:

(a) counterparts of this Agreement and any amendment to this Agreement, made in accordance with the terms of this Agreement, and any other instruments or documents required to continue and keep in good standing the Partnership as a limited partnership under the Act, or otherwise to comply with the laws of any jurisdiction in which the Partnership may carry on business or own or lease property or any jurisdiction where the General Partner considers it prudent to be registered in order to maintain the limited liability of the Limited Partners and to comply with the applicable laws of such jurisdiction (including such amendments to the Register as may be necessary to reflect the admission to the Partnership of subscribers for or transferees of Units as contemplated by this Agreement);

(b) all instruments and any amendments to or renewals, replacements or restatements of the Certificate necessary to reflect any amendment to this Agreement;

(c) any instrument required or desired in connection with the dissolution and termination of the Partnership in accordance with the provisions of this Agreement, including any elections, determinations or designations under the Code and under any similar legislation;

(d) the documents necessary to be filed with the appropriate governmental body or authority in connection with the business, property, assets and undertaking of the Partnership;

(e) such documents as may be necessary to give effect to the business of the Partnership as described in Section 2.2;

(f) the documents on its behalf and in its name as may be necessary to give effect to the sale or assignment of a Unit made in accordance with the terms of this Agreement (including a sale of Units pursuant to Section 4.8 or Schedule G) or to give effect to the admission of a subscriber for or transferee of Units to the Partnership;

(g) any return, election, determination, designation, information return or similar document or instrument as may be required at any time by any government or like authority or under the Code or under any other taxation legislation or regulations of the United States of America or of Canada or of any state, province, territory, county or other jurisdiction which relates to the affairs of the Partnership or the interest of any Person in the Partnership;

(h) without restricting the generality of any of the foregoing, but subject to obtaining the prior approval of the Limited Partners by Extraordinary Resolution, to execute and deliver on such Limited Partner's behalf and in its name or join such Limited Partner as a party to any and all documents and instruments which the General Partner considers necessary to secure or encumber (in accordance with or in conjunction with the powers of the General Partner set forth herein) any interests of whatsoever kind or nature such Limited Partner may have or claim to have in Units or in property or assets of the Partnership (including without limitation such interests as may, following the dissolution or winding up of the Partnership, be acquired, generated or come into existence in respect of the business or operations which at or prior to the time of dissolution or winding up of the Partnership had been carried on by or for the Partnership, whether acquired, generated or brought into existence by means of the activities of a receiver, receiver and manager, trustee in bankruptcy, custodian or similar official of or pertaining to the Partnership or its business or operations or otherwise) and to make covenants, agreements and provisions pertaining thereto in order to obtain financing for the construction and operation of the Facilities, including, without restricting the generality of the foregoing, deeds (including deeds under seal), trust deeds, supplemental trust deeds, agreements, debentures, mortgages, hypothecations and security agreements but without thereby creating any recourse to or claim against any other property or assets of any Limited Partner and without restricting the generality of any of the foregoing, to execute and deliver on such Limited Partner's behalf and in its name, register, file, record or deliver caveats, security notices, financing statements and other notices, and any renewals, amendments or replacements thereof pertaining to any of the foregoing; and

(i) all other instruments and documents on its behalf and in its name or in the name of the Partnership as may be deemed necessary by the General Partner to carry out fully this Agreement in accordance with its terms.

To evidence the foregoing, each Subscription Form and Transfer Form shall contain a power of attorney incorporating by reference, ratifying and confirming some or all of the powers set forth above.

The power of attorney granted herein is irrevocable, is a power coupled with an interest, shall continue despite the mental incompetence of the Limited Partner, shall survive the death or disability of a Limited Partner and shall survive the transfer or assignment by the Limited Partner, to the extent of the obligations of a Limited Partner hereunder, of the whole or any part of the interest of the Limited Partner in the Partnership, extends to the heirs, executors, administrators, other legal representatives and successors, transferees and assigns of the Limited Partner, and may be exercised by the General Partner on behalf of each Limited Partner in executing any instrument by a facsimile signature or by listing all the Limited Partners and executing such instrument with a single signature as attorney and agent for all of them. Each Limited Partner agrees to be bound by any representations or actions made or taken by the General Partner pursuant to this power of attorney and hereby waives any and all defenses which may be available to contest, negate or disaffirm the action of the General Partner taken in good faith under this power of attorney. Each Limited Partner declares that these powers of attorney may be exercised during any legal incapacity or mental infirmity on its, his or her part. The General Partner may require, in connection with the subscription for, or any transfer of, Units, that the Subscription Form or Transfer Form be accompanied by a certificate of legal advice signed by a lawyer who is not the attorney or the attorney's spouse or that the execution of the Subscription Form or Transfer Form be witnessed as required by applicable law.

This power of attorney shall continue in respect of the General Partner so long as it is the General Partner of the Partnership, and shall terminate thereafter, but shall continue in respect of a new General Partner as if the new General Partner were the original attorney.

A transferee of a Unit shall, upon becoming a Limited Partner, be conclusively deemed to have acknowledged and agreed to be bound by the provisions of this Agreement as a Limited Partner and shall be conclusively deemed to have provided the General Partner with the power of attorney described in this Section 2.9.

2.10 Limited Liability of Limited Partners

The liability of each of the Limited Partners to the Partnership under the Act shall be limited to (a) any unpaid capital contributions that such Limited Partner agreed to make to the Partnership pursuant to this Agreement, to the extent provided in Section 17-502(a) and (b) of the Act; (b) the amount of any distribution that such Limited Partner is required to return to the Partnership pursuant to Section 17-607(b) of the Act; and (c) the unpaid balance of any other payments that such Limited Partner expressly is required, pursuant to this Agreement, to make to the Partnership.

2.11 Indemnity of Limited Partners

The General Partner will indemnify and hold harmless each Limited Partner (including former Limited Partners) for all costs, expenses, damages or liabilities suffered or incurred by the Limited Partner if the limited liability of such Limited Partner is lost for or by reason of the negligence or willful misconduct of the General Partner in performing its duties and obligations hereunder.

2.12 Compliance with Laws

Each Limited Partner will, on the request of the General Partner from time to time, immediately execute any documents considered by the General Partner to be necessary to comply with any applicable law or regulation of any jurisdiction, for the continuation, operation or good standing of the Partnership.

2.13 Other Activities of General Partner

The General Partner shall not carry on any business other than its activities as General Partner of the Partnership.

2.14 General Partner May Hold Units

The General Partner may subscribe for and acquire Units or purchase Units by private contract or in the market and shall be shown on the Register as a Limited Partner in respect of the number of Units held by the General Partner from time to time.

2.15 General Partner as a Limited Partner

If the General Partner holds any Units, it shall be deemed in its capacity as the holder of such Units to be a Limited Partner with the same rights and powers as each other Limited Partner.

2.16 Private Issuer Restrictions

(a) The number of Persons who may beneficially own (within the meaning of the *Securities Act* (Alberta)), directly or indirectly, Units of the Partnership (counting two or more joint registered owners as one beneficial owner), is limited to not more than 50, exclusive of Persons: (i) who are in the employment of the Partnership, the General Partner or the employment of an Affiliate of the General Partner; or (ii) who were formerly in the employment of the Partnership, the General Partner or an Affiliate of the General Partner and while in that employment were, and have continued after that employment to be, beneficial owners of Units of the Partnership; and

(b) Any invitation to the public to subscribe for securities of the Partnership, including Units, is prohibited.

2.17 Limitation of Interest

The interest of a Partner in the Partnership consists of the rights of Partners as contained herein. Except as otherwise provided at law in regard to the General Partner, the interest of a Partner in the Partnership does not represent or include an undivided interest or other direct personal interest in the property or assets of the Partnership or the property or assets used or employed in the business or operations of the Partnership except for such interests in such property or assets as may be distributed to Partners as a result of dissolution or winding-up of the Partnership.

2.18 Security Interest

Any security interest, charge, assignment, pledge, mortgage, hypothecation or other encumbrance against or in connection with the property or assets of the Partnership granted or effected by the General Partner in the name of the Partnership or the General Partner or otherwise pursuant to its rights and powers as herein set forth, shall attach to, bind, charge or otherwise encumber all interests in such property or assets (including any interests that any Partner may have or claim to have in such property or assets) and any such security interest, charge, assignment, pledge, mortgage, hypothecation or other encumbrance shall attach to, bind, charge or otherwise encumber all interests in such property or assets (including any interests that any Partner may have or claim to have in such property or assets) notwithstanding or following the dissolution or winding up of the Partnership.

ARTICLE 3
UNITS

3.1 Authorized Units

(a) The Partnership is authorized to issue (i) one class of units, to be designated as "Class A Units", limited to 750,000 in number, (ii) one class of units, to be designated as "Class B Units", limited to 250,000 in number, (iii) one class of units, to be designated as "Class C Units", issuable in series, in an unlimited number, and (iv) the first series of Class C Units, to be limited in number to one Unit, and to be designated as "Class C Unit, Series 1", such units having attached thereto the rights, privileges, restrictions and conditions set forth or contemplated in this Section 3.1.

(b) The Class A Units shall have attached thereto the following rights, privileges, restrictions and conditions: (i) the right to one vote at all meetings of Limited Partners, except meetings at which only holders of a specified class or series of Units are entitled to vote; (ii) those rights to receive distributions made by the Partnership set out in Schedule D; and (iii) those rights to receive the remaining property and assets of the Partnership upon dissolution set out in Schedule D.

(c) The Class B Units shall have attached thereto the following rights, privileges, restrictions and conditions: (i) the right to one vote at all meetings of Limited Partners, except meetings at which only holders of a specified class or series of

Units are entitled to vote; (ii) those rights to receive distributions made by the Partnership set out in Schedule E; and (iii) those rights to receive the remaining property and assets of the Partnership upon dissolution set out in Schedule E.

(d) Subject to complying with the terms of this Agreement, specifically including without limitation Section 9.17, the Class C Units shall have attached thereto the following rights, privileges, restrictions and conditions: (i) the Class C Units may at any time and from time to time be issued in one or more series, each series to consist of such number of units as may, before the issue thereof, be determined hereunder or by the General Partner; (ii) subject to the provisions of the Act, the General Partner may fix from time to time before the issue thereof the designation, rights, privileges, restrictions and conditions attaching to each series of the Class C Units; and (iii) the class provisions attaching to the Class C Units may be amended only with the prior approval of the holders of the Class C Units by Extraordinary Resolution. Upon the designation by the General Partner of the rights, privileges, restrictions and conditions of any series of Class C Units, the General Partner shall file an amendment to the Certificate in accordance with Section 3.14 evidencing such designation and setting out such rights, privileges, restrictions and conditions.

(e) The Class C Unit, Series 1 shall, in addition to the rights, privileges, restrictions and conditions attached the Class C Units as a class, have attached thereto the rights, privileges, restrictions and conditions set out in Schedule F.

3.2 Terms of Offering(s)

Subject to complying with the terms of this Agreement specifically including without limitation Section 9.17, the General Partner may, in its discretion, determine the terms and conditions of the offering and sale of Units or rights to acquire Units from time to time and may do all things in that regard including, without limitation, preparing and filing prospectuses, offering memoranda, private placement documents and other offering or sale documents, issuing the Units, paying the expenses of issue and entering into agreements with any Person providing for a commission or fee.

3.3 Subscription for Units

Subscriptions for Units may be made for a fraction of a Unit, such fraction being expressed to a maximum of four decimal points. Each subscribing Person (who may be underwriters who have agreed to underwrite the offering) shall, unless the General Partner otherwise agrees, complete and execute the applicable Subscription Form setting forth, among other things, the total subscription price agreed to be contributed by such Person.

3.4 Admittance as Limited Partner

Upon acceptance by the General Partner of any subscription for Units, all Partners will be deemed to consent to the admission of the subscriber as a Limited Partner, the General Partner will execute this Agreement on behalf of the subscriber and will cause the Register and the Certificate to be amended, and such other documents as may be required by the Act or under legislation similar to the Act in other states or counties to be filed or amended, specifying the prescribed information and will cause the foregoing information in respect of the new Limited Partner to be included in Partnership books and records.

3.5 Payment of Expenses

The Partnership will pay, to the extent contemplated by any prospectus or other offering document, all costs, disbursements and other fees and expenses incurred in connection with the offering of Units or rights to acquire Units pursuant to such prospectus or other offering document, the organization of the Partnership and the registration of the Partnership under the Act and under similar legislation of other jurisdictions.

3.6 Effective Date

The rights and obligations of a subscriber for, or a transferee of, Units, as a Limited Partner under this Agreement, commence and are enforceable by and upon the Limited Partner as between the Limited Partner and the other Partners from the date on which the Register has been amended; a subscriber or a transferee will not become a Limited Partner until the Register is amended.

3.7 Register of Limited Partners

The General Partner shall maintain at its principal office a Register listing all names and addresses of Limited Partners and the number of Units held by them.

3.8 Changes in Membership of Partnership

Subject to Section 3.15, no change of name or address of a Limited Partner, no transfer of a Unit and no admission of a substituted Limited Partner in the Partnership shall be effective for the purposes of this Agreement until all reasonable requirements as determined by the General Partner with respect thereto have been met, including the requirements set out in this Article, and until such change, transfer, substitution or addition is duly reflected in an amendment to the Register as may be required by the Act. The names and addresses of the Limited Partners as reflected from time to time in the Register, as from time to time amended, shall be conclusive as to such facts for all purposes of the Partnership.

3.9 Notice of Change of Name or Address of Limited Partner

No name or address of a Limited Partner shall be changed and no transfer of a Unit or substitution or addition of a Limited Partner in the Partnership shall be recorded on the Register, except pursuant to a notice in writing received by the General Partner.

3.10 Inspection of Register

A Limited Partner, or an agent of a Limited Partner duly authorized in writing, has the right, upon not less than 10 days' notice in writing to the General Partner, to inspect and make copies from the Register at the cost of the Limited Partner during normal business hours.

3.11 Transfer of Units

(a) Notwithstanding anything else herein contained, except as otherwise provided herein or in Schedule G, no Project Interest or any component thereof (Units or L.L.C. Interests of the General Partner) or any rights in respect thereof shall at any time be transferred, sold, assigned, mortgaged, pledged, encumbered, hypothecated, made subject to any security interest, be declared to be held in trust or otherwise dealt with (any such action, declaration or dealing shall herein be referred to by the terms **"Sale"**, **"Sell"** or **"Sold"**) by a Limited Partner or by any means become the property of or become subject to a property interest of another Person and any such prohibited act or actions if occurring in contravention of this Agreement shall be void as between or among the Partners and the Partnership, the L.L.C. Interest holders of the General Partner and the General Partner and as between or among any Partner or the Partnership and as between and among any L.L.C. Interest holder of the General Partner and the General Partner and any Person claiming any interest in any Project Interest or any component thereof (Units or L.L.C. Interests of the General Partner) as a result of such act or actions. Limited Partners may however convey or assign the proceeds of any distributions which may be received in respect of the Units under arrangements which, except as otherwise provided herein, convey no security or other interests or rights in respect of the Units as such.

(b) Subject to the provisions of Section 2.6(b), this Article 3 and Schedule G, and compliance with applicable securities laws and the payment by the transferee of an administration fee, if any, of up to $100, Units may be transferred by a Limited Partner or its agent duly authorized in writing to any Person, but such Person shall not be recorded on the Register as the holder of Units nor, if such Person is not a Limited Partner, be entitled to become a Limited Partner, unless such Person has delivered to the General Partner a Transfer Form completed and executed in a manner reasonably acceptable to the General Partner.

(c) The General Partner has the right to deny the transfer of Units in respect of which there has been default hereunder including, without limitation, a default in payment of the subscription price until all amounts required to be paid on account of the subscription price, including any interest thereon, have been paid in full. Subject to Section 3.15, no transferee will become a Limited Partner until all filings and recordings required by the Act and this Agreement have been duly made. Where the transferee complies with the provisions aforesaid and is entitled to become a Limited Partner pursuant to the provisions hereof, subject to Section 3.8 and Schedule G, the General Partner shall be authorized to admit the transferee to the Partnership as a Limited Partner and the Limited Partners hereby consent to the admission of, and will admit, the transferee to the Partnership as a Limited Partner, without further act of the Limited Partners (other than as may be required by law).

3.12 Transfer Form

The Transfer Form shall be in the form of Schedule C or such other form approved by the General Partner and shall be signed by the transferor and by the transferee and shall be accompanied by the Unit Certificate(s), if any, issued by the Partnership representing the Units to be transferred.

3.13 Additional Documentation on Transfer

If a transferor of Units is a firm or a corporation, or purports to assign such Units in any representative capacity, or if an assignment results from the death, mental incapacity or bankruptcy of a Limited Partner or is otherwise involuntary, the transferor or its legal representative shall furnish to the General Partner such documents, certificates, assurances, court orders and other instruments as the General Partner, as applicable, may reasonably require to effect the said transfer and assignment.

3.14 Amendment of Certificate and Register

The General Partner, on behalf of the Partnership, shall from time to time promptly effect filings, recordings, registrations and amendments to the Register and the Certificate and to such other documents and at such places as in the opinion of counsel to the Partnership are necessary or advisable to reflect changes in the membership of the Partnership, transfers of Units, the creation of Class C Units and dissolution of the Partnership as herein provided and to constitute a transferee as a Limited Partner.

3.15 Non-Recognition of Trusts or Beneficial Interests

Except as provided herein, as required by law or as recognized by the General Partner in its sole discretion, no Person will be recognized by the Partnership or a Limited Partner as holding any Unit in trust, or on behalf of another Person beneficially entitled thereto, and the Partnership and Limited Partners will not be bound or compelled in any way to recognize (even when having actual notice) any equitable, contingent, future or partial interest in any Unit or any other rights in respect of any Unit except an absolute right to the entirety of the Unit in the Limited Partner shown on the Certificate as holder of such Unit.

3.16 Incapacity, Death, Insolvency or Bankruptcy

Where a Person becomes entitled to Units on the incapacity, death, insolvency, or bankruptcy of a Limited Partner, or otherwise by operation of law, in addition to the requirements of Section 2.6(b), this Article 3 and Schedule G such entitlement will not be recognized or entered into the Register until such Person:

(a) has produced evidence satisfactory to the General Partner of such entitlement;

(b) has agreed in writing to be bound by the terms of this Agreement and to assume the obligations of a Limited Partner under this Agreement; and

(c) has delivered such other evidence, approvals and consents in respect to such entitlement as the General Partner may require and as may be required by law or by this Agreement.

3.17 Transfers of Fractional Units

Subject to the terms and conditions hereof, transfers of a fraction of a Unit may be made and will be recognized or entered into the Register.

3.18 No Transfer upon Dissolution

No transfer of Units may be made or will be recognized or entered into the Register after the filing of the notice of dissolution prescribed by the Act pursuant to Section 11.4(e).

3.19 Unit Certificates

The General Partner shall issue to each Limited Partner, upon request, one or more Unit Certificates indicating that the holder thereof is the owner of the number of Units set out thereon. Every Unit Certificate must be signed (personally or by mechanical reproduction) by at least one officer or director of the General Partner, and the validity of a Unit Certificate will not be affected by the circumstance that a person whose signature is so reproduced is deceased or no longer holds the office which he or she held when the reproduction of his or her signature in that office was authorized. A Unit Certificate may be sent through the mail by registered prepaid mail or delivered to a dealer acting on behalf of the Limited Partner and neither the General Partner nor the Partnership will be liable for any loss by a Limited Partner that results from the loss of a Unit Certificate by reason that it is so sent. If any Unit Certificate is lost, mutilated, stolen or destroyed, the General Partner shall, upon request by a Limited Partner, issue a replacement Unit Certificate to the Limited Partner upon receipt of evidence satisfactory to the General Partner of such loss, mutilation or destruction, and upon receiving such indemnification (including an indemnity bond provided at the expense of the Limited Partner) as it deems appropriate in the circumstances. The General Partner upon request by the transferee shall issue a new Unit Certificate for any Units transferred. In the case of a transfer of less than all of the Units represented by a Unit Certificate, the General Partner, upon request by the transferor, shall issue a new Unit Certificate for the balance of the Units retained by the transferor.

ARTICLE 4
CAPITAL CONTRIBUTIONS AND ACCOUNTS

4.1 Capital

The capital of the Partnership consists of the aggregate of all sums of money, other property or services contributed by the Partners as Capital Contributions and not withdrawn or returned to them.

4.2 General Partner Contribution

The General Partner has contributed the sum of $1.00 as a Capital Contribution to the Partnership in exchange for one Class C Unit, Series 1. The General Partner shall not transfer any Units held by it to any Person other than a new General Partner pursuant to Section 7.19.

4.3 Limited Partner Contributions

(a) Initially, the Limited Partners have contributed the following by way of Capital Contribution to the Partnership in consideration for the Units listed below:

Limited Partner	Initial Capital Contribution	No. of Units
Jordan Cove Energy Project L.L.C	$1.00	1 Class C Unit, Series 1
Fort Chicago	$75.00	750,000 Class A Units
Energy Projects	(See Section 4.3(d))	250,000 Class B Units

(b) Subject to the terms and conditions set out in Schedule H and subject to Section 4.3(c), Fort Chicago agrees to make those additional capital contributions contemplated in Schedule H and such additional contributions shall not result in the issuance of further Units over and above those contemplated above.

(c) Notwithstanding Section 4.3(b) and Schedule H, but subject to the further provisions of this Section 4.3, Fort Chicago may, in its discretion, elect by notice in writing to the General Partner to substitute for all or any part of the Capital Contributions contemplated in Schedule H, one or more loans to the Partnership. Such loans shall:

(i) have principal and interest payments which are equivalent to the Class A Unit Preferred Distribution which would have been applicable to the substituted Capital Contribution;

(ii) be secured by such security for the outstanding amount as Fort Chicago may reasonably request subject to the requirements of third party lenders and the requirements of any ratings agency for the loans to be considered as equity for ratings purposes. No such security may have the effect of changing the relative priority of the Class A Units and Class B Units assuming such loans had been Capital Contributions for Class A Units;

(iii) be subordinated to all commercial debt of the Partnership under such terms as required by third party lenders and as required by any ratings agency to be considered as equity for ratings purposes; and

(iv) have such additional terms and conditions as may be agreed by Fort Chicago and Energy Projects, acting reasonably.

(d) In return for the 250,000 Class B Units to be issued to Energy Projects, Energy Projects shall contribute to the Partnership those assets and rights contemplated in the Contribution Agreement including, without limitation, all existing right, title and interest of Energy Projects in and to the Jordan Cove Energy Project, the concept thereof, the option and other rights to real property acquired for the Jordan Cove Energy Project and all intellectual property and other rights and interests associated with the Jordan Cove Energy Project.

(e) After making the Capital Contributions described in Sections 4.3(a) and (d), the capital account of the holder of the Class A Units shall be US $75 and the capital account of the holder of the Class B Units shall be US $250,000.

4.4 Capital Contributions

(a) In addition to the Capital Contributions contemplated in Section 4.3 and those contemplated in Schedule H, Capital Contributions to the Partnership may be made by the Limited Partners from time to time as may be determined by the General Partner and agreed to by the contributing Limited Partner. Capital Contributions may be made, but are not required to be made, in respect of a subscription for Units or right to acquire Units. The capital contribution of each Limited Partner is the total amount of money or property paid or value of services provided by such Limited Partner or a predecessor Partner to the Partnership in respect of Units or rights to acquire Units held by such Limited Partner.

(b) It is the intention of the parties that future capital requirements of the Partnership beyond those contemplated in Section 4.3 and those contemplated in Schedule H be satisfied from cash flow and/or normal commercial lending arrangements without resort to the Partners. In the event that the General Partner, in accordance with the Limited Liability Company Agreement, determines that the Partnership requires capital over and above that contemplated in the previous sentence either by way of additional Capital Contribution or loan, the Limited Partners will have the option, without obligation, to make such advances pro rata to their holdings of voting Units in return for, in the case of Capital Contributions, Class C Units issued by the Partnership to the contributing Limited Partners in a series and with terms determined by the General Partner as provided in this Agreement.

4.5 Separate Capital Accounts

The General Partner will maintain a separate capital account for each Partner and will, on receipt of an amount in respect of a Capital Contribution, credit the account of the applicable Partner with such Capital Contribution and will debit the account with the amount of any Capital Contribution actually returned from time to time by the Partnership to the Partner.

The interest of a Partner will not terminate by reason of there being a negative or nil balance in the Partner's capital account. No Limited Partner shall be responsible for any losses of any other Limited Partner, nor share in the allocation of income or loss attributable to the Units of any other Limited Partner.

If any Limited Partner shall have a deficit balance in its capital account, such Limited Partner shall have no obligation to make any contribution to the capital of the Partnership with respect to such deficit, and such deficit shall not be considered a debt owed to the Partnership or any other person or entity for any purpose whatsoever, provided however, a Limited Partner, in its sole discretion, may agree at any time to make a contribution to the Partnership up to the amount of any such deficit.

4.6 No Interest on Capital Account

Except as otherwise provided herein, the Partnership will not pay interest on any credit balance of the capital account or Capital Contribution of a Partner. Except as provided in this Agreement or the Act or similar applicable legislation in the United States of America, no Limited Partner is required to pay interest to the Partnership on any Capital Contribution returned to the Limited Partner or on any negative balance in its capital account.

4.7 Unpaid Capital Contributions and Loans Not Advanced

If any portion of a Capital Contribution by way of Unit subscription or requested in accordance with Section 4.4(b) and agreed to be made by the Limited Partner or loan advance requested in accordance with Section 4.4 (b) and agreed to be made by the Limited Partner is unpaid when due and owing, the General Partner will give 15 days' notice or such other notice as required by applicable law to the applicable Unitholder to pay such amount as remains unpaid on account of the Capital Contribution or loan advance and if such amount is not paid within such notice period, the unpaid portion of the Capital Contribution or loan advance (and in respect of all other unpaid Capital Contributions and loan advances) will be immediately due and owing and the General Partner may commence foreclosure proceedings in compliance with applicable laws in respect of the Units registered in the name of the holder or the General Partner may sell such Units in accordance with this Article 4 and applicable laws. Notwithstanding Article 10 hereof, notice given under this Section 4.7 shall be given by registered mail and shall be deemed to be received and shall be effective on the third business day following deposit of such notice in the mail.

4.8 Sale of Units

Subject to compliance with applicable laws, the General Partner may, on behalf of the Partnership, sell on such terms and conditions as the General Partner deems appropriate, any Units of a Unitholder which is in default in the payment of Capital Contributions or loan advances as aforesaid and in respect of which 15 days have elapsed since such payment was first due and apply the proceeds of sale:

(a) first, toward the costs of sale (including commissions, if any);

(b) second, toward payment of interest on the unpaid portion of the Capital Contribution or loan advance; and

(c) third, toward payment of the unpaid portion of the Capital Contribution or loan advance.

Any surplus will be payable to the Limited Partner.

4.9 Failure to Give Notice

Any failure to give, or delay in giving, notice of default to the Unitholder will not affect the liability of such holder for payment of the Capital Contribution or loan advance as aforesaid in default.

4.10 Restriction on Transfer

If a holder of a Unit is in default in payment of a Capital Contribution or loan advance as aforesaid or is otherwise in default hereunder, the Units registered in the name of such holder may not thereafter be transferred by such holder (except pursuant to Sections 4.7 and 4.8 or Articles 5, 6, 7 or 8 of Schedule G) until the portion of the Capital Contribution which is due and owing and any interest accrued in respect thereof has been paid in full.

4.11 Interest on Capital Contribution or Loan Advance in Default

A Limited Partner liable for a Capital Contribution or loan advance as contemplated in Section 4.4, which is not paid when due and owing is liable in addition to pay interest on so much of the Capital Contribution or loan advance as from time to time remains unpaid, accruing from the due date to the date of payment at an annual rate of interest (the "**Interest Rate**") equal to the rate announced from time to time by the Partnership's principal banker as its reference rate for determining the interest rates charged by it on the United States of America dollar commercial loans to its most creditworthy customers prevailing from time to time (the "**Reference Rate**") while the amount is unpaid, plus 6%, calculated and compounded monthly. All payments on account of a Capital Contribution or loan advance which is due and owing or interest thereon, however directed, will be applied first towards the costs of the General Partner in collecting such amounts or selling the Units, secondly towards interest and thirdly towards satisfaction of the unpaid portion of the Capital Contribution or loan advance. If the Partnership does not have a principal bank, it shall be deemed to be Citibank, New York.

4.12 Set-Off

The Partnership may set-off against and withhold from any amount that would otherwise be distributed to a Limited Partner, any amount that may be due and owing to the Partnership on account of any unpaid portion of a Capital Contribution or loan advance as aforesaid of such Limited Partner and interest accrued thereon.

4.13 Liability for Deficiency

The sale of a Unit pursuant to Section 4.8 and the application of the proceeds as therein provided will not, if a deficiency remains after the sale, extinguish the liability of the former Limited Partner for any amount that may remain unsatisfied or for the interest which will continue to accrue thereon.

4.14 L.L.C. Interests

In the event of a Sale of Units pursuant to this Article 4, such Sale shall include the sale of a pro rata number of the selling parties' L.L.C. Interests at a nominal price of $1.00 for each one percent of L.L.C. Interest.

ARTICLE 5
PARTICIPATION IN PROFITS AND LOSSES

5.1 Allocation of Net Income and Losses for Accounting Purposes

The net income or loss for accounting purposes for a given Fiscal Year of the Partnership will be allocated to each Limited Partner in the same proportion as net income or loss is allocated for tax purposes to each Limited Partner as provided in Sections 5.2 and 5.3.

All income allocated to a Limited Partner will be added to the capital account maintained for the Limited Partner and any losses allocated to the Limited Partner or any amounts distributed to the Limited Partner will be deducted from such capital account.

5.2 Allocation of Net Losses for Tax Purposes

The net loss for tax purposes of the Partnership for any given Fiscal Year and all other items of loss or deductions of the Partnership which may be allocated to partners of a partnership for tax purposes shall be allocated in the following order:

(a) First, to the holders of Class A Units in proportion to their respective cash Capital Contributions until the holders of Class A Units have received aggregate allocations of loss and deductions under this Section 5.2(a) equal to their aggregate cash Capital Contributions.

(b) Second, to the holders of Class A Units in proportion to their respective Class A Units until such holders have received aggregate allocations of loss and deductions under this Section 5.2(b) equal to their aggregate Class A Unit Preferred Returns received by such Limited Partners under Section 2.1(a) of Schedule D.

(c) Third, to the holders of Class B Units in proportion to their respective Capital Contribution amount under Section 4.3 of $250,000 and any cash Capital Contributions that the holders of Class B Units may make to the Partnership until the holders of Class B Units have received aggregate allocations of loss and deductions under this Section 5.2(c) equal to their aggregate Capital Contributions.

(d) Fourth, to the holders of Class B Units in proportion to their respective Class B Units until such holders have received aggregate allocations of loss and deductions under this Section 5.2(d) equal to their aggregate Class B Unit

Preferred Distributions received by such Limited Partners under Section 2.1(a) of Schedule E.

(e) Fifth, seventy-five percent (75%) to the holders of Class A Units and twenty-five percent (25%) to the holders of Class B Units.

5.3 Allocation of Net Income for Tax Purposes

The net income for tax purposes of the Partnership for any given Fiscal Year shall be allocated on an annual basis to each Limited Partner that holds Units that are entitled to receive distributions from the Partnership at the end of each such Fiscal Year in the following order:

(a) First, to the holders of Class A Units and Class B Units in proportion to the Class A Unit Preferred Returns received by the holders of Class A Units and the Class B Unit Preferred Distributions received by the holders of Class B Units until the holders of Class A Units have received aggregate allocations of income under this Section 5.3(a) equal to the aggregate Class A Unit Preferred Returns received under Section 2.1(a) of Schedule D and the holders of Class B Units have received aggregate allocations of income under this Section 5.3(a) equal to the aggregate Class B Unit Preferred Distributions received under Section 2.1(a) of Schedule E.

(b) Second, seventy-five percent (75%) to the holders of Class A Units and twenty-five percent (25%) to the holders of Class B Units until such holders have received aggregate allocations of income under this Section 5.3(b) equal to the aggregate excess distributions made to such Limited Partners under Section 2.1(b) of Schedule D and Section 2.1(b) of Schedule E, respectively.

(c) Third, to the holders of the Class A Units and Class B Units based on the amount of losses and other deductions allocated to such holders under Section 5.2 up to the amount of losses and deductions allocated to such holders under Section 5.2.

(d) Fourth, seventy-five percent (75%) to the holders of Class A Units and twenty-five percent (25%) to the holders of Class B Units.

5.4 Tax Distributions and Distributable Cash

(a) If and to the extent that the Partnership expects to report or does report to Unitholders items of income or gain on Form K-1 with respect to their Units in connection with the Partnership's US partnership return on Form 1065 for any Fiscal Year in excess of items of deduction or loss, without regard to the source thereof, minimum distributions (the "Tax Distributions") shall be made to the Unitholders in an amount equal to the amount of federal and state income tax that would be payable by an individual with respect to such net taxable income or gain (based on the highest combined federal and state marginal income tax rate then applicable to any individual in the United States, regardless of the actual tax rate applicable to a Unitholder to whom said net income or gain is allocated). The amount of such distributions shall be based upon the amount of net taxable income and gain allocated to the holders of Class A Units, Class B Units and the Class C Unit, and shall be distributed within each class in proportion to the number of Units of that class held by each Unitholder relative to the total number of Units of that class outstanding. The Tax Distributions required by this Section 5.4(a) shall be made by wire transfer not later than the first due date, without regard to extensions, on which a federal income tax return reflecting such income would be required to be filed. Tax Distributions also shall be made earlier on those dates upon which federal estimated tax payments are required for individuals (such distributions for federal estimated tax payments to be based upon reasonable estimates). Any Tax Distributions to a Unitholder pursuant to this Section 5.4(a) shall be taken into account and be a part of the distributions the Unitholder is entitled to receive pursuant to Schedules D, E, and F. Any federal, state or local income tax withholding shall be treated as a Tax Distribution to the Unitholder for whose benefit the withholding has been made.

(b) In respect of each Fiscal Year, the General Partner shall distribute to Limited Partners included in the Register on the last day of the applicable Fiscal Year that hold Units that are entitled to receive distributions of Distributable Cash from the Partnership, in accordance with the respective rights of such Units, the Distributable Cash determined in respect of that Fiscal Year. Such Distributable Cash will only be distributed to the extent that the Partnership has cash available for such payment. The payment date for Distributable Cash to be distributed in respect of a Fiscal Year shall be determined by the General Partner provided that such payment date shall not be later than 60 days after the end of such Fiscal Year.

5.5 Monthly or Quarterly Distributions and Allocations

The General Partner may, in its sole discretion, choose to make distributions of Distributable Cash on a monthly or quarterly basis based on the Distributable Cash determined in respect of each calendar month or quarter. In the event that the General Partner chooses to make distributions on a monthly or quarterly basis, the provisions of this Agreement (including the provisions of this Article 5) shall be deemed to be amended so that any references to distributions of Distributable Cash and allocations of income or loss or other amounts being made on an annual basis shall become references to distributions and allocations on a monthly or quarterly basis, as the case may be.

5.6 Repayments

If, as determined by the General Partner, it appears that any Limited Partner has received an amount under this Article 5 which is in excess of that Partner's entitlement, the Limited Partner will, forthwith upon notice from the General Partner, reimburse the Partnership to the extent of the excess, and failing immediate reimbursement, the General Partner may withhold the amount of the excess (with interest at the Interest Rate from time to time calculated and compounded monthly) from further distributions otherwise due the Limited Partner.

5.7 Allocation When Transfers Occur

If any Unit is transferred during any Fiscal Year in compliance with the provisions of this Agreement, net income, net losses, each item thereof and all other items attributable to such interest for such Fiscal Year for accounting and U.S. tax purposes shall be divided and allocated between the transferor Partner and the transferee Partner by taking into account their varying interests during the Fiscal Year in accordance with Section 706(d) of the Code, based on the portion of the year for which the transferor Partner and the transferee Partner were Partners in respect of the Units so transferred.

5.8 Permitted Amendments Pursuant to United States Treasury Regulations

The Partners intend that the allocation provisions set forth in this Article 5 have economic effect equivalence as described in Regulation Section 1.704-1(b)(2)(ii)(i). Notwithstanding the prior sentence, upon the written request of Fort Chicago, this Agreement shall be amended for United States federal and state income tax purposes only to include and comply with: (1) the alternate test for economic effect set forth in Regulation Section 1.704-1(b)(2)(ii)(d), (2) the rules set forth in Regulation Section 1.704-2 and (3) related provisions (the "**Section 704(b) Amendments**"). The Section 704(b) Amendments shall, to the maximum extent permitted under Code Section 704(b), provide for allocations of profits, gains, expenses, losses, deductions and other items and for distributions in a manner consistent with the allocations of such items and distributions under this Article 5. The Section 704(b) Amendments shall include, but not be limited to: (a) the alternate test for economic effect under Regulation Section 1.704-1(b)(2)(ii)(d) (including a "qualified income offset" provision, a provision prohibiting allocations to a partner that would cause or increase a deficit balance in such partner's capital account and a provision that upon liquidation of the partnership, distributions shall be made in accordance with the positive capital accounts of the partners), (b) the requirements of Regulation Section 1.704-2 (including a minimum gain chargeback and partner nonrecourse debt minimum gain chargeback), (c) provisions allocating depreciation deductions, nonrecourse deductions and excess nonrecourse liabilities in a manner consistent with the allocations set forth in this Article 5, and taking into account each of such allocation provisions in the order and priority set forth in this Article 5, (d) the provisions of Regulation Sections 1.704-1(b)(2)(iv)(f) and (g) relating to the revaluation of assets and other adjustments, and (e) a corrective allocation provision requiring that if any reallocation of losses or deductions among the Partners under the alternate economic effect test or other regulatory provisions under Code Section 704(b) is made, subsequent allocations of income and gain shall be made as necessary to offset such reallocation of losses or deductions. Notwithstanding anything else herein contained, the General Partner shall have full power and authority to amend this Agreement as contemplated by this Section 5.8, without the approval of the Limited Partners, and to execute, swear to, acknowledge, deliver, file and record whatever documents which may be required in connection therewith to implement the Section 704(b) Amendments, provided, however, that the holders of the Class A Units or the holders of the Class B Units may require that the Partnership retain a law firm reasonably acceptable to the holders of the Class A Units and the holders of the Class B Units to assist the General Partner in preparing the Section 704(b) Amendments so that such amendments correspond, as nearly as possible under Code Section 704(b), with Article 5 as if this Section 5.8 were not part of this Agreement. Such law firm shall be entitled to engage an independent accounting firm in the event that its determinations include accounting questions. If any holder of Class A Units or Class B Units raises any concerns regarding the Section 704(b) Amendment, such law firms' determination shall be binding on the parties hereto. The fees and expenses of the law firm and any accounting firm engaged shall be for the account of the Partnership.

ARTICLE 6
WITHDRAWAL OF CAPITAL CONTRIBUTIONS

6.1 Withdrawal

No Limited Partner has the right to withdraw any of its Capital Contributions or other amount or to receive any cash or other distribution from the Partnership except as provided for in this Agreement and except as permitted by law.

ARTICLE 7
POWERS, DUTIES AND OBLIGATIONS OF GENERAL PARTNER

7.1 Powers, Duties and Obligations

(a) The General Partner has:

(i) unlimited liability for the debts, liabilities and obligations of the Partnership;

(ii) subject to the terms of this Agreement, and to any applicable limitations set forth in the Act and applicable similar legislation, the full and exclusive right, power and authority to manage, control, administer and operate the business and affairs and to make decisions regarding the undertaking and business of the Partnership; and

(iii) the full and exclusive right, power and authority to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document necessary for or incidental to carrying out the business of the Partnership.

An action taken by the General Partner on behalf of the Partnership is deemed to be the act of the Partnership and binds the Partnership.

(b) Notwithstanding any other agreement the Partnership or the General Partner may enter into, all material transactions or agreements entered into by the Partnership must be approved by the board of directors of the General Partner in accordance with the Limited Liability Company Agreement.

7.2 Specific Powers and Duties

Subject to the terms of this Agreement, and without limiting the generality of Section 7.1, the General Partner will have full power and authority for and on behalf of and in the name of the Partnership to:

(a) negotiate, execute and perform all agreements which require execution by or on behalf of the Partnership involving matters or transactions with respect to the Partnership's activities (and such agreements may limit the liability of the Partnership to the assets of the Partnership, with the other party to have no recourse to the assets of the General Partner, even if the same results in the terms of the agreement being less favourable to the Partnership);

(b) open and manage bank accounts in the name of the Partnership and lend funds of the Partnership to any Person on such terms as the General Partner considers appropriate and otherwise spend the capital of the Partnership in the exercise of any right or power exercisable by the General Partner hereunder;

(c) borrow funds or otherwise obtain credit in the name of the Partnership from time to time, including providing in the name of the Partnership from time to time guarantees, indemnities, credit support or other forms of financial assistance in respect of the indebtedness, liabilities or obligations of the Partnership;

(d) mortgage, charge, assign, hypothecate, pledge or otherwise create a security interest in all or any property of the Partnership now owned or hereafter acquired, to secure any present and future indebtedness, liabilities or obligations and related expenses of the Partnership including, without limitation, any guarantees, indemnities, credit support or other forms of financial assistance provided to or for the benefit of any Person in respect of the indebtedness, liabilities or obligations of the Partnership;

(e) see to the sound management of the Partnership, and to manage, control and develop all the activities of the Partnership and take all measures necessary or appropriate for the business of the Partnership or ancillary thereto;

(f) acquire securities of entities engaged primarily in activities which are permitted activities for the Partnership as provided in Section 2.2;

(g) maintain, improve, expand, extend, upgrade or change the assets of the Partnership from time to time subject to the limitations provided under Section 2.2;

(h) incur all costs and expenses in connection with the Partnership;

(i) employ, retain, engage or dismiss from employment, personnel, agents, representatives or professionals with the powers and duties upon the terms and for the compensation as in the discretion of the General Partner may be necessary or advisable in the carrying on of the activities of the Partnership;

(j) engage agents or subcontract administrative functions to assist the General Partner in carrying out its management obligations to the Partnership including, without limitation: (i) designate one or more operators from time to time to manage the design, development, construction, operation, maintenance and/or administration of the Facilities; and (ii) the entering into of the Operating Agreement;

(k) invest cash assets of the Partnership that are not immediately required for the activities of the Partnership in investments which the General Partner considers appropriate;

(l) act as attorney in fact or agent of the Partnership in disbursing and collecting moneys for the Partnership, paying debts and fulfilling the liabilities and obligations of the Partnership and handling and settling any claims of the Partnership;

(m) commence or defend any action or proceeding in connection with the Partnership;

(n) file any return, election, determination, designation, information return or similar document or instrument as may be required at any time by any government or like authority or under the Code or under any other taxation legislation or regulations of the United States of America or of Canada or of any state, province, territory, county or other jurisdiction which relates to the affairs of the Partnership or the interest of any Person in the Partnership;

(o) retain legal counsel, experts, advisors or consultants as the General Partner considers appropriate and rely upon the advice of such Persons;

(p) do anything that is in furtherance of or incidental to the activities of the Partnership or that is provided for in this Agreement;

(q) execute, acknowledge and deliver the documents necessary to effectuate any or all of the foregoing or otherwise in connection with the activities of the Partnership;

(r) obtain any insurance coverage;

(s) appoint a registrar and transfer agent, if necessary;

(t) acquire or, subject to Section 9.17(i), dispose of the assets of the Partnership;

(u) after the Commercial Operations Date and subject to Section 9.17(g), designate one or more series of Class C Units as contemplated in Section 3.1, issue further Class C Units and determine the terms and conditions of the offering of Units from time to time and to do all things in this regard in accordance with Section 3.2, provided that no Class C Units may be issued which have the effect of altering the relative economic and legal positions of either of Fort Chicago, as the Class A Unitholder, or Energy Projects, as the Class B Unitholder, to the other as they exist at the time immediately prior to such issuance without the prior written consent of the party whose relative position would be affected; and

(v) generally carry out the objects, purposes and business of the Partnership.

No Persons dealing with the Partnership will be required to enquire into the authority of the General Partner to do any act, take any proceeding, make any decision or execute and deliver any instrument, deed, agreement or document for or on behalf of or in the name of the Partnership.

7.3 Loans from General Partner

The General Partner or its Affiliates may advance or loan to the Partnership funds which may be necessary for the payment of operating expenses of the Partnership. The rate of interest and any other expenses relative to such advances or borrowings shall not exceed that which the Partnership could reasonably expect to obtain from a United States of America chartered bank with respect to similar borrowings.

7.4 Exercise of Duties

The General Partner covenants that it will exercise the powers and discharge its duties under this Agreement honestly, in good faith, and in the best interests of the Partnership, and that it will exercise the degree of care, diligence and skill that a reasonably prudent Person would exercise in comparable circumstances. Furthermore, the General Partner covenants that it will maintain the confidentiality of financial and other information and data which it may obtain through or on behalf of the Partnership, the disclosure of which may adversely affect the interests of the Partnership or a Limited Partner, except to the extent that disclosure is permitted as provided herein, is required by law or is in the best interests of the Partnership.

7.5 Limitation of Liability

The General Partner is not personally liable for the return of any Capital Contribution made by a Limited Partner to the Partnership. Moreover, notwithstanding anything else contained in this Agreement, but subject to Sections 2.11 and 7.10, neither the General Partner nor any Affiliates thereof nor their respective officers, directors, shareholders, employees or agents are liable, responsible for or accountable in damages or otherwise to the Partnership or a Limited Partner for an action taken or failure to act on behalf of the Partnership within the scope of the authority conferred on the General Partner by this Agreement or by law provided the General Partner has acted in good faith, in a manner which the General Partner believed to be in the best interests of the Partnership.

7.6 Indemnity of General Partner

(a) To the fullest extent permitted by law but subject to the limitations expressly provided in this Agreement, each General Partner, any former General Partner (a "**Departing Partner**"), any Person who is or was an Affiliate of the General Partner or any Departing Partner, any Person who is or was an officer, director, employee, partner, agent or trustee of the General Partner or any Departing Partner or any such Affiliate, or any Person who is or was serving at the request of the General Partner or any Departing Partner or any such Affiliate as a director, manager, officer, employee, partner, agent or trustee of another Person (collectively, an "**Indemnitee**") shall be indemnified and held harmless by the Partnership from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including, without limitation, legal fees and expenses), judgments, fines, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as: (i) the General Partner, a Departing Partner or any of their Affiliates; (ii) an officer, director, manager, employee, partner, agent or trustee of the General Partner, any Departing Partner or any of their Affiliates; or (iii) a Person serving at the request of the General Partner, any Departing Partner or any of their Affiliates as a director, manager, officer, employee, agent or trustee of another Person; provided, that in each case the Indemnitee acted in good faith, in a manner which such Indemnitee believed to be in the best interests of the Partnership and, with respect to any criminal proceeding, had no reasonable cause to believe its conduct was unlawful. The foregoing indemnification may indemnify an Indemnitee for negligence. The termination of any action, suit or proceeding by judgment, order, settlement or conviction shall not create a presumption that the Indemnitee acted in a manner contrary to that specified above. Any indemnification pursuant to this Section 7.6 shall be made only out of the assets of the Partnership.

(b) To the fullest extent permitted by law, expenses (including, without limitation, legal fees and expenses) incurred by an Indemnitee in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Partnership prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by the Partnership of an undertaking by or on behalf of the Indemnitee to repay such amount if it shall be determined that the Indemnitee is not entitled to be indemnified as authorized in this Section 7.6.

(c) The indemnification provided by this Section 7.6 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, pursuant to any vote of the Partners, as a matter of law or otherwise, both as to actions in the Indemnitee's capacity as: (i) the General Partner, a Departing Partner or an Affiliate thereof; (ii) an officer, director, manager, employee, partner, agent or trustee of the General Partner, any Departing Partner or an Affiliate thereof; or (iii) a Person serving at the request of the General Partner, any Departing Partner or any of their Affiliates as a director, manager, officer, employee, agent or trustee of another Person, and shall continue as to an Indemnitee who has ceased to serve in such capacity and as to actions in any other capacity.

(d) The Partnership may purchase and maintain (or reimburse the General Partner or its Affiliates for the cost of) insurance, on behalf of the General Partner and such other Persons as the General Partner shall determine, against any liability that may be asserted against or expense that may be incurred by such Person in connection with the Partnership's activities, whether or not the Partnership would have the power to indemnify such Person against such liabilities under the provisions of this Agreement.

7.7 Liability of Indemnitees

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Partnership or the Limited Partners for losses sustained or liabilities incurred as a result of any act or omission if such Indemnitee acted in good faith, in a manner which the Indemnitee believed to be in the best interests of the Partnership.

(b) The General Partner may exercise any of the powers or authority granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through its agents (as contemplated in Section 7.2(j)), and the General Partner shall not be responsible for any misconduct or negligence on the part of any such agent appointed by the General Partner in good faith.

7.8 Resolution of Conflicts of Interest

Unless otherwise expressly provided in this Agreement, whenever a potential conflict of interest exists or arises between the General Partner or any of its Affiliates, on the one hand, and the Partnership or any Limited Partner, on the other hand, any resolution or course of action in respect of such conflict of interest shall be permitted and deemed approved by all Limited Partners, and shall not constitute a breach of this Agreement, or of any standard of care or duty stated or implied by law, if the resolution or course of action is fair and reasonable to the Partnership and such resolution is approved by the board of managers of the General Partner in accordance with the Limited Liability Company Agreement. The General Partner shall be authorized in connection with its resolution of any conflict of interest to consider: (i) the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interests; (ii) any customary or accepted industry practices; (iii) any applicable generally accepted accounting practices or principles; and (iv) such additional factors as the General Partner determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances. Nothing contained in this Agreement, however, is intended to nor shall it be construed to require the General Partner to consider the interests of any Person other than the Partnership. In the absence of bad faith by the General Partner, the resolution, action or terms so made, taken or provided by the General Partner with respect to such matter shall be deemed to be fair and reasonable, shall be deemed to be in, or not opposed to, the best interests of the Partnership, and shall not constitute a breach of this Agreement or a breach of any standard of care or duty imposed herein or stated or implied under the Act or by law.

7.9 Other Matters Concerning the General Partner

(a) The General Partner may rely and shall be protected in acting or refraining from acting upon any resolution, certificate, statement, instrument, opinion, report, notice, request, consent, order, bond, debenture, or other paper or document believed by it to be genuine and to have been signed or presented by the proper party or parties.

(b) The General Partner may consult with legal counsel, accountants, appraisers, management consultants, investment bankers and other consultants and advisers selected by it, and any act taken or omitted in reliance upon the opinion (including, without limitation, an opinion of counsel) of such Persons as to matters that the General Partner reasonably believes to be within such Person's professional or expert competence shall be presumed to have been done or omitted in good faith and in accordance with such opinion.

(c) The General Partner shall have the right, in respect of any of its power, authority or obligations hereunder, to act through any of its duly authorized officers.

7.10 Indemnity of Partnership

Subject to Section 2.11, the General Partner hereby indemnifies and holds harmless the Partnership and each Limited Partner from and against all costs, expenses, damages or liabilities suffered or incurred by the Partnership or such Limited Partners by reason of an act of willful misconduct or gross negligence by the General Partner or of any act or omission not believed by the General Partner in good faith to be within the scope of the authority conferred on the General Partner by this Agreement.

7.11 Restrictions upon the General Partner

The General Partner's power and authority does not extend to any powers, actions or authority not enumerated in Sections 7.1 and 7.2 unless and until an Ordinary Resolution or Extraordinary Resolution (as applicable) is passed by the Partners. Further, the General Partner will not:

(a) commingle the funds of the Partnership with the funds of the General Partner or any of its Affiliates or with the funds of any other Person;

(b) dissolve the affairs of the Partnership except in accordance with the provisions of Article 11 hereof;

(c) except in accordance with this Agreement, effect a sale of all or substantially all of the assets of the Partnership to any Person unless such sale or transfer is to a Subsidiary of the Partnership which, in the opinion of counsel to the Partnership, is or will be classified as a partnership for purposes of the Code; or

(d) withdraw as General Partner except in accordance with the provisions of Section 7.14 hereof.

7.12 Employment of an Affiliate

Subject to Section 9.17(m), the General Partner may employ or retain Affiliates of the General Partner or the Limited Partners on behalf of the Partnership to provide goods or services to the Partnership provided that, if the Partnership is to reimburse the General Partner for the costs and expenses of such goods or services, the costs of such goods or services must be reasonable and competitive with the costs of similar goods and services provided by independent third parties.

7.13 Removal of General Partner

(a) Upon the passing of any resolution of the directors or shareholders of the General Partner requiring or relating to the bankruptcy, dissolution, liquidation or winding-up or the making of any assignment for the benefit of creditors of the General Partner, or upon the appointment of a receiver of the assets and undertaking of the General Partner, or upon filing an answer or other pleading admitting or failing to contest the material allegations of a petition filed in such a proceeding, the General Partner shall cease to be qualified to act as General Partner hereunder and shall be deemed to have been removed thereupon as the General Partner of the Partnership effective upon the appointment of a new general partner and the acceptance of such appointment. A new general partner shall, in such instances, be appointed by the Limited Partners by an Extraordinary Resolution after receipt of written notice of such event (which written notice shall be provided by the General Partner forthwith upon the occurrence of such event).

(b) The General Partner may also be removed if the General Partner has committed a material breach of the Partnership Agreement, which subsists for a period of 60 days after notice, and if such removal is approved by the Limited Partners by an Extraordinary Resolution excluding for this purpose Units held by the General Partner for its own account. Any such action by the Limited Partners for removal of the General Partner under this Section 7.13(b) must also provide for the election and succession of a new general partner. Such removal shall be effective immediately following the admission of the successor general partner to the Partnership.

7.14 Voluntary Withdrawal of General Partner

The General Partner has agreed not to voluntarily withdraw as general partner, provided that the General Partner may withdraw if such withdrawal is approved by an Extraordinary Resolution excluding for this purpose Units held by the General Partner for its own account, after which time the General Partner may withdraw as such by giving 90 days' notice.

7.15 Condition Precedent

As a condition precedent to the resignation or removal of the General Partner, the Partnership shall pay all amounts payable by the Partnership to the General Partner pursuant to this Agreement accrued to the date of resignation or removal subject to any claims or liabilities of the General Partner to the Partnership.

7.16 Transfer to New General Partner

On the admission of a new general partner to the Partnership on the resignation or removal of the General Partner, the resigning or retiring General Partner will do all things and take all steps to transfer the administration, management, control and operation of the business of the Partnership and the books, records and accounts of the Partnership to the new general partner and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

7.17 Transfer of Title to New General Partner

On the resignation or removal of the General Partner and the admission of a new general partner, the resigning or retiring General Partner will, at the cost of the Partnership, transfer title to any of the Partnership's property held in the name of the General Partner to such new general partner and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

7.18 Release by Partnership

On the resignation or removal of the General Partner, the Partnership will release and hold harmless the General Partner resigning or being removed, from any costs, expenses, damages or liabilities suffered or incurred by the General Partner as a result of or arising out of events which occur in relation to the Partnership after such resignation or removal other than any of the General Partner's obligations to the Partnership under Section 7.10.

7.19 New General Partner

A new general partner will become a party to this Agreement by signing a counterpart hereof and will agree to be bound by all of the provisions hereof and to assume the obligations, duties and liabilities of the General Partner hereunder as from the date the new general partner becomes a party to this Agreement. The new general partner, if a corporation or a limited liability company, must qualify to do business in the State of Delaware pursuant to applicable law. The General Partner shall transfer all of the Units owned by it to the new General Partner who must hold, at all times while it is the General Partner of the Partnership, at least one Unit.

7.20 Expenses of the Partnership

The Partnership will reimburse the General Partner for all direct and indirect operating, general and administrative and other costs and expenses incurred by the General Partner on behalf of the Partnership or in the performance of its duties hereunder (all of which costs and expenses shall be the Partnership's responsibility). For greater certainty, such costs and expenses for which the General Partner is to be reimbursed include the Partnership's direct and indirect operating, general and administrative and other costs and expenses, including legal and audit fees, Unitholder information costs, consulting and advisory fees incurred in connection with the Partnership's business or the evaluation of investment opportunities by the Partnership, fees paid to third parties for services rendered to the General Partner or the Partnership, expenses associated with the issuance of Units and costs incurred by the directors of the General Partner in evaluating matters relating to the Partnership. The Partnership will be responsible for the payment of any goods and services tax, if any, with respect to the costs and expenses to be reimbursed by the Partnership pursuant to this Section 7.20.

ARTICLE 8
FINANCIAL INFORMATION

8.1 Books and Records

The General Partner shall keep or cause to be kept at the principal office of the Partnership appropriate books and records with respect to the Partnership's business. Any books and records maintained by or on behalf of the Partnership in the regular course of its business, including, without limitation, books of account and records of Partnership proceedings, may be kept on, or be in the form of, computer disks, hard disks, magnetic tape, or any other information storage device, provided that the books and records so maintained are convertible into clearly legible written form within a reasonable period of time. The books of the Partnership shall be maintained, for financial reporting purposes, on an accrual basis in accordance with generally accepted accounting principles.

8.2 Reports

(a) As soon as practicable, but in no event later than 90 days after the end of each Fiscal Year, the General Partner shall cause to be mailed to each holder of a Unit as indicated on the Register as of a date selected by the General Partner in its sole discretion, an annual report containing audited consolidated financial statements prepared in accordance with generally accepted accounting principles, such statements to be reported upon by the Auditor. The Limited Partners, by Extraordinary Resolution, may waive the requirement to provide audited financial reports for any year before the year including the Commercial Operations Date.

(b) As soon as practicable, but in no event later than 45 days after the end of each calendar quarter (except the last calendar quarter of each year), the General Partner shall cause to be mailed to each holder of a Unit as indicated on the Register as of a date selected by the General Partner in its sole discretion, a report containing unaudited consolidated financial statements of the Partnership and such other information as may be required by applicable securities laws, or the rules of any stock exchange on which any of the Units are listed for trading, or as the General Partner determines to be necessary or appropriate.

8.3 Right to Inspect Partnership Books and Records

(a) In addition to other rights provided by this Agreement or by applicable law, and except as limited by Section 8.3(b), each Limited Partner shall have the right, for a purpose reasonably related to such Limited Partner's interest as a limited partner in the Partnership, upon reasonable demand and upon not less than 10 days' notice in writing to the General Partner, and at such Limited Partner's own expense, to have furnished to it:

(i) a current list of the name and last known address of each Limited Partner and the General Partner;

(ii) copies of this Agreement, the Certificate, the Operating Agreement, the Limited Liability Company Agreement and amendments thereto; and

(iii) such other information regarding the affairs of the Partnership as is just and reasonable.

(b) Notwithstanding Section 8.3(a), the General Partner may keep confidential from the Limited Partners for such period of time as the General Partner deems reasonable, any information that the General Partner reasonably believes to be in the nature of trade secrets or other information the disclosure of which the General Partner in good faith believes is not in the best interests of the Partnership or could damage the Partnership or that the Partnership is required by law or by agreements with third parties to keep confidential.

8.4 Accounting Policies

The General Partner is authorized to establish from time to time accounting policies with respect to the financial statements of the Partnership and to change from time to time any policy that has been so established so long as such policies are consistent with the provisions of this Agreement and with generally accepted accounting principles in the United States of America. Any inconsistencies in accounting policies with respect to financial statements between this Agreement and generally accepted accounting principles, will be resolved in favour of such generally accepted accounting principles.

8.5 Appointment of Auditor

The General Partner shall, on behalf of the Partnership, select the Auditor on behalf of the Partnership to review and report to the Partners upon the financial statements of the Partnership for and as at the end of each Fiscal Year and to advise upon and make determinations with regard to financial questions relating to the Partnership or required by this Agreement to be determined by the Auditor.

8.6 Tax Matters

(a) **General Tax Information**. The General Partner will use reasonable efforts to send or cause to be sent to each Person who is a Limited Partner during the previous Fiscal Year, or at the date of dissolution of the Partnership, within 90 days after the end of each Fiscal Year or within 45 days of dissolution, as the case may be, or within such other shorter period of time as may be required by applicable law, all information, in suitable form, relating to the Partnership necessary for such Person to prepare their or their Affiliates' income tax returns. The General Partner shall file, on behalf of itself and the Limited Partners, annual Partnership information returns and any other information returns required to be filed under the Code and any other applicable tax legislation in respect of the Partnership and the Limited Partners.

(b) **Preparation of U.S. Tax Returns**. The General Partner shall arrange for the preparation and timely filing of all returns of Partnership income, gains, deductions, losses and other items required of the Partnership for U.S. Federal and state income tax purposes and shall furnish, as soon as reasonably practicable but no later than August 15th of each Fiscal Year (or such earlier date as may be required by law), the tax information reasonably required by the General Partner and the other Partners for U.S. Federal and state income tax reporting purposes.

(c) **U.S. Tax Elections**. Except as otherwise provided herein, the General Partner shall determine whether to make any available elections pursuant to the Code; provided, however, that the General Partner shall (i) elect for the Partnership to be taxed as a partnership for U.S. federal income tax purposes by filing, if required, Form 8832, and (ii) upon the reasonable request of any Partner, make the election under Section 754 of the Code in accordance with applicable regulations thereunder. The General Partner shall have the right to seek to revoke any such election (including, without limitation, the election under Section 754 of the Code) upon the General Partner's determination that such revocation is in the best interests of the Partners.

(d) **U.S. Tax Matters Partner**.

(i) **General**. The General Partner shall be the "tax matters partner" of the Partnership for U.S. Federal income tax purposes. Pursuant to Section 6223(c) of the Code, upon receipt of notice from the IRS of the beginning of an administrative proceeding with respect to the Partnership, the tax matters partner shall notify each other Partner. The other Partners shall provide such information to the Partnership as the General Partner shall reasonably request.

(ii) **Powers**. The tax matters partner is authorized, but not required:

(A) to enter into any settlement with the IRS with respect to any administrative or judicial proceedings for the adjustment of Partnership items required to be taken into account by a Partner for income tax purposes (such administrative proceedings being referred to as a "tax audit" and such judicial proceedings being referred to as "judicial review"), and in the settlement agreement the tax matters partner may expressly state that such agreement shall bind all Partners, except that such settlement agreement shall not bind any Partner (a) who (within the time prescribed pursuant to the Code and Regulations) files a statement with the IRS providing that the tax matters partner shall not have the authority to enter into a settlement agreement on behalf of such Partner or (b) who is a "notice partner" (as defined in Section 6231 of the Code) or a member of a "notice group" (as defined in Section 6223(b)(2) of the Code);

(B) in the event that a notice of a final administrative adjustment at the Partnership level of any item required to be taken into account by a partner for tax purposes (a "final adjustment") is mailed or otherwise given to the tax matters partner, to seek judicial review of such final adjustment, including the filing of a petition for readjustment with the U.S. Tax Court or the United States Claims Court, or the filing of a complaint for refund with the District Court of the United States for the district in which the Partnership's principal place of business is located;

(C) to intervene in any action brought by any other Partner for judicial review of a final adjustment;

(D) to file a request for an administrative adjustment with the IRS at any time and, if any part of such request is not allowed by the IRS, to file an appropriate pleading (petition, complaint or other document) for judicial review with respect to such request;

(E) to enter into an agreement with the IRS to extend the period for assessing any tax which is attributable to any item required to be taken into account by a Partner for tax purposes, or an item affected by such item; and

(F) to take any other action on behalf of the Partners of the Partnership in connection with any tax audit or judicial review proceeding to the extent permitted by applicable law or regulations.

The taking of any action and the incurring of any expense by the tax matters partner in connection with any such proceeding, except to the extent required by law, is a matter in the sole and absolute discretion of the tax matters partner, and the provisions relating to indemnification of the General Partner set forth in Section 7.6 of this Agreement shall be fully applicable to the tax matters partner in its capacity as such.

(iii) **Reimbursement**. The tax matters partner shall receive no compensation for its services. All third-party costs and expenses incurred by the tax matters partner in performing its duties as such (including legal and accounting fees) shall be borne by the Partnership. Nothing herein shall be construed to restrict the Partnership from engaging an accounting firm and a law firm to assist the tax matters partner in discharging his duties hereunder, so long as the compensation paid by the Partnership for such services is reasonable.

(e) **Organizational Expenses for U.S. Tax Purposes**. The Partnership shall elect to deduct expenses, if any, incurred by it in organizing the Partnership ratably over a 180 month period as provided in Section 709 of the Code.

ARTICLE 9
MEETINGS OF LIMITED PARTNERS

9.1 Requisitions of Meetings

(a) The General Partner may call a general meeting of Limited Partners entitled to vote at such time and place as it deems appropriate in its absolute discretion for the purpose of considering any matter set forth in the notice of meeting provided, however, that the General Partner shall call an annual meeting of Limited Partners entitled to vote to be held not later than 15 months after holding the last preceding annual meeting.

(b) In addition, where Limited Partners holding not less than 50% of the aggregate votes attached to the outstanding Units of any class entitled to vote in respect of Ordinary Resolutions (the **"Requisitioning Partners"**) give notice signed by each of them to the General Partner, requesting a meeting of the Limited Partners and stating the purpose of such meeting, the General Partner shall, within 60 days of receipt of such notice, convene such meeting, and if it fails to do so, any Requisitioning Partner may convene such meeting by giving notice in accordance with this Agreement.

(c) Every meeting of Limited Partners, however convened, will be conducted in accordance with this Agreement.

9.2 Place of Meeting

Every meeting of Limited Partners shall be held in the City of Coos Bay, Oregon or at such other place in Canada or in the United States of America as the General Partner (or Requisitioning Partners, if the General Partner fails to call such meeting in accordance with Section 9.1) may designate. Parties may attend meetings in person, by video or conference call, provided that each party can hear and speak to all other attendees. The General Partner shall provide conference call accessibility to all Parties.

9.3 Notice of Meeting

Notice of any meeting of Limited Partners will be given to each Limited Partner entitled to receive such notice not less than 21 days (but not more than 60 days) prior to such meeting, and will state:

(a) the time, date and place of such meeting; and

(b) in general terms, the nature of the business to be transacted at the meeting in sufficient detail to permit a Limited Partner to make a reasoned decision thereon.

Notice of an adjourned meeting of Limited Partners need not be given if the adjourned meeting is held within 14 days of the original meeting. Otherwise, but subject to Section 9.13, notice of adjourned meetings shall be given not less than 10 days in advance of the adjourned meeting and otherwise in accordance with this section, except that the notice need not specify the nature of the business to be transacted if unchanged from the original meeting.

9.4 Record Dates

For the purpose of determining the Limited Partners who are entitled to vote or act at any meeting of Limited Partners or any adjournment thereof, or for the purpose of any other action, the General Partner may fix a date not more than 60 days prior to the date of any meeting of Limited Partners or other action as a record date for the determination of Limited Partners entitled to vote at such meeting or any adjournment thereof or to be treated as Limited Partners of record for purposes of such other action, and any Limited Partner who was a Limited Partner holding voting Units at the time so fixed shall be entitled to vote at such meeting or any adjournment thereof even though it, he or she has since that date disposed of its, his or her Units, and no Limited Partner becoming such after that date shall be a Limited Partner of record for purposes of such action. A Person shall be a Limited Partner of record at the relevant time if the Person's name appears in the Register as amended and supplemented at such time.

9.5 Solicitation of Proxies

If proxies are solicited from Limited Partners in connection with a meeting of Partners, the Person or Persons soliciting such proxies shall prepare an information circular or other applicable disclosure statement which shall contain, to the extent that it is relevant and applicable, the information prescribed for such information circulars or disclosure statements by the *Securities Exchange of 1934*, as amended, if applicable and in compliance with all other applicable federal or state laws.

9.6 Proxies

Any Limited Partner entitled to vote at a meeting of Limited Partners may vote by proxy if a form of proxy has been received by the General Partner or the chairman of the meeting for verification prior to the commencement of the meeting.

9.7 Validity of Proxies

A proxy purporting to be executed by or on behalf of a Limited Partner will be considered to be valid unless challenged at the time of or prior to its exercise. The Person challenging the proxy will have the burden of proving to the satisfaction of the chairman of the meeting that the proxy is invalid and any decision of the chairman concerning the validity of a proxy will be final. Proxies shall be valid only at the meeting with respect to which they were solicited, or any adjournment thereof, but in any event shall cease to be valid one year from their date. A proxy given on behalf of joint holders must be executed by all of them and may be revoked by any of them, and if more than one of several joint holders is present at a meeting and they do not agree which of them is to exercise any vote to which they are jointly entitled, they will for the purposes of voting be deemed not to be present. A proxy holder need not be a holder of a Unit.

9.8 Form of Proxy

Every proxy will be substantially in the form as may be approved by the General Partner or as may be satisfactory to the chairman of the meeting at which it is sought to be exercised.

9.9 Revocation of Proxy

A vote cast in accordance with the terms of an instrument of proxy shall be valid notwithstanding the previous death, incapacity, insolvency or bankruptcy of the Limited Partner giving the proxy or the revocation of the proxy unless written notice of such death, incapacity, insolvency, bankruptcy or revocation shall have been received by the chairman of the meeting prior to the commencement of the meeting.

9.10 Corporations and other Entities

A Limited Partner which is a corporation, limited liability company or other non-individual may appoint an officer, director, manager or other authorized person as its representative to attend, vote and act on its behalf at a meeting of Limited Partners.

9.11 Attendance of Others

Any officer or director of the General Partner, legal counsel for the General Partner, a Limited Partner and the Partnership and representatives of the Auditor will be entitled to attend any meeting of Limited Partners. The General Partner has the right to authorize the presence of any Person at a meeting regardless of whether the Person is a Limited Partner. With the approval of the General Partner, that Person is entitled to address the meeting.

9.12 Chairman

The General Partner may nominate a Person, including, without limitation, an officer, director or manager of the General Partner (who need not be a Limited Partner), to be chairman of a meeting of Limited Partners and the person nominated by the General Partner will be chairman of such meeting unless the Limited Partners elect another chairman by Ordinary Resolution.

9.13 Quorum

A quorum at any meeting of Limited Partners will consist of one or more Limited Partners present in person or by proxy holding at least 51% of the aggregate votes attached to the outstanding Units entitled to be voted at the meeting. If, within half an hour after the time fixed for the holding of such meeting, a quorum for the meeting is not present, the meeting:

(a) if called by or on the requisition of Limited Partners, will be terminated; and

(b) if called by the General Partner, will be held at the same time and place on the day which is 14 days later (or if that date is not a business day, the first business day after that date). The General Partner will give three days' notice to all Limited Partners of the date of the reconvening of the adjourned meeting and at such meeting the quorum will consist of the Limited Partners then present in person or represented by proxy.

9.14 Voting

Every question submitted to a meeting of Limited Partners:

(a) which requires an Extraordinary Resolution under this Agreement will be decided by a poll; and

(b) which does not require an Extraordinary Resolution will be decided by an Ordinary Resolution on a show of hands unless otherwise required by this Agreement or a poll is demanded by a Limited Partner, in which case a poll will be taken;

and in the case of an equality of votes, the chairman will not have a casting vote and the resolution will be deemed to be defeated. The chairman will be entitled to vote in respect of any Units held by him or for which he may be a proxyholder. On any vote at a meeting of Limited Partners, a declaration of the chairman concerning the result of the vote will be conclusive.

On a poll, each Person present at the meeting will have that number of votes provided for in this Agreement and in the rights, privileges, restrictions and conditions attaching to each Unit in respect of which it, he or she is shown on the Register as the Unitholder at the record date and for each Unit in respect of which it, he or she is the proxyholder. Each Limited Partner present at the meeting and entitled to vote thereat will have one vote on a show of hands. If Units are held jointly by two or more Persons and only one of them is present or represented by proxy at a meeting of Limited Partners, such Limited Partner may, in the absence of the other or others, vote with respect thereto, but if more than one of them is present or represented by proxy, they shall vote together on the whole Units held jointly.

The General Partner, as such for its own account, shall not be entitled to vote on any poll or on a show of hands at any meeting of Limited Partners. Any Limited Partner who is in default of payment of the subscription price for or Capital Contributions or loans in respect of its, his or her Units as contemplated in Section 4.4 shall not be entitled to vote in respect of any of its, his or her Units.

9.15 Poll

A poll requested or required will be taken at the meeting of Limited Partners or an adjournment of the meeting in such manner as the chairman directs.

9.16 Powers of Limited Partners; Resolutions Binding

The Limited Partners shall have only the powers set forth in this Agreement and any additional powers provided by law or in the rights, privileges, restrictions and conditions attaching to its, his or her Units. Subject to the foregoing sentence, any resolution passed in accordance with this Agreement will be binding on all the Partners and their respective heirs, executors, administrators, successors and assigns, whether or not any such Partner was present in person or voted against any resolution so passed.

9.17 Powers Exercisable by Extraordinary Resolution

The following powers shall only be exercisable by Extraordinary Resolution passed by the Limited Partners entitled to vote thereon:

(a) approval of the withdrawal of the General Partner as provided in Section 7.14(a);

(b) dissolving the Partnership, except as otherwise provided for under Section 11.1;

(c) waiving any default on the part of the General Partner on such terms as the Limited Partners may determine;

(d) amending, modifying, altering or repealing any Extraordinary Resolution previously passed by such Limited Partners;

(e) amending this Agreement pursuant to Section 12.1;

(f) an approval referred to in Section 2.9(h);

(g) issuing further Class C Units or determining the terms and conditions of the offering of such Units;

(h) appointing a General Partner;

(i) subject to Schedule G, Section 5.3, effecting a sale of all or any material portion of the assets of the Partnership;

(j) admitting any Person as a Partner in the Partnership other than pursuant to a transfer permitted herein;

(k) approving any merger or reorganization of the Partnership;

(l) filing for bankruptcy, assigning the Partnership's assets for the benefit of creditors, or any similar act of insolvency;

(m) approving any payments to or the making or entering into any contract or agreement with any Affiliate of any Partner;

(n) providing a guaranty for, or pledging any Partnership assets as security for, any indebtedness or obligation of any Person other than the Partnership; or

(o) any other act under this Agreement that expressly requires an Extraordinary Resolution.

provided that for the purpose of the approval required for matters referred to in Sections 9.17(a), (c) and (d) (if the General Partner was not permitted to vote on the original Extraordinary

Resolution), Units owned by the General Partner for its own account shall not be permitted to vote on any resolutions and shall be deemed to not be outstanding.

9.18 Minutes

The General Partner will cause minutes to be kept of all proceedings and resolutions at every meeting and will cause all such minutes and all resolutions of the Limited Partners consented to in writing to be made and entered into books to be kept for that purpose. Any minutes of a meeting signed by the chairman of the meeting will be deemed evidence of the matters stated in them and such meeting will be deemed to have been duly convened and held and all resolutions and proceedings shown in them will be deemed to have been duly passed and taken.

9.19 Additional Rules and Procedures

To the extent that the rules and procedures for the conduct of a meeting of the Limited Partners are not prescribed in this Agreement, the rules and procedures will be determined by the General Partner.

ARTICLE 10
NOTICES

10.1 Address

Any notice or other written communication which must be given or sent under this Agreement shall be given by first-class mail or personal delivery to the postal address of the General Partner and the Limited Partners set forth for each such Partner on the signature page of this Agreement, or any other new address following a change of address in conformity with Section 10.2, and the General Partner will maintain such addresses, as may be changed hereunder, in the Partnership's Register .

10.2 Change of Address

A Limited Partner may, at any time, change its address for the purpose of service by written notice to the General Partner. The General Partner may change its address for the purpose of service by written notice to all the Limited Partners.

10.3 Accidental Failure

An accidental omission in the giving of, or failure to give, a notice required by this Agreement will not invalidate or affect in any way the legality of any meeting or other proceeding in respect of which such notice was or was intended to be given if the failure did not prejudice any party's rights hereunder.

10.4 Disruption in Mail

In the event of any disruption, strike or interruption in the applicable postal service after mailing and before receipt or deemed receipt of a document, it will be deemed to have been received on the sixth business day following full resumption of the postal service.

10.5 Receipt of Notice

Subject to Section 10.4, notices given by first-class mail shall be deemed to have been received on the third business day following the deposit of such notice in the mail and notices given by delivery shall be deemed to have been received on the date of their delivery.

10.6 Undelivered Notices

If the General Partner sends a notice or document to a Unitholder in accordance with Section 10.1 and the notice or document is returned on three consecutive occasions because the Unitholder cannot be found, the General Partner is not required to send any further notices or documents to the Unitholder until the Unitholder informs the General Partner in writing of the Unitholder's new address.

ARTICLE 11
DISSOLUTION AND LIQUIDATION

11.1 Events of Dissolution

The Partnership shall follow the procedure for dissolution established in Section 11.4 upon the occurrence of any of the following events or dates:

(a) the election of the General Partner to dissolve the Partnership, if approved by the passage of an Extraordinary Resolution;

(b) the sale, exchange or other disposition of all or substantially all of the property of the Partnership, if approved as provided herein;

(c) the removal or resignation of the General Partner unless the General Partner is replaced as provided herein or in the resolution removing the General Partner; or

(d) December 31, 2076.

11.2 No Dissolution

The Partnership shall not come to an end by reason of the death, bankruptcy, assignment of property for the benefit of creditors, insolvency, mental incompetency or other disability of any Limited Partner or upon transfer of any Units or upon the issue or conversion of Units.

11.3 Continuation After Event of Dissolution

Upon the occurrence of an event described in Section 11.1(c), if within 90 days thereafter, holders of Units entitled to vote thereon, by an Ordinary Resolution so elect, the Limited Partners shall reconstitute the Partnership and continue its business on the same terms and conditions set forth in this Agreement by forming a new limited partnership on terms identical to those set forth in this Agreement and having as a general partner a Person approved by the holders pursuant to an Extraordinary Resolution. Upon any such election by Extraordinary Resolution, all Partners shall be bound thereby and shall be deemed to have approved thereof. Unless such an election is made within the applicable time period as set forth above, the Partnership shall conduct only activities necessary to wind up its affairs. If such an election is so made, then:

(a) the reconstituted Partnership shall continue until the end of the term set forth in Section 11.1(d) unless earlier dissolved in accordance with this Article 11; and

(b) all necessary steps shall be taken to cancel this Agreement and the Certificate and to enter into and, as necessary, to file a new partnership agreement and certificate of limited partnership, and the successor general partner may for this purpose exercise the powers of attorney granted the General Partner pursuant to Section 2.10.

11.4 Procedure on Dissolution

Upon the occurrence of any of the events set forth in Section 11.1, the General Partner (or in the event of an occurrence specified in Section 11.1(c), such other Person as may be appointed by Ordinary Resolution of the Limited Partners entitled to vote thereon) shall act as a receiver and liquidator of the assets of the Partnership and shall:

(a) sell or otherwise dispose of such part of the Partnership's assets as the receiver shall consider appropriate;

(b) pay or provide for the payment of the debts and liabilities of the Partnership and liquidation expenses;

(c) if there are any assets of the Partnership remaining, distribute to the Unitholders indicated on the Certificate on the date of dissolution holding Units entitled to receive such distribution from the Partnership, subject to Sections 3.18 and 4.12, any Class A Unit Preferred Distributions, Class B Unit Preferred Distributions or Distributable Cash then unpaid to Unitholders in accordance with the provisions hereof as if the date of dissolution was the last day of the Fiscal Year;

(d) if there are any assets of the Partnership remaining, distribute such remaining assets to the Unitholders indicated in the Register on the date of dissolution who are holding Units entitled to receive assets of the Partnership on the dissolution of the Partnership, subject to Sections 3.18 and 4.12, in accordance with the respective rights of such Units;

(e) file the notice of dissolution prescribed by the Act and satisfy all applicable formalities in such circumstances as may be prescribed by the laws of other jurisdictions where the Partnership is registered. In addition, the General Partner shall give prior notice of the dissolution of the Partnership by mailing to each Limited Partner such notice at least 21 days prior to the filing of the declaration of dissolution prescribed by the Act; and

(f) file any elections, determinations or designations under the Code or under any similar legislation which may be necessary or desirable.

11.5 Dissolution

The Partnership shall be dissolved upon the completion of all matters set forth in Section 11.4.

11.6 No Right to Dissolve

Except as provided for in Section 11.1, no Limited Partner shall have the right to ask for the dissolution of the Partnership, the winding-up of its affairs or the distribution of its assets.

11.7 Agreement Continues

Notwithstanding the dissolution of the Partnership, this Agreement shall not terminate until the provisions of Section 11.4 and 11.5 shall have been satisfied.

ARTICLE 12
AMENDMENT

12.1 Amendment Procedures

Except as provided in Section 12.3 or 5.8, all amendments to this Agreement shall be made in accordance with the following requirements. Amendments to this Agreement may be proposed solely by the General Partner or by Requisitioning Partners pursuant to Section 9.1(b). Each such proposal shall contain the text of the proposed amendment. If an amendment is proposed, the General Partner shall seek the approval of the Limited Partners entitled to vote thereon by an Extraordinary Resolution.

12.2 Amendment Requirements

Notwithstanding the provisions of Sections 12.1 and 12.3, no amendment to this Agreement may: (i) give any Person any additional right to dissolve the Partnership; or (ii) modify the amendment provisions in this Article 12.

12.3 Amendment by General Partner

Each Limited Partner agrees that the General Partner (pursuant to its powers of attorney from the Limited Partners or as expressly provided herein), without the approval of any Limited

Partner may amend any provision of this Agreement, and execute, swear to, acknowledge, deliver, file and record whatever documents may be required in connection therewith, to reflect:

(a) a change in the name of the Partnership or the location of the principal place of business of the Partnership;

(b) admission, substitution, withdrawal or removal of Limited Partners in accordance with this Agreement;

(c) subject to Section 3.1, and except as otherwise provided in any series provisions of any series of Class C Units, a change that, in the sole discretion of the General Partner, is reasonable and necessary or appropriate to qualify or continue the qualification of the Partnership as a limited partnership in which the Limited Partners have limited liability under the applicable laws;

(d) subject to Section 3.1, and except as otherwise provided in any series provisions of any series of Class C Units, a change that, in the sole discretion of the General Partner, is reasonable and necessary or appropriate to enable Partners to take advantage of, or not be detrimentally affected by, changes in the Code or other taxation laws; or

(e) subject to Section 3.1, and except as otherwise provided in any series provisions of any series of Class C Units, a change that does not materially adversely affect the Limited Partners.

ARTICLE 13
NON-COMPETITION AND CONFIDENTIALITY

13.1 Non-Competition

(a) Each Partner hereby covenants and agrees with the Partnership and each of the other Partners that, commencing on the date hereof and ending 48 months after the date on which it ceases to hold any Project Interest, it will not, and it will not allow any of its Affiliates, without the prior written consent of the other Partners:

(i) directly or indirectly, whether on its own behalf, or as a consultant, partner, investor or lender of any person, firm, partnership, trust, corporation or other entity, sponsor, promote, be engaged or interested in or otherwise in any manner take part in any business or other commercial activity, howsoever carried on or conducted, which competes with the business or proposed business of the Partnership, whether directly or indirectly, anywhere within the geographic areas of: (i) in the case of Energy Projects and any Partner other than Fort Chicago, the west coast of North America; and (ii) in the case of Fort Chicago, the coast and all major waterways of the states of Oregon and Washington (collectively the

"**Restricted Area**"), and will not allow its name or any part thereof to be used in or employed by any such business;

(ii) solicit or entice, or attempt to solicit or entice, any of the customers or suppliers of the Partnership and all persons who are not customers or suppliers but who have been canvassed or solicited by the Partnership (collectively the "**Customers**"), to become a customer or supplier of any person, firm, trust, corporation or other entity that competes with the Partnership anywhere within the Restricted Area; or

(iii) solicit or entice, or attempt to solicit or entice, any of the employees of the Partnership or the General Partner to enter into employment or service with any person, firm, trust, corporation or other entity that competes with the Partnership anywhere within the Restricted Area, or entertain any offers from or enter into discussions with or employ or hire any such employees.

(b) Each Partner confirms that all restrictions in Section 13.1(a) herein are reasonable and necessary to protect the interests of the Partnership and the other Partners.

(c) The parties acknowledge and confirm that:

(i) they have each been independently advised by counsel with respect to the provisions of this Agreement;

(ii) the parties have negotiated the provisions hereof on an equal footing based on equal bargaining power at the time of entering into of this Agreement;

(iii) no party was required or induced to enter into this Agreement; and

(iv) the provisions hereof are reasonable and do not go beyond what is necessary to protect the interests of the Partnership and the Partners.

(d) Each Partner understands and agrees that the other Partners and the Partnership will suffer irreparable harm in the event that a Partner breaches any of its obligations under this Section and that monetary damages would be inadequate to compensate the Partnership or the other Partners for such breach. Accordingly, each Partner agrees that in the event of a breach or a threatened breach by it of any of the provisions of this Agreement, the Partnership or the other Partners will be entitled, in addition to any other rights, remedies or damages which may be available to the Partnership or the other Partners, at law or in equity, to obtain an interim and permanent injunction in order to prevent or restrain any such breach or threatened breach of this Agreement by a Partner, or by any or all of a Partner's partners, employers, employees, servants, agents, representatives, and any other persons directly or indirectly acting for, or on behalf of, or with, such Partner. Each Partner further agrees that the Partnership or the other Partners shall be entitled to injunctive relief without having to prove damages and shall be entitled to all of their costs and expenses incurred in order to obtain relief from any breach of a Partner's obligations under this Section, including reasonable solicitor and client legal costs and disbursements.

(e) Concurrently with the execution of this Agreement, Energy Projects shall cause Robert Braddock, Elliot Trepper, Geoffrey Mitchell, and J. Thomas Wilson, voting members of Energy Projects, to deliver to each of the Partnership and Fort Chicago individual covenants substantially in the form of this Section 13.1.

(f) Notwithstanding anything else herein contained, this Section 13.1 shall terminate and become null and void in the event that: (i) each of Fort Chicago and Energy Projects sell their Project Interests, effective as of the date of the last of such sales; or (ii) the Project is no longer being pursued by any one of the Partnership, Energy Projects, Fort Chicago or the individuals referred to in Section 13.1(e).

13.2 Confidentiality

(a) In this Section 13.2, **"Confidential Information"** means any and all confidential and proprietary information, records, trade secrets and documentation of the Partnership relating to the permitting, design, engineering, construction, commissioning, management and operation of the Facilities hereinbefore or hereafter disclosed by the Partnership to any Partner or any Affiliate thereof.

(b) Each Partner hereby acknowledges that prior to the date hereof it has had, and it will in the future have, access to and will be entrusted with Confidential Information. Each Partner covenants and agrees on its own behalf and on behalf of its Affiliates, that all Confidential Information disclosed to it (i) shall be kept in strict confidence by such Partner and its Affiliates, (ii) shall not be used, dealt with or exploited for any purpose or purposes other than the express purposes of the Partnership, and (iii) shall not be disclosed to any Person or Persons other than to the parties hereto unless otherwise required by law. Each Partner shall take all reasonable steps necessary to maintain the confidential nature of the Confidential Information.

(c) The restrictions set forth in Section 13.2(b) above shall not apply to any part of the Confidential Information which (i) is at the time of disclosure or thereafter becomes a part of the public domain through no violation of this Agreement, (ii) as confirmed by the written records of the Partner, was in the lawful possession of such Partner prior to its disclosure hereunder, (iii) is hereafter lawfully acquired by the Partner through a third party which, to the best of the Partner's knowledge, is not under an obligation of confidence to the Partnership, General Partner or either of them and which third party was not in a contractual or fiduciary relationship with the Partnership, General Partner or either of them, (iv) is disclosed following receipt of the express written consent of the General Partner on behalf of the Partnership to such disclosure being made, or (v) subject to Subsection 13.2(e) below, any Partner or any Affiliate thereof is legally compelled to disclose.

(d) Each Partner further acknowledges the competitive value and sensitive nature of the Confidential Information to the Partnership and its Affiliates, the disclosure of which to any competitor of the Partnership or its Affiliates or to the general public or to any Person would be highly detrimental to the best interests of the Partnership and its Affiliates. Each Partner agrees that the right to maintain the confidentiality of such Confidential Information, and the right to preserve the goodwill of the Partnership and its Affiliates, constitute proprietary rights which the Partnership and its affiliates are entitled to protect.

(e) If a Partner or an Affiliate thereof becomes legally compelled to disclose any of the Confidential Information, the Partner or Affiliate which is legally compelled shall provide the General Partner of the Partnership with prompt written notice of same so that the General Partner may seek a protective order or other appropriate remedy. If such protective order or remedy is not obtained, the Partner or Affiliate shall furnish only that portion of the Confidential Information which is legally required and will exercise all reasonable commercial efforts to obtain reliable assurance that the Confidential Information will be accorded confidential treatment.

(f) All Confidential Information including, without limitation, sketches, drawings, reports, notes, records, papers, documents, copies, reproductions, reprints, translation, data or information (whether of a technical, engineering, operational, economic or other nature) received from the Partnership and in the possession of a Partner or its Affiliates or of a director, officer or employee of a Partner or its Affiliates shall be and remain the sole property of the Partnership and each Partner shall hand same over (or cause same to be handed over) to the General Partner of the Partnership at any time upon demand after the Partner and all its Affiliates cease to be a Unit holder hereunder, provided that such Partner and all of its Affiliates may make and retain copies of any Confidential Information necessary or desirable to support its financial records.

(g) Notwithstanding the restrictions set forth in this Section 13.2, any Partner may disclose Confidential Information, to the extent reasonably necessary, to prospective lending institutions of such Partner or to prospective transferees of such Partner's interests in the Partnership as a Partner thereof; provided however that such Person or Persons shall be informed at the time of such disclosure of its confidential nature and provided with the confidentiality terms of this Agreement, and that such Person or Persons shall first agree in writing to comply with and be bound by all the terms and conditions of this Section 13.2.

13.3 Disclosure

The parties hereto hereby agree that all notices to third parties, including employees of the parties and all other public announcements concerning the transactions contemplated by this Agreement and/or the on-going business of the Partnership, shall require the prior approval of the General Partner, such approval not to be unreasonably withheld or delayed, unless such disclosure shall be required to meet timely disclosure obligations of any party under applicable securities laws and stock exchange rules in circumstances where prior consultation with the other party is not practicable.

13.4 Survival

The provisions of Sections 13.1, 13.2 and 13.3 shall survive the termination of this Agreement and the withdrawal of a Partner and its Affiliates from the Partnership prior to termination of this Agreement for any reason whatsoever

ARTICLE 14
MISCELLANEOUS

14.1 Binding Agreement

Subject to the restrictions on assignment and transfer herein contained, this Agreement will enure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators and other legal representatives, successors and assigns.

14.2 Time

Time shall be of the essence hereof.

14.3 Counterparts

This Agreement, or any amendment to it, may be executed in multiple counterparts, each of which will be deemed an original agreement. This Agreement may also be executed and adopted in any Subscription Form, Transfer Form or similar instrument signed by a Limited Partner with the same effect as if such Limited Partner had executed a counterpart of this Agreement. All counterparts and adopting instruments shall be construed together and shall constitute one and the same agreement.

14.4 Governing Law

This Agreement and the Schedule hereto shall be governed and construed exclusively according to the laws of the State of Delaware and the laws of the United States of America applicable thereto and the parties hereto irrevocably attorn to the non-exclusive jurisdiction of the courts of the State of Delaware.

14.5 Severability

If any part of this Agreement is declared invalid or unenforceable, then such part shall be deemed to be severable from this Agreement and will not affect the remainder of this Agreement.

14.6 Further Acts

The parties will perform and cause to be performed such further and other acts and things and execute and deliver or cause to be executed and delivered such further and other documents as counsel to the Partnership considers necessary or desirable to carry out the terms and intent of this Agreement.

14.7 Entire Agreement

This Agreement constitutes the entire agreement among the parties hereto with respect to the subject matter hereof.

14.8 Limited Partner Not a General Partner

If any provision of this Agreement has the effect of imposing upon any Limited Partner (other than the General Partner) any of the liabilities or obligations of a general partner under the Act, such provision shall be of no force and effect to the extent of such specific imposition.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date set out above.

JORDAN COVE ENERGY PROJECT L.L.C., as General Partner

By: ______________________
Stephen H. White
Manager

Notice address:

215 Central Avenue, Suite 380
Coos Bay, Oregon 97420
Telephone (541) 266-7510
Facsimile (541) 266-7510

FORT CHICAGO LNG II U.S. L.P., as Limited Partner and by its General Partner, **FORT CHICAGO ENERGY MANAGEMENT INC.**

By: ______________________
Stephen H. White
President and Chief Executive Officer

Notice address:

Suite 2150, Stock Exchange Tower
300 – 5th Avenue S.W.
Calgary, Alberta T2P 3C4
Telephone (403) 213-3639

ENERGY PROJECTS DEVELOPMENT L.L.C.,
as Limited Partner

By: ______________________
Elliot L. Trepper,
President

Notice address:

1274 Silvertip Lane
Evergreen, Colorado 80439
Telephone
Facsimile

APPENDIX A-4

Certificate of Amendment to Certificate of Limited Partnership for Energy Projects Development LLC, A Limited Partners

State of Delaware
Secretary of State
Division of Corporations
Delivered 10:30 AM 08/28/2013
FILED 10:30 AM 08/28/2013
SRV 131034773 - 3690091 FILE

STATE OF DELAWARE

AMENDMENT TO THE CERTIFICATE OF LIMITED PARTNERSHIP

The undersigned, desiring to amend the Certificate of Limited Partnership pursuant to the provisions of Section 17-202 of the Revised Uniform Limited Partnership Act of the State of Delaware, does hereby certify as follows:

FIRST: The name of the Limited Partnership is Fort Chicago LNG II U.S. L.P.

SECOND: Article 1 of the Certificate of Limited Partnership shall be amended as follows:

ARTICLE 1 – NAME

The name of the limited partnership formed hereby is Jordan Cove LNG L.P.

THIRD: Article 3 of the Certificate of Limited Partnership shall be amended as follows:

ARTICLE 3

The name and business address of the General Partner is:

Name	**Business Address**
Fort Chicago Holdings U.S. LLC	Suite 900, 222 – 3rd Avenue SW Calgary, Alberta T2P 0B4 Canada

IN WITNESS WHEREOF, the undersigned executed this Amendment to the Certificate of Limited Partnership on this 19th day of August, 2013.

FORT CHICAGO HOLDINGS U.S. LLC
General Partner

By: ______________________
Name: Kevan S. King
Senior Vice President, General
Counsel and Secretary

EXHIBIT B
PROJECT DESCRIPTION
OAR 345-021-0010(1)(B)

CONTENTS

FIGURES

APPENDIX

1.0 INTRODUCTION

The South Dunes Power Plant (SDPP) will be a natural-gas-fueled combined-cycle generating plant located on the North Spit on Coos Bay, in Coos County, across the bay from the City of North Bend. The plant will produce a nominal 420 megawatts (MW) of electrical power, and may include distribution of power for public sale. SDPP will also deliver process steam for gas conditioning prior to delivery to the Jordan Cove Liquefied Natural Gas (LNG) facility, as a cogeneration project. Jordan Cove Energy Project, L.P. (the “Applicant”) will construct and operate the SDPP, which will consist of two 210-MW blocks of high-efficiency combined-cycle combustion turbine generation, with duct-firing capability. Three combustion turbine generators (CTG), three heat recovery steam generators (HRSG), and one steam turbine generator (STG), will collectively compose each power block.

The SDPP site, including related or supporting facilities, covers approximately 137.86 acres.

2.0 FACILITY DESCRIPTION

OAR 345-021-0010(1)(b). *Information about the proposed facility, construction schedule and temporary disturbances of the site, including:*

OAR 345-021-0010(1)(b)(A). *A description of the proposed energy facility, including as applicable:*

(i) The nominal electric generating capacity and the average electrical generating capacity, as defined in ORS 469.300.

Nominal electric generating capacity is defined in Oregon Revised Statutes (ORS) 469.300(17) as the "maximum net electric power output of an energy facility based on the average temperature, barometric pressure, and relative humidity at the site during times of the year when the facility is intended to operate." The nominal electric generating capacity of the SDPP is based on the nameplate ratings of the CTGs and STGs at these conditions with duct firing. The nominal generating capacity is expected to be 420 MW for the combined two power blocks.

Average electrical generating capacity is defined as the peak generating capacity of the facility divided by a factor determined by the type of facility. Because the proposed facility uses natural gas, the factor applied to the peak generating capacity is 1.00. The average electrical generating capacity of the proposed SDPP is based on the nameplate ratings of the CTGs and STGs at these conditions with duct firing. The average generating capacity is expected to be 420 MW for the two power blocks combined.

(ii) Major components, structures and systems, including a description of the size, type and configuration of equipment used to generate electricity and useful thermal energy.

2.1 COMBUSTION TURBINE GENERATORS

The SDPP will include two blocks of combined-cycle power. Each block will consist of three CTGs of approximately 56 MW each. Each CTG will have an inlet air filter to ensure that combustion air does not contain any contaminants that could cause physical damage to the rotating parts of the CTG. The CTGs will have two shafts containing a low-pressure compressor section, high-pressure compressor section, combustor, high-pressure turbine section, and a low-pressure turbine section. The low-pressure rotor shaft of the CTGs will be connected to a generator to produce electrical power at a 60-cycle alternating current (AC). The compressor sections in the CTGs will compress the inlet air and supply compressed air to the combustion section of the CTGs, where natural gas will be supplied to provide combustion. The exhaust from the combustion section will first go through the high-pressure turbine section, rotating the CTG high-pressure rotor, before expanding through the low-pressure turbine, rotating the CTG low-pressure rotor, which in turn rotates the generator rotor, producing 60-cycle AC electrical power.

2.2 HEAT RECOVERY STEAM GENERATORS

Hot gases exit the CTGs into the HRSGs where the available energy in the exhaust gas is used to produce high-pressure (HP) steam before discharging the exhaust gas through exhaust stacks to the atmosphere. Additional heat input into the HRSGs can be provided by duct burners that would burn natural gas. The additional heat from the duct burners would produce additional steam for the STGs, increasing the plant electrical output above what can be produced using only the steam from CTG exhaust.

Steam produced in the HRSGs will be supplied to STGs and the gas conditioning facilities for process steam. HP process steam is extracted directly from the HP steam header upstream of the STG, and the remaining HP steam is routed through the steam turbine to turn the steam turbine rotor. Low-pressure (LP) process steam is supplied from a controlled steam turbine extraction supplemented by steam from the LP steam header. LP steam from the LP steam header is admitted to the steam turbine directly when the low-pressure process is not in service. Each of the two steam turbine rotors is connected to a generator, producing a maximum of 48.5 MW of 60-cycle AC power from each of the two steam turbines with duct firing. Steam produced by the HRSGs will also support the gas conditioning systems for the JCEP LNG operations, as a cogeneration facility.

2.3 AIR-COOLED CONDENSERS

The exhaust from the LP section of each steam turbine will connect to an air-cooled condenser (ACC) that will cool the steam to a point where it condenses to water. The ACC operates at a vacuum to increase the efficiency of the STGs. The condensate exiting the ACCs is then returned to the HRSGs where it is again heated to steam and the process is repeated. Vacuum pumps are provided to remove air from the ACC for the initial start-up and to remove non-condensable gases that enter the condenser during operation.

Air-cooled condensers differ from the typical cooling towers observed at most power plants operating in Oregon and elsewhere. Most power plants use an “open loop” system that creates a visible steam plume; however, the ACC units to be installed at the SDPP rely on a “closed-loop” system to remove heat from the steam that is piped from the steam turbine generator units. The closed-loop system used in ACCs is considered a dry cooling system because air is forced across a number of tubes and fins that allow the heat to dissipate without direct contact with water or exposing the steam to the atmosphere. While the ACCs have a higher cost of construction and operation, ACCs eliminate water loss and do not create a steam plume.

Related or supporting facilities are discussed in (B) below.

(iii) A site plan and general arrangement of buildings, equipment and structures.

A site plan is provided on Figure B-1, Sheets 1 and 2. All the facilities described in (ii) above are indicated by numbers on Figure B-1, Sheets 1 and 2. All related or supporting facilities are also shown on Figure B-1, Sheets 1 and 2. These figures also show minor ancillary components of the facility.

The Gas Conditioning Facility and related stacks and towers are part of the LNG facility and thus the Federal Energy Regulatory Commission (FERC) has jurisdiction over these components. Because FERC and not the Energy Facility Siting Council has jurisdiction over the Gas Conditioning Facility, these components are not included in the analysis of impacts in this application.

(iv) Fuel and chemical storage facilities, including structures and systems for spill containment.

A permanent refueling station will be located on the SDPP site for site vehicles and emergency equipment. The refueling station will include a double-walled steel 5,000-gallon aboveground storage tank for diesel fuel. The tank will be registered with the Office of the State Fire Marshal and the Oregon Department of Environmental Quality (ODEQ) and will comply with federal and state requirements for storage of combustible petroleum products. Because the tank will be double-walled, it will have integrated secondary containment. In addition to a Spill Prevention, Control, and Countermeasure (SPCC) Plan, an Operations Procedure will be prepared for use and inspection of the refueling station and for fuel deliveries to the SDPP. The refueling station will also have spill containment capable of capturing incidental spills during refueling.

Small quantities of hydraulic oil, lubricating oils, grease, and miscellaneous cleaners or degreasers in 55-gallon or smaller containers will be stored in the Maintenance Building. There are no facilities to store natural gas or liquefied natural gas on the SDPP site.

Aqueous ammonia (19 percent) will be a reagent used in the selective catalytic reduction (SCR) system to control nitrous oxide (NO_x) emissions. The liquid ammonia storage tanks will be located outdoors and within a concrete wall that will provide secondary containment capable of retaining 110 percent of the volume of one tank, plus the 100-year return frequency storm. The ammonia tank and piping system will be designed to ensure personnel safety during delivery and will be equipped with alarming equipment to minimize risk to personnel in the event of an ammonia release.

Water treatment chemicals such as scale inhibitors, sodium hydroxide, sodium bisulfate, and sodium hypochlorite will be stored in curbed areas inside the Water Treatment Building (labeled "Water Treating Area" on Figure B-1). Drums will be stored in the Maintenance Building. Sodium phosphate, used for boiler feed treatment, will be stored outdoors in the power block inside curbed areas that will provide spill control and containment. Additional information on chemicals to be used at the SDPP is provided in Exhibit G.

(v) Equipment and systems for fire prevention and control.

The June 2014 Memorandum of Understanding (MOU) between the Oregon Department of Energy and the JCEP provides a broad framework to develop and implement a coordinated Emergency Plan for the JCEP, which would include the SDPP, the LNG Plant, and the LNG carrier transit route (Appendix B-1). As part of this MOU, the JCEP is to assist in evaluating the current resources and capabilities of local emergency responders and support systems, and identify additional resource and communication needs to enable proper response should there be a need at the JCEP. One component of the MOU requires the JCEP to acquire firefighting apparatus and firefighting personnel for the JCEP. Such apparatus and staff are to be located at the Southwest Oregon Regional Safety Center (SORSC) southwest of the SDPP. The SORSC is not included as a related or supporting facility because it is primarily required for the Jordan Cove LNG Plant.

A fire protection system will be provided and designed to meet the requirements of the Oregon Structural Specialty Code, Oregon Fire Code, and all other applicable fire protection codes and standards in effect at the time of construction. Building smoke detection, annunciation, manual alarm, and sprinkler systems will be provided as required by the codes. The fire protection system will include a fire water system, a carbon dioxide (CO_2) extinguishing system provided with the CTGs, portable fire extinguishers within all buildings and at key outdoor locations in accordance with National Fire Protection Association 10 (NFPA) requirements, and smoke detection system. A loop road system within the SDPP site will be paved with asphalt, approximately 24 feet wide with sufficient turning radius for firefighting equipment in accordance with NFPA requirements.

The fire water system will include an underground fire water supply loop, fire hydrants, sprinkler and spray systems, fire water pumps, fire water storage tanks located west of the main security gate, and manual firefighting equipment placed at appropriate locations. The fire water pumps will consist of an electric fire pump and a full-size diesel fire pump with integral backup power supplies to ensure continued fire water supply during power outages. Each fire pump is sized to provide the maximum fire water demands of the site, which are either the fire flow demands or the fixed fire suppression system demands plus a hose stream allowance of 500 to 1,000 gallons per minute (gpm), whichever is larger. For the SDPP, each fire pump will be rated for 2,500 gpm.

The SDPP fire pumps are supplied from two fire water storage tanks, each of which is sized to supply the full required volume for reliability in the event that one tank is out of service. Each fire water tank volume is sufficient to provide a two-hour supply for the power block at the maximum fire water demand per NFPA 850. The fire water system also supplies the nearby gas conditioning process areas, which are provided with a four-hour reserved water supply per American Petroleum Institute (API) recommendations. Therefore, the fire water tanks are sized based on supplying a minimum of 2,500 gpm for four hours, resulting in a minimum usable volume of 600,000 gallons each.

Local fire alarm systems and associated panels are provided to monitor the various fixed fire protection systems throughout the facility. Fire alarm signals are networked to and monitored by the plant’s main fire control panel labeled the Fire Alarm Annunciator Panel (FAAP). The FAAP is located within the central control room and annunciates all fire alarm, trouble, and supervisory signals from each local fire alarm panel. In addition to annunciation at the local FAAP, each system’s local fire alarm panel will audibly annunciate each fire alarm, trouble, and supervisory signal detected within the protected space. All local panels act as stand-alone units and are capable of continued operation if the FAAP goes offline. In addition to the plant’s FAAP, fire alarm signals will be repeated on a display in the SORSC, the new manned fire station. The alarm signals will provide immediate notification of conditions to on-site safety personnel. SORSC emergency response vehicles and personnel have roadway access to the SDPP site areas.

Combustion turbine enclosures will be protected by water mist or total flooding gaseous suppression systems provided by the combustion turbine vendor. All alarms will be monitored by the plant fire alarm system.

Outdoor oil-filled transformers will be separated from adjacent transformers, buildings, and major equipment per NFPA 850 criteria or will be provided with fire walls as required to provide the necessary separation. Secondary containment will be provided to capture at least 100 percent of the oil volume plus allowances for rainfall and firefighting hose streams.

(vi) For thermal power plants:
(I) A discussion of the source, quantity and availability of all fuels proposed to be used in the facility to generate electricity or useful thermal energy.

Natural gas will be provided to the SDPP from two sources: the Pacific Connector Gas Pipeline (approximately 4 percent), and boil-off gas (BOG) and flash gas (approximately 96 percent) from the JCEP LNG Plant. The 36-inch Pacific Connector Gas Pipeline (PCGP) will enter the SDPP site near the southeast corner of the site. Assuming a 420-MW average generating plant, the total natural gas consumption is estimated at 87 million standard cubic feet per day. Natural gas will be available on a continuous basis from both sources.

(II) Process flow, including power cycle and steam cycle diagrams to describe the energy flows within the system;

Figure B-4 provides a power cycle and steam cycle diagram to describe the energy flows within the SDPP system.

(III) Equipment and systems for disposal of waste heat;

An ACC will be used to dispose of waste heat from each power block. This condenser will provide the necessary cooling for the STG exhaust steam and also return condensate to the HRSG. Waste heat is removed in the ACC by modules arranged in parallel rows, each module containing a number of fin tube bundles. An axial flow, forced-draft fan in each module forces cooling air across the heat exchange area of the fin tubes, venting the waste heat to the atmosphere.

(IV) The fuel chargeable to power heat rate;

The SDPP will provide thermal energy for process use at the JCEP LNG gas conditioning plant and intends to use this thermal energy for cogeneration to lower its net carbon dioxide emissions rate. For the purposes of this exhibit, the fuel chargeable to power heat rate has been calculated as the net heat of electric power production using the following formula:

*FCP = (FI - FD) x (*10^6 / *P),* where:

FCP = Fuel chargeable to power heat rate,
FI = Expected fuel input to the facility (Btu/hr) (HHV)
FD = Average fuel displaced by co-generation (Btu/hr) (HHV)
P = Net output of the facility in kW

Calculation:

FI = 2,745 MBTU/hr
FD = 345 MBTU/hr
P = 311,000 kW
FCP = 7,717 BT/kWh (HHV)

The average fuel displaced by cogeneration (FD) is based on the anticipated actual production of the LNG Plant (refer to Exhibit Y, Section (N)(j)). The calculated fuel chargeable to power rate (FCP) will also depend on the actual CTG(s), HRSG(s), and STG(s) selected, and the amount of HRSG duct firing used.

OAR-345-021-0010(1)(b)(A)(vii) - (viii) are not applicable, because the SDPP is neither a surface facility related to underground gas storage nor a facility to store liquefied natural gas.

OAR-345-021-0010(1)(b)(B). *A description of major components, structures and systems of each related or supporting facility.*

Figure B-1, Sheets 1 and 2, provide the facility layout and shows the major components of the South Dunes Power Plant and the associated supporting or related facilities.

2.4 ELECTRICAL SWITCHYARD

A 115-kilovolt (kV), AC, open-air switchyard serving both power blocks will be located immediately north of the CTGs/STGs. The switchyard will be a leveled and graveled area approximately 800 by 400 feet within the security fence. The switchyard will include 115-kV circuit breakers and disconnect switches to allow for clearing faults on the connected transmission lines and for maintenance of the circuit breakers and transmission lines. The circuit breakers will be arranged for ultimate connection in a breaker and one-half configuration. Steel take-off towers will be provided for termination of 115-kV overhead transmission lines that will connect the switchyard with the plant generator step-up transformers and outgoing transmission lines. A small building will be included to provide a controlled environment for the protective relaying and communication equipment.

2.5 TRANSMISSION LINES

The SDPP will supply uninterrupted power to the LNG Plant and may provide power for distribution for public sale. A one-mile, double-circuit, 115-kV transmission line, will connect the switchyard at SDPP to the gas-insulated substation at the JCEP LNG Plant. Most of this line will be located in the JCEP utility corridor. A second 115 kV transmission line, 2,024 feet in length, will connect the switchyard to the relocated Pacific Power substation in the southeast portion of the SDPP site. This single-circuit 115-kV transmission line will be 71 to 91 feet above the bottom of the baseplate. An interconnection through the Pacific Power substation to the local Pacific Power system or to the Bonneville system through Central Lincoln public utility district (PUD) may be provided at a later date for distribution of power for public sale and local grid stabilization. That interconnection is not part of this application.

2.6 PACIFIC POWER SUBSTATION

The existing on-site substation for Pacific Power will be relocated to an area in the southeast part of the SDPP site. This substation will provide an alternate source for housekeeping power (via a 115-kV overhead single-circuit line) to the SDPP. This 115-kV transmission line will be available for future sale of power to other entities.

2.7 WATER SYSTEM CONNECTION AND DISTRIBUTION

One metered connection from the existing Coos Bay North Bend Water Board (CBNBWB) municipal pipeline to the SDPP site is required to provide water for potable, service, and demineralized water systems. The connection and majority of on-site piping will be installed below grade. The Applicant will connect to the CBNBWB's municipal pipeline at the TransPacific Parkway. However, neither the selection of the connection point nor the final design are available yet. At this time, the line is estimated to be a 36-inch pipeline. The SDPP pipeline will connect to all SDPP facilities where water service is required. Since the final route has not yet been determined, the location and length of the pipeline are not currently available.

2.8 ROADS

The SDPP on-site loop roads will be 24-feet-wide paved roads. The site entrance will connect to TransPacific Parkway at the northeast corner of the site. The access road used to service the BOG line and the 115-kV transmission line is located in the utility corridor. A temporary gravel road (the "haul road") will be built across Roseburg Forest Products property between the barge berth as described below and the SDPP site to carry equipment and power plant components from the barge berth to the SDPP site, as indicated on Figure B-1. This road is approximately 50-feet wide and 1.3 miles long. Upon completion of construction this road will be returned to the Roseburg Forest Products Company for their continued use.

2.9 TEMPORARY CONSTRUCTION FACILITIES

Areas on the SDPP site will be provided for limited construction offices, construction parking, and construction laydown during the construction process.

2.10 BARGE BERTH

An earth-filled sheet pile bulkhead and docking facility for barges to deliver heavy equipment and SDPP components will be built southwest of the site at the southeast entrance to the slip for the LNG Plant. Construction of the barge berth will require both dredging of the "Access Channel" to provide ships access to barge berth and fill along the berth to allow placement of the marine sheet piling and riprap. Although the barge berth is situated below the HMT elevation and is therefore in state jurisdictional waters, it is situated above the mean low tide (i.e. mean low water line) elevation of 0.36 feet (North American Vertical Datum of 1988 (NAVD88)) and therefore not within state-owned lands. See Exhibit J, Appendix J-2, Tab H, which provides a concurrence letter from the Department of State Lands regarding this matter. Typically "within waters of the State" means waters within the State's jurisdiction. In this case, the barge berth is being constructed within waters of the State, but is not being constructed on submerged land owned by the State. This berth is necessary because larger and heavier items cannot be delivered to the southwest coast through the existing highway and rail network.

2.11 GAS PIPELINE

The 10-inch BOG natural gas line from the LNG plant to the SDPP will provide most (approximately 96 percent) of the fuel for SDPP. It will be underground from the LNG facility through the utility corridor east to the bridge over Jordan Cove Road, aboveground over the bridge and through most of the SDPP and then underground to where gas is delivered to the combustion turbines. See Figure B-2, Sheets 1 and 2. The width of the utility corridor will be approximately 150 feet between the two plants depending on terrain. The BOG line will have an operating pressure of 835 pounds per square inch (psi), and the normal operating capacity (5 combustion turbines online) will be 135,000 pounds per hour.

2.12 GAS METERING STATION

A metering station where the Pacific Connector Gas Pipeline terminates at the SDPP site will measure the gas entering the site and used in the power plant. The anticipated dimensions for the Pacific Connector Gas Metering facility are approximately 200 feet by 180 feet (36,000 square feet).

2.13 OTHER STRUCTURES AND SURFACES

- The Administration Building (administration, secretarial, accounting, IT, and bookkeeping) will be approximately 80 feet long, 55 feet wide, and 20 feet high. It will be a pre-engineered metal building with a metal roof and sidewall panels.
- The Control Building will be approximately 130 feet long, 90 feet wide, and 30 feet high. It will also be a pre-engineered building with a metal roof and sidewall panels that will house controls for SDPP, and will also have a laboratory facility.
- The Operations Building will be approximately 102 feet long, 100 feet wide, and 30 feet high and will include warehousing, receiving, parts, and maintenance personnel. This building will also be a pre-engineered metal building with a metal roof and sidewall panels.
- Parking lots will serve personnel and visitors and will occupy approximately 6 acres. An additional lot, to be shared by the Administration, Operations, and Control Buildings, will be less than one-quarter acre in size. All lots will be paved.

- A stormwater pond, used for infiltration of site runoff, will be approximately 1.5 acres in size and has been designed to provide infiltration for a 2-year, 24-hour storm event.
- A 5,000 gallon double-wall steel aboveground storage tank will store and dispense diesel fuel for truck and emergency equipment.
- Water treatment facilities. This will include a reverse osmosis system for purifying incoming water from the Coos Bay North Bend Water Board. The water treatment facility will consist of pretreatment, reverse osmosis, and ion exchange equipment to produce treated water for plant use. The equipment will be housed in the water treatment building, to be located immediately south of the SDPP power blocks, as shown in Figure B-1. This facility is a pre-engineered metal building of approximately 12,000 square feet, with heating and ventilation systems. Chemicals necessary to support these water treatment processes are: sodium hypochlorite, filter aid, scale inhibitor, sodium bisulfite and sodium hydroxide, additional details are provided in Table G-2.
- The Waste Water Treatment Plant, this plant will treat domestic sewage generated at the SDPP. The effluent will be discharged under the National Pollutant Discharge Elimination System permit (see Exhibit E).

OAR-345-021-0010(1)(b)(C). *The approximate dimensions of major facility structures and visible features.*

The SDPP will be located within a fenced area on the former Weyerhaeuser linerboard site, which was closed in 2003 and has since been demolished. Closure of the former mill site will include placement of fill and a soil cover over former settling basins and disposal areas. As an outdoor power plant located at a nominal elevation of 40 to 46 feet above mean sea level, most of the major equipment (CTGs, STGs, HRSGs, exhaust stacks, ACCs, water tanks, and switchyard equipment) will be visible from the east or south. Cranes may be on the site during construction.

Each CTG will have a metal enclosure expected to be between approximately 60 and 70 feet long. The intake air filter, ventilation, and variable bleed equipment for the combustion turbine would be located on top of the CTG enclosure. The enclosure outfitted with the intake air filter, ventilation, and variable bleed equipment on top is expected to be approximately 40 feet wide and 50 feet high.

Each STG will have a metal enclosure expected to be between approximately 60 and 90 feet long, 35 feet wide, and 50 feet high.

Each HRSG will be an outdoor metal structure occupying a footprint of approximately 140 by 25 feet. Two insulated drums will be located on top of each HRSG at an elevation of approximately 75 feet. Each HRSG will connect to the back of a CTG enclosure, extending lengthwise axially with the CTG enclosure on the opposite side of the generator. Each HRSG will connect to a steel exhaust stack approximately 119 feet above grade (165 feet above sea level) and 11 feet in diameter. The actual values for stack height and diameter will be determined from air dispersion analysis.

Each ACC consists of finned tube elements called streets, elevated on columns. Each street is divided into multiple cells, with each cell containing a fan to force air across the finned tube bundle to cool and condense the steam. Multiple streets will be required, but the total for each ACC is not expected to exceed two. The total number of cells for each ACC will be approximately 6 to 8. ACC dimensions are expected to be approximately 190 by 120 feet, with the top of the structure approximately 75 feet above grade (121 feet above sea level).

The control, administration, and maintenance buildings will be pre-engineered metal buildings with metal roofs and sidewall panels. The control building is expected to be approximately 130 feet long, 90 feet wide, and 30 feet high. The administration building will be approximately 80 feet long, 55 feet wide, and 20 feet high. The shop/warehouse building will be approximately 102 feet long, 100 feet wide, and 30 feet high.

Outdoor oil-filled generator step-up transformers and auxiliary transformers will be located in an on-site switchyard north of the CTGs and STGs. The transformers will be surrounded by concrete walls as required to provide the necessary fire barriers between the transformers.

OAR 345-021-0010(1)(b)(D). *If the proposed energy facility is a pipeline or a transmission line or has, as a related or supporting facility, a transmission line or pipeline that, by itself, is an energy facility under the definition in ORS 469.300, a corridor selection assessment explaining how applicant selected the corridor(s) for analysis in the application. In the assessment, applicant shall evaluate the corridor adjustments the Department has described in the project order, if any. The applicant may select any corridor for analysis in the application and may select more than one corridor. However, if applicant selects a new corridor, then applicant must explain why the applicant did not present the new corridor for comment at an informational meeting under OAR 345-015-0130. In the assessment, the applicant shall discuss the reasons for selecting the corridor(s).*

This section is not applicable. Under ORS 469.300(11) the related or supporting transmission lines are not an “energy facility” under ORS 469.300, because (1) the line between the SDPP and the Liquefied Natural Gas (LNG) facility is approximately one mile in length and has a capacity of 115 kV and (2) the line between the SDPP and Pacific Power’s substation is only 2,024 feet (less than half a mile) and 1,020.5 amps and 60 MW. Because both transmission lines are less than 10 miles in length they do not meet the definition of “energy facility” under ORS 469.300.

There are two transmission lines, one is a double-circuit line between the SDPP and the LNG facility to the west, and the other is a single-circuit line between the SDPP and the Pacific Power substation located in the southeast corner of the SDPP site. The routes are depicted in Figure B-1.

The transmission line between the SDPP and the LNG facility will be a double-circuit (two sets of conductors located on a single series of power pole structures) 115-kV line approximately one mile in length. The load carrying capacity of this alternating current (AC) double-circuit line is 2,041 amps. Two circuits are provided between the SDPP and the LNG facility so that an uninterrupted power supply can be provided to the LNG facility while maintenance is performed on the other circuit.

The transmission line between the SDPP and the Pacific Power substation will be a single-circuit 115-kV line. This line is approximately 2,024 feet in length. The carrying capacity of the line between the SDPP and the Pacific Power substation is 1,020.5 amps. This transmission line will also have the capability to carry 60 megawatts (MW) from the SDPP to the Pacific Power substation.

The BOG pipeline in the utility corridor is not an "energy facility" under ORS 469.300, because it will be 10 inches in diameter and only approximately one mile long, which is less than the 16-inch diameter and five-mile length required for a natural gas pipeline to be considered an "energy facility" pursuant to the definition in ORS 469.300.

Therefore, a corridor selection assessment is not required for either of the transmission lines or the BOG pipeline.

OAR 345-021-0010(1)(b)(E). *If the proposed energy facility is a pipeline or transmission line or has, as a related or supporting facility, a transmission line or pipeline of any size:*
(i) The length of the pipeline or transmission line.

The access road and utility corridor between the SDPP and the LNG Plant, where the 115-kV transmission line and the BOG line will be located, is approximately one mile long. The 60-MW transmission line between the SDPP switchyard and the Pacific Power substation is approximately 2,024 feet long. As stated above, both the 115-kV transmission line and BOG pipeline between the LNG facility and SDPP are approximately one mile in length.

(ii) The proposed right-of-way width of the pipeline or transmission line, including to what extent new right-of-way will be required or existing right-of-way will be widened.

No off-site or public rights-of-way will be required. The corridor width will be approximately 150 feet between the two plants, and will be entirely on JCEP properties, except for the overpass crossing of Jordan Cove Road.

(iii) If the proposed corridor follows or includes public right-of-way, a description of where the facility would be located within the public right-of-way, to the extent known. If the applicant proposes to locate all or part of a pipeline or transmission line adjacent to but not within the public right-of-way, describe the reasons for locating the facility outside the public right-of-way. The applicant must include a set of clear and objective criteria and a description of the type of evidence that would support locating the facility outside the public right-of-way, based on those criteria.

No public rights-of-way will be required.

(iv) For pipelines, the operating pressure and delivery capacity in thousand cubic feet per day and the diameter and location, above or below ground, of each pipeline

The BOG pipeline within the road access and utility corridor will be 10 inches in diameter and operate at a pressure of 835 psi. It will have a normal operating capacity of 135,000 pounds per hour (based on 5 CTGs online).

(v) For transmission lines, the rated voltage, load carrying capacity, and type of current and a description of transmission line structures and their dimensions.

The generator step-up transformers will be connected by overhead lines to a 115-kV switchyard for transmission of the power generated to the LNG facility and to the Pacific Power substation. The load carrying capacity of the AC double-circuit line to the LNG facility is 2,041 amps, and of the AC single-circuit line to the Pacific Power substation is 1,020.5 amps. The transmission structures will be single steel or concrete poles.

The transmission line between the Pacific Power substation and the SDPP will be a single-circuit 60-MW AC line.

OAR 345-021-0010(1)(b)(F). *A construction schedule including the date by which the applicant proposes to begin construction and the date by which the applicant proposes to complete construction. Construction is defined in OAR 345-001-0010. The applicant shall describe in this exhibit all work on the site that the applicant intends to begin before the Council issues a site certificate. The applicant shall include an estimate of the cost of that work. For the purpose of this exhibit, "work on the site" means any work within a site or corridor, other than surveying, exploration or other activities to define or characterize the site or corridor, that the applicant anticipates or has performed as of the time of submitting the application.*

As a prudent property owner, the Applicant is making general site development improvements intended to prepare the site for future use, to the property over which the Energy Facility Siting Council's site boundary is laid. The general property improvements are outlined in Table B-1. These improvements are required, regardless of whether the SDPP is constructed, in order to prepare the site for any future industrial development as there are landfills, environmental contaminants and buried logs beneath the soil. The general property improvements will allow a future industrial use to be constructed on stable ground for the above reasons. These improvements are being undertaken consistent with all necessary authorizations and have utility independent of the specific project pending before Council. Such activities are subject to the following permits: a Solid Waste Disposal Site Closure Permit for landfills and a NPDES Stormwater (1200-C) permit. The Applicant intends to begin these general improvements prior to obtaining a site certificate as they are outside Council's jurisdiction because they are not being undertaken as part of the SDPP and are not a supporting or related facility in connection with the SDPP. Approximate cost estimates are based on preliminary estimates for earthwork and property improvements.

As indicated in the schedule on Figure B-3, the proposed construction start date for the SDPP is January 2016 and the estimated construction completion date will be February 2019, with startup and commissioning anticipated by September 2019. While this is the Applicant's preferred schedule, the Applicant is requesting flexibility to start and complete construction due to the complexity of this project and the reliance upon other facilities which are currently being permitted and will need to be constructed in order to operate the SDPP. The operation of the SDPP requires the delivery of gas from the Pacific Connector Gas Pipeline and the use of processed gas that has been through the gas conditioning facility, which is part of a larger LNG terminal.

As noted in prior Council documents[1], in relation to OAR 345-027-0020(4)[2], Council has stated that ‘construction is complete’ when: (1) as defined by the construction contract documents, (2) acceptance testing has been satisfactory completed, and (3) the facility is *ready to begin continuous operation*. (Emphasis added.) Thus, the standard to have ‘completed construction’ requires that the facility be ready to begin continuous operation and as described above, the SDPP is part of a larger multifaceted facility which will require a pipeline and LNG terminal to have also been constructed before the SDPP will be ready to begin continuous operation and meet the ‘completed construction’ requirement.

The Applicant requests flexibility to begin and complete construction for the following reasons:

- The Applicant has diligently been working toward permitting the SDPP, the pipeline and the LNG terminal. The already incurred, substantial time investment to arrive at the current point of permitting evidences the need to grant the Applicant adequate time to complete the permitting process for this complex development project.
  - The Notice of Intent (NOI) to apply for a site certificate for the SDPP was submitted over two years ago on August 1, 2012. The Applicant anticipates a site certificate will be issued in the second quarter of 2016, nearly four years after the NOI was submitted.
  - On June 6, 2013 Pacific Connector filed its application for a certificate of public convenience and necessity to construct, own and operate the pipeline to FERC. A certificate is anticipated to be issued in June 2015, which will be two years from the time the application was submitted.
  - The Jordan Cove Energy Project, L.P. submitted its application to FERC on May 21, 2013 seeking permission to site, construct and operate an LNG terminal. The Applicant anticipates FERC will issue an approval for the LNG terminal in June 2015, nearly two years after the application was submitted.
- The need to fully entitle, which includes review by the Federal Energy Regulatory Commission and construct the LNG facility to provide gas to operate the SDPP.
- The need to fully entitle, which includes review by the Federal Energy Regulatory Commission and the acquisition and right of way for the pipeline, and construct 230 miles of gas pipeline.
- Permitting complexities including:
  - The Applicant requires Department of State Land approval for a Removal-Fill permit for the LNG facility and pipeline.

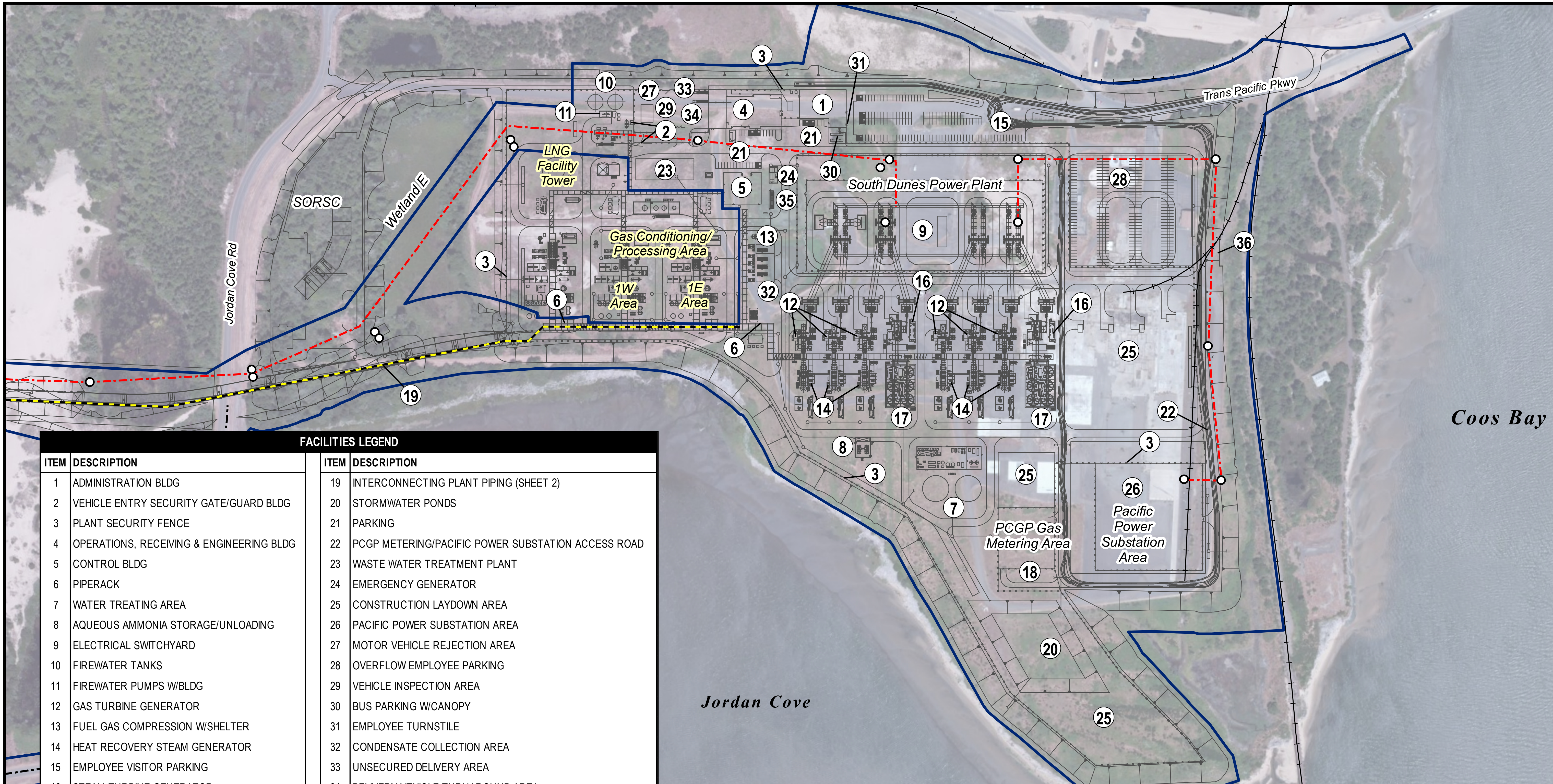
[1] Brush Canyon Wind Power Facility, Draft Proposed Order, p. 23. Troutdale Energy Center, Proposed Order, p. 14. Carty Generating Station, Site Certificate, p. 8.
[2] Requiring Council to specific the dates by which construction will begin and be completed.

  - Because the SDPP is in the coastal zone, the applicant requires a consistency determination under the Coastal Zone Management Act.

- Unanticipated delays due to weather, construction, component delivery, etc. which proportionally are greater with a project of the this scale and complexity.

For the above reasons, the Applicant proposes that construction begin within three years of the effective date of a site certificate and that construction be completed within five years of beginning construction. This schedule simultaneously limits the permitted construction window as much as possible and allows a realistic period to obtain necessary permits and complete construction. No work requiring authorization under Council's jurisdiction is proposed to begin prior to issuance of the site certificate.

Figure B-1 Sheet 1. Facility Layout with Related or Supporting Facilities



FACILITIES LEGEND			
ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	ADMINISTRATION BLDG	19	INTERCONNECTING PLANT PIPING (SHEET 2)
2	VEHICLE ENTRY SECURITY GATE/GUARD BLDG	20	STORMWATER PONDS
3	PLANT SECURITY FENCE	21	PARKING
4	OPERATIONS, RECEIVING & ENGINEERING BLDG	22	PCGP METERING/PACIFIC POWER SUBSTATION ACCESS ROAD
5	CONTROL BLDG	23	WASTE WATER TREATMENT PLANT
6	PIPERACK	24	EMERGENCY GENERATOR
7	WATER TREATING AREA	25	CONSTRUCTION LAYDOWN AREA
8	AQUEOUS AMMONIA STORAGE/UNLOADING	26	PACIFIC POWER SUBSTATION AREA
9	ELECTRICAL SWITCHYARD	27	MOTOR VEHICLE REJECTION AREA
10	FIREWATER TANKS	28	OVERFLOW EMPLOYEE PARKING
11	FIREWATER PUMPS W/BLDG	29	VEHICLE INSPECTION AREA
12	GAS TURBINE GENERATOR	30	BUS PARKING W/CANOPY
13	FUEL GAS COMPRESSION W/SHELTER	31	EMPLOYEE TURNSTILE
14	HEAT RECOVERY STEAM GENERATOR	32	CONDENSATE COLLECTION AREA
15	EMPLOYEE VISITOR PARKING	33	UNSECURED DELIVERY AREA
16	STEAM TURBINE GENERATOR	34	DELIVERY VEHICLE TURNAROUND AREA
17	AIR COOLED CONDENSER	35	13.8 KV SWITCHGEAR
18	PACIFIC CONNECTOR GAS METERING AREA	36	RETAINING WALL

N

0 160 320 Feet

1 inch = 320 feet

EFSC Site Boundary
Power Pole
Existing Rail
Heavy Equipment Truck Haul Road Centerline
Gas Pipeline
Overhead Power Transmission Line (115kV)

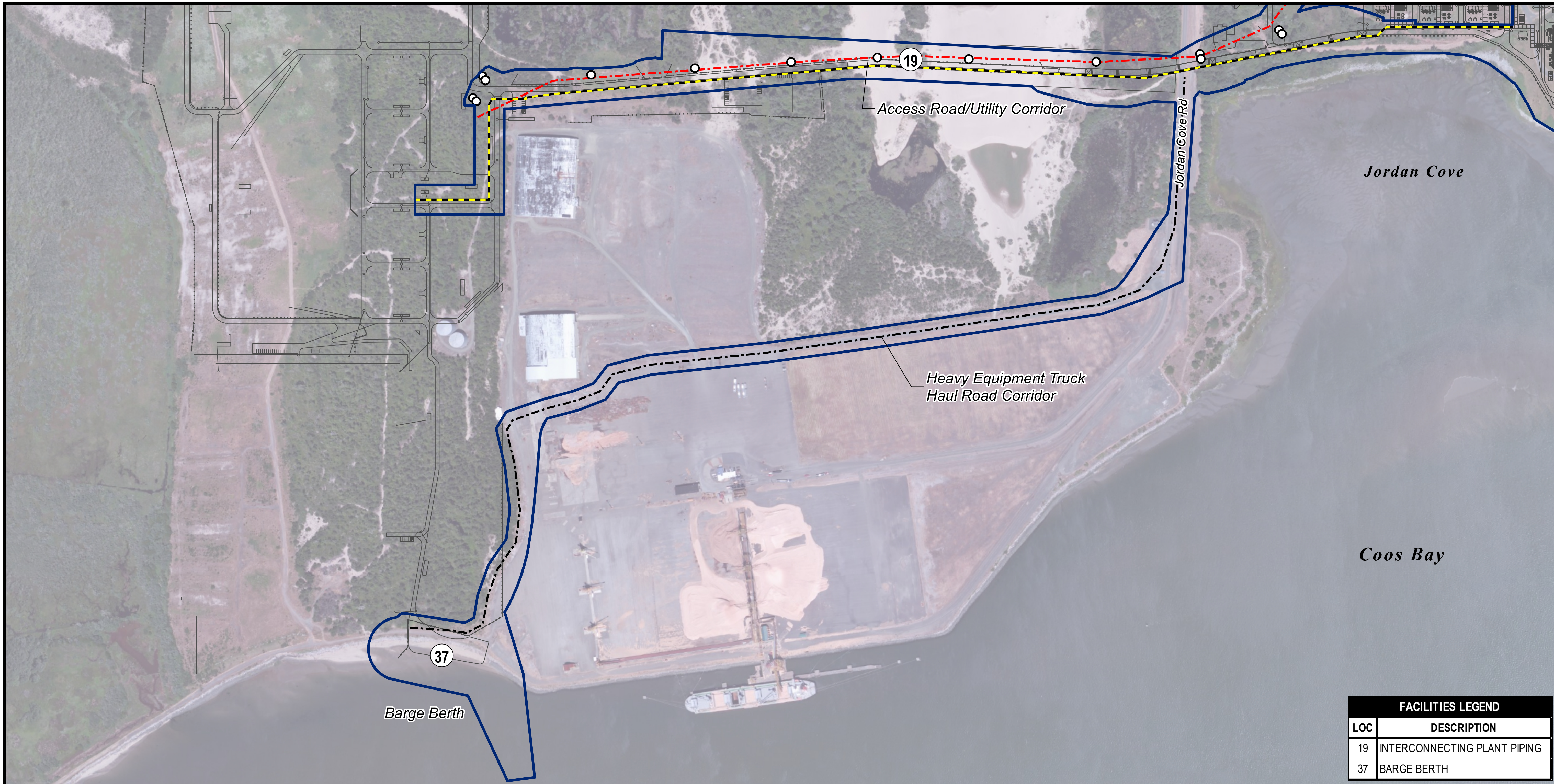
South Dunes Power Plant Project

EFSC Application

EXHIBIT B
Figure B-1, Sheet 1 of 2
Facility Layout with Related or Supporting Facilities

Date: 10/2/2014
Reviewed By MM
Designed By SAST

Figure B-1 Sheet 2. Facility Layout with Related or Supporting Facilities



FACILITIES LEGEND	
LOC	DESCRIPTION
19	INTERCONNECTING PLANT PIPING
37	BARGE BERTH

N

0 250 500 Feet

1 inch = 500 feet

EFSC Site Boundary
Heavy Equipment Truck Haul Road Centerline
Gas Pipeline
Overhead Power Transmission Line (115kV)
Existing Rail
Power Pole

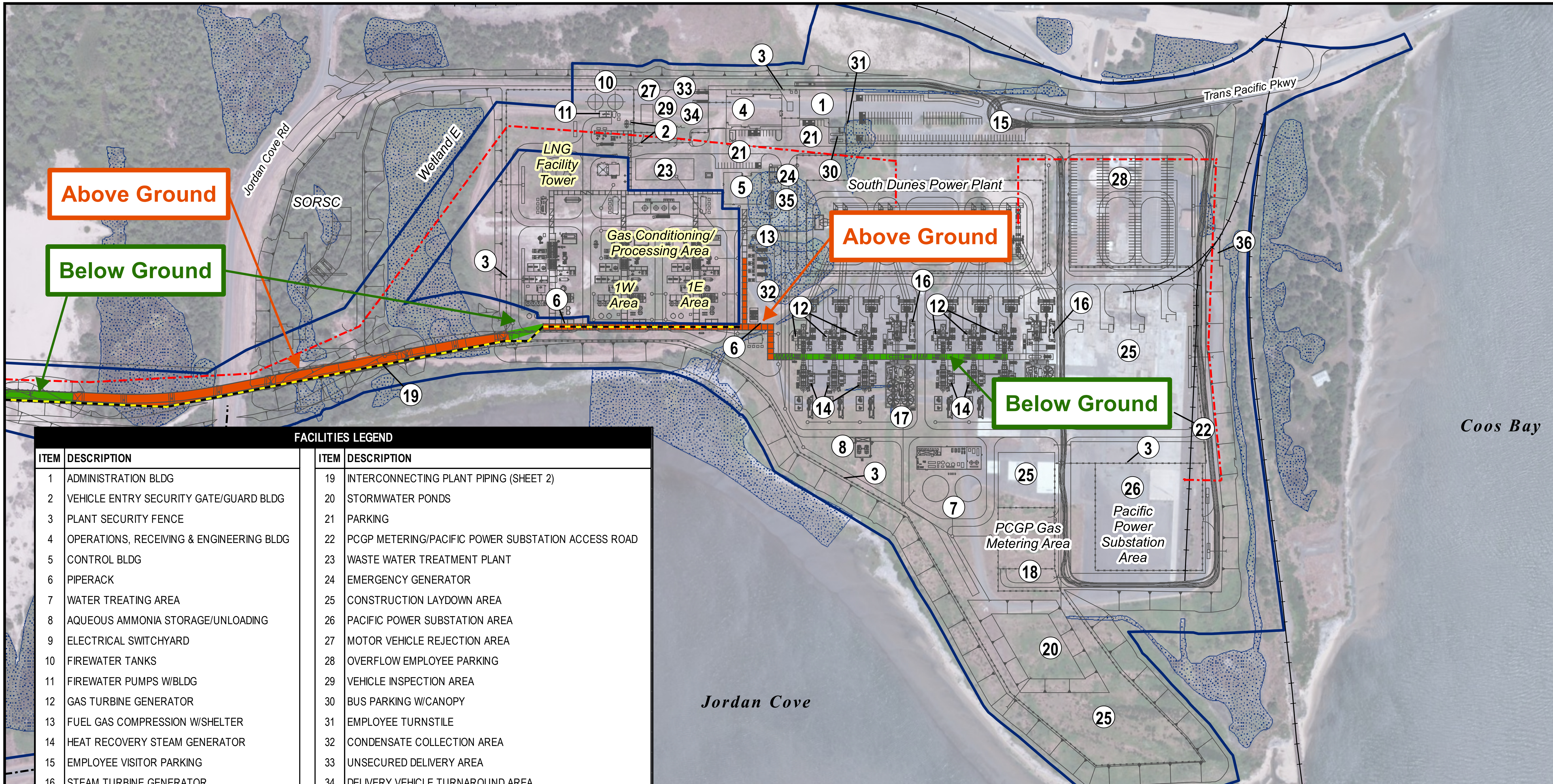
South Dunes Power Plant Project

EFSC Application

EXHIBIT B
Figure B-1, Sheet 2 of 2
Facility Layout with Related or Supporting Facilities

Date: 9/18/2014
Reviewed By BL
Designed By SAST

Figure B-2 Sheet 1. Facility Layout with Above and Below Ground Gas Lines



FACILITIES LEGEND			
ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	ADMINISTRATION BLDG	19	INTERCONNECTING PLANT PIPING (SHEET 2)
2	VEHICLE ENTRY SECURITY GATE/GUARD BLDG	20	STORMWATER PONDS
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4	OPERATIONS, RECEIVING & ENGINEERING BLDG	22	PCGP METERING/PACIFIC POWER SUBSTATION ACCESS ROAD
5	CONTROL BLDG	23	WASTE WATER TREATMENT PLANT
6	PIPERACK	24	EMERGENCY GENERATOR
7	WATER TREATING AREA	25	CONSTRUCTION LAYDOWN AREA
8	AQUEOUS AMMONIA STORAGE/UNLOADING	26	PACIFIC POWER SUBSTATION AREA
9	ELECTRICAL SWITCHYARD	27	MOTOR VEHICLE REJECTION AREA
10	FIREWATER TANKS	28	OVERFLOW EMPLOYEE PARKING
11	FIREWATER PUMPS W/BLDG	29	VEHICLE INSPECTION AREA
12	GAS TURBINE GENERATOR	30	BUS PARKING W/CANOPY
13	FUEL GAS COMPRESSION W/SHELTER	31	EMPLOYEE TURNSTILE
14	HEAT RECOVERY STEAM GENERATOR	32	CONDENSATE COLLECTION AREA
15	EMPLOYEE VISITOR PARKING	33	UNSECURED DELIVERY AREA
16	STEAM TURBINE GENERATOR	34	DELIVERY VEHICLE TURNAROUND AREA
17	AIR COOLED CONDENSER	35	13.8 KV SWITCHGEAR
18	PACIFIC CONNECTOR GAS METERING AREA	36	RETAINING WALL

N

0 160 320 Feet

1 inch = 320 feet

EFSC Site Boundary
Heavy Equipment Truck Haul Road Centerline
Gas Pipeline
Overhead Power Transmission Line (115kV)
Existing Rail
Above Ground Gas Line
Below Ground Gas Line
Delineated Wetland

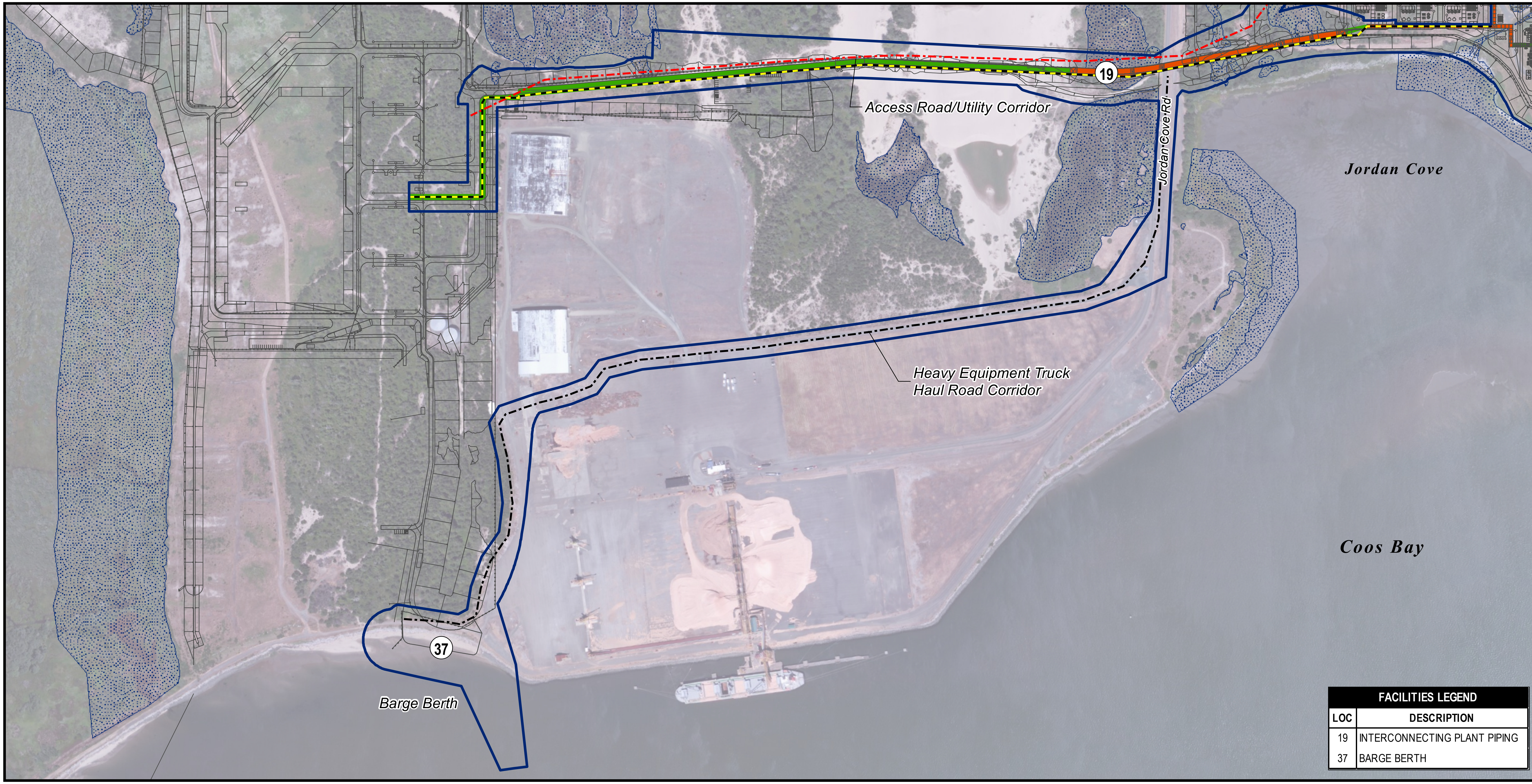
South Dunes Power Plant Project

EFSC Application

EXHIBIT B
Figure B-2, Sheet 1
Facility Layout with Above and Below Ground Gas Lines

Date: 9/22/2014
Reviewed By PS
Designed By SAST

Figure B-2 Sheet 2. Facility Layout with Above and Below Ground Gas Lines



N

0 250 500 Feet

1 inch = 500 feet

EFSC_Site_Boundary
Heavy Equipment Truck Haul Road Centerline
Gas Pipeline
Overhead Power Transmission Line (115kV)
Existing Rail
Above Ground Gas Line
Below Ground Gas Line
Delineated Wetland

South Dunes Power Plant Project

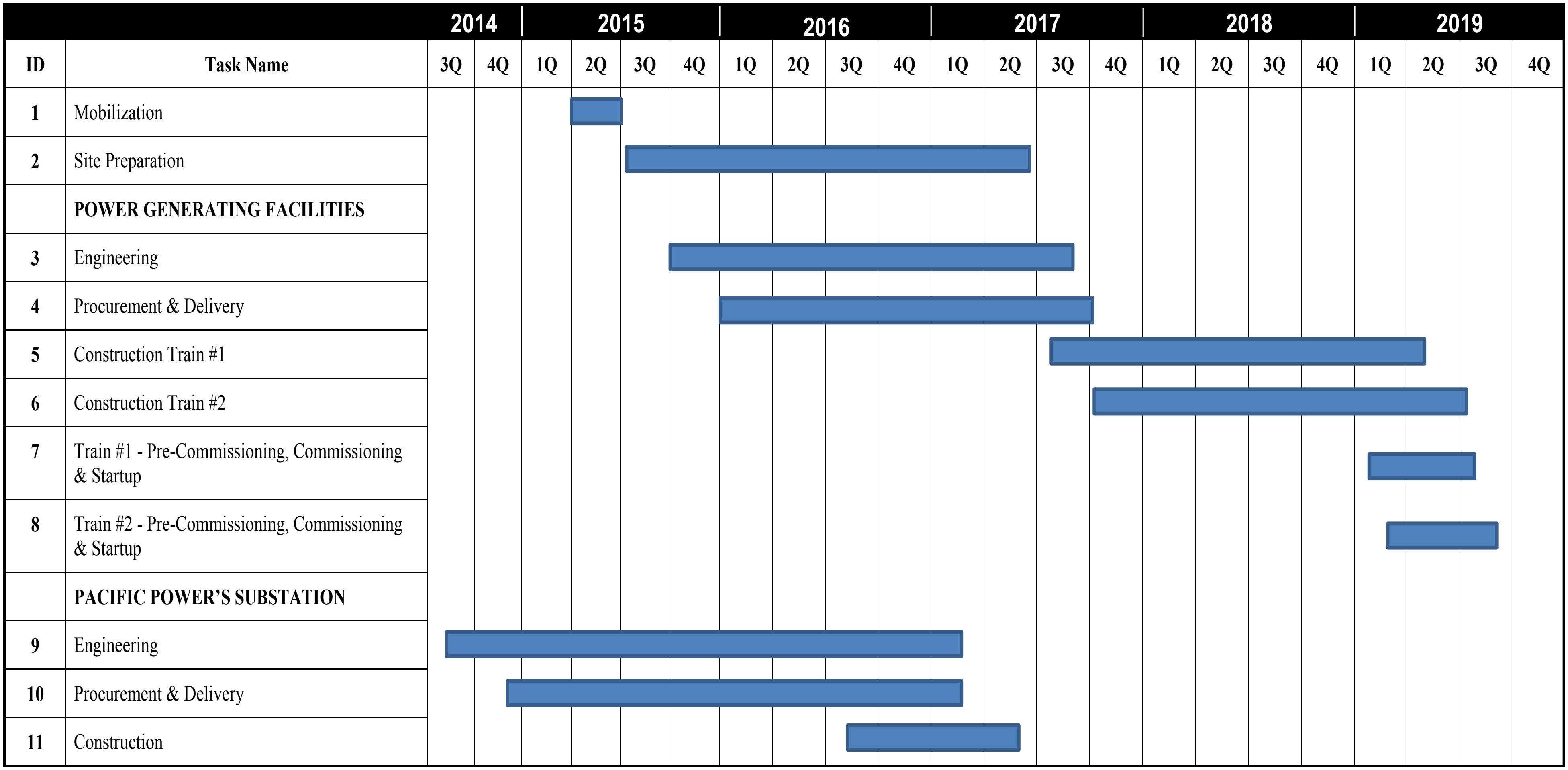
EFSC Application

EXHIBIT B
Figure B-2, Sheet 2 of 2
Facility Layout with Above and Below Ground Gas Lines

Date: 9/18/2014
Reviewed By PS
Designed By SAST

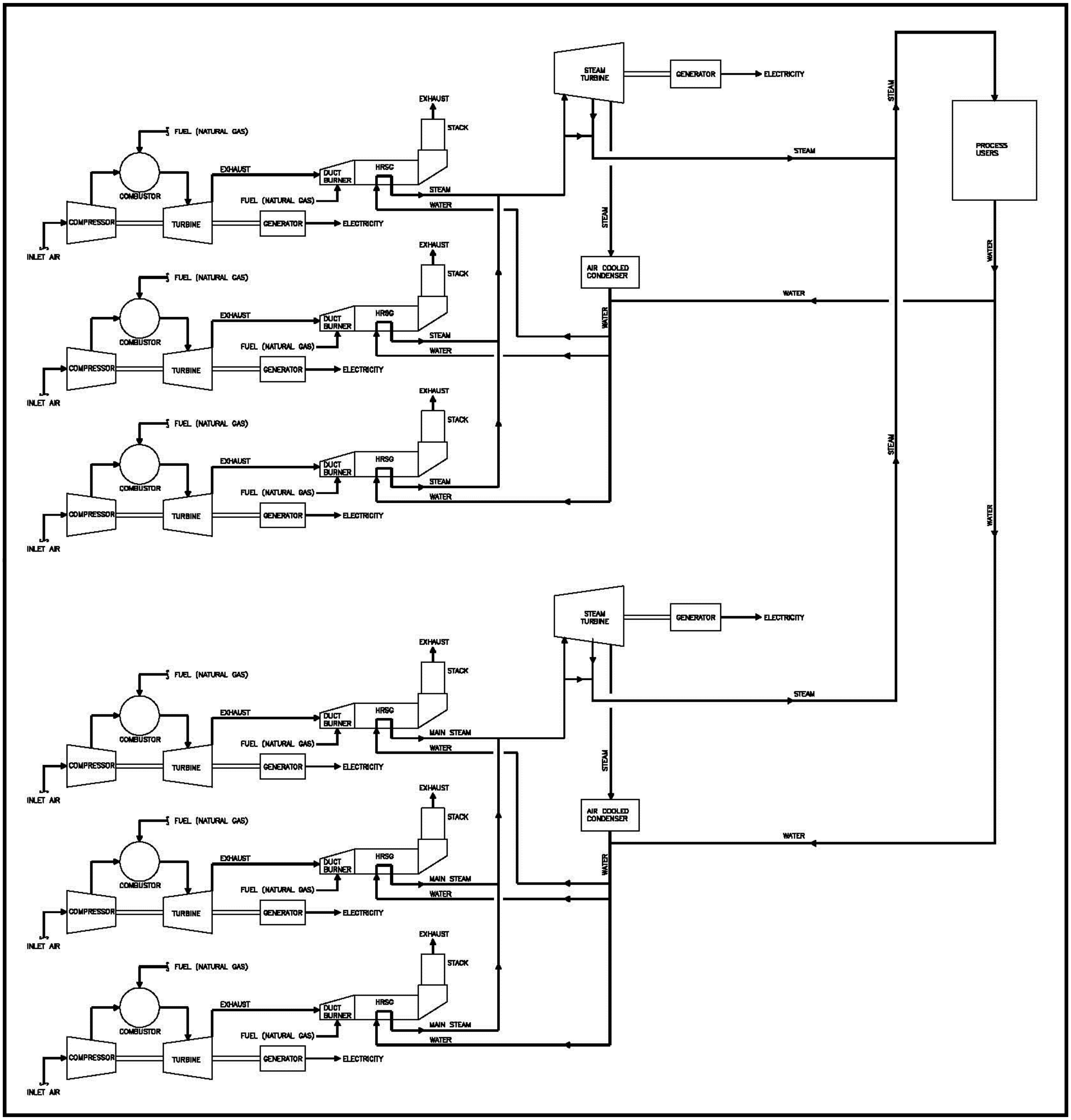
Figure B-3. South Dunes Power Plant Schedule

South Dunes Power Plant Schedule
Site Certificate on January 1, 2016
In-Service on September 1, 2019



South Dunes Power Plant Project	
EFSC Application	
EXHIBIT B Figure B-3 South Dunes Power Plant Schedule	Date: 10/9/2014 Reviewed By BL Designed By MMF

Figure B-4. Process Flow Diagram



	South Dunes Power Plant Project
	EFSC Application
EXHIBIT B **Figure B-4** **Process Flow Diagram**	Date: 10/15/2014 Reviewed By SB Designed By SAST

APPENDIX B-1

Memorandum of Understanding and Agreement No. 14-008 by and between Jordan Cove Energy Project and the State of Oregon for LNG Emergency Preparedness

MEMORANDUM OF UNDERSTANDING AND AGREEMENT No. 14-009 BY AND BETWEEN JORDAN COVE ENERGY PROJECT AND THE STATE OF OREGON FOR CO2 AND FINANCIAL ASSURANCE FOR FACILITIES RETIREMENT

I. RECITALS

WHEREAS, in August 2005, President Bush signed into law the Energy Policy Act of 2005 giving the Federal Energy Regulatory Commission ("FERC") exclusive authority to approve or deny the siting, construction, expansion or operation of an LNG terminal located onshore or in state waters. Prior to the 2005 Energy Policy Act, the Oregon Department of Energy ("ODOE") and the Energy Facility Siting Council ("EFSC") had siting authority over proposed LNG facilities in Oregon.

WHEREAS, the Energy Policy Act of 2005 requires LNG terminal applicants to develop an Emergency Response Plan for terminal operations, subject to consultation with the United States Coast Guard and state and local agencies, and subject to FERC approval.

WHEREAS, recognizing the importance of participating in the federal review process, the Governor in January 2006 designated ODOE as the lead state agency for ensuring that Oregon's interests are addressed in the federal FERC siting process.

WHEREAS, ODOE has been delegated the responsibilities for emergency preparedness for LNG facilities (ORS 469). This includes working with LNG developers to develop and maintain an emergency response plan to protect citizens from LNG leaks and fires should a terminal be built and to provide oversight throughout the life of the project.

WHEREAS, Jordan Cove Energy Project (JCEP) started its siting process with the state prior to the Energy Policy act of 2005, JCEP agreed to maintain state standards for C02 and facility financial assurance not otherwise covered by federal authority.

WHEREAS, Jordan Cove Energy Project (JCEP) has applied to FERC for authorization to construct and operate an LNG export terminal located on a 400 acre site on the north shore of Coos Bay, Oregon. The site is approximately seven miles up the channel that connects the bay to the Pacific Ocean, and about 1.2 miles northwest of the North Bend Municipal Airport. ("Terminal").

WHEREAS, JCEP and ODOE entered into Memorandum of Understanding and Agreement No. 09-100 by and Between Jordan Cove Energy Project and the State of Oregon for Emergency Preparedness, CO2, and Retirement and Financial Assurance on February 27, 2009 ("2009 MOU");

WHEREAS JCEP and ODOE desire for convenience to separate the 2009 MOU into two agreements: this Memorandum of Understanding and Agreement No. 14-008 by and Between Jordan Cove Energy Project and the State of Oregon for CO2 and Financial Assurance for Facilities Retirement ("MOU") and the separate Memorandum of Understanding and Agreement No. 14-009 by and Between Jordan Cove Energy Project and the State of Oregon for LNG Emergency Preparedness ("Emergency Preparedness MOU").

NOW THEREFORE, the parties hereby agree as follows:

II. EFFECT ON 2009 MOU

The 2009 MOU is superseded in its entirety by this MOU and the Emergency Preparedness MOU, and the 2009 MOU is of no further force or effect.

III. Purposes

This Memorandum of Understanding (MOU) establishes a framework for cooperation and outlines responsibilities for the State of Oregon and the Jordan Cove Energy Project (JCEP) for 1) mitigating CO2 emissions from the operation of the proposed LNG terminal and any Non-EFSC jurisdictional associated electric cogeneration facility (Cogeneration Facility); and 2) providing a retirement cost estimate and funding surety that is consistent with the state requirements for energy facilities.

IV. Objectives

JCEP agrees to cooperate to mitigate carbon dioxide (CO2) emissions from the operation of the proposed LNG terminal and Cogeneration Facility pursuant to Section IV, which establishes that CO2 mitigation terms shall be consistent with the existing requirements that apply to electric generating facilities under EFSC jurisdiction.

JCEP agrees to cooperate to provide a retirement cost estimate and funding surety described in Section V, which is consistent with the existing requirements for energy facilities under EFSC jurisdiction.

V. CO2 Authorities and Responsibilities

JCEP will commit to mitigate carbon dioxide (CO2) emissions from the operation of the proposed LNG terminal and Cogeneration Facility pursuant to the terms of this Section IV. Notwithstanding anything to the contrary herein, to the extent JCEP is required to mitigate, offset, or reduce CO2 emissions pursuant to any future state or federal CO2 emissions mitigation, offset, or reduction program, ODOE shall, to the extent allowable under the applicable program, consider the CO2 mitigation performed pursuant to the MOU as being applicable toward the new program. CO2 mitigation terms shall be consistent with the current requirements that apply to electric generating facilities under EFSC jurisdiction. For such facilities, the EFSC standard for CO2 is written in terms of output CO2 per unit electricity produced.

There is no parallel standard for LNG terminals. However, the basic CO2 standard for EFSC facilities requires that licensees match the best available technology, and then improve on the best available technology by 17%. EFSC jurisdictional facilities that improve on the best available technology by 17% or more are deemed to meet the CO2 standard outright. Any emissions in excess of 17% below the emissions produced using best available technology must be offset, either directly or by providing offset funds to a "qualified organization" as described in ORS 469.503. The EFSC has found that the Oregon Climate Trust is a qualified organization.

Therefore, for the proposed LNG terminal, ODOE and JCEP agree that a CO2 offset method consistent with the one used by EFSC shall be followed. The proposed LNG terminal would emit CO2 by the use of natural gas fuel in combustion vaporizers and fired heaters. JCEP has committed to using the most efficient commercially available vaporizer and heater design. Therefore, to be consistent with the EFSC standard for generating facilities, JCEP shall be required to offset 17% of those emissions. Provided The Climate Trust agrees to the terms and conditions of the applicable provisions of this MOU, ODOE and JCEP will adopt the following terms and conditions:

(1) Before beginning construction of the facility, JCEP shall make payment to The Climate Trust in the amount of the monetary path payment requirement (in 2009 dollars) as determined by the calculations set forth in Condition (3). The purposes of this MOU "the binding agreement between the State of Oregon and the applicant, authorizing the applicant to construct and operate a facility on an approved site, incorporating all conditions imposed by the council on the applicant (ORS 469.300(26))" as such term is used herein, means the offset funds and selection and contracting funds that JCEP must disburse to The Climate Trust pursuant to this MOU. The offset fund rate for the monetary path payment requirement shall be the rate in dollars per short ton of CO2 that EFSC has set forth in Oregon Administrative Rules at OAR Chapter 345-024-0560 as in effect at the time of payment. The calculation of 2009 dollars shall be made using the Gross Domestic Product Implicit Price Deflator as published by the Oregon Department of Administrative Services (Index).

   (a) In the event of any dispute between JCEP and The Climate Trust with respect to whether the monetary path payment complies with the requirements of this MOU, either JCEP or The Climate Trust may submit the matter to ODOE for its determination as to whether JCEP is in compliance with the requirements of this Section IV(1). ODOE shall make its determination within 60 days following receipt of all relevant information regarding the dispute and its decision shall be binding on all parties.

   (b) In the event that FERC approves a new license holder for the LNG facility, the new license holder shall submit to ODOE for ODOE's approval evidence of payment to the Climate Trust in the amount calculated under this MOU for the monetary path payment.

   (c) If the full monetary path payment is not paid by December 31, 2014, the amount of the monetary path payment shall increase annually by the percentage increase in the Index and shall be prorated within the year to the date of disbursement to The Climate Trust from the date FERC approval of the facility.

(2) JCEP shall disburse to The Climate Trust offset funds and selection and contracting funds as requested by The Climate Trust. JCEP shall make disbursements in response to requests from The Climate Trust in accordance with subsections (a), (b), and (c).

(a) JCEP shall disburse all selection and contracting funds to the Climate Trust prior to beginning construction, which funds shall not exceed 10% of the offset funds up to $500,000 and 4.286% of any offset funds in excess of $500,000.

(3) JCEP shall submit monetary path payment requirement calculations to ODOE for verification in a timely manner before making the monetary path payment to the Climate Trust. JCEP shall use the contracted design parameters for heat exchanger and combustion turbine heat rates that it reports pursuant to Condition (4) to calculate the monetary path payment requirement.

(4) JCEP shall include an affidavit certifying the heat rates and capacities reported in subsections (a) and (b).

(a) Before beginning construction of the facility, JCEP shall notify ODOE in writing of its final selection of LNG vaporization technology, expected thermal efficiency of combustion vaporizers and fired heaters, the design annual throughput of the facility assuming full time operations at 100% capacity factor, and the expected annual consumption of fuel in vaporizers and fired heaters under the assumption of 100% capacity operations over the full year at annual average site temperature and pressure.

(b) Before beginning construction of the Cogeneration Facility, if applicable, JCEP shall submit written design information to ODOE sufficient to verify the Cogeneration Facility's designed new and clean heat rate and its net power output at average annual site conditions.

(5) JCEP shall calculate the monetary path payment requirement as follows:

(a) For submerged combustion vaporizers ("SCV's") and hot oil heaters, the monetary path payment requirement is

EAC x 30 x 0.17 x 117/2000 x MPR

Where

- EAC = the expected annual consumption of natural gas combusted (in MMBTU's) in SCV's and other heaters, assuming 100% capacity operations for the full year at average annual ambient temperature
- 30 is the facility lifetime in years
- 17 is the percentage of emissions for a state of the art facility required to be offset at electric generating facilities under Oregon Statute
- 117/2000 is pounds of CO_2 emitted per MMBTU of natural gas combusted, converted to short tons, and
- MPR is the monetary path rate set for at OAR 345-024-0580 ($1.27 as of September 2013, but subject to change every two years)

(b) For a natural gas fired combustion turbine that produces electricity and incorporates waste heat recovery to be used in LNG vaporization, the monetary path payment requirement is

[(EACCT x 30 x 117/2000) – (KW x 8760 x 30 x 0.675/2000)] x MPR

where

- EACCT is the annual consumption of natural gas expressed in MMBTU's assuming 100% power operations over the full year at average annual ambient temperature and pressure, using the heat rate reported in condition (4) above.
- 30 is the facility lifetime
- 117/2000 is the CO2 production per MMBTU expressed in tons
- KW is the new and clean nameplate capacity of the electric generating facility
- 0.675/2000 is the EFSC standard for allowed CO2 emissions from power plants without offsets, expressed in tons per KWH, and
- MPR is as above

(6) JCEP shall calculate the Fuel Chargeable to Power Heat Rate as that term is defined in OAR 345-01-0010(24), and the percentage of output energy produced in the form of useful thermal energy. JCEP shall provide those calculations for ODOE review.

(7) Year One Test and True Up Provision:

(a) At the end of the first full year of commercial operations, JCEP shall report the facility's actual fuel consumption in combustion vaporizers and fired heaters, and the facility's actual throughput of LNG product as a percentage of maximum designed annual throughput that was reported under condition 4(a) above. JCEP shall submit this report to ODOE within six months of the end of the first full year of operations. JCEP shall normalize the actual fuel consumption to actual facility operating capacity factor as follows:

$$FC_{normalized} = FC_{actual} \text{ x } TP_d/TP_{actual}$$

Where
FCactual = the actual fuel consumption over the first full year of operations
TPd = the design LNG throughput reported under condition 4(a), and
TPactual = the actual LNG throughput over the first full year of operations.

If the calculated normalized fuel consumption is less than the annual fuel consumption used in the calculations performed under condition (5), then the facility is considered to be as thermally efficient as was assumed, and no additional payment is required but no refund shall be provided to JCEP. If, however, JCEP has overpaid on account of fuel consumption in combustion vaporizers and fired heaters but underpaid on account of natural gas combusted in the combustion turbine electric generating plant, any overpayment shall be offset against any additional payment required on account of natural gas combusted in the combustion turbine electric generating plant.

If the calculated normalized fuel consumption is within 5% of the annual fuel consumption used in the calculations performed under condition (5) then no additional payment shall be required.

If the calculated normalized fuel consumption is greater than 5% above the annual fuel consumption assumed in the calculations performed under condition (5) then JCEP shall recalculate the monetary path payment requirement for 30 years using the same method as set forth in condition (5) using the normalized annual fuel consumption and the MPR in effect at the time, subtract off the amount already disbursed to the Climate Trust under condition (2), and make a "true up payment" to the Climate Trust, equal to the difference.

(b) Concurrently with the report described in condition (a) above, JCEP shall report the actual natural gas fuel combusted in the Cogeneration Facility during the first full year of operations, the actual kwhr produced over the year, and the actual heat rate. If the actual calculated heat rate is more than 5% greater than the heat rate used in the calculations performed under condition (5), then JCEP shall recalculate the monetary path payment requirement using the actual heat rate and the MPR in effect at the time, subtract off payments made to the Climate Trust for the electric generating plant, and make an additional "true up" Climate Trust payment equal to the difference. If the actual heat rate is less than the rate reported under condition (5), no refund shall be provided. If, however, JCEP has overpaid on account of natural gas combusted in the Cogeneration Facility but underpaid on account of fuel consumption in combustion vaporizers and fired heaters, any overpayment shall be offset against any additional payment required on account of fuel consumption in combustion vaporizers and fired heaters.

VI. Retirement and Financial Assurance Authorities and Responsibilities

JCEP agrees to provide a retirement cost estimate and funding surety that is consistent with the requirements for energy facilities under EFSC jurisdiction. ODOE and JCEP agree to the following terms, which are consistent with the requirements for the EFSC Retirement and Financial Assurance Standard at OAR Chapter 345 Divisions 21 and 22.

(1) Two years before closure of the terminal or the Cogeneration Facility, and following consultation with Coos County, JCEP shall submit to ODOE a proposed final retirement plan for the facility and site that conforms substantially with the requirements of OAR 345-027-0110, including:

(a) A plan for retirement that provides for completion of retirement within two years of permanent cessation of operation of the facility and that protects the public health and safety and the environment;

(b) A description of actions JCEP proposes to take to restore the site to a useful, nonhazardous condition, including options for postretirement land use, information on how it would minimize impacts to fish, wildlife and the environment during the retirement process; and measures it would take to protect the public against risk or danger resulting from postretirement site conditions; and

(c) A current detailed cost estimate, a comparison of that estimate with the dollar amount contained in the bond or letter of credit, in combination with any funds that JCEP may have irrevocably committed to retirement, and a plan for ensuring the availability of adequate funds for completion of retirement.

(2) JCEP shall retire the facility if JCEP permanently ceases construction or operation of the facility. JCEP shall retire the facility according to a final retirement plan prepared pursuant to Condition (1) and which shall be approved by ODOE if the plan complies with OAR 345-027-0110.

(3) JCEP shall prevent the development of any conditions on the site that would preclude restoration of the site to a useful, nonhazardous condition to the extent that prevention of such site conditions is within the control of JCEP.

(4) Before beginning any construction of the facility, JCEP shall submit a detailed engineering estimate of the cost to retire the facility and restore the site to a useful and non-hazardous condition, consistent with the site's zoning. The estimate shall include a discussion and justification of the methods and assumptions used to estimate the retirement and restoration cost. The information provided in the estimate shall substantially conform to the information requirements of OAR 345-021-0010(w). Both the estimate and the methodology used to develop the estimate are subject to ODOE review and approval.

In estimating the site restoration cost, no credit shall be allowed for scrap value or salvage of equipment, consistent with the EFSC policy for jurisdictional energy facilities.

(5) Before beginning construction of the facility, JCEP shall submit to the State of Oregon through ODOE a bond or letter of credit in the amount of the above estimate (in 2014 dollars) naming the State of Oregon, acting by and through ODOE, as beneficiary or payee.

(a) The calculation of 2014 dollars shall be made using the US Gross Domestic Product Implicit Price Deflator, Chain-Weight, as published in the Oregon Department of Administrative Services' "Oregon Economic and Revenue Forecast," or by any successor agency ("the Index"). The amount of the letter of credit account shall increase annually by the percentage increase in the Index. If, at any time, the Index is no longer published, ODOE shall select a comparable calculation of 2014 dollars.

(b) The amount of the bond or letter of credit account shall increase annually by the percentage increase in the Index.

(c) JCEP shall not revoke or reduce the bond or letter of credit before retirement of the facility without approval by ODOE.

(d) The reduction or revocation of the bond or letter of credit before completion of retirement of the facility shall constitute an event of default under this Agreement if not consented to by ODOE or cured by JCEP within thirty (30) days.

(6) JCEP shall report annually to ODOE the status of the retirement surety to ensure it has adequate funds to restore the site; provided, however, that if the bond or letter of credit is reduced or withdrawn, JCEP shall provide notice of such reduction or withdrawal to ODOE within five (5) business days.

(7) Not later than 10 years after the date of commercial operation, and every 10 years thereafter during the life of the energy facility, JCEP shall complete an independent Phase I Environmental Site Assessment of the energy facility site, in accordance with an accepted industry standard, such as ASTM Standard E1527. Within 30 days after its completion, JCEP shall deliver the Phase I Environmental Site Assessment report to ODOE.

(8) In the event that any Phase I Environmental Site Assessment identifies improper handling or storage of hazardous substances or improper record-keeping procedures, JCEP shall correct such deficiencies within six months after completion of the corresponding Phase I Environmental Site Assessment. It shall promptly report its corrective actions to ODOE. JCEP shall comply with Oregon Department of Environmental Quality corrective action requirements.

(9) JCEP shall report any release of hazardous substances above reportable quantities under state and federal law to ODOE within one working day after the discovery of such release. This obligation shall be in addition to any other reporting requirements applicable to such a release.

(10) If JCEP has not remedied a release consistent with applicable Oregon Department of Environmental Quality standards or if JCEP fails to correct deficiencies identified in the course of a Phase I Environmental Site Assessment within six months after the date the release becomes known or the date of completion of the Phase I Environmental Site Assessment, JCEP shall, within such six-month period, submit to ODOE for its approval an independently prepared estimate of the remaining cost of remediation or correction.

(a) Upon approval of an estimate by ODOE, JCEP shall increase the amount of its bond or letter of credit by the amount of the estimate.

(b) In no event, however, shall JCEP be relieved of its obligation to exercise all due diligence in remedying a release of hazardous substances or correcting deficiencies identified in the course of a Phase I Environmental Site Assessment.

(11) All funds received by JCEP from the salvage of equipment and buildings shall be committed to the restoration of the energy facility site to the extent necessary to fund the approved site restoration and remediation.

(12) If ODOE finds that JCEP has permanently ceased construction or operation of the facility without retiring the facility according to an approved final retirement plan prepared pursuant to Condition (1), ODOE will notify JCEP and request that JCEP submit a proposed final retirement plan to the Department within a reasonable time not to exceed 90 days.

(a) If JCEP does not submit a proposed final retirement plan by the specified date, ODOE may contract with a qualified site restoration contractor at JCEP's expense to prepare a proposed a retirement plan.

(b) ODOE may draw on the bond or letter of credit described in Condition (5) and shall use the funds to restore the site to a useful, non-hazardous condition according to the final retirement plan

(c) If the amount of the bond or letter of credit is insufficient to pay the actual cost of retirement, JCEP shall pay any additional cost necessary to restore the site to a useful, non-hazardous condition.

VII. Agreements

JCEP will provide adequate funding through the "Contract for Services with JCEP" (ODOE #11-140) to ODOE to pay the additional costs ODOE incurs as a result of the responsibilities listed in Section V and VI.

Oregon agrees to develop a program for carrying out the responsibilities listed in Section V and VI as they apply to JCEP. The execution of the responsibilities of the Governor of Oregon under this MOU is hereby assigned and delegated to ODOE.

To the extent the terms or conditions of the FERC permit authorizing the siting, construction, and operation of an LNG terminal by JCEP expressly conflict with the terms or conditions of this MOU, the terms and conditions of the order shall prevail over the terms and conditions of this MOU. To the extent a provision of this MOU imposes a more stringent requirement on JCEP than the FERC permit imposes on JCEP, this MOU shall not be deemed to be in conflict with the FERC permit unless the permit specifically prohibits the imposition of a more stringent requirement. If this MOU addresses an issue but the FERC permit is silent with respect to that issue, the FERC permit shall not be deemed to be in conflict with this MOU with respect to that issue. JCEP shall not intentionally take any action that would tend to cause FERC to issue an order (i) in conflict with this MOU or (ii) that would prohibit the imposition of more stringent requirements under the terms of this MOU.

VIII. Liabilities

JCEP will assume liability for all costs incurred by the State of Oregon arising out of an LNG incident at the import terminal and along the transit route except to the extent such incident was caused or exacerbated by the negligence or willful misconduct of the State of Oregon.

IX. SUCCESSORS AND ASSIGNS

This MOU binds and benefits JCEP and ODOE and their respective successors and assigns.

X. GOVERNING LAW

This MOU is to be governed by and construed in accordance with the laws of Oregon, without regard to its conflict of law principles.

XI. SEVERABILITY

If any provision of this MOU is held by a court of competent jurisdiction to be invalid or unenforceable, the Parties shall negotiate an equitable adjustment to the affected provisions of the MOU with a view toward effecting the purpose of the MOU, and the validity and enforceability of the remaining provisions, portions or applications thereof, shall continue in full force and effect.

XII NOTICES

Any notice required to be given by either ODOE or JCEP under this MOU shall be in writing and be delivered in person, or sent by first class mail, or transmitted by facsimile or other electronic means to the appropriate addresses of ODOE or JCEP, respectively. The notice shall be effective on the date received if delivered in person, the date of mailing as shown by the postmark if sent by mail, or the date transmitted if sent by facsimile or other electronic means.

XIII. Revisions

JCEP and ODOE agree to review this MOU and update it as necessary. Amendments or modifications may be made to this MOU only upon written notice by both parties.

XIV. Term of Agreement

This MOU shall become effective upon approval, and shall remain in effect until completion of retirement of the facility; provided, that expiration of the term of this MOU will not relieve either party of any claims against it that arise under this MOU prior to such expiration.

The agreement is executed this 10th day of June, 2014.

Michael Kaplan, Acting Director
Oregon Department of Energy

Robert L. Braddock
Robert L. Braddock, Project Manager
Jordan Cove Energy Project

EXHIBIT C
LOCATION
OAR 345-021-0010(1)(C)

CONTENTS

FIGURES

1.0 INTRODUCTION

OAR 345-021-0010(1)(c). *Information about the location of the proposed facility.*

2.0 MAPS

OAR 345-021-0010(1)(c)(A). *A map or maps showing the proposed locations of the energy facility site, all related or supporting facility sites and all areas that might be temporarily disturbed during construction of the facility in relation to major roads, water bodies, cities and towns, important landmarks and topographic features, using a scale of 1 inch = 2,000 feet or smaller when necessary to show detail.*

Figure C-1 shows the location of the proposed South Dunes Power Plant (SDPP) site and its relation to Highway 101 and Coos Bay. The City of North Bend, the Southwest Oregon Regional Airport and other nearby landmarks are also shown, as well as the federally and state owned or managed lands in the area.

3.0 LOCATION DESCRIPTION

OAR 345-021-0010(1)(c)(B). *A description of the location of the proposed energy facility site, the proposed site of each related or supporting facility and areas of temporary disturbance, including the approximate land area of each. If a proposed pipeline or transmission line is to follow an existing road, pipeline or transmission line, the applicant shall state to which side of the existing road, pipeline or transmission line the proposed facility will run, to the extent this is known.*

The SDPP will be located on the east side of Jordan Cove on the North Spit of Coos Bay, approximately one mile north of the City of North Bend, Oregon. The SDPP site totals 137.86 acres in Township 25 South, Range 13 West, Sections 03/04, Willamette Meridian, Coos County. This acreage includes the power plant site; all associated equipment and related or supporting facilities; the access road and utility corridor from the SDPP to Jordan Cove Road, in which the transmission line and boil-off gas (BOG) line are located; the barge berth; and haul road. The natural gas CO_2 removal/dehydrating equipment for the liquefied natural gas (LNG) process (the “gas conditioning facility”) is excluded. Figure C-1 depicts the proposed power plant location, barge berth, haul road and utility corridor between the South Dunes Power Plant (SDPP) and the LNG Plant.

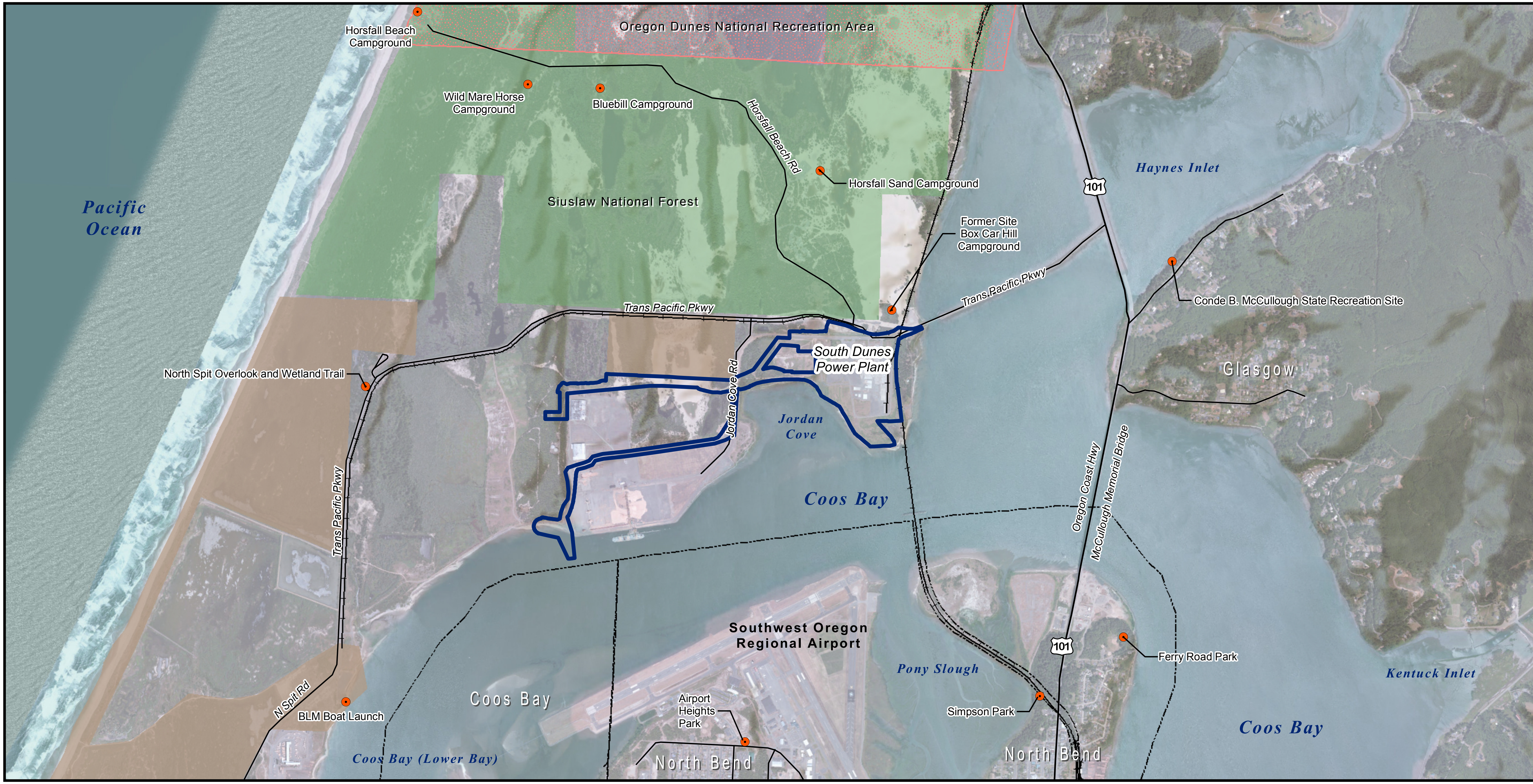
Figure C-2 depicts areas of permanent disturbance (94.59 acres) and areas that will be temporarily disturbed, but where restoration is planned (25.59 acres). Portions of the site shown as an “Undisturbed Area” on Figure C-2 denote locations where the transmission line spans wetlands and other areas that are not anticipated to be disturbed (17.68 acres).

4.0 OTHER FACILITIES

OAR 345-021-0010(1)(c)(C). *For energy generation facilities, a map showing the approximate locations of any other energy generation facilities that are known to the applicant to be permitted at the state or local level within the study area as defined in OAR 345-001-0010 for impacts to public services.*

There are no known energy generation facilities within the study area.

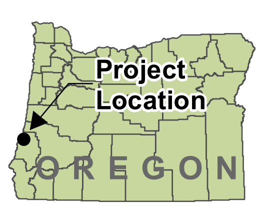
Figure C-1. Facility Site Location



N

0 1,000 2,000 Feet

1 inch = 2,000 feet



EFSC Site Boundary
Siuslaw National Forest
Oregon Dunes NRA
BLM Lands on the North Spit and Coos Bay Shorelands
Recreation Opportunity

City Limits
Existing Rail

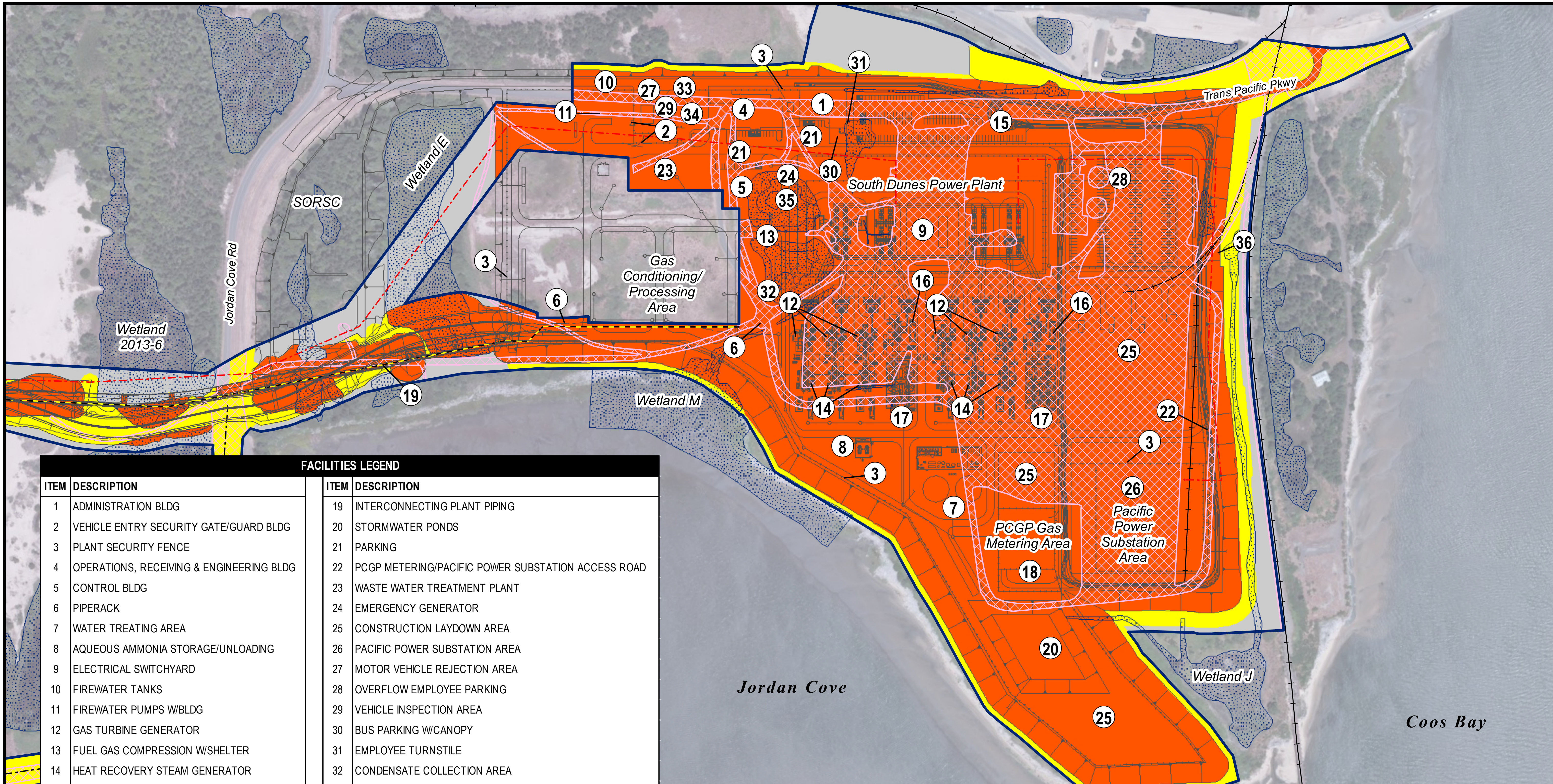
South Dunes Power Plant Project

EFSC Application

EXHIBIT C
Figure C-1
Facility Site Location

Date: 9/17/2014
Reviewed By RH
Designed By SAST

Figure C-2 Sheet 1. Facility Layout and Disturbance Areas



FACILITIES LEGEND

ITEM	DESCRIPTION	ITEM	DESCRIPTION
1	ADMINISTRATION BLDG	19	INTERCONNECTING PLANT PIPING
2	VEHICLE ENTRY SECURITY GATE/GUARD BLDG	20	STORMWATER PONDS
3	PLANT SECURITY FENCE	21	PARKING
4	OPERATIONS, RECEIVING & ENGINEERING BLDG	22	PCGP METERING/PACIFIC POWER SUBSTATION ACCESS ROAD
5	CONTROL BLDG	23	WASTE WATER TREATMENT PLANT
6	PIPERACK	24	EMERGENCY GENERATOR
7	WATER TREATING AREA	25	CONSTRUCTION LAYDOWN AREA
8	AQUEOUS AMMONIA STORAGE/UNLOADING	26	PACIFIC POWER SUBSTATION AREA
9	ELECTRICAL SWITCHYARD	27	MOTOR VEHICLE REJECTION AREA
10	FIREWATER TANKS	28	OVERFLOW EMPLOYEE PARKING
11	FIREWATER PUMPS W/BLDG	29	VEHICLE INSPECTION AREA
12	GAS TURBINE GENERATOR	30	BUS PARKING W/CANOPY
13	FUEL GAS COMPRESSION W/SHELTER	31	EMPLOYEE TURNSTILE
14	HEAT RECOVERY STEAM GENERATOR	32	CONDENSATE COLLECTION AREA
15	EMPLOYEE VISITOR PARKING	33	UNSECURED DELIVERY AREA
16	STEAM TURBINE GENERATOR	34	DELIVERY VEHICLE TURNAROUND AREA
17	AIR COOLED CONDENSER	35	13.8 KV SWITCHGEAR
18	PACIFIC CONNECTOR GAS METERING AREA	36	RETAINING WALL

N

0 160 320 Feet

1 inch = 320 feet

- EFSC Site Boundary
- Heavy Equipment Truck Haul Road Centerline
- Gas Pipeline
- Overhead Power Transmission Line (115kV)
- Existing Rail
- Previously Disturbed Habitat
- Permanent Disturbance Area
- Temporary Disturbance Area
- Undisturbed Area
- Delineated Wetland

South Dunes Power Plant Project

EFSC Application

EXHIBIT C
Figure C-2, Sheet 1 of 2
Facility Layout and Disturbance Areas

Date: 9/25/2014
Reviewed By BL
Designed By SAST

Figure C-2 Sheet 2. Facility Layout and Disturbance Areas

FACILITIES LEGEND	
LOC	DESCRIPTION
19	INTERCONNECTING PLANT PIPING
37	BARGE BERTH

N

0 250 500 Feet

1 inch = 500 feet

- EFSC Site Boundary
- Heavy Equipment Truck Haul Road Centerline
- Gas Pipeline
- Overhead Power Transmission Line (115kV)
- Previously Disturbed Habitat
- Permanent Disturbance Area
- Temporary Disturbance Area
- Undisturbed Area
- Delineated Wetland

South Dunes Power Plant Project

EFSC Application

EXHIBIT C
Figure C-2, Sheet 2 of 2
Facility Layout and Disturbance Areas

Date: 9/25/2014
Reviewed By BL
Designed By SAST

EXHIBIT D
ORGANIZATIONAL EXPERTISE
OAR 345-021-0010(1)(D)

CONTENTS

TABLE

APPENDIX

1.0 INTRODUCTION

OAR 345-021-0010(1)(d). *Information about the organizational expertise of the applicant to construct and operate the proposed facility, providing evidence to support a finding by the Council as required by OAR 345-022-0010, including:*

Exhibit D demonstrates the requisite organizational expertise necessary to construct and operate the proposed South Dunes Power Plant ("SDPP"). As detailed below, the Applicant relies upon Veresen's expertise and experience, the personnel responsible for constructing and operating the facility, and qualifications of the engineers and contractors responsible for design and construction in order to demonstrate expertise in the construction and operation of the SDPP.

2.0 APPLICANT'S PREVIOUS EXPERIENCE

OAR 345-021-0010(1)(d)(A). *The applicant's previous experience, if any, in constructing and operating similar facilities.*

Veresen, Inc. ("Veresen") controls Jordan Cove Energy Project, L.P. ("Applicant") through the general partner, Jordan Cove Energy Project, L.L.C. [1] Jordan Cove Energy Project, L.P. was formed specifically for the development of the Jordan Cove Energy Project which includes the SDPP and other facilities.

The parent company, Veresen, has prior experience in constructing and operating similar facilities. Most recently, Veresen completed the York Energy Centre in Ontario, Canada, which met its scheduled startup in May 2012. Like the proposed SDPP, the York Energy Centre is a natural gas-fired electricity generating facility. In addition to the fourteen completed energy generation facilities listed in Table D-1, Veresen is currently working on additional projects including: the Jordan Cove LNG Project (SDPP is one part of this project), the St. Columbian Wind Project, and the Grand Valley III Wind Project.

With respect to the SDPP, Veresen is directly engaged in reviewing the design, construction and operation plans for the proposed SDPP. Veresen's previous experience is focused in four key areas in the energy market:

- Gas-fired generation (includes: simple cycle and combined cycle natural gas-fired cogeneration plants);
- Renewable energy (includes: wind and run-of-river);
- District energy; and
- Waste heat.

Table D-1 documents Veresen's generation facilities to date. Veresen has over 955 megawatts (MW) of capacity in operation and under construction, as well as an additional 40 MW currently under development (not including the proposed SDPP). Veresen has grown their power business in recent years and continues to assess high value, lower-risk power investments to serve key energy-consuming markets secured with long term contracts.

[1] Additional details regarding the legal entities are in Exhibit A.

Table D-1. Veresen Generation Facilities

Facility	PPA[2]	MW	Technology	Interest
Gas-fired Generation				
York Energy Centre	To 2032	400	Siemens SGT-5000F	50%
East Windsor	To 2029	84	GE LM6000 Sprint	100%
Brush	To 2019	70	GE Frame 6A	100%
Ripon	To 2018	49	GE LM5000 STIG 120	100%
San Gabriel	To 2016	44	GE LM5000 STIG 120	100%
Renewable Energy				
Furry Creek (run-of-river)	To 2024	11	Pelton Turbine	
Clowhom (run-of-river)	To 2034	22	Pelton & Francis Turbines	100%
Glen Park (run-of-river)	Rolling		33	Francis Turbines
Dasque-Middle (run-of-river)	To 2053	20	Pelton & Francis Turbines	100%
Grand Valley I & II (wind)	To 2032		20	Siemens
District Energy				
PEI	N/A		72	Waste, wood, oil fired
London	To 2029		100	Solar Mars GT Cogen
Waste Heat				
EnPower	To 2028		10	Ormat Energy Recovery
NRGreen	Range of expiries	20	Ormat Energy Recovery	50%
Total Generating Capacity			955	

[2] PPA = Power Purchase Agreement

3.0 QUALIFICATIONS OF APPLICANT'S PERSONNEL

OAR 345-021-0010(1)(d)(B). *The qualifications of the applicant's personnel who will be responsible for constructing and operating the facility, to the extent that the identities of such personnel are known when the application is submitted*

Veresen's key qualified and experienced staff are supervising the design, construction, and operation of the SDPP. Most recently, Veresen managed the development, design, construction, startup, and operation of the 400 MW York peaking facility. The facility began operation on schedule and within budget, and complied with all environmental permits and regulations. Similarly, the East Windsor facility was developed, constructed, and is now operated by Veresen.

Veresen management and key plant staff have well over 100 years of experience operating gas turbine facilities for both peaking and baseload operation. This experience covers both heavy frame and aeroderivative gas turbines, including units with the latest advanced technology.

Veresen senior management promotes engagement with fellow users to share operating and maintenance information to continuously improve operations. For example, the Western Operations Vice President was the President of the Western Turbine Users group for 17 years, the largest GE LM engine users group in the world, growing the group from 25 participants to over 1,000.

Mr. Thomas (Tom) Day, Veresen Inc, Senior Vice President, Operations and COO. Mr. Day has over 36 years of experience in plant operations, maintenance, project management, commercial, business integration and strategic planning in the energy industry. Currently responsible for providing leadership, oversight and effective controls to Veresen's power, midstream and pipelines businesses, including engineering and construction and Environmental Health & Safety (EH&S) programs associated with Veresen owned assets, including the Jordan Cove Liquefied Natural Gas Plant (LNG Plant) and the SDPP. Prior to joining Veresen, Mr. Day had a 33-year career with Suncor Energy (and predecessor companies), where his responsibilities included management of a 140-kbpd oil refinery and project development of a $16B (Can) bitumen upgrading facility.

Mr. Paul Eastman, Veresen Inc, Vice President, Power. Mr. Eastman is a power industry executive with over 25 years of diverse experience with Dow Chemical & Transalta, including the commercial, development, operations, and maintenance areas of power and thermal energy production. He has well-established credibility in the leadership of people, labor relations, project management, and management of external relations, including customers and joint venture partners. His strong customer focus has led to several successful energy agreements with a wide range of commercial, institutional, and industrial counterparties. With a background in Mechanical Engineering, Mr. Eastman is also responsible for leading solutions to a host of energy related issues to create positive long-term economic results including the SDPP at the Jordan Cove Energy Project (JCEP).

Mr. Ian Hunt, Veresen Inc., Director Power Operations. Mr. Hunt has over 23 years of experience, including plant construction, commissioning, operations, maintenance, and project management in the energy industry. Mr. Hunt is currently responsible for providing leadership and oversight to Veresen's western power businesses, including operations, and applying engineering and EH&S programs associated with Veresen owned assets in western Canada and the United States, including operating and engineering input to the SDPP project which is part of the JCEP. Prior to joining Veresen, Mr. Hunt had a 20-year career with Westinghouse, Siemens, ATCO Power and Sithe Energy, where his responsibilities included service, construction, commissioning, and operations of Gas Turbine and Combined Cycle power facilities.

Veresen currently operates six gas turbine plants, including East Windsor, which uses the gas turbine technology associated with the SDPP. Under Veresen’s oversight, the Applicant will lead the construction and operation of the SDPP. The Applicant is managed by Mr. Robert (Bob) Braddock. Mr. Braddock has considerable experience in construction, development, and operation of energy facilities and oil and gas infrastructure. Mr. Braddock’s selected biography is presented here:

Mr. Robert (Bob) Braddock, Jordan Cove Energy Project, L.P., Founder and Project Manager. Mr. Braddock has over 40 years of experience in the power and energy industry. Prior to JCEP he was the President & Principal Shareholder of Silvertip Project Partners that engaged in the development of energy based industrial projects for its own account and major U.S. and foreign corporations. Mr. Braddock was also the General Manager and a Limited Partner at Sand Creek Chemical, L.P. He was responsible for the development, construction and operation of the project including: creation and execution of business, operation and marketing plans; securing all permits and governmental consents; negotiating natural gas supply and transportation agreements; contracting for the marketing of all methanol production; management of construction and plant start-up; and securing project financing and staffing. As Project Manager of the Jordan Cove Energy Project, L.P., Mr. Braddock relies on his previous executive management experience in the oil and gas industry, previous energy development projects and the expertise of his limited partners and contracted technical consulting team.

4.0 QUALIFICATIONS OF KNOWN CONTRACTORS

OAR 345-021-0010(1)(d)(B). *The qualifications of any architect, engineer, major component vendor, or prime contractor upon whom the applicant will rely in constructing and operating the facility, to the extent that the identities of such persons are known when the application is submitted.*

Veresen's key qualified and experienced staff are supervising the design, construction, and operation of the SDPP. Most recently, Veresen managed the development, design, construction, startup, and operation of the 400 MW York peaking facility. The facility began operation on schedule and within budget, and complied with all environmental permits and regulations. Similarly, the East Windsor facility was developed, constructed, and is now operated by Veresen.

The Applicant will rely on the design and consulting services of several companies in the facility design, permitting, preconstruction testing, and construction. These include:

- Black & Veatch, Inc. - heavy civil engineering design, power plant design, port terminal design, and permitting;
- Kiewit Corporation – pre-construction testing and constructability design;
- A consortium of Black & Veatch, Inc., and Kiewit Corporation – construction;
- David Evans and Associates, Inc. – civil engineering design, construction and permitting;
- SHN Consulting Engineers & Geologists, Inc. – civil engineering design, construction observation, and permitting;
- Geotechnical Resources Inc. - geotechnical investigation and design, construction observation, and permitting; and
- POWER Engineers, Inc. - reviewing equipment specifications going into the SDPP, once bids are received for specifications prepared by the contractor, POWER Engineers, Inc. will also review bids received for the equipment.

4.1 FACILITY DESIGN

Black & Veatch is an employee-owned, global leader in building Critical Human Infrastructure™ in Energy, Water, Telecommunications and Government Services. Headquartered in United States, Black & Veatch has over 100 offices worldwide including Portland, OR. Black & Veatch has executed over 156,000 MW of energy facilities (including both coal and combustion turbine facilities), with nearly 51,000 MW on an Engineering, Procurement, Construction (EPC) basis. Black & Veatch Energy has in-house professionals that provide siting, acoustic and air quality modeling, analysis and permitting for power plants and related components, including transmission line projects. Black & Veatch's Permitting Unit has extensive experience in obtaining the various federal, state, and local permits and approvals that are required to construct and operate all types of industrial plants, including power generating stations and their ancillary facilities.

Kiewit Corporation (Kiewit) offers a fully integrated delivery model for union construction and startup services for power plant construction projects. Kiewit entered the gas power generation market in the early 1990s, and has since installed more than 8,500 MW of simple- and combined-cycle projects across North America. Kiewit provides fully integrated construction services for multiple power markets including gas, Air Quality Control Systems, renewables, and power delivery.

David Evans and Associates, Inc. (DEA) is an employee-owned multidiscipline consulting firm headquartered in Portland, Oregon, with offices across the western United States. DEA is an infrastructure planning and design firm in the transportation, water resources, land development, and energy business. With more than 700 professional engineers, surveyors, planners, architects, landscape architects, natural resources scientists, and construction managers, they work together to understand client needs, provide creative thinking and technical excellence, and deliver extraordinary service that exceeds expectations**.** DEA also provides comprehensive ecological restoration services. Their multidisciplinary approach assures projects are consistent with regulatory and client expectations; are based on the best available science; thoughtfully consider the site's opportunities and constraints based on a thorough site analysis; and provide economically and technically sound design solutions.

Geotechnical Resources, Inc. (GRI) was established in 1984. Each of the principals of GRI has practiced in the Pacific Northwest for over 25 years. The firm has a total staff of 30, with a technical staff of 25 geotechnical engineers and engineering geologists. The size and technical excellence of the staff permit GRI to offer a broad range of expertise, plus personalized service to each client. GRI personnel have the practical, hands-on experience required to economically and accurately characterize site conditions and provide innovative yet practical and buildable recommendations for design and construction.

SHN Consulting Engineers & Geologists, Inc. is a privately held California Corporation, with offices in Coos Bay, Oregon, and has been in operation since 1979. SHN meets the engineering and geologic needs of both public and private clients throughout the Pacific Northwest. As a firm of more than 90 professional engineers, geologists, surveyors and environmental scientists, SHN offers a broad range of services that include civil engineering, environmental services, geosciences, materials testing, planning and permitting and surveying.

POWER Engineers, Inc. is a global consulting engineering firm specializing in the delivery of integrated solutions which began in 1976. POWER Engineers, Inc. has over 160,000 MW of installed power plant capacity on more than 300 generating units. The firm offers support from a range of services including preliminary engineering to construction support.

4.2 FACILITY OPERATION AND MANAGEMENT

The Applicant will rely on the experience of its management team and Veresen, based in Calgary, Alberta, Canada, that owns and operates energy infrastructure assets across North America. Given Veresen's long history with utility power purchase agreements, Veresen Operations is attuned to the daily and long-term requirements for reliable and efficient energy supply. Veresen employs qualified plant staff, usually with multiple years of operating experience. Training programs emphasize safety, environmental compliance, and dispatch reliability. Veresen's objective is to provide seamless operation for the host utility or process, maximizing production while maintaining full environmental and safety compliance.

Veresen Environmental, Health, and Safety (EH&S) staff manage Veresen's overall compliance, training, and tracking programs. Veresen employs a sophisticated software program available to all employees to report incidents, make positive observations, and track compliance tasks and due dates.

4.3 FACILITY CONSTRUCTION

The Applicant has selected a consortium of Black and Veatch, Inc., and Kiewit Corporation to construct the SDPP, with Black and Veatch acting as principal designer.

The Applicant has not yet selected a combustion turbine vendor for the SDPP, but expects that Siemens, General Electric, or equivalent will supply the equipment.

5.0 APPLICANT'S PAST PERFORMANCE

OAR 345-021-0010(1)(d)(D). *The past performance of the applicant, including but not limited to the number and severity of any regulatory citations in constructing or operating a facility, type of equipment, or process similar to the proposed facility.*

Veresen owns the following similar natural gas-fired generation facilities:

- York Energy Centre - 400 MW;
- East Windsor - 84 MW;
- London Cogeneration - 19.5 MW;
- San Gabriel Cogeneration - 46 MW;
- Ripon Cogeneration - 49.9 MW; and
- Brush Cogeneration - 72 MW.

The Environmental Health & Safety (EH&S) performance of each of these facilities is governed by the facility-specific EH&S Management Plans. While these facilities are operated by a third-party contractor, Veresen provides corporate oversight on all EH&S matters.

Past environmental incidents and citations at San Gabriel, Ripon, and Brush (facilities located within the United States) include the following:

Ripon Cogeneration:

1. On November 16, 2011, an ammonia release occurred during maintenance of the gas turbine inlet chilling system. The Incident Investigation identified that the root cause for the release was human error combined with mechanical failure. There were no reports of any environmental impacts or human health-related issues following the release.

2. On August 29, 2013, an ammonia release occurred when a tube ruptured in the Gas Turbine Inlet Air Cooler System. No injuries were reported resulting from the release and no potential environmental receptors were impacted. The root cause of the tubing failure was traced to vibration and mechanical failure of the HT Chiller Compressor unit. The cause of the vibration was due to a sheared shaft on one of two internal compressor screws, which caused the screw to contact the compressor housing.

Incident investigations were completed for each occurrence or citation to identify the cause of the incident and implement mitigation in the form of additional safety training for personnel and/or improvement of engineering and maintenance controls to prevent reoccurrence of the incident. These events were reported to the appropriate regulatory agencies as required.

In addition to the ammonia releases, there have been four noncompliance events involving mono-nitrogen oxides (NOx) permit limit exceedances resulting from equipment issues/failures:

three at the Ripon facility and one at the Brush facility. No injuries or significant environmental impacts occurred due to these non-compliance events. Pollution control equipment was inspected and repaired to meet compliance standards.

Past citations include a notice from the regulator stating their intent to issue a Notice of Violation for San Gabriel Cogeneration in November 2013 regarding the late submission of two daily emission reports in 2012 and three missed daily emission reports in 2013. Additional training and management oversight has mitigated the late reporting for emissions at this facility.

6.0 APPLICANT WITH NO PREVIOUS EXPERINCE

OAR 345-021-0010(1)(d)(E). *If the applicant has no previous experience in constructing or operating similar facilities and has not identified a prime contractor for construction or operation of the proposed facility, other evidence that the applicant can successfully construct and operate the proposed facility. The applicant may include, as evidence, a warranty that it will, through contracts, secure the necessary expertise.*

This section is not applicable. As described in (C) above, the Applicant has identified the experienced contractors to construct the SDPP.

7.0 ISO CERTIFIED PROGRAM

OAR 345-021-0010(1)(d)(F). *If the applicant has an ISO 9000 or ISO 14000 certified program and proposes to design, construct and operate the facility according to that program, a description of the program.*

The Applicant does not propose to design, construct, and operate the facility according to an International Organization for Standardization (ISO) 9000 or ISO 14000 certified program. However, the Applicant will design, construct and operate the facility in accordance with Veresen's Environmental Health and Safety (EH&S) Management System.

The Applicant's EH&S Management System is not ISO certified but is aligned with ISO 9000 and ISO 14000 to deliver on the continuous improvement cycle of "Plan, Do, Check, Act." The Applicant's EH&S control framework has been established on the principal of no harm to people and no damage to the environment and is anchored by Veresen's EH&S Policy (attached as Appendix D-1) . The fundamentals of the program establish the requirement to identify the hazards and risks associated with activities and to mitigate the risk prior to undertaking the task. Compliance to the requirements of the EH&S Management System are supported by the commitment that "*everyone has the right and obligation to STOP the job if it is deemed unsafe or may have detrimental environmental impacts*."

The Applicant reinforces EH&S performance as a line responsibility and is supported from the very top of the organization by demonstrating leadership and commitment to sustainable performance in every aspect of Veresen's operations, construction and company performance.

In addition to Veresen's EH&S Plan, the lead construction contractors, subcontractors and operations will have additional Health and Safety Plans (H&S Plans). The following paragraphs provide an explanation of the additional plans.

Health and Safety Plans (H&S Plans) are generally project and activity-specific, with the Applicant developing an overall EH&S Plan that describes their safety philosophy, policies and general expectations. The Applicant's EH&S Plan will rely, in part, on the individual subcontractors' experiences and their own H&S Plans to achieve compliance with applicable safety regulations. Each subcontractor will be required to read and comply with the broad requirements of the Applicant's EH&S Plan and will develop a H&S Plan that has detailed procedures applicable to their scope, equipment, and any materials they will use. The Applicant will review each subcontractor's H&S Plan to assess whether it conforms to the Applicant's standards and may require revision to the subcontractors' H&S Plan to address any deficiencies.

Depending upon the breath and scope of subcontractor tasks, the specific environmental goals included in the subcontractors' H&S Plan may be limited to items such as spill prevention, proper waste management requirements, and environmental recordkeeping. The Applicant's EH&S Plan would address at least the following environmental and safety items: training and hazard communication, waste, chemical and materials management and disposal, spill prevention and containment (citing or including as an appendix, the Spill Prevention, Control and Countermeasures Plan), recordkeeping, reporting requirements for accidents, contingency plans, key safety personnel as well as the local hospital to be used for medical emergencies, and other environmental and safety concerns.

Some health and safety requirements will be the same during the construction, cperation and retirement/restoration phases, but since activities will differ during each phase, components of the Applicant's and subcontractors' H&S Plans will also differ. For example, large cranes will be required during the construction and retirement phase, but their use will decline or be intermittent during operations. The Applicant's EH&S Plan may have a limited list of the expected contractor's qualifications and equipment, but the crane contractor's H&S Plan would include detailed requirements for the operator and oiler qualifications, specific safety procedures. For example, procedures for personnel working near the crane; inspection requirements of the crane, rigging and equipment; verification of the load weights before each lift; restrictions on use, such as when wind speed may exceed "*X*" miles per hour; and other requirements specific to safe crane assembly, operation and maintenance.

Health and safety practices during operation would include operation and maintenance of the combustion turbines, heat recovery steam generators and other components, as well as delivery, loading, inspection of fuel, chemicals, aqueous ammonia, and other materials on the plant. Waste management procedures, fall protection, communications and training programs, spill reporting, and updates to the H&S Plan will be required whenever there are changes in key safety personnel or should operations be modified based on site-specific experiences.

8.0 DEMONSTRATION OF COMPLIANCE

OAR 345-021-0010(1)(d)(G). *If the applicant relies on mitigation to demonstrate compliance with any standards of Division 22 or 24 of this chapter, evidence that the applicant can successfully complete such proposed mitigation, including past experience with other projects and the qualifications and experience of personnel upon whom the applicant will rely, to the extent that the identities of such persons are known at the date of submittal.*

The Applicant, in coordination with the construction contractor, and other listed professional engineering and environmental consulting firms will oversee and ensure that identified mitigation actions are successfully implemented. Specific mitigation efforts will include revegetation for erosion, upland habitat improvements, wetland habitat improvements, and traffic improvements.

The Applicant proposes to construct the SDPP on the North Spit of Jordan Cove, a current brownfield site of the former Weyerhaeuser North Bend Container Board Mill. The site currently consists of industrial landscapes with remnant foundations, pavement, as well as permitted industrial landfill consisting of three landfill cells. This site will be significantly transformed to a beneficial reuse with the construction of the SDPP. Landfill cell one has been capped, and prior to construction cell two is proposed to be capped under the current conceptual closure plan (on file with the Oregon Department of Environmental Quality), and cell three is currently undergoing a waste characterization process in anticipation of removing the waste in cell three.

The Applicant has located the SDPP where development previously occurred and the quantity and quality of natural resource impacts will be minimal. The required restoration of temporary construction disturbance associated with the SDPP is minimal. Wetland mitigation will be accommodated as described in Exhibit J. Other actions will be taken to limit impacts in accordance with applicable building codes and construction regulations, such as erosion and sediment control.

The Applicant's consultants have experience in similar mitigation to that proposed for the SDPP; the experience provided below demonstrates compliance with Division 22 and 24 standards. These prior projects have included requisite mitigation efforts including habitat, wildlife, and revegetation improvements.

Mitigation efforts (including the proposed upland and wetland mitigation) for the SDPP will be primarily designed by David Evans and Associates, Inc. However, SHN Consulting Engineers and Geologists, Inc., Kiewit Corporation, and Black and Veatch may also contribute to mitigation efforts. Each company currently operates in Oregon and has designed numerous habitat enhancement projects throughout the Pacific Northwest, including wetland and habitat restoration and mitigation and riparian enhancement for numerous energy and transportation projects in Oregon. The following are recent examples of mitigation designed by David Evans and Associates:

Kentuck Slough Bridge Replacement, for Coos County, Oregon
Oregon Department of Transportation contracted with DEA to provide preliminary and construction engineering services to replace the Kentuck Slough Bridge and tide gate with a new 40-foot single span bridge and fish-friendly, side-mounted steel tide gates. The new tide gate now allows upstream fish migration while limiting tidal influence from Coos Bay into adjacent private properties along the slough. DEA provided bridge design engineering services and also prepared the compensatory wetland mitigation plans to offset impacts to high and low marsh estuarine wetlands. DEA conducted the post-construction monitoring, which documented successful establishment of salt marsh habitats.

Rivergate Industrial District Habitat Restoration, Port of Portland, Oregon
DEA developed wetland and riparian area restoration plans and provided construction monitoring support at the Rivergate Industrial District adjacent to the Columbia River Slough and Smith and Bybee Wetlands Natural Area. The project included excavating approximately 600,000 cubic yards of dredge fill, restoring 40 acres of wetland and riparian habitat, creating 4,000 feet of off-channel swales, and constructing an 8,000-foot segment of the 40-Mile Loop Trail. The restoration efforts have greatly improved the ecological functions within the slough.

Port Westward Wetland Mitigation, for Portland General Electric and Aadland Evans Constructors, Inc., Columbia County, Oregon
DEA partnered with sister company Aadland Evans Constructors, Inc. (AEC) to design, construct, and maintain a turnkey mitigation project to offset wetland impacts resulting from construction of Portland General Electric's Port Westward Generating Plant in Columbia County, Oregon. The project resulted in the construction and establishment of approximately two acres of mitigation wetland. Construction components included wetland excavation and grading, site preparation, large woody debris installation, planting and seeding, temporary irrigation, and a one-year plant establishment period.

Fort Clatsop Estuary Restoration, for Columbia River Estuary Study Task Force, Clatsop County, Oregon
DEA led the consulting team effort to restore nearly 50 acres of historic estuarine wetland along the Lewis and Clark River near the Fort Clatsop National Memorial. The Columbia River Estuary Study Taskforce (CREST) and the National Park Service hired DEA to identify, develop and implement a restoration plan that would maximize ecological gain and minimize the potential for overtopping Fort Clatsop Road. The project involved replacing a 60-inch culvert and tide gate with a 46-foot single span bridge. Services provided by the team included project management, land survey, hydraulic and hydrologic modeling and analysis, geotechnical exploration, alternatives analysis, scour analysis, bridge design, construction documentation, constructability review, bidding assistance, contractor selection, construction contract negotiation, and construction administration. The project was successfully constructed and estuarine habitats restored.

Barney Reservoir Expansion Wetland Mitigation, for the Barney Reservoir Joint Ownership Commission, Washington County, Oregon
DEA led the Phase II wetland mitigation design team for the reservoir expansion, which raised the dam 50 feet and increased storage capacity from 4,000 acre-feet to 20,000 acre-feet. DEA designed and provided construction phase services for 20 acres of emergent and scrub-shrub wetlands. The project included the relocation of a perennial stream and protection and relocation of an adjacent community of threatened Nelsons checkermallow, *Sidalcea nelsoniana*. DEA conducted the 5-year post-construction monitoring of the mitigation areas, which documented successful establishment of wetland habitats and establishment of a new population of Nelsons checkermallow.

Crissey Field State Recreation Site, Brookings, Oregon (Oregon Parks and Recreation Department)
DEA was lead design firm for this new 40 acre State Recreation Site, situated along dune lands of the southern Oregon coast. DEA provided wetland mitigation and overall site landscape architectural design services in addition to transportation planning and design, civil and structural engineering, and architectural design services for a sustainably designed visitor center. The wetland mitigation site covered several acres of interdunal scrub-shrub and emergent freshwater wetland habitats.

The following are recent examples of eelgrass mitigation projects completed by SHN Consulting:

Humboldt Bay Aquatic Center Floating Dock, Eureka, California
Humboldt State University ("HSU") wished to replace its deteriorating Aquatic Center dock on Humboldt Bay. Eelgrass beds occur intermittently along the shoreline within the boundaries of the project area.

Eelgrass beds are an important marine habitat type in Humboldt Bay and are recognized as essential fish habitat by the National Marine Fisheries Service ("NMFS"). The plant is vulnerable because it has a narrow tolerance for turbidity, sediment disturbance, and eutrophication, and needs high ambient light. With the loss of eelgrass, fish abundance and diversity decline dramatically. The project required an eelgrass mitigation and monitoring plan as required under Special Condition #2 of the Coastal Commission Notice of Intent to issue a Coastal Development Permit and for review by the NMFS and California Department of Fish and Game ("CDFG").

The eelgrass survey methods followed NMFS procedures for the evaluation of eelgrass coverage and density modified to meet the conditions of the project site and the monitoring needs for this project. Adverse impacts to eelgrass due to construction of the new gangway and floating dock were measured as the difference between the pre-construction and post-construction estimates of eelgrass cover and density.

SHN's surveys documented that despite eelgrass mitigation planting having had a relatively poor long-term track record in Northern California (75% failure), project construction at the HSU

Aquatic Center Floating Dock resulted in substantial increases in available eelgrass habitat as compared to pre-project conditions.

Salt Marsh Mitigation & Restoration, Inner Channel Revitalization Project, Eureka, California

SHN planned and oversaw re-establishment of three salt marsh habitats to mitigate for lost sensitive habitat along the inner channel developments.

APPENDIX D-1

Veresen Environmental Health and Safety Policy

VERESEN

ENVIRONMENTAL, HEALTH & SAFETY POLICY

Policy Statement

Veresen is committed to meeting or exceeding existing safety and environmental laws, regulations and appropriate industry standards at each of our facilities in respect of the health and safety of its employees, and the public and the protection of the environment. Veresen executives, management, staff and contractors are each responsible for understanding and fulfilling the expectations inherent in this policy.

Key Policy Elements

Resources

Veresen will provide the necessary resources and utilize industry best practices to create a safe workplace and ensure all employees and contractors are properly trained as required to operate the facilities and conduct company business in a safe, environmentally conscious and responsible manner.

Environment, Health, and Safety Management Systems

Planning - Veresen will strive for Continuous Improvement by developing, maintaining, enhancing and improving our Environmental, Health & Safety (EH&S) Management System through identifying, assessing, mitigating and managing environmental impacts and safety hazards associated with Veresen activities so that they are minimized.

Measurement and Evaluation – Veresen will set standards and monitor safety and environmental performance throughout the organization. We will maintain a self-monitoring program to ensure compliance with safety and environmental legislation and utilization of an EH&S database for compliance, monitoring and reporting.

Review and Improve – Veresen will regularly review and update our safety and environmental programs and will implement and maintain an EH&S Management System to ensure the safety and health of our employees, and the public and protection of the environment.

Employee Participation

All Veresen employees are responsible for their own safety, the safety of fellow employees, and the safety of the public at each of our facilities and offices. They are expected to participate in the EH&S Management System including adherence to the policies and procedures, reviews, and improvements related to environment, health and safety. Veresen is responsible for providing the appropriate training and necessary resources to ensure the health and safety of its employees and the public. Visible leadership and accountability throughout our organization is required.

Communication

Veresen will maintain regular communication with employees, contractors and other stakeholders on environmental, health and safety matters as well as provide appropriate Regulatory Agencies with information as required.

No exception may be made to this policy without written consent of the Veresen EH&S Board Committee.

Donald Althoff, President and Chief Executive Officer

February 26, 2013

EXHIBIT E
PERMITS NEEDED FOR CONSTRUCTION AND OPERATION
OAR 345-021-0010(1)(E)

CONTENTS

TABLES

APPENDICES

REFERENCES

Appendix J-2	DSL Removal-Fill Permit Application No. 54908-RF (submitted March 20, 2014)
Appendix J-3	USACE Section 404/10 Permit Application (submitted October 11, 2013)

1.0 INTRODUCTION

OAR 345-021-0010(1)(e). *Information about permits needed for construction and operation of the facility, including:*

This exhibit provides information regarding federal, state, and local government permits needed for construction and operation of the South Dunes Power Plant (SDPP). The permits are organized into four major headings: (1) federal permits, (2) state permits: federally delegated, (3) state permits: not federally delegated, and (4) local permits. Jordan Cove Energy Project, L.P. is the “Applicant.”

2.0 IDENTIFICATION AND DESCRIPTION OF REQUIRED PERMITS

OAR 345-021-0010(1)(e)(A) *Identification of all federal, state and local government permits related to the siting of the proposed facility, a legal citation of the statute, rule or ordinance governing each permit, and the name, mailing address, email address and telephone number of the agency or office responsible for each permit.*

OAR 345-021-0010(1)(e)(B) *A description of each permit, the reasons the permit is needed for construction or operation of the facility and the applicant's analysis of whether the permit should or should not be included in and governed by the site certificate.*

2.1 FEDERAL PERMITS

Table E-1 identifies and describes federal permits required for construction and operation of the SDPP.

Table E-1. Federal Permits Required for Construction and Operation

Permit Name	Agency Name and Contact	Authority	Description
Section 404/10 Permit to Discharge Dredged or Fill Material	Federal: United States Army Corps of Engineers (USACE) Portland District Regulatory Office 333 SW First Ave. P.O. Box 2946 Portland, OR 97208-2946 (503) 808-4373 carol.a.mcintyre@usace.army.mil State: Oregon Department of Environmental Quality (ODEQ) 811 SW 6th Ave. Portland, OR 97204-1390 (503) 229-5696 deq.info@deq.state.or.us	Clean Water Act Section 404 (33 U.S.C. § 1344) Rivers and Harbors Act Section 10 (33 USC § 403) Clean Water Act Section 401 (33 USC § 1341) 33 CFR Part 323 ORS Chapter 468B OAR Chapter 340, Division 48	A Section 404 Permit is required prior to filling or dredging in regulated waters of the United States. Responsibility for administering and enforcing Section 404 is shared by the USACE and U.S. Environmental Protection Agency, and Section 10 is administered and enforced by USACE. This permit is needed for construction and operation because the Applicant will be filling and dredging in regulated waters of the United States. The Section 404/10 Permit Application submitted October 11, 2013 is attached to Exhibit J, Appendix J-3. The Applicant will satisfy the requirements of this permit in direct coordination with USACE and this permit should not be included in and governed by the Site Certificate.

Permit Name	Agency Name and Contact	Authority	Description
Notice of Proposed Construction 7460 Form	Federal Aviation Administration 1601 Lind Ave. SW Renton, WA 98055-4056 Dan Shoemaker (425) 227-1389 Dan.shoemaker@faa.gov	Federal Aviation Act of 1958 (14 USC § 44718) 14 CFR § 77	Notices of proposed construction have been submitted to the Federal Aviation Administration (FAA). Copies are attached as Appendix E-6. No physical hazards to airspace are proposed as a part of the SDPP site certificate application. All structures within the Site Boundary will be under 167.1 feet, which is the height of the Horizontal Surface. The Applicant has received No Hazard Determinations for all structures within the Site Boundary. See Appendix E-7. These Notices should not be included in and governed by the Site Certificate as the FAA has not delegated authority to make the determinations and has already issued No Hazard Determinations.

2.2 STATE PERMITS: FEDERALLY DELEGATED

Table E-2 identifies and describes the state permits: federally delegated that are required for construction and operation of the SDPP.

Table E-2. State Permits: Federally Delegated

Permit Name	Agency Name and Contact	Authority	Description
Prevention of Significant Deterioration (PSD) Permit & Air Contaminant Discharge Permit (ACDP)[1]	Oregon Department of Environmental Quality Air Quality Division Tom Peterson 811 SW 6th Avenue Portland, OR 97204-1390 (541) 776-6199 deq.info@deq.state.or.us	Clean Air Act (42 USC § 7401 et seq.) 40 CFR Parts 51 ORS Chapters 468 and 468A OAR Chapter 340, Division 224 and 225	PSD Permit authority under the federal Clean Air Act has been delegated to the ODEQ by the U.S. Environmental Protection Agency (EPA). In Oregon, the PSD requirements are satisfied with an ACDP. The PSD and ACDP will regulate air emissions from the SDPP. The SDPP will require a ACDP because emissions will be greater than 100 tons per year for criteria air pollutants. A PSD is required because

[1] This air permit includes DEQ's ACDP to construct and operate both the Liquefied Natural Gas (LNG) and SDPP facilities.

Permit Name	**Agency Name and Contact**	**Authority**	**Description**
			the SDPP will be located in an attainment area for all pollutants and will potentially emit more than 100 tons per year of several air pollutants. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate. The Applicant is working directly with DEQ to obtain the PSD and ACDP Permits. The permit application is attached as **Appendix E-2**.
Title V Operating Permit	Federal: Environmental Protection Agency 1200 6th Street Seattle, WA 98101 (206) 553-1200 epa-seattle@epa.gov State: Department of Environmental Quality Tom Peterson 811 SW 6th Avenue Portland, OR 97204-1390 (503) 229-5696 deq.info@deq.state.or.us (541) 776-6010 Ext. 247	Clean Air Act, Title V (42 USC § 7661-7661f) 40 CFR Part 70 ORS Chapters 468 and 468A OAR Chapter 340, Division 218	ODEQ rules do not allow a new source to directly apply for the Title V Operating Permit; instead, pursuant to the granting of an ACDP, the Title V Operating Permit may be granted after the source is constructed and operated for a certain time period. The ODEQ Air Quality Division administers the Title V Air Permit program under federally delegated authority. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate.
Construction Storm Water Discharge Permit, 1200-C	ODEQ Water Quality Division Kristy Sewell 811 SW 6th Ave Portland, OR 97204-1390 (541) 686-7858 Deq.info@deq.state.or.us	Clean Water Act (33 USC §§ 1251 *et seq*.) 40 CFR Parts 122 ORS Chapters 468B OAR Chapter 340, Division 45 and 52	The 1200-C is required for collection and discharge of stormwater runoff from the site during construction. The Applicant is coordinating submittal of the permit application with ODEQ. The 1200-C permit application will be attached as **Appendix E-3**. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate.
National Pollutant Discharge Elimination System (NPDES) Industrial Waste Water Permit Modification to add Hydrostatic Water Testing	ODEQ Chuck Costanzo 811 SW 6th Avenue Portland, OR 97204-1390 (541) 776-6130 deq.info@deq.state.or.us	Clean Water Act (33 USC §§ 1251 et seq.) 40 CFR Parts 122 ORS Chapters 468B OAR Chapter 340,	This is a major modification to an existing NPDES individual permit for industrial waste water discharge. The permit will be modified to add hydrostatic water testing and waste water discharge. The existing NPDES permit is Number 101499. The Applicant is coordinating with ODEQ on the submittal of a

Permit Name	**Agency Name and Contact**	**Authority**	**Description**
and Wastewater Discharge		Division 45 and 52	modification application. The application will be attached as **Appendix E-4**. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate.
Section 401 Permit for Removal Fill activities which includes a Post Construction Storm Water Management Plan	ODEQ Water Quality Division Chris Stine 811 SW 6th Avenue Portland, OR 97204-1390 (541) 686-7810 Deq.info@deq.state.or.us	Clean Water Act Section 401 (33 USC § 1341) 33 CFR Part 323 ORS Chapter 468B OAR Chapter 340, Division 48	ODEQ is responsible for issuing the Section 401 Permit which is a state water quality certification that flows from a Section 404 Permit. This process allows the ODEQ to determine if state water quality standards and conditions are met. Post-construction stormwater will also be covered under the 401 Water Quality Certification. The permit application for a Section 404 Permit is the same application used for a Section 401 Permit. The Section 404 Permit Application is attached as **Exhibit J**, **Appendix J-3**. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate.
Hazardous Waste Activity Notification	Federal: EPA Region 10 1200 6th Ave Seattle, WA 98101 (206) 553-1200 State: ODEQ 811 SW 6th Ave. Portland, OR 97204-1390 (503) 229-6938 hazwaste@deq.state.or.us	ORS 466 OAR 340-102-0012	Hazardous waste generators are required to register with the Environmental Protection Agency (EPA). The SDPP is expected to generate wastes such as used oils and spent solvents during construction and operation. The Resource Conservation and Recovery Act (RCRA) Site Identification Form will be submitted to ODEQ prior to construction. Conditionally Exempt Small Quantity Generator or Small Quantity Generator status is anticipated for the SDPP. The information required to register and obtain a generator identification number is included as **Appendix E-1**. As a federally delegated authority to ODEQ, this permit will not be included in the site certificate.

2.3 STATE PERMITS: NOT FEDERALLY DELEGATED

Table E-3 identifies and describes the state permits: not federally delegated required for construction and operation of the SDPP.

Table E-3. State Permits: Not Federally Delegated

Permit Name	Agency Name and Contact	Authority	Description
Site Certificate	Energy Facility Siting Council Oregon Department of Energy Andrea Goodwin 625 Marion Street NE Salem, OR 97301-3737 (503) 378-4040 energy.in.internet@odoe.state.or.us	ORS 469.300 to ORS 469.570 OAR Chapter 345, Divisions 1, 21-24	The SDPP will be an "energy facility" as defined in ORS 469.300(11). Therefore, construction and operation of the SDPP and its related or supporting facilities must be authorized through a site certificate issued by the Energy Facility Siting Council (EFSC). This Application for Site Certificate (ASC) provides the information required to demonstrate that applicable siting standards will be met.
Department of State Lands (DSL) Fill - Removal Permit	Department of State Lands Bob Lobdell 775 Summer Street NE Suite 100 Salem, OR 97301-1279 (503) 986-5200 robert.lobdell@dsl.state.or.us	ORS 196.795-990 OAR Chapter 141, Division 85	Required for removal or fill to be placed in "waters of the State" defined as "natural waterways including tidal and non-tidal bays, intermittent streams, lakes, wetlands, and other bodies of water in the state, navigable and non-navigable." The DSL Removal-Fill Application number is 54908-RF dated September, 2014 and is attached in **Exhibit J**, **Appendix J-2**. This application contains the necessary information to find compliance with the applicable criteria.
Notice of Proposed Construction 7460 Form	Oregon Department of Aviation John Wilson 3040 25th Street SE Salem, OR 97302-1125 503-378-4880 aviation.mail@state.or.us	ORS 836.535 OAR Chapter 738, Division 70	Notices of proposed construction have been submitted to the Oregon Department of Aviation (ODA). Copies attached as **Appendix E-6**. No physical hazards to airspace are proposed as a part of the SDPP site certificate application. All structures within the Site Boundary will be under 167.1 feet, which is the height of the Horizontal Surface.

2.4 LOCAL PERMITS

Table E-4 identifies and describes the local permits required for construction and operation of the SDPP.

Table E-4. Local Permits (Requested from EFSC & Prior Approvals) Required for Construction and Operation of the SDPP

Permit Name	Agency Name and Contact	Authority	Description
1) Approvals Requested from EFSC			
Administrative Conditional Use (ACU) for Compliance Determinations with Applicable Provisions of LDO & CCCP	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	LDO Sec. 4.2.100 LDO Sec. 4.2.600 LDO Table 4.2e LDO Art. 4.6 - Overlay zones LDO Art.4.7 - Special Considerations LDO Chap. V - Administration (ACU Extensions) LDO Art. 4.4 - Development Standards LDO Chap. III - Supplemental Provisions LDO Chap. VII (Street & Road Standards)	ACU for compliance determinations to allow power plant use in IND zone in Area 1, Area 1-A & Area 1-B, as required by LDO Section 4.2.100 and the supplemental provisions of Chapter III (prior to issuance of a zoning verification letter under LDO Section 3.1.200, discussed below). Applies to all Facilities in the IND zone.
ACU to allow Development in Dune Areas with "Limited Development Suitability"	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	LDO Phenomenon 4. Beaches and Dunes	ACU to allow development of the transmission corridor and the accessory road and utility corridor in IND zone that have been identified as dune areas with "Limited Development Suitability."
ACU for Compliance Determination for Accessory Substation	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	LDO Secs. 3.1.300(A), (B), (F) LDO Secs. 3.2.150(1), (2)	ACU for compliance determination to allow the substation as an accessory use to primary use, the SDPP.
Zoning Verification Letter	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423	LDO Sec. 3.1.200LDO Sec. 3.1.200	Coos County has no building official. Coos County issues a zoning compliance letter to the state building official following the compliance determinations described above, that relevant zoning has been complied

Permit Name	Agency Name and Contact	Authority	Description
	(541) 396-3121 Ext. 21		with and that a building permit may be issued. Applies to all Facilities in the IND zone.
ACU to Allow Power Plant Use & Fill	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 7-D	ACU to allow power plant use in 7-D zoning areas east of Jordan Cove Road as Industrial & Port Facilities use; and to allow temporary fill in the 7-D zone in Area 1-B to allow construction of a bridge over wetlands.
ACU to allow Development in Special Flood Hazard Areas	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 7-D CBEMP Policy #27 LDO Sec. 4.6.230	The LDO requires an ACU approval to allow development in "Special Flood Hazard Areas." The ACU requires review of Policy #27, which triggers review of LDO Section 4.6.230.
ACU to allow Development in Dune Areas with "Limited Development Suitability"	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 7-D CBEMP Policy #30	ACU to allow development in 7-D areas that have been identified as dune areas with "Limited Development Suitability."
ACU for Land Transportation Facility in 8-WD	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 8-WD	ACU to allow a public road connection to TransPacific Parkway.
ACU for compliance determination for Accessory Road and Utility Corridor.	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 6-WD LDO Article 3	ACU for compliance determination for the accessory road and utilty corridor. The applicable criteria are the accessory use criteria from the LDO Article 3.
Administrative Conditional Use to Allow New and Maintenance Dredging	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 6-DA	ACU to allow new and maintenance dredging in Area 1-E in zoning district 6-DA to dredge the "access triangle" to provide access to the barge berth.
Administrative Conditional Use to Allow Construction, Fill	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex	CBEMP Zoning District 6-DA	ACU to allow construction, temporary and permanent fill, and shoreline stabilization in Area 1-E in zoning district

Permit Name	Agency Name and Contact	Authority	Description
and Shoreline Stabilization for the barge berth	Coquille, OR 97423 (541) 396-3121 Ext. 21		6-DA to construct the barge berth.
Zoning Verification Letter	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	LDO Sec. 3.1.200	Coos County has no building official. Coos County issues a zoning compliance letter to the state building official following the compliance determinations described above, that relevant zoning has been complied with and that a building permit may be issued. Applies to all Facilities in the CBEMP.
2) Prior Approvals			
Hearings Body Conditional Use Approval; County Order No. 07-12-309PL; County Order No. 09-08-053PL.	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP 6-WD	Conditional use approval of LNG facility as Industrial & Port Facilities use. Includes approval of accessory road & utility corridor west of Jordan Cove Road, as "Energy production facility" an Industrial & Port Facilities use.
Hearings Body Conditional Use Approval; County Order No. 07-12-309PL, File No.: #HBCU-07-03	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 6-WD CBEMP Zoning District 6-DA CBEMP Zoning District 7-D LDO Sec. 4.2.100 LDO Sec. 4.2.600 LDO Table 4.2e LDO Art. 4.6 - Overlay zones LDO Art.4.7 - Special Considerations LDO Chap. V - Administration LDO Art. 4.4 - Development Standards LDO Chap. III – Supplemental Provisions	Conditional use approval to allow the Port's Slip & Access-Waterway as an Industrial & Port Facilities use in zoning districts 6-WD & 6-DA. Allows barge berth and dock as part of approved Industrial & Port Facilities use for Port's Marine Terminal. Also approved fill in portions of IND & 7-D zones on Mill Site.
County Order No. 09-08-053PL	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423	CBEMP Zoning District 6-WD LDO Sec. 5.8.800	Remand proceedings regarding compliance with wetland map in 6-WD.

Permit Name	**Agency Name and Contact**	**Authority**	**Description**
	(541) 396-3121 Ext. 21		
County File No. R-09-02	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 6-WD LDO Sec. 4.1.450	Planning Director's wetland map correction in 6-WD
Administrative Boundary Interpretation County File No. ABI-12-01	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 7-D LDO Sec. 4.1.300 LDO Sec. 4.1.400 LDO Sec. 4.1.450	The Planning Director made an interpretation to correct the location of the Coastal Shoreline Boundary (CSB), the northern boundary of the 7-D zone (common boundary of 7-D zone and the Industrial zone), and the location of the 100-year floodplain on the Mill Site.
Administrative Boundary Interpretation County File No. ACU-12-12/ABI-12-02	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	CBEMP Zoning District 5-WD CBEMP Zoning District 6-WD LDO Sec. 4.1.300 LDO Sec. 4.1.400 LDO Sec. 4.1.450	The Planning Director made an interpretation to correct the location of the common boundary between zoning district 5-WD and zoning district 6-WD (the LNG facility), together with a Planning Director's Administrative Decision approving additional fill in 6-WD, including within the road and utility corridor east of Jordan Cove Road (Area 1-C).
Administrative Conditional Use ACU-12-16/ACU-12-17/ ACU-12-18	Coos County Planning Department Jill Rolfe, Planning Director Coos County Courthouse Annex Coquille, OR 97423 (541) 396-3121 Ext. 21	LDO Sec. 4.2.100 LDO Sec. 4.2.600 LDO Table 4.2e LDO Art. 4.6 - Overlay zones LDO Art.4.7 - Special Considerations LDO Chap. V - Administration LDO Art. 4.4 - Development Standards LDO Chap. III – Supplemental Provisions CBEMP Zoning District 7-D	The decision approved the activity of fill on the Mill Site to make it ready for development in the reconfigured IND zone. The decision also approved a conditional use permit for fill and vegetative shoreline stabilization in CBEMP zoning district 7-D.

3.0 EVIDENCE FOR STATE PERMITS: NOT FEDERALLY DELEGATED

OAR 345-021-0010(1)(e)(C) *For any state or local government permits, licenses or certificates that are proposed to be included in and governed by the site certificate, evidence to support findings by the Council that construction and operation of the proposed facility will comply with the statutes, rules and standards applicable to the permit. The applicant may show this evidence.*

The SDPP site certificate is a state permit issued by the Energy Facility Siting Council. Evidence to support findings by the Council that construction and operation of the proposed facility will comply with the statutes, rules and standards applicable to the site certificate are included in Exhibits A-CC which collectively make up the application for a site certificate.

Please see **Exhibit K** for evidence to support findings by the Council that the construction and operation of the facility will comply with local Coos County standards applicable to the permit.

With respect to the 7460 Notice of Proposed Construction, the Applicant has submitted Notices of Proposed Construction to the FAA and the ODA. The FAA issued No Hazard Determinations on July 24, 2014. Although thermal plumes are not regulated by the FAA, the Applicant has conducted a Thermal Plume Study, attached as **Exhibit U, Appendix U-4**.

(i) In Exhibit J for permits related to wetlands;

Please see **Exhibit J** for permits related to wetlands, specifically **Appendix J-2**, the DSL Removal-Fill Permit Application Number 54908-RF (September, 2014).

(ii) In Exhibit O for permits related to water rights.

The Applicant is not requesting any permits related to water rights.

4.0 AGENCY REVIEW OF STATE PERMITS: FEDERALLY DELEGATED

OAR 345-021-0010(1)(e)(D) *For federally-delegated permit applications, evidence that the responsible agency has received a permit application and the estimated date when the responsible agency will complete its review and issue a permit decision.*

Pursuant to OAR 345-021-0000(7) ODEQ has submitted a letter regarding the status of all of the Applicant's federally-delegated permit applications. See **Appendix E-5**.

The Applicant submitted an ACDP/PSD application in March 2013, ODEQ deemed it complete in December 2013, a public meeting was held on March 18, 2014 and comments were accepted through April 15, 2014. The estimated ACDP/PSD permit timeline is: summer 2014 DEQ drafts the permit, a public hearing is held in Coos Bay on the draft permit, and a public comment period is open on the draft permit. Summer/fall 2014: ODEQ reviews public comments. Winter 2014: the Environmental Protection Agency (EPA) reviews the draft permit; the permit could change based upon EPA comments. The Applicant anticipates the ODEQ will complete its review and issue a permit decision in the spring of 2015.

The Title V permit will not be applied for until after operation of the SDPP commences. It is anticipated that a Title V permit would be issued at least one year after operation commences.

Applications for the 1200-C, Construction Stormwater Discharge Permit and the NPDES modification were submitted summer of 2014. It is anticipated that ODEQ will complete an initial review in fall 2014. Permit decisions are anticipated in spring 2015.

The 401 water quality certification process has been initiated via an application for a Section 404 Permit which was submitted on October 11, 2013. The Applicant is working toward a completeness determination with ODEQ. Prior to approval ODEQ will need a biological opinion from the United States Department of Fish and Wildlife and the National Marine Fisheries Services. Review is expected to be completed in the fourth quarter of 2014 and a permit decision issued in the second quarter of 2015.

The Hazardous Waste Activity Notification application for a site identification number will be submitted prior to construction and operation. It is anticipated that it will be applied for winter 2015. It takes ODEQ approximately ten days to issue a site identification number once an application is received.

5.0 THIRD-PARTY STATE OR LOCAL PERMITS

OAR 345-021-0010(1)(e)(E) *If the applicant relies on a state or local government permit or approval issued to a third party, identification of any such third-party permit and for each:*

> *(i) Evidence that the applicant has, or has a reasonable likelihood of entering into, a contract or other agreement with the third party for access to the resource or service to be secured by that permit.*
>
> *(ii) Evidence that the third party has, or has a reasonable likelihood of obtaining, the necessary permit.*
>
> *(iii) An assessment of the impact of the proposed facility on any permits that a third party has obtained and on which the applicant relies to comply with any applicable Council standard.*

The only state permit issued to a third party that the Applicant is relying upon is the Coos Bay North Bend Water Board's ("CBNBWB") water rights. As explained below, the Applicant has entered into an agreement with the CBNBWB, the CBNBWB has already obtained the water rights, and the SDPP will have no impacts to CBNBWB's water rights.

The Applicant currently has an agreement with the third party for the supply of water. As stated in the September 5, 2013 letter from CBNBWB, the CBNBWB currently provides the Applicant with approximately 0.5 millions of gallons per day ("mgd") of raw water. The letter further explains that the CBNBWB has adequate capacity to meet the Applicant's potable and raw water needs. See **Exhibit O, Appendix O-1**. In sum, the Applicant currently receives water from the CBNBWB, the Applicant has a current agreement to receive water with the CBNBWB, and the Applicant is reasonably likely to enter into a future agreement at the time the additional water is required.

The CBNBWB has obtained the necessary water rights. See **Exhibit O, Appendix O-2**.

The SDPP will not impact any of the water rights the CBNBWB has obtained. As mentioned above, the CBNBWB has adequate capacity to provide two potable water services and one raw water service as requested by the Applicant. The CBNBWB also recently completed a major water supply project in 2001 with the construction of a new dam on Upper Pony Creek Reservoir, effectively tripling the surface water supply and meeting the needs of the community through 2050 and beyond. The Applicant relies upon the water rights obtained by the CBNBWB to demonstrate compliance with OAR 345-021-0010(1)(o)(B), which requires a description of each source of water. In sum, the Applicant will not impact the CBNBWB's water rights.

6.0 THIRD-PARTY FEDERALLY DELEGATED PERMITS

OAR 345-021-0010(1)(e)(F) *If the applicant relies on a federally-delegated permit issued to a third party, identification of any such third-party permit and for each:*

(i) Evidence that the applicant has, or has a reasonable likelihood of entering into, a contract or other agreement with the third party for access to the resource or service to be secured by that permit.

(ii) Evidence that the responsible agency has received a permit application.

(iii) The estimated date when the responsible agency will complete its review and issue a permit decision.

The Applicant is not relying on any federally-delegated permits issued to a third party, therefore this section is not applicable.

The Applicant holds and maintains an existing NPDES permit (Number 101499). Wastewater under this permit is discharged through an industrial wastewater pipeline and the International Port of Coos Bay's ocean outfall pipeline. An NPDES modification application has been submitted to ODEQ for modification of the NPDES permit conditions to include wastewater and stormwater associated with the SDPP development. No other associated permits are required or held in relation to discharge of wastewater to the industrial wastewater pipeline and the ocean outfall for the SDPP. The industrial wastewater pipeline is intended to serve any potential industry developed on the industrial land of the North Spit. No third party permits are held by the Port of Coos Bay or any other third party for the continued use of the industrial wastewater pipeline.

7.0 MONITORING

OAR 345-021-0010(1)(e)(G) *The applicant's proposed monitoring program, if any, for compliance with permit conditions.*

In collaboration with associated agencies, the Applicant will establish any monitoring programs required for compliance with permit conditions.

Compliance with permit conditions related to the SDPP is the responsibility of the Applicant, and proposed monitoring programs for compliance with permit conditions are described in applicable exhibits. The Applicant will comply with all permit conditions related to the SDPP by developing a compliance tracking system that assigns due dates and/or trigger events for site certificate conditions. In addition, a responsible individual will be assigned to manage the compliance requirements.

8.0 SUMMARY

For the foregoing reasons, the Applicant has demonstrated compliance with the requirements of OAR 345-021-0010(1)(e) and proposes that the Energy Facility Siting Council find the Applicant is compliant with the above criteria for permits needed for construction and operation of the South Dunes Power Plant.

APPENDIX E-1

RCRA Waste Site Identification Form

RCRA Waste Site Identification Form

Site ID

State of Oregon Department of Environmental Quality
Accounting Section
811 SW Sixth Avenue, Portland, OR 97204-1390
Questions: (503) 229-6938 in Portland, OR or toll free in Oregon: (800) 452-4011 Ext. 6938
Fax: (503) 229-6977
TTY: (800) 735-2900
Email: hazwaste@deq.state.or.us
Web site: www.oregon.gov/DEQ/

DEQ State of Oregon Department of Environmental Quality

1. Reason for Submittal

To provide **New** Notification of Regulated Waste Activity (complete entire form) Amount Enclosed:$ ________

☒ Initial notification ($200 non-refundable fee required)
☐ Change in business ownership (represent the new owner, no fee required)
☐ Reactivation of RCRA Site ID Number (no fee required) Effective Date: ________

If you already have a RCRA Identification number, please use a pre-populated Site Identification Form to update your information. The Form is available at www.deqhazwaste.net or by calling the annual report hotline at 503-229-6938.

2. RCRA Site ID Number:

3a. Site Location Information

Company Name:	Jordan Cove Energy Project, South Dunes Power Plant
Site Location:	North Spit of Coos Bay
City/State/Zip:	Coos Bay, Oregon 97420
County:	Coos
Corp. Div. Reg. Nbr.:	30763395
NAICS Code:	237130
Employee Count:	45

4a. Site Contact (Whom DEQ should contact about site visits)

Person Name:	Robert L. Braddock
Mailing Address:	125 Central Avenue, Suite 380
City/State/Zip:	Coos Bay, OR 97420
Country:	USA
Phone Number (Ext):	(541) 266.7510
Email Address:	bobbraddock@attglobal.net

5a. Land Owner of Site Location

Name:	Fort Chicago Holding II U.S. LLC
Mailing Address:	Veresen, Inc., Livingston Place, South Tower, Suite 900, 222 - 3rd Avenue SW
City/State/Zip:	Calgary, Alberta T2P 0B4
Country:	Canada
Phone Number (Ext):	(541) 266.7510
Owner Type:	☒ Private ☐ Federal ☐ State ☐ County ☐ District ☐ Municipal ☐ Tribal ☐ Other

RCRA Waste Site Identification Form (continued)

Site ID

RCRA Site ID Number:

6a. Legal Owner of Company Applying for Site ID Number

Name:	Jordan Cove Energy Project L.P.
Mailing Address:	125 Central Avenue, Suite 380
City/State/Zip:	Coos Bay, OR 97420
Country:	USA
Phone Number (Ext):	(541) 266.7510
Owner Since:	12/14/2012 (mm/dd/yyyy)
Owner Type:	☒ Private ☐ Federal ☐ State ☐ County ☐ District ☐ Municipal ☐ Tribal ☐ Other

7a. Site Operator (Legal entity which is responsible for overall operation of the site)

Name:	Veresen, Inc.
Mailing Address:	Livingston Place, South Tower, Suite 900, 222 - 3rd Avenue SW
City/State/Zip:	Calgary, Alberta T2P 0B4
Country:	Canada
Phone Number (Ext):	(403) 213.3643
Operator Since:	See Block 14 (mm/dd/yyyy)
Operator Type:	☒ Private ☐ Federal ☐ State ☐ County ☐ District ☐ Municipal ☐ Tribal ☐ Other

8a. Forms Contact (Person responsible for preparing annual report)

Person Name:	Robert L. Braddock
Organization:	Jordan Cove Energy Project
Mailing Address:	Suite 380, 125 Central Avenue
City/State/Zip:	Coos Bay, OR 97420
Country:	USA
Phone Number (Ext):	(541) 266.7510
Email Address:	bobbraddock@attglobal.net

9a. Fee Contact (Contact person for invoice)

Person Name:	Robert L. Braddock
Organization:	Jordan Cove Energy Project
Mailing Address:	Suite 380, 125 Central Avenue
City/State/Zip:	Coos Bay, OR 97420
Country:	USA
Phone Number (Ext):	(541) 266.7510
Email Address:	bobbraddock@attglobal.net

RCRA Waste Site Identification Form (continued)

Site ID

RCRA Site ID Number:

10. Hazardous Waste Activities (Mark the appropriate boxes for activities that apply to your site)

1. Generator of Hazardous Waste

☐ a. LQG: Large Quantity Generator (Generates greater than 2,200 lbs/mo or more than 2.2 lbs of acute hazardous waste)

☒ b. SQG: Small Quantity Generator (Generates between 220 – 2,200 lbs/mo or more than 2,200 lbs accumulated on-site)

☐ c. CEG: Conditionally Exempt Generator (Generates between 0 – 220 lbs/mo, less than 2.2 lbs of acute hazardous waste and less than 2,200 lbs accumulated on-site)

2. Are you a hazardous waste generator due only to remediation of environmental contamination or because of a business closure?

☐ Yes ☒ No If yes, find out about expedited annual reporting at: www.deq.state.or.us/lq/pubs/factsheets/hw/HWFeesForCleanups.pdf

☐ **3. Importer of Hazardous Waste**

☐ **4. Generator of Mixed Waste (hazardous and radioactive)**

5. Transporter of Hazardous Waste

☐ a. Transports hazardous waste generated at this facility

☐ b. Transports for commercial purposes

☐ c. Hazardous waste transfer facility

☐ **6. Treatment, Storage, Disposal (TSD) Facility**

(Note: A RCRA Permit is required for this activity)

7. Recycler of Hazardous Waste

☐ a. Recycles HW generated at this facility

☐ b. Recycles HW generated by other facilities

8. Hazardous waste management in RCRA permit exempt units (e.g., elementary neutralization units, waste water treatment units, or accumulation tanks or containers)

☒ a. Manages HW generated at this facility

☐ b. Manages HW generated by other facilities

9. Exempt Boiler and/or Industrial Furnace

☐ a. Small Quantity On-site Burner Exemption

☐ b. Smelting, Melting, Refining Furnace Exemption

10. Underground Injection Control

☐ Yes ☒ No If yes, there may be additional reporting requirements at: www.deq.state.or.us/wq/uic/uic.htm

11. Description of Hazardous Wastes

1. Waste Codes for Federally Regulated Hazardous Wastes: Identify the federal hazardous waste codes that best describe your waste (e.g., D001 – Ignitable, D002 – Corrosive, D003 – Reactive, etc.) List additional federal codes in the comment section.

D001	D002	D003	D008	D009		D040	F001
F002	F003	F004	F005				

2. Waste Codes for State Regulated (i.e., non-federal) Hazardous Wastes: Identify the Oregon state-only hazardous waste codes that best describe your waste (e.g., ORX001, ORX007, ORP003, ORU001, etc.)

12. Universal Waste Activities (Mark the appropriate boxes for activities that apply to your site)

☐ **1. Large Quantity Handler of Universal Waste**

Accumulates a total of 11,000 lbs. or more of universal waste at any time, at the location at which it was generated.

☐ **2. Off-site Universal Waste Collection Site**

Accumulates a total of 2,200 lbs. or more of universal waste received from off-site). If yes, there are additional notification requirements at: **http://www.deq.state.or.us/lq/pubs/forms/hw/uwnotification.pdf**

☐ **3. Pesticide Collection Program**

Collects and accumulates waste pesticides from off-site. If yes, there are additional notification requirements at: **http://www.deq.state.or.us/lq/pubs/forms/hw/uwnotification.pdf**

☐ **4. Destination Facility for Universal Waste**

A facility that treats, dispose of, or recycles universal wastes on-site.

5. Mark all boxes that apply (skip if you did not check one of the other boxes in this section)

	Manage
a. Batteries	☐
b. Mercury containing equipment	☐
c. Lamps	☐
d. Pesticides	☐

13. Used Oil Activities (Mark the appropriate boxes for activities that apply to your site)

☐ **1. Used Oil Collection Center**

☐ **2. Used Oil Transporter**

☐ **3. Used Oil Transfer Facility**

4. Used Oil Processor/Re-refiner

Indicate type(s) of activity(s)

☐ a. Processor

☐ b. Re-refiner

☐ **5. Off-Specification Used Oil Burner (not used oil space heaters operating according to CFR 279.23)**

6. Used Oil Fuel Marketer

Indicate type(s) of activity(s)

☐ a. Marketer who directs shipments of off-specification used oil to off-specification used oil burner

☐ b. Marketer who first claims the used oil to meet the specifications

RCRA Waste Site Identification Form (continued)

Site ID

RCRA Site ID Number:

14. Comments

Block 7a "Operator since" No month/day/year was entered as construction of the facility has not begun. It is anticipated to start mid June 2014, with facility operations to begin in mid 2018.

Additional sheets may be attached for comments if needed.

15. Certification — **This form cannot be processed without a signature**

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Signature

Date

Robert Braddock

Name (print or type)

Vice President/Project Manager

Title

If you have any questions, special accommodation needs or require this document in an alternative format, please contact the Hazardous Waste Section in Portland at 503-229-6938 or toll-free within the State of Oregon at 1-800-452-4011, extension 6938.

16. Electronic Submittals

DEQ will issue a PIN and electronic filing instructions in a letter addressed to the Forms Contact in Section 8 on this form. The electronic reporting system may be used for your company's annual reporting and site identification updates.

APPENDIX E-2

Air Contaminant Discharge/Prevention of Significant Deterioration Permit Application

Jordan Cove Energy Project, L.P.
PSD Air Permit Application

Prepared for:

Oregon Department of Environmental Quality

Prepared by:

TRC Environmental Corporation
Lyndhurst, NJ

March 2013
Supplemental Section May 2013

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LIST OF ACRONYMS

Acronym	Definition
ACDP	Air contaminant discharge permit
AP-42	Compilation of Air Pollutant Emission Factors, Fifth Edition
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
BHP	Brake Horsepower
BPIPPRM	Building Profile Input Program for PRIME
Btu	British thermal unit
CAAA	Clean Air Act Amendments
CARB	California Air Resources Board
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CM	Channel miles
CO	carbon monoxide
CO_2	carbon dioxide
COC	Community of concern
CTG	combustion turbine generator
DB	duct burner
DEM	Digital Elevation Model
DLN	dry low-NO_x
EJ	Environmental Justice
ESA	Endangered Species Act
F	fluoride
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FLM	Federal Land Manager
Ft	Feet
GE	General Electric
GEP	good engineering practice
GPM	gallons per minute
GHG	greenhouse gas
H_2O	Water
H_2SO_4	sulfuric acid

Acronym	Definition
HAP	Hazardous Air Pollutant
HF	hydrogen fluoride
HHV	higher heating value
HRSG	heat recovery steam generator
K	degrees on the Kelvin scale
Km	kilometer
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
LNB	low-NO_x burner
LNG	liquefied natural gas
$\mu g/m^3$	microgram per cubic meter
m/s	meters per second
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
MMTPA	million metric tons per annum
MSL	mean sea level
MW	megawatt
N_2	nitrogen
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 1983
NCDC	National Climatic Data Center
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
$(NH_4)_2SO_4$	ammonium sulfate
NH_4HSO_4	ammonium bisulfate
NO	nitric oxide
NMFS	National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NNSR	Non-Attainment New Source Review
NSR	New Source Review
NWA	National Wilderness Area
NWR	National Wildlife Refuge

Acronym	Definition
NWS	National Weather Service
O_2	oxygen
O_3	Ozone
OAAQS	Oregon Ambient Air Quality Standards
ODEQ	Oregon Department of Environmental Quality
OAQPS	EPA Office of Air Quality Planning and Standards
Pb	Lead
PM	particulate matter
PM-2.5	particulate matter with an aerodynamic diameter of 2.5 microns or less
PM-10	particulate matter with an aerodynamic diameter of 10 microns or less
Ppm	parts per million
Ppmvd	parts per million dry volume
PSEL	plant site emission limit
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SICs	Significant Impact Concentrations
SILs	Significant Impact Levels
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
STG	steam turbine generator
TO	Thermal oxidizer
Tpy	tons per year
TRI	Toxic Release Inventory
TSP	total suspended particulate
ULSD	Ultra low sulfur distillate
USEPA	United States Environmental Protection Agency

Acronym	Definition
USFS	United States Fish and Wildlife Service
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1.0 INTRODUCTION

1.1 Project Overview

Jordan Cove Energy Project, L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal on an approximate 168-acre site located on the bay side of the North Spit of Coos Bay, Oregon between Coos Bay Navigation Channel Miles (CM) 7.0 and 8.0. The project, known as the Jordan Cove Energy Project (JCEP) LNG Terminal Project, or Project (or Facility) will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The LNG terminal will be capable of loading LNG ships ranging in capacity from 89,000 cubic meters (m^3) to 160,000 m^3. Approximately 90 ships per year are anticipated to call on the LNG terminal. The LNG loaded onto the ships will be transferred by cryogenic service piping from two 160,000 m^3 (1,006,000 barrels) full-containment LNG storage tanks where it will be stored in a liquefied state until it is pumped out to the LNG vessels. The following liquefaction facilities are proposed for the Project:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 billion SCF/day (Bscf/d);
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

There are two sites to be referenced within this one facility. The first is the Liquefaction site, which contains the four (4) Liquefaction trains, two (2) LNG full containment tanks, and the marine berthing and load-out facilities. The second area is referred to as the South Dunes Power Station site which contains two gas pre-treatment trains, the South Dunes Power Plant, and the common infrastructure for the plant entrance and administration buildings. Figure 1-1 shows the location of the proposed facility equipment and the surrounding area.

1.2 Summary of Federal and State-Level Emission Control Requirements

The following provides a general description of the proposed facility's regulatory and emission control requirements set forth by applicable Federal and State-Level air programs. Please see Section 3 of this Air Permit Application for a detailed regulatory analysis and Table 3-1 for a comparison of the proposed facility's potential emissions to the regulatory applicability thresholds.

Based upon potential emission calculations for the project sources, facility emissions will be greater than 100 tons per year for criteria air pollutants and thus, the project will require an Oregon DEQ Air Contaminant Discharge Permit (ACDP). Also, because the proposed facility is located in an attainment area for all pollutants and will potentially emit more than 100 tons per year of several air pollutants, it will be subject to federal Prevention of Significant Deterioration (PSD) permitting.

Best Available Control Technology (BACT) must be applied to control emissions of pollutants that are subject to PSD review based on potential emissions of each pollutant for which the project site area is in attainment. A complete BACT analysis is included in Section 4 of this Application.

1.3 Assessment of Air Quality Impact

1.3.1 Impact on Ambient Air Quality Standards and PSD Increments

The proposed Plant Site Emission Limits (PSELs) shown in Table 3-1 will exceed the Significant Emission Rates established in Oregon Administrative Rules OAR 340-200-0020 for NO_x, CO, VOC, SO_2, and PM/PM-10/PM-2.5 and therefore an air quality modeling analysis is required to show that no National Ambient Air Quality Standards (NAAQS) or PSD Increments will be violated in accordance with OAR 340-222-0041(3)(b)(c). Atmospheric dispersion modeling was performed in accordance with United States Environmental Protection Agency (U.S. EPA) and Oregon Department of Environmental Quality (ODEQ) modeling guidelines to estimate maximum expected air quality impacts from the proposed facility. The air quality analysis demonstrates that the proposed facility will be compliant with all applicable PSD increment levels and National Ambient Air Quality Standards (NAAQS).

1.3.2 Class I Area Impacts

Proposed major sources within 100 km of a Class I area may be required to perform an assessment of potential impacts in that Class I area. There are no Class I areas within 100 km of the proposed Facility, however, Class I areas within 200 kilometers of JCEP include:

- Crater Lake National Park (Oregon) 165 kilometers
- Redwood National Park (California) 177 kilometers
- Kalmiopsis Wilderness Area (Oregon) 110 kilometers
- Diamond Peak Wilderness Area (Oregon) 164 kilometers

- Three Sisters Wilderness Area (Oregon) 184 kilometers

The Federal Land Manager (FLM) for the Class I areas were notified on January 11, 2013 to determine if assessments of impacts on air quality related values (AQRVs) in the Class I area would be required. The FLM has reviewed the proposed Facility's details and related correspondence and has confirmed in a January 29, 2013 email that a Class I analysis for the proposed Facility is not required (see Appendix D).

1.3.3 Additional Required Air Quality Assessments

An analysis was performed to assess the proposed facility's impact on soils, vegetation, visibility, and industrial, commercial, and residential growth. This analysis demonstrated that the proposed facility would have negligible effects on these special concerns.

1.4 Conclusions

The conclusions reached from the results of the engineering and air quality modeling analyses are that the proposed LNG facility will: 1) meet all control technology requirements resulting BACT; 2) not cause or contribute to a violation of the NAAQS for any pollutant; 3) not exceed the PSD Class II increment for any pollutant; 4) not cause adverse impacts to soils, vegetation, growth and visibility; and 5) comply with all other applicable Federal and ODEQ air quality requirements.

1.5 Summary of Proposed Emission Limits

Tables 1-1 through 1-4 present a summary of the permit limits proposed for Jordan Cove Energy Project. These limits reflect the application of BACT control technology, as appropriate. In addition, Section 5.0 of this application provides atmospheric dispersion modeling documentation that confirms that the facility operating at the proposed limits will not contravene the NAAQS/ OAAQS or PSD Class II increment air quality levels.

1.6 Contents of Application Support Document and Appendices

The application forms for the project have been prepared and are included as Appendix A of this document. Emission calculation spreadsheets providing supporting calculations for the application forms are included as Appendix B. Air quality modeling data files are included in Appendix G.

1.7 Project Schedule

Preliminary schedule milestones for the planned Jordan Cove Energy Project are as follows:

• Air permit application submitted to ODEQ	March 2013
• Review Period	March 2013 – December 2013
• Public Comment Period	January 2014 – February 2014
• Final Permit Issuance	March 2014
• Commence Construction	Third Quarter 2014
• Commercial Operation	Second Quarter 2018

Table 1-1: Summary of Proposed Permit Limits
Combustion Turbine and Duct Burner (Steady-State Operation)

Pollutant	Stack Emissions[1,2,3]	
	Gas Firing	
	(lb/MMBtu)	(ppm)
Nitrogen Oxides (NO_x)		
CT Only	0.0073	2.0
CT w/ DB	0.0073	2.0
Volatile Organic Compounds (VOC)		
CT Only	0.0052	4.0
CT w/ DB	0.0052	4.0
Carbon Monoxide (CO)		
CT Only	0.0090	4.0
CT w/ DB	0.0090	4.0
PM/PM-10/PM-2.5[4]		
CT Only	0.0187	N/A
CT w/ DB	0.0187	N/A
Sulfur Dioxide (SO_2)		
CT Only	0.0031	N/A
CT w/ DB	0.0031	N/A
Sulfuric Acid Mist (H_2SO_4)		
CT Only	0.0037	N/A
CT w/ DB	0.0043	N/A
Ammonia		
CT Only	N/A	5.0
CT w/ DB	N/A	5.0
Pollutant	**lb/MWh**	**ton/yr/turbine**
Greenhouse Gases (GHG)		
	1,100	283,273

1 "ppm" refers to ppmvd @ 15% O2; lb/MMBtu limits are HHV basis. All ppm values are one-hour averages.
2 Facility may exceed short-term limits during defined startup and shutdown periods.
3 All proposed emission limits (in units of ppm, lb/hr, and lb/MMBtu) do not serve as the basis for determining annual emission limits. Refer to Appendix B for potential annual emissions calculations.
4 Includes filterables, condensables, and sulfates.

Table 1-2: Summary of Proposed Permit Limits – Emergency Equipment

Pollutant	Emissions		
	South Dunes Fire Pump	Liquefaction Area Fire Pumps	Emergency Generators
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
NO_x	0.9120	0.9120	1.4592
VOC	0.0740	0.0740	0.1183
CO	0.9958	0.9958	0.8545
PM/PM-10/PM-2.5	0.0493	0.0493	0.0493
SO_2	0.0015	0.0015	0.0015
H_2SO_4	0.00012	0.00012	0.00012
	(tons/year/unit)	(tons/year/unit)	(tons/year/unit)
GHG	44	307	1,471

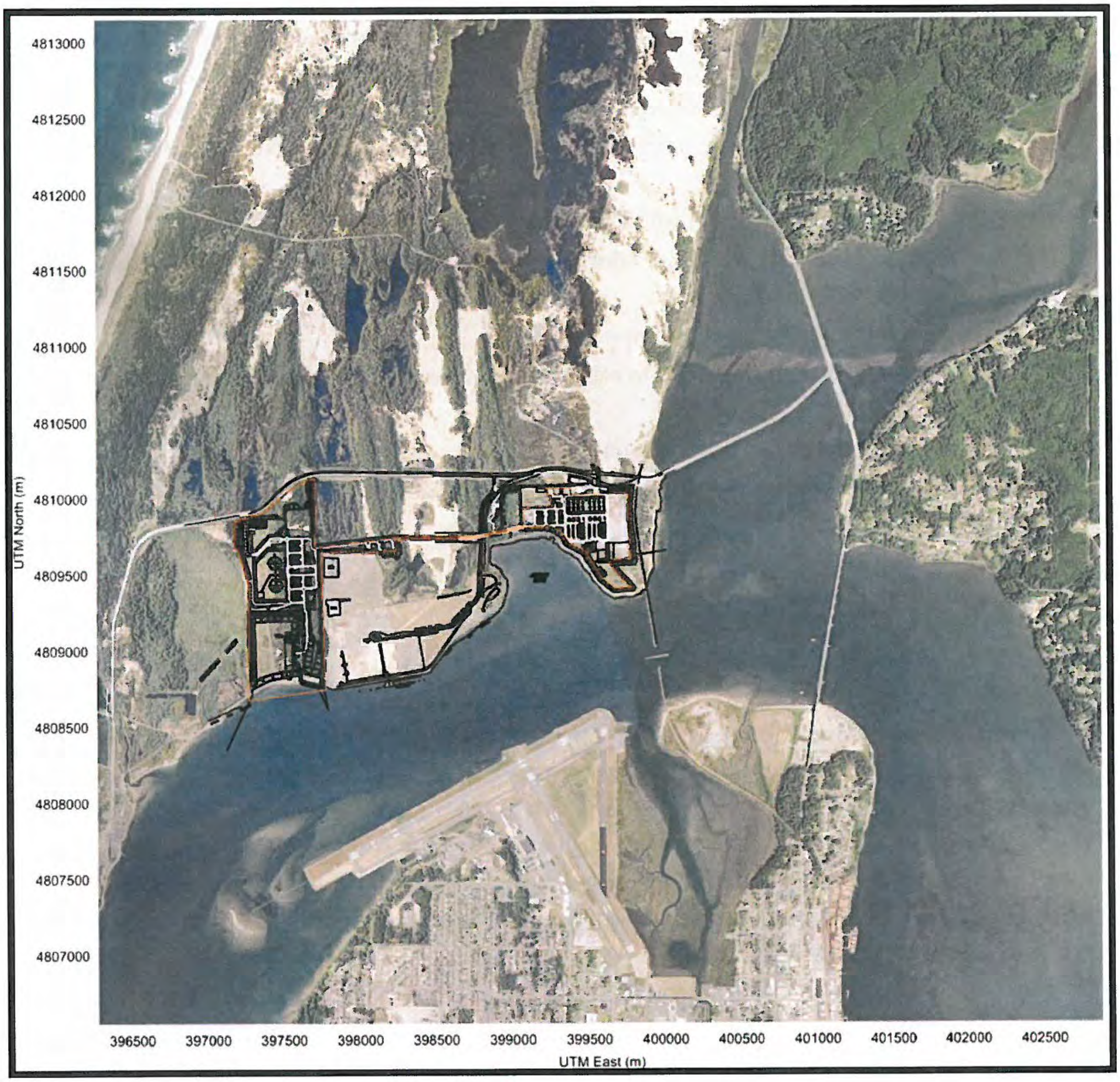
Table 1-3: Summary of Proposed Permit Limits –Thermal Oxidizers

Pollutant	Emissions (lb/hr/unit)
NOx	6.65
VOC	0.055
CO	2.00
PM/PM-10/PM-2.5	0.13
SO_2	1.99
	(tons/year/unit)
GHG	223,505

Table 1-4: Summary of Proposed Permit Limits –Flares

Pollutant	Emissions
	(lb/hr/unit)
NOx	0.02
VOC	0.16
CO	0.04
PM/PM-10/PM-2.5	0.00032
SO2	0.003
	(tons/year/unit)
GHG	278

Figure 1-1: Site Location Map



2.0 PROJECT DESCRIPTION

2.1 Facility Conceptual Design

Jordan Cove Energy Project, L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal in Coos Bay County, Oregon. The facility is identified as the JCEP LNG Terminal Project and will consist of equipment to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The Project will include the following equipment:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 billion SCF/day;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

2.2 Equipment/Fuels

The project will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF) and which will be equipped with natural gas-fired duct burners for supplementary firing and two steam turbine generators (STGs). By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Station) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Station).

Emissions from the six combined cycle units will be controlled by the use of dry low-NO_x burner technology and SCR for NO_x control, an oxidation catalyst for CO and VOC control, and the use of clean low-sulfur fuels only (i.e., natural gas) to minimize emissions of SO_2, PM/PM-10/PM-2.5, and H_2SO_4. Exhaust gases from the combined cycle units after emission controls will be dispersed to the atmosphere via individual stacks. Steam from the steam turbine will be sent to a condenser where it will be cooled to a liquid state and returned to the heat recovery steam generator (HRSG). Waste heat from the condenser will be dissipated through the air cooled condensers.

In addition to the South Dunes Power Station, the LNG Liquefaction Project will have a number of fugitive VOC emission sources from piping/flanges/valves from both land-based and vessel based sources. The four LNG liquefaction trains will be electric and thus, only fugitive VOC emissions are expected from that equipment.

While combustion emissions from the LNG vessels during hoteling, berthing, deberthing, and transit are expected, these activities are exempt from ODEQ and PSD permitting requirements as they are not considered direct emissions from the Facility. The power to provide for the pumps to load the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the loading process that would be subject to ACDP and PSD review.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Hydrogen sulfide and mercaptans are removed using a scavenging system.

The gas conditioning trains consist of two parallel trains, each containing two systems in series: a scavenger system to reduce hydrogen sulfide and mercaptans, a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas from the Amine Stripper will be sent to a thermal oxidizer in order to oxidize sulfur components. Each thermal oxidizer is assumed to have a 96% reliability. In the unlikely event of thermal oxidizer downtime, the waste gas will vent to the atmosphere. Air emissions from the amine and dehydration systems are not expected.

Two ground flares are included in the Project design. One flare is included to handle gas relieved during emergency upset conditions caused by events including but not limited to: extended power outages, extended emergency shutdown events, and unexpected loss of vapor handling equipment during LNG ship loading with the LNG Storage Tank operating near maximum normal operating pressure. A second ground flare will be used in emergency situations to relieve and protect equipment in the Gas Conditioning portion of the plant. Low pressure flare headers will be continuously purged with fuel gas. A small pilot (42,500 Btu/hr) on each flare with electronic ignition will be continuously operated.

2.3 Operation

The combined cycle units will be operated to follow electrical demand (i.e., dispatch mode) of the liquefaction facility, but will be designed and permitted to operate on a continuous basis. The combined cycle units typically will not operate at steady-state below 50% load and the duct burner will only operate at full load conditions for the combustion turbines. Therefore, the HRSG steam production will follow the combustion turbine loads and higher HRSG steam output will only occur when duct firing is employed during combustion turbine full load operation.

The thermal oxidizers are expected to operate continuously while the gas conditioning system is in operation. In the unlikely event that a thermal oxidizer is down, the waste gas will vent to the atmosphere.

Figure 2-1 presents the Jordan Cove Energy Project, L.P general site plan on an aerial map showing locations of major facility processing areas and equipment. See Figures 5-1 and 5-2 for detailed general arrangement drawings of the South Dunes area and the LNG liquefaction and storage area. Figures 2-2 through 2-4 present process flow diagrams for the major Facility components.

2.4 Source Emission Parameters

Emissions of air contaminants from the proposed Project have been estimated based upon expected vendor emission guarantees, control analysis results, emission factors presented in the U.S. EPA publication AP-42, mass balance calculations, and engineering estimates. Emission calculations used to develop the emission estimates for the proposed equipment are included in this application as Appendix B.

2.4.1 Emissions from the Combined Cycle Units

Emissions from the combined cycle units will include criteria pollutants, non-criteria pollutants, and hazardous air pollutants (HAPs). Short-term and annual emission rates of these pollutants from the combined cycle units are described below.

2.4.1.1 Criteria Pollutants

Combustion turbine performance and emissions are affected by ambient temperature, fuel consumption, power output and fuel type. Proposed emission rates and exhaust characteristics for the combined cycle units are provided in Appendix B. Exhaust and emission parameters are presented for the combustion turbine firing natural gas at three ambient temperatures (20 degrees Fahrenheit, 59 degrees Fahrenheit, and 90 degrees Fahrenheit) and three loads (50%, 75%, and 100%). In addition, emission rates and stack parameters are presented for duct firing during natural gas operation at 100% load. A total of 12 total combustion turbine steady-state operating scenarios are presented.

Criteria pollutant potential emission rates from the combined cycle units are based on vendor emissions data.

2.4.1.2 Greenhouse Gases

For PSD purposes, greenhouse gases (GHGs) are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). CO_2, N_2O and CH_4 are the only pollutants of concern for the combustion turbine units. Potential emissions of CO_2 are based on vendor emissions data. CH_4 and N_2O emissions from the proposed combined cycle units are based on 40 CFR Part 98 emission factors.

2.4.1.3 HAPs

Appendix B presents a summary table of potential emissions of HAPs from the proposed combined cycle units based on U.S. EPA's AP-42 emission factor guidance document. Because the AP-42 formaldehyde emission factor is based on old testing data with limited data points that are not representative of the proposed units, formaldehyde emissions from the combustion turbines while firing natural gas are based upon the California Air Resource Board (CARB) emission inventory that is more representative of the type of high-efficiency dry low-NOx units specified for this project.

2.4.1.4 Other Pollutants

Sulfuric acid mist (H_2SO_4) and ammonia (NH_3) emissions are based on vendor emission estimates.

2.4.2 Emergency Diesel Engines Emissions

JCEP is proposing to use seven (7) diesel internal combustion engines for the emergency generators and back-up fire pumps ranging in size from 400 hp to 3,350 hp. Short-term potential emission rates for each engine are provided based on a combination of potential equipment vendor design data and fuel sulfur content (15 ppm Sulfur oil). HAP emissions from the diesel engines are based on U.S. EPA's AP-42 Emission Factor Guidance Document. GHG emissions are based on 40 CFR Part 98 emission factors. Due to the limited operation of these sources, annual PTE emissions are calculated using the maximum hourly emission rate and 200 hours per year operation per engine. Please see Appendix B for potential emission calculation details.

2.4.3 Thermal Oxidizer Emissions

The Project will consist of two thermal oxidizers (one for each train) to control emissions from the amine treating system and the molecular sieve dehydrators. The thermal oxidizers have a destruction efficiency of greater than 99.5 percent for H_2S, VOC and HC. Emissions from the thermal oxidizers were based on total annual vendor emission estimates. The thermal oxidizers are expected to have a reliability of at least 96%. In the unlikely event that a thermal oxidizer is down, the waste gas will be vented to the atmosphere.

2.4.4 Ground Flare Pilot/Purge Emissions

The ground flares may be used during the following situations:

- Initial cool down of the facility;
- Extended power outage;
- Extended emergency shutdown events;
- Unexpected loss of vapor handling equipment during LNG Ship loading with the LNG storage tank operating near maximum normal operating pressure; and
- Emergency situations to relieve and protect equipment in the Gas Conditioning portion of the plant.

The low pressure flare headers are continuously purged with fuel gas. A small natural gas pilot (42,500 Btu/hr) on each flare with electronic ignition will be continuously operated. The flare pilots have a combustion efficiency of greater than 99 percent.

CO_2, methane, ethane and propane emissions are based on vendor emission estimates. NO_x and CO emissions are calculated using emission factors from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers" (October 2000).

2.4.5 Equipment Leak Fugitive Emissions

Fugitive emissions result from leaking process components such as valves and flanges, from LNG storage tank overpressure venting and pressure relief valves and from the LNG loading arms during marine vessel loading. These emissions mainly consist of methane and VOC content of the natural gas. Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment at the proposed Plant and emission factors for each component type taken from EPA's "Protocol for Equipment Leak Emission Estimate" (1995).

2.4.6 Facility Total Potential Annual Emissions

Total potential annual emissions for the proposed Project are presented in Table 2-1. Annual emission values in Table 2-1 represent total PTE from all proposed sources and were based on the following worst-case operating scenarios:

- Year-round (8,760 hours), full load operation of each combustion turbine (at 59°F annual average ambient temperature);
- The equivalent of 4,000 hours of duct firing at maximum design firing rate for each combustion turbine;
- A total of 275 annual combined cycle shutdown/startup events per turbine (30 cold starts, 85 warm starts and 160 hot starts);
- 200 hours per year of operation of the emergency diesel generators and 200 hours per year of operation of the diesel fire pump engines;
- Year-round (8,760 hours) operation of the thermal oxidizers and ground flares; and.
- 4% annual operation of the thermal incinerator vents.

Fugitive emissions from the LNG storage tanks, marine vessel loading operations and process equipment leaks were also included in the Project's annual potential to emit.

Table 2-1: Summary of Project Criteria Pollutant and Total HAPs Annual Emissions

Source	Potential Annual Emissions (tons/year)						
	NO_X	CO	VOC	SO_2	PM/PM-10/ PM-2.5	GHG [CO2e]	HAPS[a]
Combined Cycle Units[b]	106.32	129.97	74.78	46.1	180.42	1,695,525	--
Start-Up/Shutdown Emissions[c]	47.77	2.31	0.0	--	0.0	--	--
South Dunes Fire Pump[d]	0.24	0.27	0.02	0.00041	0.01	44	--
Liquefaction Area Fire Pumps[d]	1.71	1.87	0.14	0.0029	0.09	307	--
Emergency Generators[d]	6.56	3.84	0.53	0.0068	0.22	1,471	
Thermal Oxidizers/Vents[e]	58.3	17.5	1.61	17.4	1.15	464,465	--
Flares[e]	0.14	0.28	1.12	0.01	0.0022	555.4	--
Fugitives[f]	--	--	131.05	--	--	3,549	--
Facility-Wide Total	**221.0**	**156.1**	**209.3**	**63.5**	**181.9**	**2,165,917**	**2.5/8.9**

Notes:

[a] The potential HAP emission calculations presented in Appendix B result in total HAP emissions less than 25 tons/yr. Additionally, potential annual emissions of the maximum individual HAP are less than 10 tons/yr.

[b] Potential annual emissions from the combined cycle units assume the equivalent of 8,760 hr/yr of combustion turbine operation and 4,000 hr/yr of duct firing.

[c] Combined cycle unit start-up/shutdown emissions are added to the baseline steady-state PTE values if the total start-up/shutdown emissions are more than the steady-state full-load equivalent during the period of unit off-line downtime and duration of the start-up (and previous shutdown). For start-up/shutdown emissions noted above as "–" for certain pollutants, the start-up/shutdown emissions addition to the baseline steady-state PTE is not applicable since mass emissions of these pollutants are fuel input based (lb/MMBtu) and the full-load, steady-state basis represents the worst-case scenario for PTE emission

[d] Potential annual emissions from the emergency diesel generators and fire pumps assume 200 hours per year of operation.

[e] Potential emissions from the thermal oxidizers and ground flares assume year-round (8,760 hours) operation. Annual emissions from the TO vents assume 4% annual operation.

[f] Fugitive emissions include emissions from the LNG storage tanks, marine vessel loading operations and process equipment leaks.

Figure 2-1: Locations of Major Facility Equipment and Processing Areas

Figure 2-2: Process Flow Diagram for Gas Conditioning System

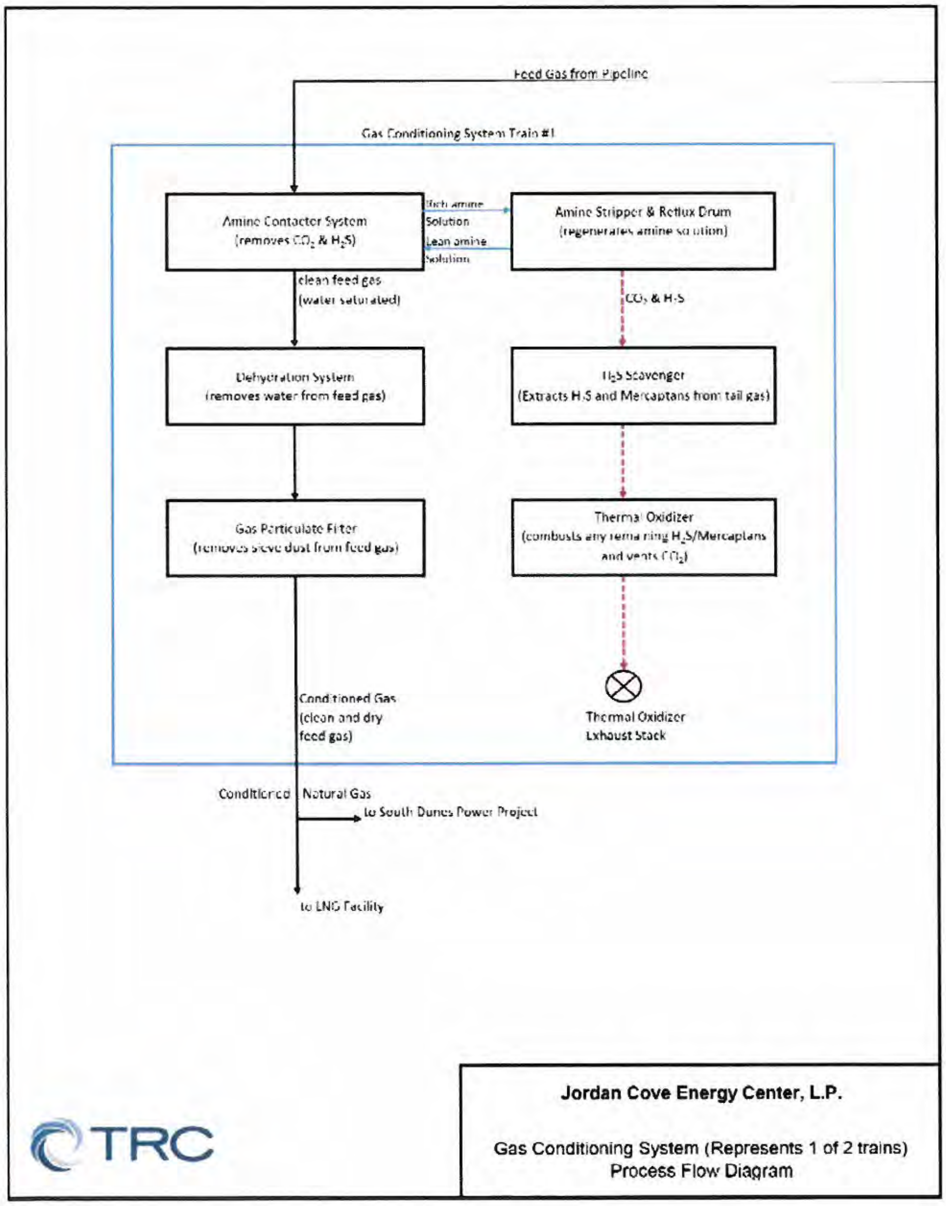


Figure 2-3: Process Flow Diagram for South Dunes Power Plant

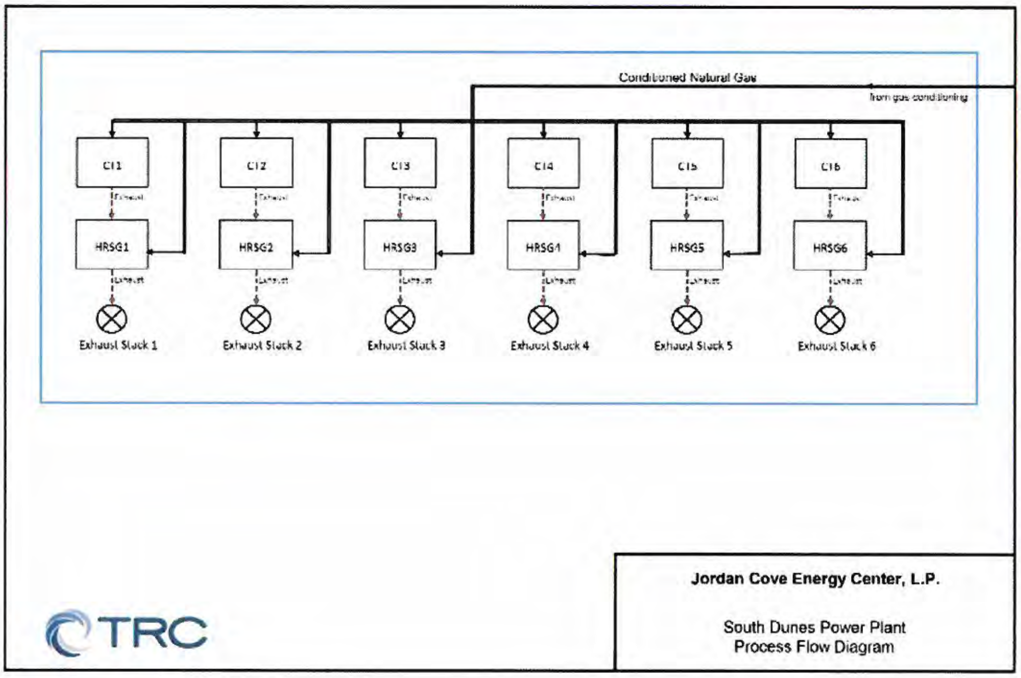
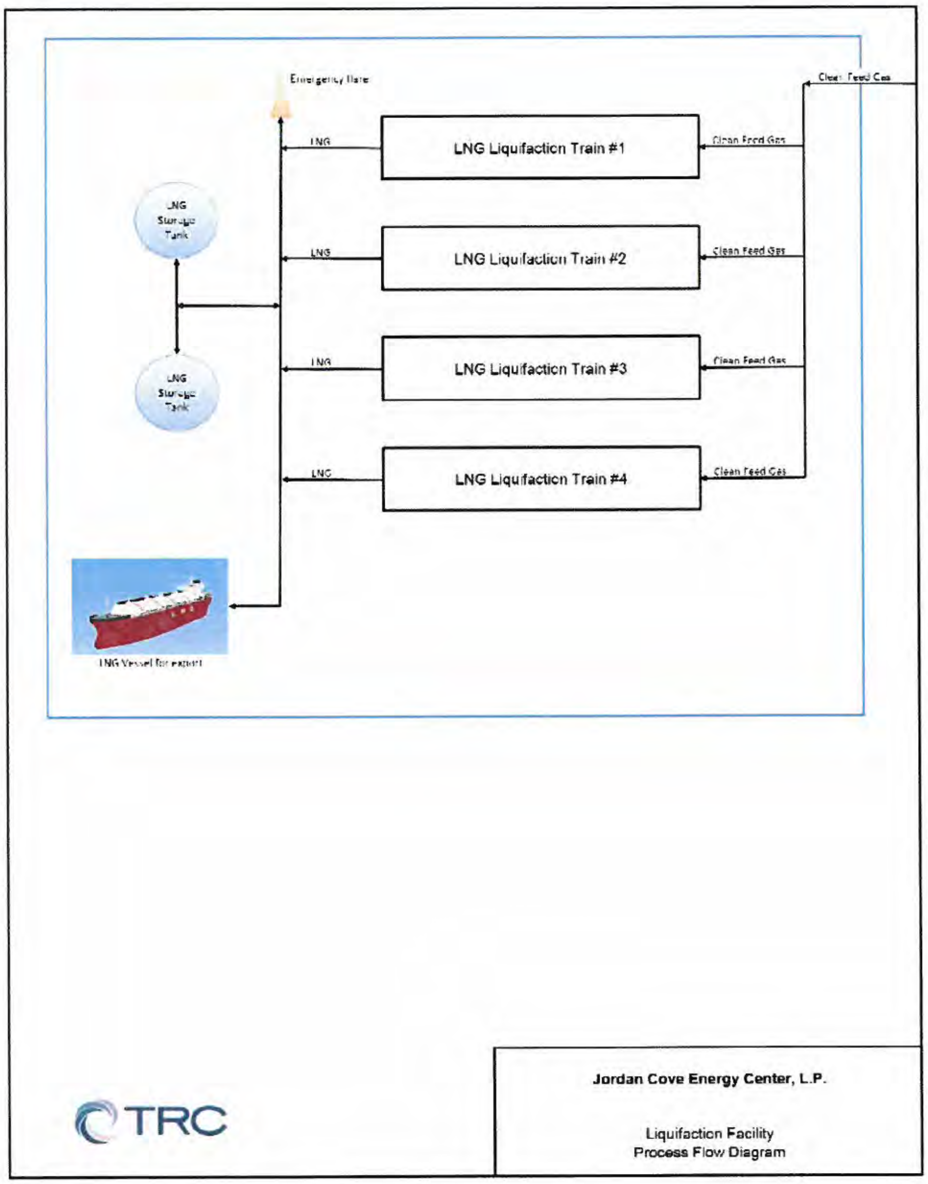


Figure 2-4: Process Flow Diagram for Liquefaction Area



3.0 APPLICABLE REQUIREMENTS AND REQUIRED ANALYSES

This section contains an analysis of the applicability of federal and state air quality regulations to the proposed Project in Coos Bay, Oregon. The specific regulations included in this applicability review are the Prevention of Significant Deterioration (PSD) requirements, Federal New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPs)/Maximum Achievable Control Technology (MACT) applicability for HAPs, and ODEQ Regulations.

3.1 Attainment Status and Compliance with Air Quality Standards

The U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for each of the following criteria air pollutants: particulate matter (PM) with an aerodynamic diameter of 10 microns or less (PM_{10}), PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead (Pb).

Areas in which the NAAQS are being met are referred to as attainment areas. Areas in which the NAAQS are not being met are referred to as nonattainment areas. Areas that were formerly nonattainment areas but are now in attainment and covered by a maintenance plan are referred to as maintenance areas. Areas for which sufficient data are not available to determine a classification are referred to as unclassifiable. The federal attainment status designations of areas in Oregon with respect to NAAQS are listed at 40 CFR 81.338. The Project is located in Coos County in the Southwest Oregon Intrastate Air Quality Control Region (AQCR). The proposed location of the JCEP facility is in an area currently designated as in attainment/unclassifiable for all criteria pollutants.

3.2 Prevention of Significant Deterioration

3.2.1 Applicability

The Oregon Administrative Rules adopt the Prevention of Significant Deterioration program pursuant to 40 CFR 51.166, which is administered through the ODEQ air permitting process, and applies to a new or modified major facility located in an attainment area. The Department accepted administration of the PSD program from the U.S. EPA in January of 1986 through approved State Implementation Plans (SIPs).

The PSD regulations define a major source as any source with a potential to emit regulated pollutants in amounts equal to or greater than 250 tons per year (tpy) or 100 tpy for 28 specific source categories identified in 40 CFR 52.21. Natural gas processing plants are not one of the listed 28 named source categories, however, because the facility will include a fossil fuel fired steam electric plant with a heat input capacity greater than 250 MMBTU/hr (which is one of the 28 named sources), the JCEP will be subject to the 100 ton per year PSD major source threshold.

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of PSD for greenhouse gas (GHG) emissions. Under the tailoring rule, application of PSD to GHGs will be implemented in multiple steps. The first step began on January 2, 2011 and ended on June 30, 2011. Under step 1, PSD applies to GHG emissions from a new source only if the source is already subject to PSD due to emissions of criteria pollutants and the potential GHG emissions from the project would be equal to or greater than 100,000 tons/year on a $CO2_e$ basis. Projects which are not subject to PSD review for criteria pollutants and that receive permits and commence construction prior to July 1, 2011 will not be subject to PSD for GHGs. The second step started on July 1, 2011 and requires sources solely considered "major" sources due to GHG emissions to obtain a PSD permit.

Table 3-1 summarizes the facility's potential emissions. Based on the potential to emit, the proposed facility is subject to PSD permitting requirements for NO_x, CO, VOC, PM/PM-10/PM-2.5, SO_2, H_2SO_4 and GHG emissions.

3.2.2 Requirements

The PSD regulations state that facilities subject to PSD review must perform an air quality analysis (which can include atmospheric dispersion modeling and preconstruction ambient air quality monitoring), and a Best Available Control Technology (BACT) demonstration for those pollutants that exceed the pollutant-specific significant emission rates identified in the regulations as well as an additional impacts analysis that examines the impacts of air emissions from the project on visibility, soils and vegetation.

3.2.2.1 Best Available Control Technology

JCEP must utilize BACT controls for emissions of NO_x, CO, VOC, PM/PM-10/PM-2.5, SO_2, H_2SO_4, and GHG from each piece of new equipment. As previously stated, BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of energy, economic and environmental factors. In a BACT analysis, the energy, environmental, and economic factors associated with each alternate control technology are evaluated, in addition to the benefit of reduced emissions that the technology would bring. The BACT analysis for the proposed facility is detailed in Section 4.

3.2.2.2 Air Quality Analysis

The PSD air quality impact analysis (described in detail in Section 5) requires dispersion modeling that uses emission rates and stack parameters (stack height and flue gas exit temperature and velocity, etc.) coupled with historical meteorology representative of the site to predict the location and magnitude of maximum impacts for various pollutants and averaging periods. If dispersion modeling indicates that the predicted air quality impact concentration of a given pollutant emitted from the proposed facility is lower than its respective Significant Impact Level (SIL) shown in Table 3-2, it is considered to have an insignificant impact and no further air quality analysis is required. If modeled concentrations of one or more pollutants exceed their respective SILs, the proposed facility is considered to have an area of impact and requires additional air quality analysis.

3.2.2.2.1 Ambient Air Quality Monitoring

Proposed facilities subject to PSD review may have to perform up to one year of preconstruction monitoring unless granted an exemption by the reviewing agency, ODEQ. TRC, on behalf of the Project, submitted a request to the ODEQ for an exemption from the requirement to perform one year of pre-construction ambient air quality monitoring at the proposed facility site on January 28, 2013. The request for waiver from pre-construction ambient air quality monitoring was approved by ODEQ on March 13, 2013 and can be found in Appendix D.

3.2.2.2.2 Impact Area Determination

A proposed facility subject to the PSD regulations must determine its impact on air quality for any pollutant for which it does not have an insignificant impact. The area of impact is defined as the greatest distance from the proposed facility site within which the emissions result in concentrations greater than the significant impact concentrations.

3.2.2.2.3 Additional Impact Analyses

The fact that the proposed facility's potential emissions are greater than the applicable PSD significant emission rate thresholds means that certain additional analyses are required as part of the PSD review. These include modeling to assess potential for impacts to soils and vegetation, visibility, and include emissions from associated industrial, commercial, and residential growth as well as the emissions from the proposed facility. A more detailed explanation of this analysis is presented in Section 5 of this application. Additionally, Section 6 provides an assessment of Environmental Justice issues and Section 7 addresses impacts to threatened and endangered species.

3.2.2.2.4 Impacts on Class I Areas

Per guidance from ODEQ, air quality concentrations of NO_x, SO_2, PM-2.5 and PM-10 in Class I areas within 200 km of the proposed facility were determined. Class I areas within 200 kilometers include:

Crater Lake National Park (Oregon)	165 kilometers
Redwood National Park (California)	177 kilometers
Kalmiopsis Wilderness Area (Oregon)	110 kilometers
Diamond Peak Wilderness Area (Oregon)	164 kilometers
Three Sisters Wilderness Area (Oregon)	184 kilometers

See Section 5.6 for a detailed discussion the impacts to Class I areas.

3.3 Federal New Source Performance Standards

The NSPS are technology-based standards applicable to new, modified, and reconstructed stationary sources. The NSPS requirements are established for approximately 70 source categories. Five subparts of these standards apply to the proposed facility: General Provisions (40 CFR 60, Subpart A), Standards of Performance for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK), Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII), Standards of Performance for Volatile Organic Liquid Storage Vessels (40 CFR 60, Subpart Kb) and Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (40 CFR 60, Subpart OOOO).

3.3.1 Subpart A: General Provisions

Each source type that is subject to a NSPS of 40 CFR 60 is also subject to the general provisions of Subpart A. The applicable general provisions of Subpart A are detailed in 40 CFR Parts 60.7 (Notification and Recordkeeping) and 60.8 (Performance Tests).

3.3.2 Subpart KKKK: Stationary Combustion Turbines

On July 6, 2006, the U.S. EPA promulgated Subpart KKKK to establish emission standards and compliance schedules for the control of emissions from new stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. Note that stationary combustion turbines regulated under Subpart KKKK are exempt from Subpart GG requirements, which are applicable to units constructed, modified, or reconstructed prior to February 18, 2005. Additionally, heat recovery steam generators (HRSGs) and duct burners regulated under Subpart KKKK are exempt from the requirements set forth in Subparts Da, Db, and Dc for fossil fuel combustion units.

Subpart KKKK establishes emission limits for NO_x for combustion turbines with a heat input capacity (exclusive of duct burners) greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr. During natural gas firing, NO_x emissions from the turbine and duct burner are limited to 25 ppm (dry basis by volume, corrected to 15% O_2) or 1.2 lb/MW-hr of useful output. Emissions of SO_2 from combustion turbines regardless of fuel type are limited to 0.90 lb/MW-hr gross output or low-sulfur fuel to achieve no greater than 0.060 lb/MMBtu.

The Facility's proposed emission rates from the combustion turbines and duct burners are well below the applicable Subpart KKKK emission standards.

3.3.3 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII establishes emission standards, fuel sulfur limitations, maintenance requirements, operating limitations, monitoring requirements, and recordkeeping requirements for affected units. An affected unit must be a compression ignition designed internal combustion engine that is new (dates vary between April 1, 2006 and 2007 model year) or reconstructed after July 11, 2006. JCEP will purchase and install a total of seven (7) internal combustion diesel engines for the emergency generators and back-up fire pumps that will meet the requirements of Subpart IIII. Therefore, the proposed potential emission rates of NO_x, CO, PM-10, and VOC from the emergency diesel engines do not exceed the applicable emission standards set forth in Subpart IIII.

3.3.4 Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels

40 CFR 60, Subpart Kb establishes standards of performance for volatile organic liquid (VOL) storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984. A VOL is any organic liquid which can emit volatile organic compounds (VOC), as defined in 40 CFR 51.100, into the atmosphere. Methane and ethane are not considered VOC due to their low atmospheric reactivity (40 CFR 51.100(s)(1)). Subpart Kb does not apply to storage vessels with storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). LNG is comprised primarily of methane and ethane, with small amounts of VOC (e.g., propane, butanes). The maximum true vapor pressure of the LNG tanks is greater than 3.5 kPa, therefore NSPS Subpart Kb will apply.

Subpart Kb prescribes tank design control equipment specifications for fixed and external floating roof tanks as well as visual inspection, monitoring and recordkeeping requirements. The LNG tanks will be fixed roof tanks which meet the control specifications identified in 40 CFR 60.112b(a)(1).

3.3.5 Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

40 CFR 60, Subpart OOOO establishes VOC emission standards for onshore natural gas processing plants that are constructed, reconstructed or modified after August 23, 2011. The different types of affected sources which potentially could be applicable to the proposed facility and associated standards are summarized below.

- **Pneumatic Controllers**: Each single pneumatic controller is an affected facility. Of note, pneumatic controllers are exempt from the initial notification requirements in 40 CFR § 60.7. Zero-emission pneumatic controllers are required at onshore natural gas processing plants, absent a demonstration to the EPA that a high-bleed controller is needed. Other pneumatic controllers must have emissions of no more than 6 standard cubic feet of natural gas per hour.
- **Storage Vessels**: Each storage vessel is an affected facility. Storage vessels must meet NESHAP Subpart HH requirements (95% control of VOC emissions—see below), except that storage vessels with VOC emissions of less than 6 tons per year (tpy) are exempt. Because the LNG tanks will have potential VOC emissions less than 6 tpy they are exempt from Subpart OOOO.
- **Onshore Natural Gas Processing Plants**: Each compressor in VOC or wet gas service at an onshore gas processing plant is an affected facility, as is the group of all equipment (except compressors) within a process unit. Other associated equipment, such as compressor stations, dehydration units, and gathering systems, are also affected facilities, if located at an onshore gas processing plant. In general, owners and operators must comply with the leak detection and repair requirements in NSPS Subpart VVa (40 CFR § 60.480a, et seq.).
- **Natural Gas Sweetening Units**: Each onshore sweetening unit or combination of sweetening unit and sulfur recovery unit is an affected facility, except that facilities with a design capacity of less than 2 long tons per day of hydrogen sulfide and facilities processing gas for reinjection are largely exempt. For each affected facility, owners and operators must achieve a minimum SO_2 emission reduction efficiency established based on sulfur feed rate and sulfur content of the inlet gas. This reduction efficiency is designed to be 99.9%. The proposed amine unit has a maximum design capacity of less than 2 long tons per day of H_2S and is therefore exempt from the requirements of Subpart OOOO.

In addition, affected facilities are subject to a number of notification, testing, monitoring, recordkeeping, and reporting requirements.

3.4 National Emission Standards for Hazardous Air Pollutants

The National Emissions Standards for Hazardous Air Pollutants (NESHAPs) are emissions standards set by the U.S. EPA for an air pollutant not covered by the National Ambient Air Quality Standards (NAAQS) and that may cause an increase in fatalities or in serious, irreversible, or incapacitating illness. The standards for a particular source category require the maximum degree of emission reduction that the U.S. EPA determines to be achievable, which is known as the Maximum Achievable Control Technology (MACT). These standards are authorized by Section 112 of the Clean Air Act and the regulations are published in 40 CFR Parts 61 and 63. The proposed facility is subject to the following two subparts: General Provisions (40 CFR Part 63, Subpart A) and the emission standards for Reciprocating Internal Combustion Engines (RICE) (40 CFR Part 63, Subpart ZZZZ).

3.4.1 40 CFR Part 63, Subpart A – General Provisions

The emergency diesel generator and fire pump are subject to the general provisions for NESHAPs units in 40 CFR Part 63 Subpart A. These include the requirements for notification, record keeping, and performance testing.

3.4.2 40 CFR Part 63, Subpart ZZZZ – Reciprocating Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. An area source is defined as a source which is not a major source of HAP emissions. The proposed emergency diesel generator and fire pump are subject to these rules. By complying with the NSPS Subpart IIII, the units will comply with Subpart ZZZZ.

3.5 Oregon Department of Environmental Quality Regulations

3.5.1 Division 202 (Ambient Air Quality Standards)

Division 202 of OAR 340 contains ambient air quality standards that apply throughout the state of Oregon. The Oregon Ambient Air Quality Standards (OAAQS) are included in Table 3-3. The OAAQS are comparable to or more stringent than National Ambient Air Quality Standards (NAAQS) that EPA has established for designated criteria pollutants.

3.5.2 Division 216 (Air Contaminant Discharge Permits)

Division 216 is the preconstruction and operating permit program for major sources in Oregon. The rule states that "no person may construct, install, establish, develop or operate any air contaminant source which is referred to in Table 1 without first obtaining an ACDP from the Department. Table 1 of OAR 340-216 lists natural gas processing and associated fuel burning equipment as an affected source with the requirement that sources with emissions above 100 tons per year of any criteria air pollutant must obtain a Standard ACDP. The JCEP will have emissions of NO_x, CO, VOC, SO_2, and PM-10/PM-2.5 above 100 tons per year and thus, a Standard ACDP will be applied for and obtained from the ODEQ.

A Standard ACDP contains the following:

- All applicable requirements, including general ACDP conditions for incorporating generally applicable requirements.
- Source Specific Plant Site Emission Limits (PSELs) or Generic PSELs as specified in OAR 340 Division 222.
- Testing, Monitoring, Recordkeeping, and Reporting Requirements sufficient to determine compliance with the PSEL and other emission limits and standards.
- A permit duration not to exceed 5 years.

3.5.3 Division 218 (State Operating Permit Program)

A Title V major source, as defined in 40 CFR Part 70.2, is any source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit criteria pollutants or HAPs above the established applicability thresholds. The Title V program requires major sources of air pollutants to obtain Federal operating permits. In Oregon, the authority to issue Title V operating permits has been delegated to ODEQ by the EPA. The proposed Project is subject to the Title V operating permit and as such, will obtain an Oregon Title V operating permit pursuant to the rules established in OAR 340-218.

3.6 Greenhouse Gas Monitoring

On September 22, 2009, EPA promulgated the final 40 CFR Part 98 greenhouse gas monitoring and reporting regulations that require approximately 10,000 facilities to report their greenhouse gas (GHG) emissions annually. The reporting rule generally applies to facilities that emit more than 25,000 tons of GHG a year and identifies 29 specific categories of covered sources. The proposed facility is subject to the federal GHG Monitoring requirements and will prepare a GHG Monitoring Plan which outlines the proposed methodology for calculating GHG emissions along with appropriate quality assurance measures.

3.7 Risk Management Program

The Risk Management Program ("RMP") is a federal regulation designed to prevent the release of hazardous materials from accidents and to minimize impacts when releases do occur. The regulation is contained in the CAA Amendments of 1990, Section 112(r). The RMP rule is codified in 40 CFR 68. The regulation contains a list of substances and threshold quantities for determining applicability of the rule to a facility. If a facility stores, handles, or processes one or more substances on this list at a quantity equal to or greater than that specified in the regulation, the facility must prepare and submit a risk management plan that meets the requirements of the RMP. If a facility does not have a listed substance on site, or the quantity of a listed substance is below the applicability threshold, the facility does not have to prepare an RMP. However, a facility must still comply with requirements of the General Duty Clause in the RMP rule if it has any regulated substance or other extremely hazardous substance on site. Compliance with the General Duty Clause does not require the submittal of documentation, but requires that facility owners be continuously vigilant about hazards and take steps to reduce hazards if needed.

Aqueous ammonia will be used as the reducing agent in the project's SCR system for controlling NO_x emissions from the combustion turbines. The NO_x reduction achieved by the SCR system is affected by the ratio of ammonia (NH_3) to NO_x. Section 112(r) of the Clean Air Act and the U.S. EPA's Risk Management Program regulations (40 CFR Part 68) require modeling a catastrophic release of any stored ammonia at 20% concentration or above in order to ensure the protection of the off-site public. Furthermore, based on the "general duty" clause of Section 112(r), such analyses can be required even if the aqueous ammonia solution is diluted below 20%. JCEP proposes to store aqueous ammonia at a maximum ammonia concentration of 19% or less as the means of complying with Section 112(r).

The rule applies only to stationary sources. It does not apply to transportation, including storage incident to transportation. Transportation includes, but is not limited to, transportation subject to oversight or regulation under 49 CFR parts 192 (Federal safety standards for transportation of natural and other gas by pipeline), 193 (Federal safety standards for liquefied natural gas facilities), or 195 (Federal safety standards for transportation of hazardous liquids by pipeline), or a state natural gas or hazardous liquid program for which the state has in effect a certification to DOT under 49 U.S.C. 60105. Therefore, the LNG tanks are not subject to 40 CFR 68 since they are regulated under 49 CFR 193.

The facility is anticipated to store ethane and propane in quantities in excess of 10,000 pounds. As such, the facility will be subject to CAA § 112r and 40 CFR Part 68 and JCEP will prepare a RMP prior to storage of these materials.

Table 3-1: Comparison of Facility Potential Emissions to PSD Significant Emission Rate Thresholds[a]

Pollutant	Proposed Facility Potential Emissions (tons/yr)	PSD Significant Emissions Increase Level (tons per year)
Carbon Monoxide	156.1	100
Sulfur Dioxide	63.5	40
Particulate Matter (PM)	181.9	25
Particulate Matter less than 10 microns (PM-10)	181.9	15
Particulate Matter less than 2.5 microns (PM-2.5)	181.9	10
Nitrogen Oxides	221.0	40
Ozone (VOC)	209.3	40
Greenhouse Gases (GHG)	2,165,917	75,000
Lead	0.008	0.6
Fluorides	N/A	3
Sulfuric Acid Mist	55.8	7
Hydrogen Sulfide	<1	10
Total Reduced Sulfur (including H_2S)	<1	10
Reduced Sulfur Compounds (including H_2S)	<1	10

[a] Pursuant to 40 CFR 52.21 (b)(23)(i).

Table 3-2: National Ambient Air Quality Standards, PSD Increments, Significant Monitoring Concentrations, and Significant Impact Levels

Pollutant	Averaging Period	NAAQS[a] (μg/m³)	Class II PSD Increment (μg/m³)	Significant Monitoring Concentrations (μg/m³)	Significant Impact Level (μg/m³)
Carbon Monoxide	1-Hour 8-Hour	40,000 10,000	-- --	-- 575	2,000 500
Nitrogen Dioxide	1-Hour Annual	188 100	-- 25	-- 14	7.5[b] 1
Ozone (VOC)	8-Hour	160	--	--	--
Coarse Particulate Matter (PM-10)	24-Hour Annual	150 --	30 17	10 --	5 1
Fine Particulate Matter (PM-2.5)	24-Hour Annual	35 12	9 4	4 --	1.2 0.3
Sulfur Dioxide	1-Hour 3-hour 24-Hour Annual	197 1,300 365 80	-- 512 91 20	-- -- 13 --	7.9[c] 25 5 1
Lead	3-Month	0.15	--	0.1	--

Notes:
(--) indicates there are no standards for this pollutant.
[a]All short-term (1-hr, 3-hr, 8-hr, and 24-hr) standards except ozone, PM-2.5,PM-10, and 1-hour SO_2 and NO_2 are not to be exceeded more than once per year. For 8-hr ozone, EPA uses the average of the annual 4th highest 8-hour daily maximum concentrations from each of the last three years of air quality monitoring data to determine a violation of the standard. For 24-hour PM-10, EPA uses the 6th highest 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standards. For 24-hour PM-2.5, EPA uses the 98% percentile 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standard. For the 1-hour NO2 NAAQS, compliance would be determined by the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area and for the 1-hour SO2 NAAQS, compliance would be determined with the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area.
[b]Interim SIL per Guidance from EPA.
[c]Interim SIL per August 12, 2010 memorandum "Guidance Concerning the Implementation of the 1-hour SO2 NAAQS for the Prevention of Significant Deterioration Program" from Steven Page (Director of U.S. EPA OAQPS).

Table 3-3: Oregon Ambient Air Quality Standards

Pollutant	Averaging Period	OAAQS[a] (ug/m³)
Sulfur Dioxide	Annual 24-hour average 3-hour average	52.4 262 1,300
PM-10	Annual 24-hour average	50 150
Carbon Monoxide	8-hour average 1-hour average	10,000 40,000
Ozone	8-hour average	160
Nitrogen Dioxide	Annual	100
Lead	Rolling 3-month average	1.5

[a]Oregon short-term standards are not to be exceeded more than once in any 12 month period. Long-term standards are never to be exceeded.

4.0 CONTROL TECHNOLOGY ANALYSIS

4.1 Overview

Pre-construction review for new major stationary sources located in the State of Oregon involves an evaluation of Best Available Control Technology (BACT). A control technology analysis has been performed for the proposed Facility based upon guidance presented in the draft USEPA Guidance Document *New Source Review Workshop Manual*, (October, 1990). In summary, the BACT analysis was conducted in the following manner:

- Step 1: Identify All Control Technologies
- Step 2: Eliminate Technically Infeasible Options
- Step 3: Rank Remaining Control Technologies by Effectiveness
- Step 4: Evaluate Most Effective Controls and Document Results
- Step 5: Select BACT

As the aforementioned BACT methodology suggests, if it cannot be shown that the top level of control is infeasible (for a similar type source and fuel category) on the basis of technical, economic, energy, or environmental impact considerations, then that level of control must be declared to represent BACT for the respective pollutant and air emissions source. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site and project-specific consideration of the aforementioned screening criteria (i.e., technical, economic, energy, and environmental considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental considerations. BACT cannot be determined to be less stringent than the emissions limits established by an applicable NSPS for the affected air emission source.

Note that throughout this section, "ppm" concentration levels for gaseous pollutants are parts per million by volume, dry basis, corrected to 15% O_2 content (ppmvd @ 15% O_2), unless otherwise noted. Likewise, all emission factors expressed as pounds of pollutant per million Btu of fuel (lb/MMBtu) are based upon the higher heating value (HHV) of the fuel.

4.2 Applicability of Control Technology Requirements

An applicability determination, as discussed in this section, is the process of determining the level of emission control required for each applicable air pollutant. Control technology requirements are generally based upon the potential emissions from the new or modified source and the attainment status of the area in which the source is to be located. A detailed determination of applicable regulations, including control technology requirements under the

PSD, is provided in Section 3. The following sections discuss the applicability of BACT for emissions from equipment included in this permit application.

4.2.1 PSD Pollutants Subject To BACT

Pollutants subject to PSD review are subject to a BACT analysis. BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental and economic considerations. The proposed Facility is considered a "major" source for PSD purposes since potential emissions exceed major source thresholds. Therefore, individual regulated pollutants are subject to BACT requirements if potential emissions exceed the significant emission rates presented in 40 CFR 52.21(b)(23) in a PSD (attainment) area, as presented in Table 3-1. Based upon these criteria, NO_x, CO, VOC, PM/PM-10/PM-2.5, SO_2, H_2SO_4 and GHG are all subject to BACT requirements.

4.3 BACT Methodology

The BACT methodology presented herein is based on USEPA's recommended "top-down," 5-step analysis process to evaluate the available and applicable emission control technologies for the affected pollutants. BACT is defined as: *"An Emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.'*

In practice, USEPA's top-down BACT analysis methodology results in the most stringent control technology and emissions limitation combination available for a similar source or source category of emission units. At the head of the list in the top-down analysis are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative and must be considered under the BACT analysis process. BACT cannot be determined to be less stringent than the emission limits established by an applicable New Source Performance Standard (NSPS) for the affected air emission source. The methodology uses a 5-step process, which is summarized below.

Step 1 - Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as precombustion controls. Post-combustion controls include the various add-on controls for the pollutant being controlled.

Step 2 - Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to eliminate the technically infeasible control options from those identified in Step 1. A control option that is determined to be technically infeasible is eliminated from further consideration in the BACT analysis process. A technically infeasible control option is one that has not been "demonstrated"; or more specifically, a technology that has not been installed and operated successfully on a similar type of unit of comparable size. A technology is considered "demonstrated" for a given unit based on its "availability" and "applicability". "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench scale/laboratory testing/pilot scale testing) are classified as not available. The second demonstration requirement; "applicability," is defined as an available control option that can reasonably be installed and operated on the unit type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of unit of comparable size, or a source with similar gas stream characteristics.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining (feasible) control alternatives not eliminated in Step 2, based on their control effectiveness for the pollutant under review. In this step, the feasible technologies are reviewed in order to determine the control effectiveness on either a percent removal basis or emission level, or both, based on an engineering analysis and document review of the technology applied to similar units. The following informational databases, clearinghouses, documents, and studies were used to identify recent control technology determinations for similar source categories and emission units:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- Federal/State/Local new source review permits.
- Technical journals, newsletters, and reports.
- Information from air quality control technology suppliers.
- Engineering design studies for this and similar units.

Step 4 - Evaluate Most Effective Controls

Once the hierarchy of control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed in order to assist in the final control technology decision. The additional evaluations consider and compare the energy, environmental, and economic impacts associated with implementing the viable control alternatives.

The energy impact evaluation considers the energy penalty or benefit resulting from the operation of the control technology at the facility. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which ultimately affects the cost-effectiveness of the control technology.

The environmental impact evaluation considers the collateral environmental effects resulting from the operation of each viable control alternative. Example environmental impacts may include additional water discharge and consumption, collateral emission increases, as well as disposable solids and waste generation.

The third and final impact analysis addresses the economics of the proposed control technologies in order to evaluate and compare two or more alternatives. This analysis is performed to assess the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters is obtained from established reference sources. Documented assumptions can be made in the absence of available information for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost effectiveness ($/tons) of the control technology is determined.

Cost-effectiveness is used to assess the economic cost to achieve the required emissions reduction in the most economical manner. Two types of cost-effectiveness are considered in a BACT analysis: average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a useful measure of economic viability when comparing technologies that have similar removal efficiencies.

Step 5 - Select BACT

The highest ranked control technology from Step 3 that is not eliminated in Step 4 based on unacceptable economic, energy, or environmental impacts, is proposed as BACT for the pollutant and emission unit under review. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and/or project-specific consideration of the aforementioned screening criteria (e.g., technical, energy, environmental, and economic considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

4.4 BACT Analysis for Combined Cycle Units

4.4.1 BACT Analysis for Combined Cycle Unit NOx Emissions

4.4.1.1 Review of NO_x RBLC Database

The search of the RBLC and available permits identified over 350 natural gas-fired combined cycle combustion turbine projects with NO_x emission limits ranging from 2 to 102 ppm with the majority of the NO_x emission limits at or below 9 ppm. Fifty-seven (57) of these projects are permitted for a NO_x emission limit of 2 ppm and all use selective catalytic reduction in addition to dry low-NO_x (DLN) or low-NO_x burner (LNB) technology. Many of these projects have additional permitted NO_x emission limits above 2 ppm for alternative operating modes when employing either duct firing or for oil-fired operation.

4.4.1.2 Identification of NO_x Control Options and Technical Feasibility

The following sections detail the options that were identified for controlling NO_x emissions from the proposed emission units. The technical feasibility and respective level of commercially demonstrated NO_x reduction of each option is also discussed.

The following control technologies for NO_x were evaluated: Lean Burn Combustion, Selective Catalytic Reduction, Selective Non-Catalytic Reduction and XONON™ .

Lean Burn Combustion – Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel and in the combustion zone, with additional air introduced downstream. This is the point where the highest combustion temperature and quickest combustion reactions (including NO_x formation) occur. Fuel-to-air ratios below stoichiometric are referred to as fuel-lean mixtures (i.e., excess air in the combustion chamber); fuel-to-air ratios above stoichiometric are referred to as fuel-rich (i.e., excess fuel in the combustion chamber). The rate of NO_x production falls off dramatically as the flame temperature decreases. Thus, very lean, dry combustors can be used to control emissions.

Based upon this concept, lean combustors are designed to operate below the stoichiometric ratio, thereby reducing thermal NO_x formation within the combustion chamber. The lean combustors typically are two-staged premixed combustors designed for use with natural gas fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage.

Selective Catalytic Reduction (SCR) – SCR is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine/duct burner. SCR involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x contained within the flue gas to form nitrogen gas (N_2) and water (H_2O) in accordance with the following chemical equations:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

The catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path in order to achieve maximum conversion efficiency and minimum back pressure on the gas turbine/duct burner. The most common configuration is a "honeycomb" design. Ammonia is then fed and mixed into the combustion gas stream upstream of the catalyst bed. Excess NH_3 which is not reacted in the catalyst bed and which is emitted from the stack is referred to as NH_3 slip.

An important factor that affects the performance of an SCR is operating temperature. The temperature range for standard base metal catalysts is between 400 and 800°F. Since SCR's effective temperatures are below the turbine exit temperature and above the stack temperature, the catalyst must be located within the HRSG.

An undesirable side-effect of SCR is the potential formation of ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$), referred to as ammonium salts, which are corrosive and can stick to the heat recovery surfaces, duct work, or stack at low temperatures and results in additional PM/PM-10 formation if emitted. NH_4HSO_4 and $(NH_4)_2SO_4$ are reaction products of SO_3 and NH_3. Use of low sulfur fuels minimizes the formation of SO_3 and the subsequent formation of these ammonium salts.

Selective Non-Catalytic Reduction (SNCR) – SNCR is another method of post-combustion control of NO_x emissions. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injection location and temperature to achieve proper reagent/flue gas mixing for optimum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x removal efficiency. The optimum temperature range for ammonia injection is 1,500° to 1,900°F. The NO_x removal efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions, also referred to as "slip". Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the Project's combined cycle combustion turbine unit is between 200 – 300°F, which is significantly less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this BACT analysis.

XONON™ – A newer NO_x control technology has been developed by Catalytica Energy Systems, with the trade name of XONON™. This combustion technology includes a pre-burner, a fuel injection and mixing system, a flameless catalyst module and a flameless burnout zone. The pre-burner starts the turbine and a fuel injection system provides a uniform fuel and air mixture to the catalyst, where a portion of the fuel is combusted at reduced temperature to reduce thermal NO_x emissions. Catalytica has reported NO_x emissions at less than 3 ppm at 15 percent O_2 from test units under 2 MW. The first commercial version of the XONON™ combustion system is operating in a 1.55 MW gas turbine in Santa Clara, CA. This system has demonstrated NO_x emission levels of less than 2.5 ppm.

The XONON™ system is not yet commercially available from Catalytica Energy Systems for turbines of the size proposed for the Project. However, in December 2000, the California Energy Commission approved the construction of a 750-MW facility in Bakersfield, California. The Pastoria Energy Facility (Pastoria) proposed to use the XONON™ system as BACT to control NO_x emissions from three large combined cycle combustion turbines. The approval was based on the anticipation that the XONON™ technology would be available by the time installation of the Project components was scheduled. If XONON™ was not available in time, Pastoria would install SCR to control emissions of NO_x. Calpine completed construction of the Pastoria facility in 2005 and ultimately installed SCR technology as opposed to XONON™. To date, XONON™ technology is not commercially available for large combustion turbines.

Based on the fact that the XONON™ technology is not currently commercially available and has not been proven on combustion turbines of the size proposed by the Project, it is not further considered in this analysis.

4.4.1.3 Determination of BACT for NO_x

JCEP proposes DLN in combination with SCR, in order to achieve BACT for NO_x emissions from the Project's combined-cycle units. The proposed NO_x emission limit for the turbine is 2.0 ppm while firing natural gas with and without duct firing.

4.4.2 BACT Analysis for Combined Cycle Unit Volatile Organic Compound Emissions

4.4.2.1 Review of VOC RBLC Database

The search of the RBLC and available permits identified approximately 295 natural gas-fired combined cycle combustion turbine projects with VOC emission limits ranging from 0.3 to 34.2 ppm with the majority of the VOC emission limits at or below 1.4 ppm. Most units employ an oxidation catalyst to control VOC emissions. The majority of the units identified in the RBLC consist of larger, Frame 7 combustion turbines. Unlike the Frame 7 turbines, the LM6000 combustion turbine has higher VOC emissions when operating at low loads (50% load). Recent permits for GE LM6000 units operating in combined cycle mode include the Highwood Generating Station in Montana and the Cheyenne Power and Light facility in Wyoming. These permits limit VOC emissions to 3.2 ppm and 3 ppm, respectively. It is unknown whether these permits include operation as low as 50% load.

4.4.2.2 Identification of VOC Control Options and Technical Feasibility

Combustion turbines have inherently low VOC emissions. The emissions of VOC in a combustion process are a result of the incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and H_2O.

The only post-combustion control method practical to reduce VOC emissions from combustion turbines is an oxidation catalyst. The optimum location for VOC control, in the 900 to 1,100°F range, would be upstream of the HRSG or in the front-end section of the HRSG. However, at the high temperatures necessary to make the oxidation catalyst optimized for VOC reduction there is the undesirable result of causing substantially more conversion of SO_2 to SO_3 which may, in turn, react with water and/or ammonia to form sulfuric acid mist and/or ammonia salt PM-10 emissions. Therefore, the placement of the oxidation catalyst in the "cooler" section of the HRSG necessary for CO control is optimal, and has the additional side benefit of reducing VOC emissions from the combustion turbine.

4.4.2.3 *Determination of BACT for VOC*

The Project is proposing to install an oxidation catalyst designed to reduce VOC emissions to 4.0 ppm with and without duct firing across all operating loads.

4.4.3 BACT Analysis for Combined Cycle Unit Carbon Monoxide Emissions

4.4.3.1 *Review of CO BACT Database*

A review of approximately 300 natural gas-fired combined cycle facilities listed in the U.S. EPA's RBLC as well as recently issued air permits (see Appendix C) lists CO emission limits ranging from 0.9 to 188.7 ppm. Similar to VOC emission, CO emissions from the LM6000 combustion turbine at low loads are higher than Frame 7 turbines. The recent Cheyenne Power and Light facility (Wyoming) received a permit with a CO limit of 4 ppm for a GE LM6000 turbine operating in combined cycle mode.

4.4.3.2 *Identification of CO Control Options and Technical Feasibility*

The following sections detail the options that were identified for controlling CO emissions from the combustion turbines/duct burners, auxiliary boiler, fuel gas heater and emergency engines pump. The technical feasibility of each option is also discussed.

The formation of CO in the exhaust of a combustion turbine is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion, including insufficient O_2 availability, poor air/fuel mixing, cold wall flame quenching, reduced combustion temperature, decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

After combustion control, the only practical control method to reduce CO emissions from combustion turbines is an oxidation catalyst. Exhaust gases from the turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide (CO_2). CO reduction efficiencies in the range of 80 to 90 percent can be guaranteed, although CO reduction may at times be somewhat less than the design value at the low inlet concentrations that are expected for the GE 7FA.05. No other technically feasible options are identified for combustion turbine CO control. Drawbacks of the oxidation catalyst include added cost, reduced turbine output and efficiency due to increased back pressure, and the potential for increased PM/PM-10/PM-2.5 and/or sulfuric acid mist emissions.

4.4.3.3 *Determination of BACT for CO*

The Project is proposing to install an oxidation catalyst designed to reduce CO emissions to 4.0 ppm during natural gas (with and without duct firing).

4.4.4 BACT Analysis for Combined Cycle Unit PM/PM-10/PM-2.5 Emissions

4.4.4.1 *Review of PM/PM-10/PM-2.5 BACT Databases*

A review of approximately 295 natural gas-fired combined cycle facilities from the USEPA's RBLC and recently issued air permit searches (see Appendix C) lists PM/PM-10 emission limits ranging from 0.0013 to 0.1400 lb/MMBtu.

In many instances, the pollutant listed in the RBLC database is TSP or PM. TSP and PM typically only includes the filterable portion of particulate matter; therefore, many of these limits cannot be compared to the proposed project. In fact, many pre-2001 permits were issued PM/PM-10 limits for only the front-half, filterable portion of particulate matter, therefore comparisons are difficult to make. Control technologies, good combustion practice and low-sulfur, should be considered the driving factor for proposing BACT.

4.4.4.2 *Identification of PM/PM-10/PM-2.5 Control Options and Technical Feasibility*

PM, PM-10 and PM-2.5 emissions from the combustion turbines may be formed from non-combustible constituents in fuel or combustion air, from products of incomplete combustion, or from the formation of ammonium sulfates due to the conversion of SO_2 to SO_3, which is then available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion. It is conservatively expected that all PM from the turbines will be equal to PM-10 and PM-2.5. PM, PM-10 and PM-2.5 emissions from combustion turbine are inherently low.

The combustion of clean burning fuels is the most effective means for controlling PM emissions from combustion equipment. JCEP is not aware of any combustion turbine project that has been required to add on PM, PM-10 or PM-2.5 controls. Post-combustion controls, such as baghouses, scrubbers and electrostatic precipitators (ESP) are impractical due to the high pressure drops associated with these units, the large flue gas volumes and the low concentrations of PM/PM-10/PM-2.5 present in the exhaust gas.

4.4.4.3 *Determination of BACT for PM/PM-10/PM-2.5*

Good combustion techniques and low-sulfur fuels have been proposed to limit PM/PM-10/PM-2.5 emissions. Proposed emission limit for PM/PM-10/PM-2.5 from in the combustion turbines is 0.0187 lb/MMBtu for the combustion turbine with and without duct firing. This value is within the range of recent BACT determinations for combustion turbines.

4.4.5 *BACT Analysis for Combined Cycle Unit Sulfur Dioxide and Sulfuric Acid Mist Emissions*

SO_2 emissions are formed from oxidation of sulfur in the fuel. H_2SO_4 emissions, in addition to being a function of fuel sulfur content, are also related to the amount of oxidation of fuel sulfur to SO_3. Sulfuric acid is produced when a fraction of the SO_2 that forms upon combustion of sulfur is converted to SO_3 during combustion and/or in the presence of a catalyst and is then further combined with water to form H_2SO_4 (sulfuric acid). Note that to be available to react with water to form sulfuric acid, the SO_3 would have to avoid first reacting with ammonia slip (and forming ammonia salts). During the combustion process, most of the sulfur is converted to SO_2. For the combustion turbine, thirty three percent of the SO_2 is assumed to be converted to SO_3 as a result of the combined effects of the combustion process and oxidation of the SCR and oxidation catalysts, and eventually to H_2SO_4 and/or ammonium sulfate salts.

4.4.5.1 *Review of SO_2 and H_2SO_4 BACT Database*

A review of the RBLC and search of recently issued air permits indicated only one option for SO_2 and H_2SO_4 control. For all units where SO_2 and H_2SO_4 control was identified, the only option considered was the combustion of low-sulfur fuels.

A search of approximately 225 permits for natural gas-fired combined cycle combustion turbines yielded a range of SO_2 emission limits between 0.0002 and 1.0212 lb/MMBtu. A search of approximately 95 permits for natural gas-fired combined cycle combustion turbines yielded a range of BACT H_2SO_4 emission limits between 0.0001 and 0.00188 lb/MMBtu.

4.4.5.2 *Identification of SO_2 and H_2SO_4 Control Options and Technical Feasibility*

Strategies for the control of SO_2 and H_2SO_4 emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low-sulfur fuels. Post-combustion controls comprise various wet and dry flue gas desulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to high-pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low sulfur concentrations in this situation. The use of natural gas results in low emission levels of SO_2 and H_2SO_4.

4.4.5.3 *Determination of BACT for SO_2 and H_2SO_4*

JCEP proposes to use natural gas (1.0 grain/100 scf) to meet BACT for SO_2 and H_2SO_4. SO_2 emissions will be limited to 0.0031 lb/MMBtu and H_2SO_4 emissions will be limited to 0.0043 lb/MMBtu.

4.4.6 *BACT Analysis for Combined Cycle Unit Greenhouse Gas (GHG) Emissions*

4.4.6.1 *Review of GHG BACT Database*

A search of the RBLC for "carbon dioxide" did not yield any results for combined cycle combustion turbines, however JCEP is aware of several projects which have recently been permitted with CO_2 limits; these facilities are identified in Appendix C. JCEP is aware of only one permit with a GHG limit for a GE LM6000 combined cycle turbine. The Cheyenne Power and Light facility has a GHG limit of 1,100 lb CO_{2e}/MWh.

4.4.6.2 *Identification of GHG Control Options and Technical Feasibility*

The following control technologies for GHG were evaluated: Carbon Capture and Sequestration (CCS) and Good Operation and Maintenance for Thermal Efficiency.

Carbon Capture and Sequestration (CCS) – EPA has classified CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel fired power plants. Carbon sequestration is a geo-engineering technique used to remove the CO_2 from an exhaust gas stream and store it permanently in underground reservoirs (typically depleted oil or gas reservoirs) or other geological features. The technology captures CO_2 before it enters the atmosphere, compresses the CO_2 to a near liquid state, and transports it via pipeline to a site where it is injected deep underground. The deep geological formations that receive and hold CO_2 must be far below fresh water aquifers and below an impermeable cap rock or seal so they cannot contaminate groundwater or escape into the atmosphere. Ideal geological formations for sequestration include depleted oil and gas fields and deep ocean masses.

Thermal Efficiency – Contrary to other pollutants, CO_2 is not the byproduct of incomplete combustion and contaminants in the fuel supply. It is the essential product of the chemical reaction between fuel and oxygen and inherent in any fossil-fuel combustion technology. Therefore, the only way to reduce the amount of CO_2 generated is to minimize the amount of fuel combustion required to produce the desired amount of electricity. This is achieved by operating the units efficiently and conducting periodic maintenance to regain any recoverable efficiency degradation. Natural gas generates a lower amount of CO_2 when combusted in comparison to other fossil fuels.

4.4.6.3 *Evaluation of Control Technologies*

In this section, JCEP addresses the potential energy, environmental, and economic feasibility of implementing CCS technology as BACT for GHG emissions from the proposed Project. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

CO2 Capture and Compression - Though amine absorption technology for CO2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO2 concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

> "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."[1]

In its current CCS research program plans, the DOE-NETL confirms that commercial CO_2 capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

> "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:
> (1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
> (2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;
> (3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;
> (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."[2]

To corroborate that commercial availability of CO_2 capture technology for large-scale power plant projects will not occur for several more years, Alstom, one of the major developers of

[1] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).
[2] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan*, at 10 (Feb. 2011).

commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web site that its CO_2 capture technology will become commercially available in 2015.[3] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be able to handle the volume of CO_2 emissions generated by a project of the size of JCEP.

Environmental Impacts

Another challenge of CO_2 capture is conservation of water resources. A modern natural gas fired combined cycle facility requires four to five million gallons of water per day for condenser cooling and boiler make-up service. This amount will vary based on ambient temperature and humidity as well as the level of duct firing in the HRSG. Adding CO_2 separation facilities and compression equipment significantly increases the cooling water requirements of a generating station. Studies have indicated that the water consumption of a natural fired combined cycle facility with CCS may have an increased water consumption of more than 90%.

CO2 Transport - Even if it is assumed that CO2 capture and compression could feasibly be achieved for the proposed project, the high-volume CO2 stream generated would need to be transported to a facility capable of storing it. Potential geologic storage sites in Oregon, Washington, and Idaho to which CO2 could be transported if a pipeline was constructed are illustrated in Figure 4-1. The potential length of such a CO2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO2 storage. The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO2, which is an enhanced oil recovery (EOR) reservoir site located within 120 miles of the proposed Project. However, none of the potential sites have yet been technically demonstrated for large-scale, long-term CO2 storage.

CO2 Storage - Even if it is assumed that CO2 capture and compression could feasibly be achieved for the proposed project and that the CO2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO2 into the formations. Potential

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[3] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/

environmental impacts resulting from CO2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to
- the biosphere, underground drinking water sources, and/or surface water,[4]
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Oregon and Washington. In fact, sites with such recognized potential for some geological storage of CO_2 are located within 120 miles of the proposed project, but such sites have not yet been technically demonstrated with respect to all of the suitability factors described above.

Based on the reasons provided above, JCEP believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, JCEP has estimated such costs.

The estimated costs associated with implementation of a carbon capture system at JCEP are shown in Tables 4-1 and 4-2. Capital cost components include equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management and contingencies. Operating cost components include operating and maintenance labor, consumables, fuel, waste disposal and co-product or by-product credit. The results of this analysis show that the cost of CCS for the project would be approximately $115 per ton of CO2 removed, which is not considered to be cost effective for GHG control. This equates to approximately $223,000,000 per year.

In addition to the high construction and operating costs associated with CCS, the carbon capture equipment requires a substantial amount of energy to operate, thereby reducing the net electrical output of the plant. Operation of carbon capture equipment at a typical natural gas fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (HHV) to approximately 42.9% (HHV).[5]

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[4] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100

[5] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

4.4.6.4 Determination of BACT for GHG

The only feasible control technology for reducing GHG emissions is good operation and maintenance to retain the thermal efficiency of the equipment and using natural gas fuel. JCEP proposes a limit of 1,100 lb CO_{2e}/MWh which is consistent with other GE LM6000 facilities.

4.5 BACT Analysis for Emergency Diesel Engines

4.5.1 BACT Analysis for Emergency Diesel Engine NOx Emissions

4.5.1.1 Review of NO_x RBLC Database

The RBLC indicates that the range of permitted NO_x limits for diesel engines similar to the fire water pumps are 0.414 to 29.8 lb/MMBtu, with only 4 permits less than 1.0 lb/MMBtu, as summarized in Appendix C. The range of permitted NO_x limits for diesel engines similar in size to the emergency generator diesel engine are 1.132 to 4.35 lb/MMBtu, as summarized in Appendix C.

4.5.1.2 Identification of NO_x Control Options and Technical Feasibility

USEPA's Alternative Control Techniques (ACT) Document for reciprocating engines lists add-on techniques such as SCR, as well as combustion control techniques such as ignition timing retard, for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for small emergency diesel engines that operate less than 500 hours/year. In addition, add-on techniques would be ineffective. Since the emergency diesel fire pump and emergency diesel generator will run for limited duration, the SCR would never reach the operating temperature required to remove any substantial NO_x emissions, and thus would provide no benefit. Therefore, add-on controls do not represent NO_x BACT for the emergency diesel engines.

Ignition retard is accomplished in a reciprocating engine by delaying the injection of the fuel into the compressed air in the cylinder. The result is that combustion occurs at lower peak pressures and temperatures. In addition, the duration of the peak pressure and temperatures is shorter than for standard timing of the fuel injection. The lower peak flame temperature and the shorter exposure reduce the formation of NO_x. However, as a result of the reduction in peak pressures and temperatures, ignition retard reduces maximum power output and engine efficiency while increasing emissions (particulates, VOC and CO) and fuel consumption. Vendors no longer recommend this technology for emergency diesel engines, due to the various limitations of ignition retard outweighing its limited effectiveness. Fuel consumption can increase up to 5 percent, while emissions of hydrocarbons and particulates can double. With these factors and each engines proposed limited operation during emergencies and testing only, ignition retard does not represent NO_x BACT for the emergency diesel fire pumps or the emergency diesel generators.

4.5.1.3 Determination of BACT for NO_x

Although add-on controls, such as SCR, have been employed to reduce emissions from diesel engines with greater annual operating capacity factors, the limited annual operation rules out such controls. Combustion controls such as ignition retard are also not proposed for reasons cited above. Thus, JCEP proposes limited hours of operation (200 hours per year each) and good combustion practices as BACT to achieve a NO_x emission rate of 1.4592 lb/MMBtu for the emergency diesel generators and 0.912 lb/MMBtu for the emergency diesel fire pumps.

4.5.2 BACT Analysis for Emergency Diesel Engine Volatile Organic Compound Emissions

4.5.2.1 Review of VOC RBLC Database

The most stringent VOC emission permit limit for an emergency diesel generator is 0.007 lb/MMBtu for an 11.4 MMBtu/hr emergency engine at the PSEG Waterford Energy Station in Ohio. It is unknown whether the facility is operating in compliance. The most recently permitted emergency generator similar in size to the ones proposed for the Project is for the Ohio River Clean Fuels Plant in Ohio with a VOC limit of 0.059 lb/MMBtu, but it is unknown whether this facility is operating.

The most stringent VOC emission permit limit shown in the RBLC database and permit search for a diesel fire pump of similar size and use as the proposed emergency diesel fire pump is 0.021 lb/MMBtu. The entire range of VOC emission limits for diesel fire pumps is 0.0133 – 0.9739 lb/MMBtu.

4.5.2.2 Identification of VOC Control Options and Technical Feasibility

VOC from diesel engines are composed of a variety of organic compounds emitted into the atmosphere because of incomplete combustion. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. The quench layer is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperature to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. Add-on controls are not technically feasible.

4.5.2.3 Determination of BACT for VOC

The application of good combustion practices and limited operating hours is proposed in order to achieve BACT for the emergency diesel fire pumps and emergency diesel generators. The maximum VOC emissions from the emergency diesel generators and emergency fire pumps are 0.1183 lb/MMBtu and 0.0740 lb/MMBtu, respectively.

4.5.3 BACT Analysis for Emergency Diesel Engine Carbon Monoxide Emissions

4.5.3.1 Review of CO BACT Database

The RBLC indicates that the CO permit limits for diesel engines similar in size to the proposed emergency diesel generators range from 0.202 to 1.53 lb/MMBtu, as summarized in Appendix C. The permit limits for diesel engines similar in size to the proposed diesel fire pumps range from 0.069 to 3.719 lb/MMBtu, as summarized in Appendix C.

4.5.3.2 Identification of CO Control Options and Technical Feasibility

As reflected by existing permits, add-on control technology is not practicable for control of CO emissions from emergency diesel engines operating less than 200 hours per year. Good combustion control practices and limited operating hours represent CO BACT for the Project's emergency diesel fire pumps and emergency diesel engines.

4.5.3.3 Determination of BACT for CO

Existing permits show that add-on control technology is not practical for control of CO emissions from emergency equipment. Therefore, the Project is proposing BACT for CO emissions through good combustion practices and limiting operating hours. The proposed emission rate from the emergency diesel generators is 0.8545 lb/MMBtu and the proposed CO emission rate from the emergency diesel fire pumps is 0.9958 lb/MMBtu.

4.5.4 BACT Analysis for Emergency Diesel Engine PM/PM-10/PM-2.5 Emissions

4.5.4.1 Review of PM/PM-10/PM-2.5 BACT Databases

A review of the RBLC shows that only good combustion, limitations on operating hours and low-sulfur fuels have been used as BACT for emergency diesel engines. The RBLC PM/PM-10 emission levels for diesel generators similar in size to those proposed for this Project range from 0.037 to 0.091 lb/MMBtu, as summarized in Appendix C. The RBLC PM/PM-10 emission levels for emergency diesel fire pumps range from 0.016 to 2.11 lb/MMBtu, as summarized in Appendix C.

4.5.4.2 Identification of PM/PM-10/PM-2.5 Control Options and Technical Feasibility

Particulate matter emissions from oil-fired internal combustion engines may result from trace metals present in the fuel, unburned carbon-containing materials and sulfate formation. Good combustion practices and use of clean fuels are the methods currently utilized to minimize PM and PM-10/PM-2.5 emissions from diesel engines. Post-combustion controls, such as baghouses, scrubbers and ESPs are impractical due to the high-pressure drops associated with these technologies and the low concentrations of PM, PM-10 and PM-2.5 present in the exhaust gas. In addition, any add-on controls applied would have extremely high cost, on a dollar per ton PM/PM-10/PM-2.5 removed basis, since this emergency equipment is expected to operate infrequently. No other PM, PM-10 or PM-2.5 control devices are identified for diesel engines in USEPA's AP-42, Compilation of Air Pollutant Emission Factors, Section 3.

4.5.4.3 Determination of BACT for PM/PM-10/PM-2.5

Good combustion techniques and low-sulfur fuels have been proposed to limit PM/PM-10/PM-2.5 emissions. The proposed emission limit for PM/PM-10/PM-2.5 from the emergency diesel engines is 0.0493 lb/MMBtu.

4.5.5 BACT Analysis for Emergency Diesel Engine Sulfur Dioxide and Sulfuric Acid Mist Emissions

4.5.5.1 Review of SO_2 and H_2SO_4 BACT Database

The only SO_2 emission controls identified in the RBLC are limitations on hours of operation and good combustion practices with restrictions on fuel oil sulfur content. While a search of the RBLC for H_2SO_4 emissions from emergency diesel engines did not yield any results, because H_2SO_4 is dependent upon the sulfur content of the fuel, the SO_2 analysis will be used for H_2SO_4 as well.

4.5.5.2 Identification of SO_2 and H_2SO_4 Control Options and Technical Feasibility

The only practical control technique available for emergency diesel engines that will operate no more than 200 hours per year is the use of low-sulfur fuel.

4.5.5.3 Determination of BACT for SO_2 and H_2SO_4

JCEP proposes to use natural gas (1.0 grain/100 scf) to meet BACT for SO_2 and H_2SO_4. SO_2 emissions will be limited to 0.0015 lb/MMBtu and H_2SO_4 emissions will be limited to 0.00012 lb/MMBtu for each emergency diesel engine.

4.5.6 BACT Analysis for Emergency Diesel Engine Greenhouse Gas (GHG) Emissions

4.5.6.1 Review of GHG BACT Database

A search of the RBLC for "carbon dioxide" and "GHG" did not yield any results for emergency diesel engines. There have been several projects permitted recently that include emergency diesel engines. These permits only include an annual ton/year limit on CO2e emissions which correspond to the unit's proposed hours of operation.

4.5.6.2 Identification of GHG Control Options and Technical Feasibility

The available GHG emission control strategies for emergency generators and firewater pumps that were analyzed as part of this BACT analysis include: (1) Carbon Capture and Sequestration (CCS); (2) Good Operation and Maintenance for Thermal Efficiency.

Carbon Capture and Sequestration - CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

Good Operation and Maintenance for Thermal Efficiency - Since JCEP is proposing to install all new firewater pumps and emergency generators, the equipment is designed for optimal combustion efficiency. JCEP will conduct periodic maintenance to keep the equipment operating at it maximum efficiency.

4.5.6.3 Determination of BACT for GHG

JCEP proposes to select equipment with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions
JCEP proposes the following CO_{2e} BACT limits based on a 12-month rolling average basis:

- 43.9 tons/yr for the South Dunes fire pump;
- 76.8 tons/yr for each of the Liquefaction Area fire pumps; and
- 368 tons/yr for each emergency diesel generator.

4.6 BACT Analysis for Thermal Oxidizers

The use of a thermal oxidizer results in emissions of products of combustion. While these emissions relate to the selection of appropriate control technology for the Project, a BACT analysis was performed for the thermal oxidizers to determine if secondary measures would be required to satisfy the BACT requirement for these pollutants.

4.6.1 BACT Analysis for Thermal Oxidizer NOx Emissions

4.6.1.1 Review of NO_x RBLC Database

The search of the RBLC and available permits identified only one facility, Shintech in Louisiana, using SCR to control nitrogen oxide emissions from a thermal oxidizer. The facility is the Plaquemine PVC Plant and the controlled NO_x emission rate is reported as 0.025 lbs/MMBtu.

4.6.1.2 Identification of NO_x Control Options and Technical Feasibility

Low-NO_x Burners – Low NO_x burners reduce NO_x through staged combustion. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_x formation. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low-NO_x burners. The application for the proposed destruction system for JCEP is quite different from furnace/boiler applications that have the benefit of specific fuel characteristics that are essentially constant. The thermal oxidizer needs to support inlet gases which have varying compositions. Therefore, it is not conducive to a burner design that is highly dependent on the fuel composition for its success in generating low NOx emissions and high destruction efficiencies. For this reason the design features which support low NOx and those which support widely varying combustion conditions tend to be mutually exclusive. As such, low-NOx burners are not considered feasible for this project and will not be considered further for this BACT analysis

SCR – Selective Catalytic Reduction (SCR) technology uses ammonia as a reducing agent in the presence of oxygen over a catalyst. The general chemical reaction is:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The process includes an ammonia delivery system and a selective catalytic reaction section. Vaporized ammonia (or urea) is introduced into the flue gas stream via an injection grid located upstream of the catalyst. NO_x emission reductions of 75 to 85 percent have been achieved through the use of SCR. While SCR was reported for use with thermal oxidizers at the Shintech Louisiana PVC facility, the volume flow rates, concentrations and other conditions, including the possible opportunity for heat recovery, suggest that this precedent is not reasonable to apply to natural gas processing plants. Further, SCR cannot be considered feasible for the Project since the thermal oxidizer's temperature is well above the optimum operating temperatures of SCR systems using high temperature zeolite catalysts.

4.6.1.3 Determination of BACT for NO_x

The Project is proposing BACT for NO_x emissions from the thermal oxidizer as good combustion practices with a NO_x emission rate of 6.65 lb/hr/unit.

4.6.2 BACT Analysis for Thermal Oxidizer Volatile Organic Compound Emissions

4.6.2.1 Review of VOC RBLC Database

A review of the RBLC identifies only one facility with a VOC limit for a thermal oxidizer. Flopam is required to achieve 99% control of VOC emissions.

4.6.2.2 Identification of VOC Control Options and Technical Feasibility

Since the thermal oxidizer reduces VOC emissions by 99.5%, no additional control options were considered in this analysis.

4.6.2.3 Determination of BACT for VOC

The Project is proposing good equipment design and proper combustion practices to achieve a 99.5% control efficiency for VOC emissions for the thermal oxidizer.

4.6.3 BACT Analysis for Thermal Oxidizer Carbon Monoxide Emissions

The formation of CO in the exhaust of the proposed thermal oxidizer is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion, including insufficient O_2 availability, poor air/fuel mixing, cold wall flame quenching, reduced combustion temperature, decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

4.6.3.1 Review of CO BACT Database

A review of the RBLC shows that no add-on control devices were selected as BACT for thermal oxidizers.

4.6.3.2 Identification of CO Control Options and Technical Feasibility

The common practice for CO control is ensuring efficient operation and proper design of the equipment. Oxidation catalysts are sometimes used on combustion devices to achieve control of CO emissions; especially turbines, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. Due to the high temperatures of the thermal oxidizer, oxidation catalysts are not considered feasible for the proposed project.

4.6.3.3 Determination of BACT for CO

The Project is proposing BACT for CO emissions from the thermal oxidizer as good combustion practices represented by a CO emission rate of 2.0 lb/hr/unit.

4.6.4 BACT Analysis for Thermal Oxidizer PM/PM-10/PM-2.5 Emissions

PM, PM-10 and PM-2.5 emissions from the vapor combustion units may be formed from non-combustible constituents in fuel or combustion air and from products of incomplete combustion. It is conservatively expected that all PM from the Project will be equal to PM-10 and PM-2.5.

4.6.4.1 Review of PM/PM-10/PM-2.5 BACT Databases

A review of the RBLC shows that only good combustion and low-sulfur fuel have been used as BACT for thermal oxidizers.

4.6.4.2 Identification of PM/PM-10/PM-2.5 Control Options and Technical Feasibility

The combustion of clean burning fuels is the most effective means for controlling PM emissions from combustion equipment. JCEP is not aware of any thermal oxidizer that has been required to add on PM, PM-10 or PM-2.5 controls. Post-combustion controls, such as baghouses, scrubbers and electrostatic precipitators (ESP) are impractical due to the high pressure drops associated with these units and the low concentrations of PM/PM-10/PM-2.5 present in the exhaust gas.

4.6.4.3 Determination of BACT for PM/PM-10/PM-2.5

The Project is proposing BACT for PM emissions from the thermal oxidizer as good combustion practices and the use of natural gas with an emission rate equal to 0.13 lb/hr/unit.

4.6.5 BACT Analysis for Thermal Oxidizer Sulfur Dioxide Emissions

4.6.5.1 Review of SO_2 BACT Database

Very limited data exists on the RBLC with respect to SO_2 emissions from thermal oxidizers. None of the data reported for similar sources in the RBLC has been required to employ add on control systems to reduce SO_2 emissions. JCEP knows of one proposed Project which has included an H_2S scavenger system into its design to reduce SO_2 emissions.

4.6.5.2 Identification of SO_2 Control Options and Technical Feasibility

The only available control technology to reduce sulfur compounds in the natural gas is H_2S scavenging. H_2S scavenger systems use a liquid, catalyst or solid media to convert H_2S into a risk-free compound that can be easily disposed of in an environmentally safe method without sulfur emissions. Field configurations are usually multiple or single vessel systems that are capable of operating without supervision. JCEP will utilize the Ultrafab Sweet 100 Process to remove 98% of H_2S and 60% of the mercaptans in the gas stream.

4.6.5.3 Determination of BACT for SO_2

The Project is proposing BACT for SO_2 emissions from the thermal oxidizer as an H_2S scavenger system to reduce H_2S by 98% and mercaptans by 60%.

4.6.6 BACT Analysis for Thermal Oxidizer Greenhouse Gas (GHG) Emissions

4.6.6.1 Review of GHG BACT Database

No information was found when performing an RBLC search for GHG control technologies for thermal oxidizers, however JCEP is aware of two projects which have recently been permitted which include GHG limits for thermal oxidizers: the Lone Star NGL, Belvieu Gas Plant and the Jackson County Gas Plant, both located in Texas. These permits contain annual GHG limits which correspond to the size and operation of the units.

4.6.6.2 Identification of GHG Control Options and Technical Feasibility

The available GHG emission control strategies for the thermal oxidizer combustion emissions include:

- Carbon Capture and Sequestration
- Proper Thermal Oxidizer Design and Operation
- Fuel Selection

Carbon Capture and Sequestration - The primary source of CO_2 emissions from the thermal oxidizers will be from routing of CO_2 emissions from the amine unit. A small fraction of the CO_2 emissions emitted from the thermal oxidizer will result from the combustion of natural gas. Since the amine unit will be used to remove CO_2 and sulfur compounds in order to meet the downstream liquefaction process specifications, the CO_2 emissions are inherent to the process. The gas stream from the amine unit will also contain relatively small amounts of CH_4 and VOCs entrained in the gas. The vent gas stream from the amine unit will be routed to the thermal oxidizer in which CH_4 and VOCs will be converted to CO_2 in the combustion zone. Therefore, CO_2 will be the major component of GHG emissions from the thermal oxidizer. While the process exhaust stream from the thermal oxidizer is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement CCS. These include separation (removal of PM and other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, large compression units, and pipelines to transfer CO_2. These additional units would require additional electricity and generate additional air emissions. The available post-combustion capture technologies include oxy-combustion; solvent capture and stripping; and post-combustion membranes. The oxycombustion technology is still in the research stage and solvent capture and stripping technology is being implemented in the chemical industry. The post-combustion membrane technology is still in the research stage, and its industrial application is at least 10 years away. JCEP conducted studies to evaluate potential options to capture and geologically sequester CO_2 from the entire facility. As illustrated in Section 4.4.6.3, CCS is not considered feasible for the proposed Project.

Proper Design, Operation and Maintenance - Good thermal oxidizer design can be employed to destroy any CH_4 entrained in the waste gas removed from the amine unit. Good thermal oxidizer design includes flow measurement and monitoring/control of waste gas heating values. In addition, periodic tune-up and maintenance will be performed per the manufacturer recommendation.

Fuel Selection - The fuel for firing the proposed thermal oxidizer will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the thermal oxidizer.

4.6.6.3 Determination of BACT for GHG

The following design elements and work practices are proposed as BACT from the thermal oxidizer:

- Proper Thermal Oxidizer Design and Operation; and
- Use of natural gas as fuel.

In addition, JCEP proposes an annual GHG limit of 232,233 short tons of CO_2e per year for each thermal oxidizer (based on a 12-month rolling average).

4.7 BACT Analysis for Ground Flares

The ground flares may be used during initial cool down of the facility, extended power outages, emergency events such as emergency shutdowns and unexpected loss of vapor handling equipment during LNG Ship loading and in emergency situations to relieve and protect equipment in the Gas Conditioning portion of the plant. To be conservative, potential emissions from the flare were calculated assuming 8,760 hours of operation per year, however, the flare will only be utilized for short periods of time over the course of the year.

4.7.1 BACT Analysis for Ground Flare NOx Emissions

4.7.1.1 Review of NO_x RBLC Database

With the exception of enclosures, the RBLC search indicated no specific add-on controls for NO_x from flares. There are no flares listed in the RBLC of similar size to that proposed for the Project.

4.7.1.2 Identification of NO_x Control Options and Technical Feasibility

Due to the intermittent nature, short duration, and unconfined nature of ground flares, there are no technically feasible add-on control technologies to reduce NOx emissions.

Flare Gas Recovery - Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks where the recovered gas is then utilized by introducing it into the fuel system as applicable. While installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares, flaring at JCEP will be limited to emergency situations. Due to infrequent nature of these situations and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system.

4.7.1.3 Determination of BACT for NO_x

JCEP proposes to meet a NO_x BACT limit of 0.02 lb/hr from each flare.

4.7.2 BACT Analysis for Ground Flare Volatile Organic Compound Emissions

4.7.2.1 Review of VOC RBLC Database

The RBLC identifies several projects which have a 98% VOC destruction efficiency limit.

4.7.2.2 *Identification of VOC Control Options and Technical Feasibility*

Because each flare will reduce VOC emissions by 99.5%, no further control technologies were evaluated.

4.7.2.3 *Determination of BACT for VOC*

To ensure complete combustion of the vent stream, a flame will be maintained at the flare tip at all times. This practice will reduce emissions of VOC by 99.5%.

4.7.3 BACT Analysis for Ground Flare Carbon Monoxide Emissions

4.7.3.1 *Review of CO BACT Database*

With the exception of enclosures, the RBLC search indicated no specific add-on controls for CO from flares. There are no flares listed in the RBLC of similar size to that proposed for the Project.

4.7.3.2 *Identification of CO Control Options and Technical Feasibility*

No feasible technology exists for the control of CO emissions from ground flares. The high transient conditions of flaring and the unconfined nature of ground flares along with the low CO emissions preclude the use of traditional add-on control technologies such as an oxidation catalyst. Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare which will in turn reduce CO emissions. Good combustion practices include proper operation, maintenance, and tune-up of the flare per the manufacturer's specifications.

4.7.3.3 *Determination of BACT for CO*

To ensure complete combustion of the vent stream, a flame will be maintained at the flare tip at all times. This practice will minimize emissions of CO. A CO limit of 0.04 lb/hr/unit is proposed as BACT from each unit.

4.7.4 BACT Analysis for Ground Flare PM/PM-10/PM-2.5 Emissions

4.7.4.1 *Review of PM/PM-10/PM-2.5 BACT Databases*

The RBLC search indicated no specific add-on controls or requirements for particulate emissions from flares.

4.7.4.2 *Identification of PM/PM-10/PM-2.5 Control Options and Technical Feasibility*

No feasible technology exists for the control of SO_2 and H_2SO_4 emissions from ground flares. The high transient conditions of flaring and the unconfined nature of ground flares preclude the use of traditional add-on control technologies such as baghouses and ESPs. Only good combustion and low-sulfur fuel would be feasible options to control particulate emissions.

4.7.4.3 *Determination of BACT for PM/PM-10/PM-2.5*

Good combustion practices and the use of natural gas as the pilot fuel are proposed as BACT for PM/PM-10/PM-2.5 emissions from the flares. JCEP proposes a PM/PM-10/PM-2.5 BACT limit of 0.00032 lb/hr/unit.

4.7.5 BACT Analysis for Ground Flare Sulfur Dioxide Emissions

4.7.5.1 *Review of SO_2 BACT Database*

The RBLC search indicated no specific controls or requirements for SO_2 emissions from flares.

4.7.5.2 *Identification of SO_2 Control Options and Technical Feasibility*

No feasible technology exists for the control of SO_2 emissions from ground flares. The high transient conditions of flaring and the unconfined nature of ground flares preclude the use of traditional add-on control technologies such as wet and dry flue gas desulfurization (FGD) processes. Further, methodologies to remove sulfur compounds in the gas stream prior to flaring have been proven to be cost prohibitive (see Section 4.6.5.3).

4.7.5.3 *Determination of BACT for SO_2*

JCEP will burn low sulfur fuels minimizing SO_2 emissions to satisfy BACT requirements.

4.7.6 BACT Analysis for Ground Flare Greenhouse Gas (GHG) Emissions

4.7.6.1 *Review of GHG BACT Database*

The RBLC search indicated one project, Sabine Pass LNG Terminal in Louisiana, which identifies proper plant operations and maintaining a flame at the flare tip during combustion as BACT for GHG emissions from flares.

4.7.6.2 *Identification of GHG Control Options and Technical Feasibility*

The available GHG emission control strategies for the flare that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration (CCS);
- Fuel Selection;
- Flare Gas Recovery; and
- Good Combustion, Operating, Maintenance Practices

CCS - With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option. Pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent process gas streams routed to a flare. Flaring will be limited to emergency situations of limited duration resulting in a very intermittent CO_2 stream; thus, CCS is not considered a technically feasible option. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

Fuel Selection - The pilot gas fuel for the proposed flare will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel.

Flare Gas Recovery - Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable. While, installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares, flaring at JCEP will be limited to emergency situations. Due to infrequent nature of these situations and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system.

Good Combustion, Operating, and Maintenance Practices - Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare per the manufacturer's specifications.

4.7.6.3 Determination of BACT for GHG

JCEP proposes the following design elements and work practices as BACT for the flares:

- use of natural gas as fuel; and
- implementation of good combustion, operating, and maintenance practices.

JCEP proposes the following as numerical BACT limits for GHG emissions associated with the flare to no more than 278 tons/year/unit of CO_2e (12-month rolling basis).

4.8 BACT Analysis for Fugitive Emissions

Fugitive components at the proposed JCEP plant include traditional components (valves, flanges, pressure relief valves, pumps, compressors, and connectors), O_2 sensors, and gas chromatographs.

4.8.1 BACT Analysis for Fugitive Volatile Organic Compound Emissions

4.8.1.1 Identification of VOC Control Options and Technical Feasibility

The following available control technologies were identified and are discussed below:

- Installing leakless technology components to eliminate fugitive emission sources;
- Installing air-driven pneumatic controllers;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

Leakless Technology Components - Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown which often generates additional emissions. Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

Air-Driven Pneumatic Controllers -Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.

LDAR Programs -LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors).[6]

Alternative Monitoring Program - Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

AVO Monitoring Program - Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids piping components are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry. Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

High Quality Components - A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

4.8.1.2 Determination of BACT for VOC

The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. In addition, JCEP proposes to implement an LDAR program, with a control effectiveness of 97% for most equipment. JCEP will also utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high-quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. The product pumps containing VOCs will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when

[6] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

the first seal begins to leak. Since JCEP is implementing the most effective control options available, additional analysis is not necessary.

JCEP is not proposing a numerical BACT limit on VOC emissions from fugitive components since fugitive emissions are estimates only.

4.8.2 BACT Analysis for Fugitive Greenhouse Gas (GHG) Emissions

4.8.2.1 Identification of GHG Control Options and Technical Feasibility

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified and are discussed below: Installing leakless technology components to eliminate fugitive emission sources;

- Installing air-driven pneumatic controllers;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

Leakless Technology Components - Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown which often generates additional emissions. Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

Air-Driven Pneumatic Controllers -Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.

LDAR Programs -LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors).[7]

Alternative Monitoring Program - Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

AVO Monitoring Program - Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids piping components are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry. Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

High Quality Components - A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

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7 TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

4.8.2.2 Determination of BACT for GHG

The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. In addition, JCEP proposes to implement an LDAR program, with control effectiveness of 97% for most equipment. JCEP will also utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high-quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. The product pumps containing VOCs, and potentially CH_4 and CO_2, will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when the first seal begins to leak. Since JCEP is implementing the most effective control options available, additional analysis is not necessary.

JCEP is not proposing a numerical BACT limit on GHG emissions from fugitive components since fugitive emissions are estimates only.

Table 4-1: CCS Cost Analysis for Combined Cycle Unit

CCS System Component	Cost [1,2] ($/ton)	CO_2 Removed[3] (ton/yr)	Total Annualized Cost[4]
CO2 Capture & Compression Facilities	$103	1,943,991	$201,045,962
CO2 Transport Facilities	$10.82	1,943,991	$21,043,521
CO2 Storage Facilities	$0.51	1,943,991	$987,594
Total CCS System Cost	$115	1,943,991	$223,077,077

[1] CO_2 capture/compression and storage costs are from *Report of the Interagency Task Force on Carbon Capture (August, 2010).* Cost includes initial investment, O&M, and cost of fuel.
[2] CO_2 transport cost is calculated per pipeline cost equations from *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs,* National Energy Technology Laboratory, US Department of Energy, DOE/NETL-2010/1447 (March, 2010).
[3] Tons of CO_2 removed assumed 90% capture of all CO_2 emissions from combined cycle turbines, duct burners and thermal oxidizers.

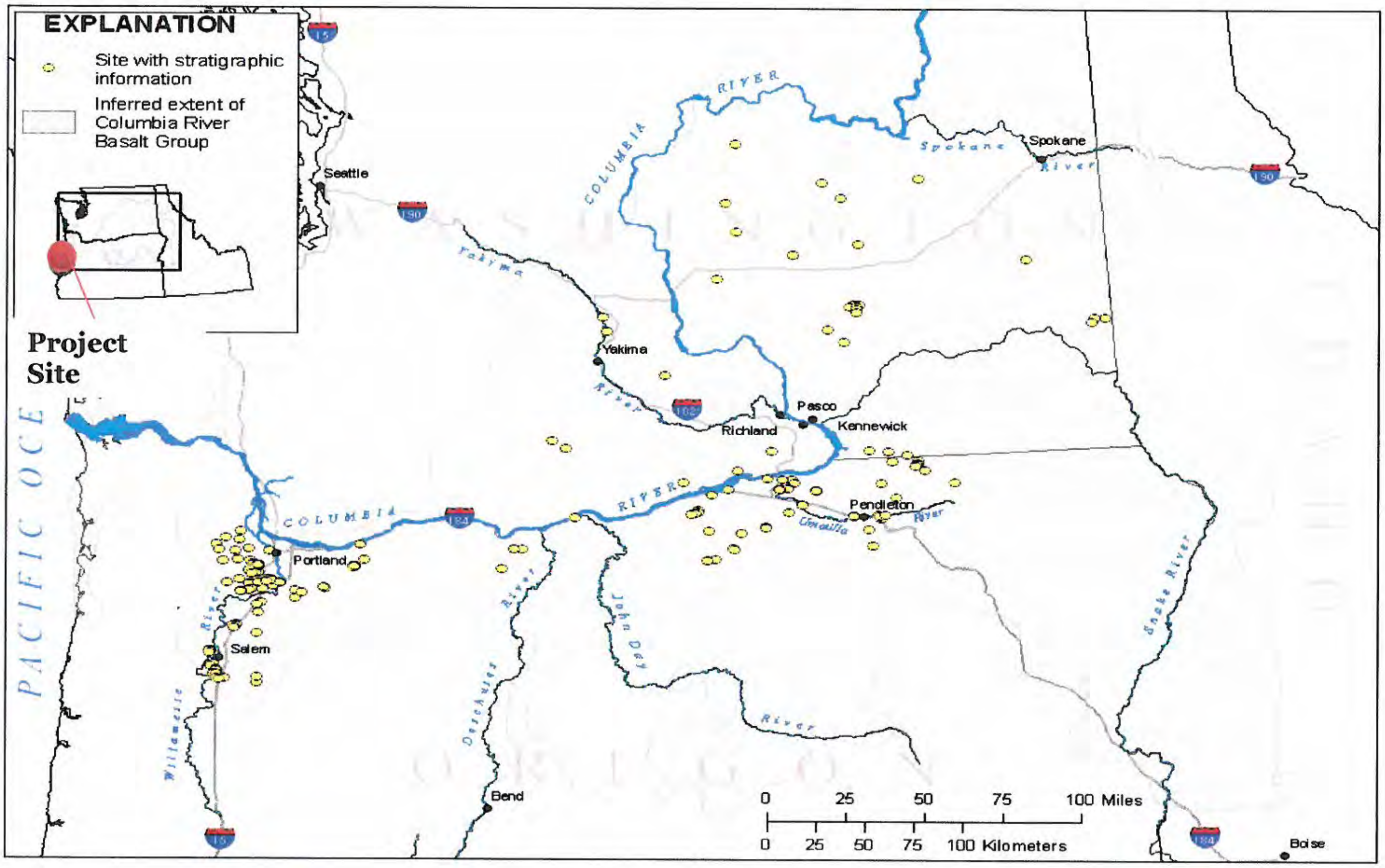
[4] Annualized costs based on 7% interest rate and 20 year equipment life.

Table 4-2: CO_2 Pipeline Construction Cost Estimate[1]

Description	Cost	Basis
Capital Cost:		
AGI Pipeline - 26" diameter		120 mile pipeline
Materials	$59,612,180	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$101,560,351	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$43,014,176	$150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	$6,497,797	$48,037 + $1.20 x L x (577 x D + 29,788)
CO2 Surge Tank	$1,150,636	
Pipeline Control System	$110,632	
Total Capital Cost	***$211,945,772***	
Annual Operating Cost:		
O&M Cost	$1,035,840	$8,632/mile/year
Total Annual Operating Cost	***$1,035,840***	
Capital Recovery Factor	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost	$20,007,681	
Total Annual Cost	**$21,043,521**	
GHG Emissions Removed	1,943,991	
Cost Effectiveness ($/ton)	**$10.82**	

[1] CO_2 transport cost is calculated per pipeline cost equations from *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs,* National Energy

Figure 4-1: Potential CO2 Storage Sites



5.0 AIR QUALITY IMPACT ANALYSIS

5.1 Regional Description

Jordan Cove Energy Project L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal on an approximate 168-acre site located on the bay side of the North Spit of Coos Bay, Oregon between Coos Bay Navigation Channel Miles (CM) 7.0 and 8.0. The project, known as the Jordan Cove Energy Project (JCEP), or Project (or Facility) will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG.

The area surrounding the facility (within 3 kilometers) consists mainly of forested areas, sand dunes, and water bodies to the east, north, and west of the site with some industrial use along the bay to the south. The residential area of North Bend as well as North Bend Municipal Airport (currently known as the Southwest Oregon Regional Airport) is located to the south of the facility. Approximately 90% of the land uses within 3 kilometers of the facility consist of water, forest/undeveloped areas and sand dunes.

The graded elevation of the proposed facility site will vary from 30 to 60 feet above mean sea level (MSL). Topography proximate of the facility is relatively flat with elevations ranging from MSL to 160 feet above MSL within 1 kilometer of the site. To the east of the site lies some rolling terrain with hill top elevations ranging up to approximately 600 feet above MSL.

The proposed facility will be located at approximately 43.434024 North Latitude, 124.243219 West Longitude, North American Datum 1983 (NAD83). The approximate Universal Transverse Mercator (UTM) coordinates of the proposed facility are 399,383 meters Easting, 4,809,765 meters Northing, in Zone 10, NAD83.

5.2 Background Ambient Air Quality

Consistent with the air quality modeling protocol (see Appendix E) submitted to and approved by ODEQ, background ambient air quality data was obtained from various approved existing monitoring locations. Based on review of the locations of Oregon Department of Environmental Quality (ODEQ) ambient air quality monitoring sites, the closest monitoring sites were initially used to represent the current background air quality in the site area.

Background data for CO was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0013), and approximately 117 km northeast of the proposed facility. The monitor is located at Lane Community College at 1059 Willamette, approximately at 44.047896 North Latitude, 123.092049 West Longitude, in a commercial/suburban area.

Background data for PM-10 was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0058), and approximately 113 km northeast of the proposed facility. The monitor is located at 450 Pacific Highway North, approximately at 44.066304 North Latitude, 123.139831 West Longitude, in a residential/suburban area.

Background data for PM-2.5 was obtained from the Cottage Grove station located in Lane County, Oregon (EPA AIRData # 41-039-9004), and approximately 103 km east-northeast of the proposed facility. The monitor is located at 425 N. 14th Cottage Grove City Shops, approximately at 43.799570 North Latitude, 123.053490 West Longitude, in a residential/suburban area.

Background data for NO2 and SO2 was obtained from the Portland monitoring station located in Multnomah County, Oregon (EPA AIRData # 41-051-0080), and approximately 265 km north-northeast of the proposed facility. The monitor is located at 5824 SE Lafayette, approximately at 45.966667 North Latitude, 122.602222 West Longitude, in a residential/suburban area.

The above monitors are located within or nearby to the two largest cities in Oregon (i.e., Portland and Eugene). These areas have a substantially higher population than the Coos Bay area and have a significantly higher density of industrial facilities. The monitors are located in areas with a substantially greater amount of both mobile and point source air emissions compared to the Project area. Thus, these monitors would be considered to conservatively represent the ambient air quality within the Project area.

The monitoring data for three recent years (2009-2011) are presented and compared to the NAAQS in Table 5-1. The maximum measured concentrations for each of these pollutants during the last three years are all below applicable standards and are proposed to be used in a NAAQS analysis.

5.3 Modeling Methodology

Air quality dispersion modeling was performed consistent with the procedures found in the following documents: Guideline on Air Quality Models (Revised) (U.S. EPA, 2005), New Source Review Workshop Manual (U.S. EPA, 1990), and Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (U.S. EPA, 1992).

The following methodology was incorporated into the assessment:

- Use of five (5) years (2007-2011) of concurrent surface meteorological data collected from a meteorological tower at North Bend Municipal Airport (WBAN 24284) (also known as the Southwest Oregon Regional Airport) in Coos County. The airport is located approximately 1.7 km south of the proposed facility site at an elevation of approximately 12 feet above MSL. Concurrent upper air sounding data from Salem McNary Field Airport (WBAN 24232), in Marion County was also used. These data were used with the concurrent hourly surface data to create the meteorological dataset required for the modeling analysis;
- Load screening of the combustion turbine operating scenarios (including supplementary duct firing on natural gas) to account for varying loads (50%, 75%, and 100%); and
- Modeling of several plant start-up/shutdown scenarios as well as modeling of facility auxiliary equipment (i.e., thermal oxidizers and emergency equipment).

Results of the combustion turbine load screening with sequential modeling to identify the worst case operating conditions were compared to the significant impact concentrations (SICs) established in the PSD regulations. These modeled concentrations are greater than the SICs for all pollutants and averaging periods with the exception of CO, 3-hour and 24-hour SO_2, and all of the standards based upon annual averaging.

The modeling methodology used for assessing the proposed facility's air quality impact, was detailed in the Air Quality Modeling Protocol submitted to the ODEQ on November 28, 2012 and approved on January 23, 2013 A copy of the air quality modeling protocol can be found in Appendix E.

5.3.1 Urban/Rural Area Analysis

A land cover classification analysis was performed to determine whether the urban source modeling option in AERMOD should be used in quantifying ground-level concentrations. The urban option in AERMOD accounts for the effects of increased surface heating on pollutant dispersion under stable atmospheric conditions. Essentially, the urban convective boundary layer forms in the night when stable rural air flows onto a warmer urban surface. The urban surface is warmer than the rural surface because the urban surface cools at a slower rate than the rural surface when the sun sets. The methodology utilized to determine whether the project is located in an urban or rural area is described below.

An aerial map covering the area within a 3-kilometer radius of the site was reviewed (see Figure 1-1) along with a USGS topographical map and indicated that approximately 90% of the surrounding area is water, wooded areas, and sand dunes. Note that the "AERMOD Implementation Guide" published on October 19, 2007 cautions users against applying the 3-kilometer Land Use Procedure on a source-by-source basis and instead consider the potential for urban heat island influences across the full modeling domain (i.e., 20 kilometers x 20 kilometers). This approach is consistent with the fact that the urban heat island is not a localized effect, but is more regional in character.

The population density within 3 kilometers of the proposed site was assessed utilizing the data from the U.S. Census Bureau. The population density within 3 kilometers of the site is approximately 580 persons per square kilometer.

In summary, the area within 3 kilometers of the proposed site is characterized primarily by rural land uses and the population density is below the 750 persons per square kilometer threshold for utilizing the Urban Source option in AERMOD. Because the urban heat island is more of a regional effect, the Urban Source option in AERMOD was not utilized since the area is more rural in nature over the modeling domain.

5.3.2 Good Engineering Practice Stack Height

Section 123 of the Clean Air Act (CAA) Amendments required the United States Environmental Protection Agency (U.S. EPA) to promulgate regulations to assure that the degree of emission limitation for the control of any air pollutant under an applicable State Implementation Plan (SIP) was not affected by (1) stack heights that exceed GEP or (2) any other dispersion technique. The U.S. EPA provides specific guidance for determining GEP stack height and for determining whether building downwash will occur in the Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations), (EPA-450/4-80-023R, June, 1985). GEP is defined as "...the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain "obstacles"."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) are avoided. The U.S. EPA GEP stack height regulations specify that the GEP stack height be calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

Where:
H_B = the height of adjacent or nearby structures, and
L = the lesser dimension (height or projected width of the adjacent or nearby structures).

A site plan for the proposed Facility is shown in Figures 5-1 and 5-2. A GEP stack height analysis has been conducted using the U.S. EPA approved Building Profile Input Program with PRIME (BPIPPRM, version 04274). The results of the analysis are presented in Table 5-2. The largest controlling structure at the South Dunes Station will be the air cooled condensers, at a height of 75 feet above grade, resulting in a formula GEP height of 187.5 feet above grade. The largest controlling structure at the liquefaction area will be the LNG storage tanks, at a height of 200 feet above grade, resulting in a formula GEP height of 500 feet above grade. Since non-GEP stacks are proposed, direction-specific downwash parameters for the combustion turbine exhaust stacks were determined using BPIPPRM, version 04274. Direction-specific downwash parameters for the additional auxiliary equipment exhaust stacks to be modeled (i.e., thermal oxidizer and emergency equipment) were also determined using BPIPPRM, version 04274.

Figure 5-3 provides an isometric view of the Facility structures included in the BPIP analysis.

5.3.3 Model Selection

The U.S. EPA has compiled a set of preferred and alternative computer models for the calculation of pollutant impacts. The selection of a model depends on the characteristics of the source, as well as the nature of the surrounding study area. Of the four classes of models available, the Gaussian type model is the most widely used technique for estimating the impacts of nonreactive pollutants.

The AERMOD model was designed for assessing pollutant concentrations from a wide variety of sources (point, area, and volume). AERMOD is currently recommended for modeling studies in rural or urban areas, flat or complex terrain, and transport distances less than 50 kilometers, with one hour to annual averaging times. In November 2005, AERMOD became a U.S. EPA guideline model replacing the Industrial Source Complex (ISCST3) model which had been the preferred model for many years for most modeling applications.

AERMOD (version 12345) was used for the PSD modeling of the proposed Facility's potential emissions to determine the maximum ambient air concentrations. The regulatory default option was used in the dispersion modeling analysis.

5.3.4 Meteorological Data

Five (5) years (2007-2011) of concurrent meteorological data collected from a meteorological tower at North Bend Municipal Airport, approximately 1.7 km south of the proposed Facility and from radiosondes launched from Salem McNary Field Airport were used to create the meteorological dataset (using AERMOD's meteorological processor, AERMET (version 12345)) required for the modeling analyses. Addtionally, the three surface land use parameters required by AERMOD (i.e., bowen ratio, albedo, roughness length) were obtained by running

AERSURFACE. The meteorological data is representative of the site area per EPA guidance as discussed in the approved Air Quality Modeling Protocol.

5.4 Receptor Grid

5.4.1 Basic Grid

The AERMOD model requires receptor data consisting of location coordinates and ground-level elevations. The receptor generating program, AERMAP (Version 11103), was used to develop a complete receptor grid to a distance of 10 kilometers from the proposed facility. AERMAP uses digital elevation model (DEM) or the National Elevation Dataset (NED) data obtained from the USGS. The preferred elevation dataset based on NED data was used in AERMAP to process the receptor grid. This is currently the preferred data to be used with AERMAP as indicated in the U.S. EPA AERMOD Implementation Guide (U.S. EPA, 2009). AERMAP was run to determine the representative elevation for each receptor using 1/3 arc second NED files that were obtained for an area covering at least 20 kilometers in all directions from the Facility. The NED data were obtained through the USGS Seamless Data Server (http://seamless.usgs.gov/index.php).

The following rectangular (i.e. Cartesian) receptors were used to assess the air quality impact of the proposed facility:

- Fine grid receptors ≤ 60 meters for a 10 km (east-west) x 10 km (north-south) grid centered on the proposed facility site.
- Coarse grid receptors ≤ 600 meters for a 20 km x 20 km grid centered on the proposed facility site.

All of the maximum modeled pollutant and averaging specific impacts occurred within the fine grid receptors and thus, it was not necessary to expand the fine grid. However, because the modeled impacts exceeded some pollutants specific SICs at the extent of the 20 km coarse grid, the coarse grid was extended to 50 km in all directions from the center of the site. This receptor grid was then utilized to determine the significant impact area (SIA) for those pollutants and averaging periods with modeled impacts above the SICs.

Plots of the facility receptor grid are presented in Figures 5-4 and 5-5.

5.4.2 Property Line Receptors

Receptors were also placed along the facility fence line or property boundary every 25 meters. Grid receptors within the fenced plant property were excluded from the grid as public access will be precluded in this area. Receptors were not included in the ship berthing area since this area will be restricted to public access and is not considered ambient air.

5.4.3 Special or Elevated Receptors

There are no special receptors (i.e., schools, hospitals, day care, or senior care facilities) within one (1) kilometer of the proposed Facility. Any sensitive population areas beyond one (1) kilometer are adequately represented by the 60-meter spaced modeling receptor grid. There are also no elevated receptor locations nearby to the facility that would be required to be modeled as flagpole receptors (i.e., open and accessible apartment building balconies, public walking bridges, etc.). The approximate 1-mile long Oregon State Highway 101 Bridge located to the east of the facility is used for vehicular travel and would not be expected to used by the general public for substantial periods of time (i.e., more than 0.5 hours) for emergency (i.e., vehicle breakdown) or recreational purposes (i.e., walking if permitted by local authorities). Thus, the bridge would not be considered as ambient air since the general public is precluded from permanent non-vehicular access over the span.

5.5 Source Parameters, Worst Case Load and Operating Scenario Determination

The project will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is less than 1.00 grains/100 SCF), which will be equipped with a natural gas-fired duct burner for supplementary firing and two steam turbine generators (STGs). By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Station) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Station). Figure 5-1 presents a general arrangement drawing of the proposed South Dunes Power Plant facility while Figure 5-2 presents a general arrangement of the liquefaction area.

Emissions from the six combined cycle units will be controlled by the use of dry low-NO_x burner technology and SCR for NO_x control, an oxidation catalyst for CO and VOC control, and the use of clean low-sulfur fuels only (i.e., natural gas) to minimize emissions of SO_2, PM/PM-10/PM-2.5, and H_2SO_4. Exhaust gases from the combined cycle units after emission controls will be dispersed to the atmosphere via individual stacks. Steam from the steam turbine will be sent to a condenser where it will be cooled to a liquid state and returned to the HRSG. Waste heat from the condenser will be dissipated through the air cooled condensers.

In addition to the South Dunes Power Station, the LNG Liquefaction Project will have a number of fugitive VOC emission sources from piping/flanges/valves from both land-based and vessel based sources. The four LNG liquefaction trains will be electric and thus, only fugitive VOC emissions are expected from that equipment.

While combustion emissions from the LNG vessels during hoteling, berthing, deberthing, and transit are expected, these activities are exempt from ODEQ and PSD permitting requirements as they are not considered direct emissions from the Facility. The power to provide for the pumps to onload the LNG from the liquefaction facility to the LNG vessels will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the onloading process that would be subject to ACDP and PSD review as well as the requirement to model the dispersion of those emissions. Because cumulative ambient air quality modeling analysis with offsite sources is necessary, these stationary vessel based emission sources will be included as offsite sources for the purposes of an air quality standards compliance demonstration.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Trace amounts of hydrogen sulfide are removed as well in the CO_2 removal system, due to the characteristics of the absorbent. The gas conditioning trains consist of two parallel trains, each containing two systems in series: a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas from the Amine Stripper will be sent to a waste gas incinerator (one for each of the two trains) in order to oxidize sulfur components. Air emissions from the amine and dehydration systems are not expected and thus, were not included in the modeling analysis.

A Ground Flare is included in the project design (one at each of South Dunes Station and the LNG liquefaction area) to handle gas relieved during emergency upset conditions including but not limited to: extended power outages, extended emergency shut down events, and unexpected loss of vapor handling equipment during LNG Ship loading with the LNG Storage Tank operating near maximum normal operating pressure. The low pressure flare header is continuously purged with fuel gas. A small pilot (42,500 btu/hr) with electronic ignition will be continuously operated. The flares were not included in the modeling analysis as they will only operate during emergency events with the exception of the small continuous flare pilot flame, which will have negligible air emissions as shown on Table 1-4.

5.5.1 Modeling Emission Parameters

Exhaust characteristics of the turbine/HRSG stack during different operating scenarios are provided in Table 5-3. Exhaust parameters are presented for gas firing at three ambient temperatures (20 degrees Fahrenheit, 59 degrees Fahrenheit, and 90 degrees Fahrenheit) and three loads (50%, 75%, and 100%). Table 5-4 presents the potential emission rates for each of the operating scenarios. In addition, emission rates and stack parameters are presented for duct firing during natural gas operation at 100% load. Thus, emission rates and stack parameters for twelve (12) ambient temperatures and load combinations were used to determine the "worst-case" operating scenario for the turbines.

To account for secondary particulate from the PM-2.5 precursor pollutants NO_x and SO_2 additional secondary particulate was calculated and added to the direct and condensable PM-2.5 emissions from the facility equipment. Per Guidance from ODEQ, secondary particulate formations emissions were based upon the PM-2.5 offset ratios codified in OAR 340-225 for SO_2 and NO_x. For example, an emission rate of 100 lb/hr of NO_x was modeled as 1 lb/hr of PM-2.5 to account for secondary particulate formation based upon a ratio of 100 tons per year of NO_x can offset 1 ton per year of PM-2.5. Similarly for SO_2 emissions, 100 lb/hr of SO_2 was modeled as 2.5 lb/hr of secondary PM-2.5 using the offset of ratio of 40 tons per year of SO_2 offsets 1 ton per year of PM-2.5.

Finally, Tables 5-5 to 5-8 present the stack parameters and emission rates for the thermal oxidizers, emergency diesel firepumps, and emergency diesel generators. As discussed in Section 3.3 of the Air Quality Modeling Protocol (Appendix E), the emergency diesel firepumps and emergency diesel generators were included in the modeling analysis for appropriate pollutants and averaging periods when used for readiness testing (i.e., less than 1-hour per day).

5.5.1.1 Start-Up Scenarios

Startup is a short-term, transitional mode of operation for the combined cycle units. In combined cycle operation, where the exhaust gases are directed through a HRSG to produce steam for a steam turbine generator, additional startup time is necessary in order to reduce thermal shock and excessive wear in both the HRSG and the steam turbine. Emission rates of some pollutants may be higher during startup operations because emission controls may not become fully effective until a minimum threshold operating load and/or control device temperature is attained. The need for additional modeling to account for predicted short-term Project impacts during startup of the combined cycle units was assessed for those criteria pollutants whose short-term emission rates during startup may exceed those during normal operation and for which a short-term NAAQS or PSD increment has been defined (i.e., for CO and NO_2). In addition, the need for startup modeling was assessed for SO_2 and PM-10/PM-2.5.

Startup and shutdown conditions refer to all times when the CTG operates below the minimum operating load (~50% load). Startups are defined as cold, warm, and hot. The cold startup refers to startups after 72 hours of shutdown time and requires approximately 3.8 hours to achieve emissions compliance load. The warm startup refers to startups after typically 8.1 – 72 hours of shutdown time and requires approximately 2.2 hours. The hot startup refers to a typical shutdown time of about 8 hours or less and can be achieved in 1.7 hours. Shutdowns can occur at any time and take approximately 0.6 hours.

The short-term duration of startup and the relatively limited cumulative time of startup relative to normal operation means that startup impacts will not have an appreciable effect on annual impacts when taking into account the downtime necessary for each start-up type. For these reasons, only start-up/shutdown modeling for the annual NO_2 impacts was conducted since the calculated potential to emit for this pollutant only, does increase when considering the start-up/shutdown events for NO_x. Since SO_2 emissions are strictly dependent upon fuel flow (and hence are lower during start-up than continuous operation), SO_2 start-ups/shutdowns were not modeled for short-term or annual averaging periods.

As discussed previously, the South Dunes Power Plant will consist of two separate power blocks, each in a 3 x 1 configuration that are used primarily to provide power for the liquefaction trains. JCEP does not expect that both power blocks would start-up or shutdown simultaneously due to the need to allow for safe and reliable startup and shutdown of each of the four liquefaction trains. Also, JCEP expects that only two combustion turbines could startup simultaneously for similar operational reasons (i.e., it is expected that two turbines would be used to startup a liquefaction train and only one liquefaction train would be started at a time). Additionally, due to the standard startup sequence for a GE LM6000 3x1 combined cycle power block it is expected that while two of the three turbines are below emissions compliance load (i.e., 50%), that the third turbine is unfired. For these reasons, worst-case startup and shutdown modeling for the 1-hour averaging period included two of the three combustion turbines in startup mode in the first power block with the second power block operating at worst-case modeled load.

Startup emissions and associated stack parameters have been estimated for three varieties of startup (cold, warm, and hot) based on vendor data and are shown in Table 5-9. As shown in the table, worst case emissions and stack parameters for NO_x occur during warm starts and thus, 1-hour NO_2 modeling was conducted for the warm start mode only. Similarly, worst case emissions for CO occur during shutdown and thus, modeling for CO was conducted assuming shutdown conditions with the balance of the averaging period time occurring at worst-case modeled load for CO.

Because the shutdown durations will be shorter than some of the averaging periods modeled, the modeled concentrations for these averaging periods that extend beyond the shutdown duration were determined based on the combination of the shutdown conditions for the appropriate amount of time and the worst-case full-load pollutant- and averaging period-specific operating scenario determined in the combustion turbine load analysis (i.e., Case 10 (Table 5-3) for CO and NO_2).

In summary, the worst-case startup/shutdown emissions for CO and NO_x were modeled since these pollutants have significantly higher emissions during startup and shutdown conditions when compared to normal operation for short-term averaging periods (i.e., NO_x and CO) and for annual averaging periods (i.e., NO_x).

5.5.2 Combustion Turbine Load Screening Modeling Analysis

To determine the worst case operating scenario for the proposed combustion turbines, a detailed load screening analysis was performed. As previously discussed, twelve (12) combinations of load conditions and ambient operating temperatures were calculated. The turbine load screening analysis results can be found in Appendix F. Appendix F shows maximum modeled concentrations of all pollutants for all averaging periods to be less than their respective SICs, except 24-hour and annual PM-2.5, 24-hour PM-10, and 1-hour SO_2 and NO_2. Note that the highlighted cells in this Appendix represent the maximum modeled pollutant specific impact over the range of 12 modeled operating scenarios.

Of the 12 operating scenarios described in Section 5.5.1, the worst case turbine operating scenario (i.e., operating scenarios which yielded the maximum modeled concentrations) was Case 10 (combustion turbine at peak load with duct firing at 90 F ambient temperature) for all averaging periods. This operating case was then utilized in all subsequent modeling analyses for the combustion turbines.

5.5.3 Start-up/Shutdown Modeling Analysis

The results of the start-up/shutdown modeling analysis are summarized in Table 5-10. The maximum modeled impacts are compared to the SICs and Class II PSD increments. As shown in Table 5-10, the maximum modeled start-ups/shutdowns do not exceed any applicable SIC, except for 1-hour NO_2. Additionally, none of the pollutants exceed any applicable PSD Class II increment. Note that the start-up/shutdown modeling included simultaneous operation of Facility auxiliary equipment when applicable.

5.5.4 Maximum Modeled Facility Concentrations

In summary, Table 5-11 presents the maximum modeled Facility air quality concentrations (including maximum modeled concentrations due to startups and auxiliary equipment) calculated by AERMOD during operation of the proposed Facility. As shown in this table, the maximum concentrations are below the applicable SICs, except for 24-hour and annual PM-2.5, 24-hour PM-10, and 1-hour SO_2 and NO_2. Additionally, none of the pollutants exceed any applicable PSD Class II increment. Figures 5-6 through 5-16 provide the locations and concentration gradients for each of the modeled pollutants and averaging periods. As shown on the figures, the maximum modeled concentrations typically occur at or on the facility fenceline and in locations of elevated terrain approximately 3 kilometers to the east of the facility.

Under longstanding U.S. EPA guidance and interpretations, the SICs are used to determine if a source makes or could make a significant contribution to a predicted violation of a NAAQS or PSD increment. If a source is predicted to have maximum impacts that are below the SICs, then a cumulative (or "full") impact analysis that includes other facilities is not required, and the impacts of the project are considered to be *de minimis* or insignificant. By showing that maximum predicted Project impacts will be below the corresponding SICs for CO, the Project is exempt from the requirement to conduct any additional analyses to demonstrate compliance with the NAAQS for this pollutant. Additionally, the modeled impacts for annual SO_2, NO_2 and PM-10 are below the corresponding SICs and thus, the Project is also exempt from the requirement to conduct additional analysis for the annual SO_2, NO_2 and PM-10 averaging periods.

5.5.5 Area of Impact Determination

24-hour and annual PM-2.5, 24-hour PM-10, 1-hour, and 1-hour NO_2 have been determined to be significant; therefore, they are the only pollutants/averaging periods determined to have an area of impact (SIA), thus requiring additional impact assessments. Per EPA Policy, the impact area is a circular area with a radius extending from the
source to (1) the most distant point where dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 km, whichever is less. Based upon the modeling results the area of impacts for each pollutant and averaging period is shown below:

Pollutant	Averaging Period	SIA
NO_2	1-Hour	50 km
PM-2.5	24-Hour	39.3 km
PM-2.5	Annual	9.2 km
PM-10	24-Hour	14.6 km
SO_2	1-Hour	17.7 km

The additional impact assessment required for the above pollutants and averaging periods is a multiple source NAAQS modeling assessment.

The air quality NAAQS modeling analysis for the 1-hour NO_2 NAAQS will be performed consistent with the guidance and procedures established in the March 1, 2011 guidance memorandum from Tyler Fox (EPA OAQPS) titled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 NAAQS" (Memorandum).

A multi-source air quality modeling protocol will be submitted under separate cover for approval by the department after a list of offsite sources to be included in the NAAQS analyses is provided by the department. The multisource protocol will discuss the applicable modeling methodology to be used in the NAAQS analysis along with appropriate offsite source emissions.

5.6 Class I Impacts

Per guidance from ODEQ, air quality concentrations of NO_x, SO_2, and PM-10/PM-2.5 in Class I areas within 200 km of the proposed facility were determined for purposes of Class I increment modeling. Class I areas within 200 kilometers of JCEP include:

- Crater Lake National Park (Oregon) 165 kilometers
- Redwood National Park (California) 177 kilometers
- Kalmiopsis Wilderness Area (Oregon) 110 kilometers
- Diamond Peak Wilderness Area (Oregon) 164 kilometers
- Three Sisters Wilderness Area (Oregon) 184 kilometers

The Class I screening receptors were developed first by placing a ring of receptors at 50 kilometers and 0.1 degree intervals from the Facility site. Actual Class I receptors and heights for each of the areas noted above were obtained from the National Park Service. Screening receptors within the circular sector area for each Class I area were assigned the minimum and maximum heights within that Class I area in order to develop a set of representative screening receptors at 50 kilometers. The height for final plume rise as determined by running SCREEN3 at F-stability and a 2.5 meter per second wind speed was also modeled for any Class I areas that have a minimum actual height less than the height of final plume rise. Any receptors that were not within the circular sector area were removed from the analysis as they would not represent any Class I areas. Figure 5-17 depicts the locations of the five Class I areas along with the locations of the modeled receptors at 50 kilometers from the JCEP Facility. Maximum concentrations were then compared to the PSD Class I Increments as presented in Table 5-12.

The results of the modeling indicate that the Facility impacts are much lower than the PSD Class I increments for all pollutants and averaging times. It should be noted that the modeling results are highly conservative since they reflect the concentrations at a distance of 50 kilometers from the Facility rather than the nearest Class I area that is actually at a distance of 110 km (i.e., the Kalmiopsis Wilderness Area). Modeling was performed at a distance of 50 kilometers based upon ODEQ Class I modeling guidance and on the spatial limitations of the AERMOD model.

The screening modeling results indicate that the Class I SILs are potentially exceeded for PM-10 PM-2.5, and SO_2 at the lower elevations in Redwood National Park and the Kalmiopsis Wilderness Area. Based upon a review of terrain data between these Class I areas and the facility location it is noted that there is substantial intervening terrain that would serve to obstruct a plume from reaching the lower elevations in the Class I areas. Thus, it is highly likely that the maximum modeled impacts are also below the Class I SILs in all five Class I areas based upon the conservative screening modeling and assessment of intervening terrain. Therefore, per the Class I screening analysis, the Project is exempt from the need to perform additional refined Class I increment modeling.

The Federal Land Manager (FLM) for the Class I areas were notified on January 11, 2013 to determine if assessments of impacts on air quality related values (AQRVs) in the Class I areas would be required. The FLM has reviewed the proposed Facility's details and related correspondence and has confirmed in a January 29, 2013 email that a Class I AQRV analysis for the proposed Facility is not required (see Appendix D).

5.7 ODEQ Air Toxics Risk Analysis

The receptor-point concentrations of any toxic substance identified by ODEQ as a Hazardous Air Pollutant (HAP) that could potentially be emitted from the proposed Facility were assessed in order to evaluate the potential health risk to the public beyond the property line of the proposed Facility. The ODEQ has published reference concentrations in OAR 340 Division 246 that are defined as an air toxic in outdoor air that would result in an excess lifetime cancer risk level of one in a million (1×10^{-6}) or a non-cancer hazard quotient of one. For each HAP with a prescribed reference concentration, a hazard quotient is calculated that is based upon the ratio of the potential exposure to a single air toxic to the reference concentration for that pollutant. If the hazard quotient is calculated to be less than or equal to 1, then no adverse health effects are expected as a result of exposure. If the hazard quotient is greater than 1, then adverse health effects are possible.

An air quality modeling analysis was conducted for potential non-criteria pollutant emissions from the proposed combustion turbines and thermal oxidizers. Each combustion turbine was modeled using a unit emission rate across the matrix 12 of operating scenarios. The maximum modeled annual XOQs were determined for cases both with and without duct firing. Maximum annual impacts were then based on the higher of combustion turbines operating without duct firing for the entire year or a weighted average of impacts from 4,760 hours without duct firing and 4,000 hours with duct firing. The resulting upper bound estimates of impacts were compared to the ODEQ reference concentrations for each non-criteria pollutant.

Appendix H presents a summary of maximum predicted non-criteria pollutant impacts relative to the associated reference concentrations. Predicted Project impacts of HAPs are all well below the associated reference concentrations, and are also below a hazard quotient of 1.0. Therefore, it is concluded that Project impacts will comply with ODEQ reference concentrations for air toxics.

5.8 PSD Additional Impacts Analyses

5.8.1 Impacts to Soil and Vegetation

A component of the PSD review includes an analysis to determine the potential air quality impacts on sensitive vegetation types that may be present in the vicinity of the proposed facility. The evaluation of potential impacts on vegetation was conducted in accordance with A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, (U.S. EPA, 1980). Calculated concentrations of various constituents from the proposed Facility were added to ambient background concentrations and compared to screening concentrations (levels at which change has been reported) to provide an assessment regarding the potential for adversely impacting vegetation with significant commercial and/or recreational value.

Screening concentrations used in this assessment represent the minimum ambient concentrations reported in the scientific literature for which adverse effects (e.g., visible damage or growth retardation) to plants have been reported. Of the pollutants emitted by the proposed Facility that triggered PSD review, vegetative screening concentrations are available for CO, SO_2, and NO_2. Screening concentrations for particulate matter are not currently available. Table 5-13 presents a comparison of maximum modeled concentrations from the proposed Facility (including ambient background levels) for the three constituents of concern (i.e., SO_2, NO_2, and CO) with their respective vegetation screening concentrations. This table demonstrates that modeled ground-level concentrations from the proposed Facility are well below levels at which even sensitive vegetation would be affected; thus, the proposed Facility will not adversely impact vegetation in the site area.

5.8.2 Impact on Visibility

In order to assess the potential impact on regional visibility, the conservative Level–1 screening analysis using the VISCREEN model was conducted using a visual background range of 40 kilometers. This is the visual distance indicated on Figure 9 – Regional Background Values, in the visibility assessment procedure described in the Workbook for Plume Visual Impact Screening and Analysis (U.S. EPA, 1988). The screening procedure involves calculation of three plume contrast coefficients using emissions of NO_2, PM/PM-10, and sulfates (H_2SO_4). The Level-1 screening procedure determines the light scattering impacts of particulates, including sulfates and nitrates, with a mean diameter of two micrometers with a standard deviation of two micrometers. These coefficients consider plume/sky contrast, plume/terrain contrast, and sky/terrain contrast.

A Level-1 screening analysis using the U.S. EPA VISCREEN (Version 1.01) model was performed for the calculated potential to emit (PTE) emissions. The visibility assessment was performed for an observer at the visual range of 40 kilometers from the proposed Facility site. The results of the analysis are presented in Table 5-14 and indicate that the proposed Facility will not impact visibility in the area surrounding the proposed Facility site.

Electronic output files from the VISCREEN model have been provided on the DVD-ROM contained in Appendix G.

5.8.3 Impact on Industrial, Commercial, and Residential Growth

The operation of the proposed Facility will generate tax revenue for the local, county, and state economies. Since the air emissions from the proposed Facility will not result in excessive PSD increment consumption, increment is available for new industry desiring to locate in the area. Therefore, the proposed Facility should have no effect on future industrial, commercial, or residential growth in the region.

5.9 Modeling Data Files

All modeling data files for the PSD modeling analyses to determine the maximum ambient ground-level concentrations from the proposed Facility are included on DVD-ROM in Appendix G.

5.10 References

U.S. EPA, 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA 450/2-81-078. Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. December 1980.

U.S. EPA, 1985. Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised). EPA-450/4-80-023R. U.S. Environmental Protection Agency.

U.S. EPA, 1988. Workbook for Plume Visual Impact Screening and Analysis. EPA-450/4-88-015. Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. September 1988.

U.S. EPA, 1990. "New Source Review Workshop Manual, Draft". Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

U.S. EPA, 1992. "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised". EPA Document 454/R-92-019, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

U.S. EPA, 2005. "Guideline on Air Quality Models (Revised). Appendix W to Title 40 US Code of Federal Regulations (CFR) Parts 51 and 52, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

Table 5-1: Maximum Measured Ambient Air Quality Concentrations

Pollutant	Averaging Period	Maximum Ambient Concentrations ($\mu g/m^3$)			NAAQS ($\mu g/m^3$)
		2009	2010	2011	
SO_2	1-Hour[a]	23.6	21.0	23.6	197
	3-Hour	**21.0**	21.0	15.7	1,300
	24-Hour	**10.5**	8.7	7.9	365
	Annual	**4.2**	3.7	NA	80
NO_2	1-Hour[b]	75.2	62.0	62.0	188
	Annual	**19**	17	17	100
CO	1-Hour	**2,415**	2,185	NA	40,000
	8-Hour	**1,840**	1,495	NA	10,000
PM-10	24-Hour	**55**	41	38	150
PM-2.5[c]	24-Hour	30	18	21	35
	Annual	8.5	6.9	7.1	12

[a]1-hour 3-year average 99th percentile value for SO_2 is **22.7** ug/m³.
[b]1-hour 3-year average 98th percentile value for NO_2 is **66.4** ug/m³.
[c]24-hour 3-year average 98th percentile value for PM-2.5 is **23.0** ug/m³; Annual 3-year average value for PM-2.5 is **7.5** ug/m³.
High second-high short term (1-, 3-, 8-, and 24-hour) and maximum annual average concentrations presented for all pollutants other than PM-2.5 and 1-hour SO_2 and NO_2.
Bold values represent the proposed background values for use in any necessary NAAQS analyses.
Monitored background concentrations obtained from the U.S. EPA AIRData and Oregon DEQ Air Quality Reports for 2009-2011.

Table 5-2: GEP Stack Height Analysis

Structure	Height (ft)	Maximum Projected Width (ft)	5L Region of Influence (ft)	H_{GEP}=H+1.5L (ft)
HRSGs	70	58	290	157
ACCs	75	252	375	187.5
Steam Turbine Generator	50	65	250	125
Administration Building	36	192	180	90
Maintenance Building	36	212	180	90
Control Building	15	160	75	37.5
Liquefaction Train	70	127	350	175
LNG Tank	200	266	1000	500
Fire Pump Building	15	110	75	37.5

Table 5-3: Combustion Turbine Modeled Source Parameters

Operating Case	Fuel	Ambient Temperature (°F)	Operating Load (%)	Duct Burner Operation (On/Off)	Modeling Stack Parameters: Exhaust Temperature (K)	Modeling Stack Parameters: Exhaust Velocity (m/s)[a]
Case1	Gas	20F	100	Off	399.6	24.54
Case2	Gas	20F	100	On	394.8	24.29
Case3	Gas	20F	75	Off	399.8	19.84
Case4	Gas	20F	50	Off	399.8	16.20
Case5	Gas	59F	100	Off	395.3	22.97
Case6	Gas	59F	100	On	392.9	22.86
Case7	Gas	55F	75	Off	399.8	20.51
Case8	Gas	55F	50	Off	399.8	15.75
Case9	Gas	90F	100	Off	395.8	21.09
Case10	Gas	90F	100	On	391.9	20.98
Case11	Gas	90F	75	Off	399.8	17.94
Case12	Gas	90F	50	Off	399.8	14.55

[a]Based on a stack diameter of 10.0 feet.

Table 5-4: Combustion Turbine Modeled Emission Rates

Operating Case	Modeled Emission Rate (g/s)[a]				
	NO_x	CO	PM-10/PM-2.5[b]	Secondary PM-2.5[c]	SO_2
Case1	0.491	0.605	0.769	0.010	0.215
Case2	0.542	0.655	0.970	0.011	0.233
Case3	0.378	0.466	0.693	0.008	0.164
Case4	0.290	0.353	0.643	0.006	0.123
Case5	0.491	0.605	0.806	0.010	0.214
Case6	0.517	0.630	0.920	0.011	0.224
Case7	0.391	0.479	0.706	0.008	0.168
Case8	0.290	0.353	0.668	0.006	0.125
Case9	0.428	0.529	0.769	0.009	0.186
Case10	0.529	0.643	1.109	0.011	0.229
Case11	0.340	0.416	0.706	0.007	0.145
Case12	0.252	0.315	0.655	0.005	0.110

[a]Emissions are for one (1) combustion turbine.
[b]Filterable plus condensable (Primary Fraction).
[c]Secondary PM-2.5 formation resulting from direct SO_2 and NO_x emissions per ODEQ formation ratios.

Table 5-5: Thermal Oxidizer Exhaust Characteristics and Emissions

Emission Parameter	
Pollutant	**lb/hr**
NO_x	6.65
CO	2.00
PM-10/PM-2.5 (Primary)	0.13
Secondary PM-2.5	0.12
Total PM-2.5 (Primary and Secondary)	0.25
SO_2	1.99
Exhaust Parameter	
Exhaust Height (ft above grade)	75
Exhaust Height (m above grade)	22.86
Exhaust Temperature (deg F)	980
Exhaust Flow (acfm)	36,744
Exhaust Velocity (ft/sec)	63.6
Exhaust Velocity (m/sec)	19.40
Inner Diameter (ft)	3.50
Inner Diameter (m)	1.07
Stack Base Elevation (ft)	48
Stack Locations (UTM NAD83)	399,180.6 m East 4,809,908.2 m North 399,253.7 m East 4,809,910.4 m North

Table 5-6: South Dunes Areas Emergency Diesel Fire Pump Exhaust Characteristics and Emissions

Emission Parameter	
Pollutant	**lb/hr**
NO_x	2.45
CO	2.67
PM-10/PM-2.5 (Primary)	0.13
Secondary PM-2.5	0.025
Total PM-2.5 (Primary and Secondary)	0.16
SO_2	0.004
Exhaust Parameter	
Exhaust Height (ft above grade)	15
Exhaust Height (m above grade)	4.57
Exhaust Temperature (deg F)	749
Exhaust Flow (acfm)	3,648
Exhaust Velocity (ft/sec)	309.7
Exhaust Velocity (m/sec)	94.4
Inner Diameter (ft)	0.5
Inner Diameter (m)	0.15
Stack Base Elevation (ft)	44
Stack Location (UTM NAD83)	399,595.4 m East 4,809,515.7 m North

Table 5-7: Emergency Diesel Generators Exhaust Characteristics and Emissions

Emission Parameter	
Pollutant	**lb/hr**
NO_x	32.79
CO	19.2
PM-10/PM-2.5 (Primary)	1.11
Secondary PM-2.5	0.33
Total PM-2.5 (Primary and Secondary)	1.44
SO_2	0.034
Exhaust Parameter	
Exhaust Height (ft above grade)	15
Exhaust Height (m above grade)	4.57
Exhaust Temperature (deg F)	915
Exhaust Flow (acfm)	19,582
Exhaust Velocity (ft/sec)	415.5
Exhaust Velocity (m/sec)	126.7
Inner Diameter (ft)	1.0
Inner Diameter (m)	0.30
Stack Base Elevation (ft)	46
Stack Location (UTM NAD83)	Liquefaction EDG 397,715.5 m East 4,809,589.1 m North South Dunes EDG 399,500.7 m East 4,809,892.7 m North

Table 5-8: Liquefaction Area Fire Pump Exhaust Characteristics and Emissions

Emission Parameter	
Pollutant	**lb/hr**
NO_x	4.28
CO	4.68
PM-10/PM-2.5 (Primary)	0.23
Secondary PM-2.5	0.043
Total PM-2.5 (Primary and Secondary)	0.27
SO_2	0.007
Exhaust Parameter	
Exhaust Height (ft above grade)	15
Exhaust Height (m above grade)	4.57
Exhaust Temperature (deg F)	875
Exhaust Flow (acfm)	3,200
Exhaust Velocity (ft/sec)	271.6
Exhaust Velocity (m/sec)	82.8
Inner Diameter (ft)	0.5
Inner Diameter (m)	0.15
Stack Base Elevation (ft)	60
Stack Locations (UTM NAD83)	Liquefaction FP1 397,320.8 m East 4,809,797.6 m North Liquefaction FP2 399,315.4 m East 4,809,797.5 m North Liquefaction FP3 397,309.9 m East 4,809,797.3 m North Liquefaction FP4 399,304.4 m East 4,809,797.1 m North

Table 5-9: Combustion Turbine Start-up and Shutdown Emission Rates and Stack Parameters

Estimated GE LM6000 PG Combustion Turbine Start-up/Shutdown Parameters

Event	Elapsed Time (hr)	Stack NOx (lb/event)	Stack NOx (lb/hour)	Stack CO (lb/ event)	Stack CO (lb/hr)	Stack PM-10/ PM-2.5 (lb/ event)	Stack PM-10/ PM-2.5 (lb/hr)	Average Stack Exhaust Flow (acfm)	Average Stack Exhaust Velocity (m/s)	Average Stack Exhaust Temperature (Degrees F)
Cold Start	3.83	126.7	33.0	24.7	6.4	11.2	2.9	181,505	11.74	260
Warm Start	2.23	96.7	43.3	13.0	5.8	8.2	3.7	181,505	11.74	260
Hot Start	1.65	62.3	37.8	5.7	3.4	5.3	3.2	194,023	12.55	260
Shutdown	0.61	13.0	NA	12.7	NA	5.0	NA	243,507	15.75	260

	Type of Start-up or Shutdown Event			
	Cold Startup	Warm Startup	Hot Startup	Shutdown
Duration of Turbine at 0% load prior to Start-up (hours)	>72	8.1 to 72	0 to 8	--
Duration of Start-up or Shutdown Event (hours)	3.83	2.23	1.65	0.61
Maximum Number per Year	30	85	160	275

Table 5-10: Maximum Modeled Concentrations During Start-Up/Shutdown

Pollutant	Averaging Period	Significant Impact Concentration (μg/m3)	Class II PSD Increment (ug/m3)	Maximum Modeled Concentration (μg/m3)
CO	1-Hour	2,000	-	890.3[d]
	8-Hour	500	-	73.1[d]
NO_2	1-Hour	7.5	-	175.7[a,b,c]
	Annual	1.0	25	0.82[c,d]

[a]Assumed 80% of NO_x is NO_2 per EPA guidance.
[b]Based upon maximum of 5-year average 1st highest maximum modeled concentrations per EPA guidance for comparison with SIC.
[c]Determined from operation of combustion turbines during a warm start-up sequence with the addition of facility ancillary equipment.
[d]Determined from operation of combustion turbines during shutdown sequence with the addition of facility ancillary equipment.

Table 5-11: Facility Maximum Modeled Concentrations

Pollutant	Averaging Period	Significant Impact Concentration (μg/m³)	Class II PSD Increment (ug/m³)	NAAQS/ OAAQS (ug/m³)	Maximum Modeled Concentration[d] (μg/m³)
CO	1-Hour	2,000	-	40,000	890.3
	8-Hour	500	-	10,000	73.1
SO_2	1-Hour[a]	7.8	-	197	23.8/NA/16.5
	3-Hour	25	512	1,300	13.1/11.0/11.0
	24-Hour	5	91	365/262	2.5/2.0/2.0
	Annual	1	20	80/52	0.22
PM-2.5	24-Hour[a]	1.2	9	35	7.0/7.7/3.9
	Annual	0.3	4	15	0.71/0.80
PM-10	24-Hour	5	30	150	9.3/7.6/7.6
	Annual	1	17	50	0.79
NO_2	1-Hour[a]	7.5	-	188	175.7/NA/92.7[b]
	Annual	1	25	100	0.82[c]

[a]Based upon maximum of 5-year average 1st highest maximum modeled concentrations per EPA guidance for SIC comparisons.
[b]Assumed 80% of NO_x is NO_2 per EPA guidance.
[c]Assumed 75% of NO_x is NO_2 per EPA guidance.
[d]Presented in the form of SIC/Increment/NAAQS for short-term standards due to the differing structure of those thresholds.

Table 5-12: Facility Maximum Modeled Class I Screening Concentrations

Pollutant	Averaging Period	Class I PSD Increment (ug/m³)	Maximum Modeled Concentration (μg/m³)
SO_2	3-Hour	25	1.1
	24-Hour	5	0.2
	Annual	2	0.01
PM-2.5	24-Hour	2	0.9
	Annual	1	0.04
PM-10	24-Hour	8	0.9
	Annual	4	0.04
NO_2[a]	Annual	2.5	0.03

[a]Assumed 75% of NO_x is NO_2 per EPA guidance.

Table 5-13: Comparison of Maximum Modeled Concentrations of Pollutants to Vegetation Screening Concentrations

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m³)	Background Concentration[g] (µg/m³)	Total Concentration[a] (µg/m³)	Vegetation Screening Concentrations[f] (µg/m³)		
					Sensitive	Intermediate	Resistant
SO_2	1-Hour	24	23	47	917	-	-
	3-Hour	13	21	34	786	2,096	13,100
NO_2	4-Hour	176[b]	66[c]	242	3,760	9,400	16,920
	8-Hour	176[b]	66[c]	242	3,760	7,520	15,404
	Annual	0.8	19	20	-	94	-
CO	1-Week	73[e]	1,840[d]	1,913	1,800,000	-	1,800,000

[a]Total concentration = maximum modeled facility concentration + background concentration.
[b]Maximum modeled concentration conservatively based on 1-hour averaging period.
[c]Maximum background concentration conservatively based on 1-hour averaging period.
[d]Maximum background concentration conservatively based on 8-hour averaging period.
[e]Maximum modeled concentration conservatively based on 8-hour averaging period.
[f]Screening concentrations found in Table 3.1 of "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA, 1980).
[g]High second-high short term and maximum annual average concentrations presented for all pollutants.
(-) No screening concentration available.

Table 5-14: VISCREEN Maximum Surrounding Area Visual Impacts

Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E[a]		Contrast[b]	
					Criteria	Plume	Criteria	Plume
Inside Class I Area (Kalmiopsis Wildlife Refuge)								
Sky	10	162	110	6	2.00	0.010	0.05	0.000
Sky	140	162	110	6	2.00	0.003	0.05	-0.000
Terrain	10	162	110	6	2.00	0.024	0.05	0.000
Terrain	140	162	110	6	2.00	0.007	0.05	0.000
Inside Surrounding Area								
Sky	10	25	28.6	144	2.00	1.041	0.05	0.015
Sky	140	25	28.6	144	2.00	0.353	0.05	-0.016
Terrain	10	0	1.0	168	2.00	1.866	0.05	0.018
Terrain	140	0	1.0	168	2.00	0.562	0.05	0.018

[a]Color difference parameter (dimensionless).
[b]Visual contrast against background parameter (dimensionless).

Figure 5-1: Facility Site Plan (South Dunes Station)

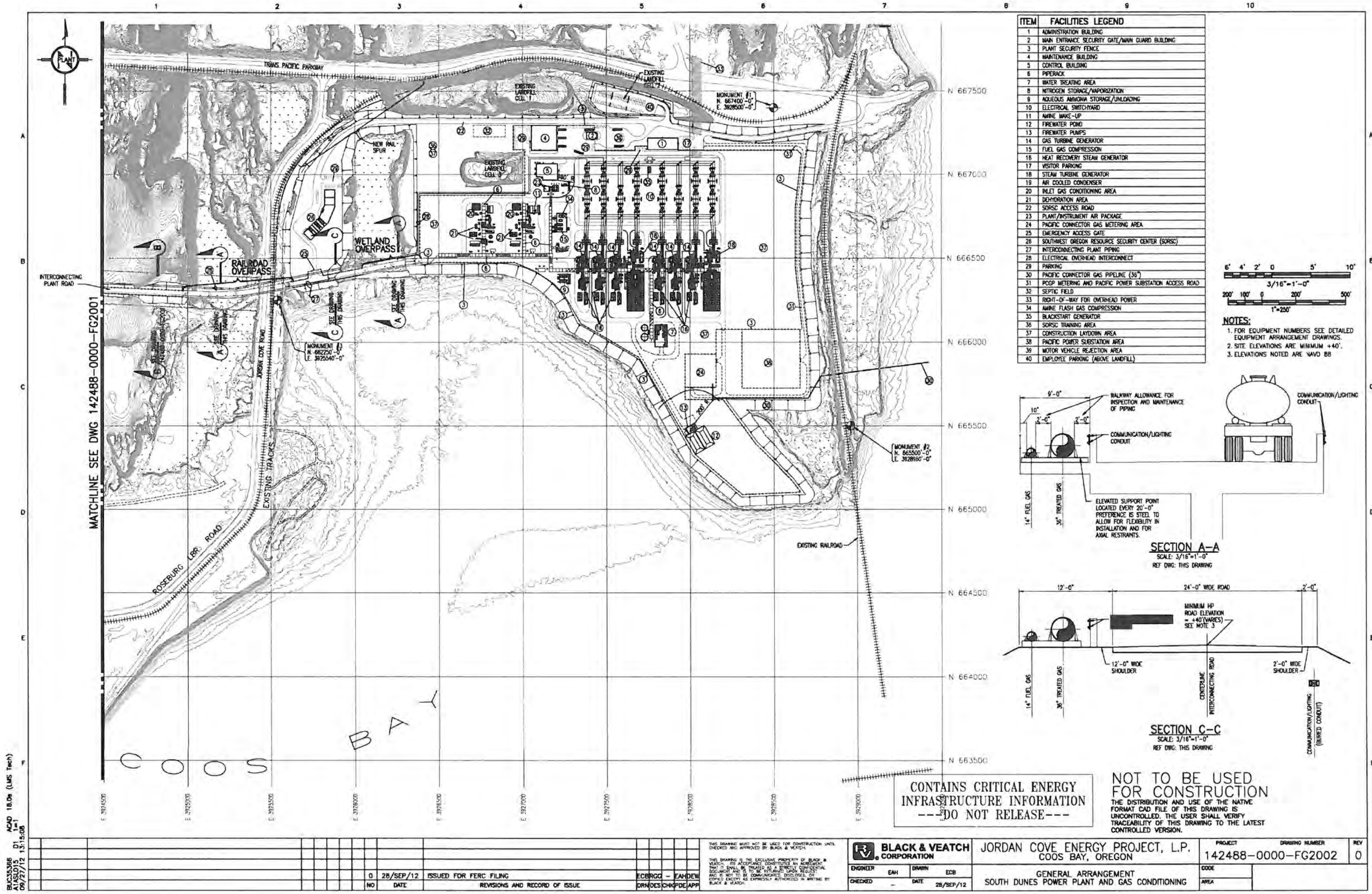


Figure 5-2: Facility Site Plan (Liquefaction Area)

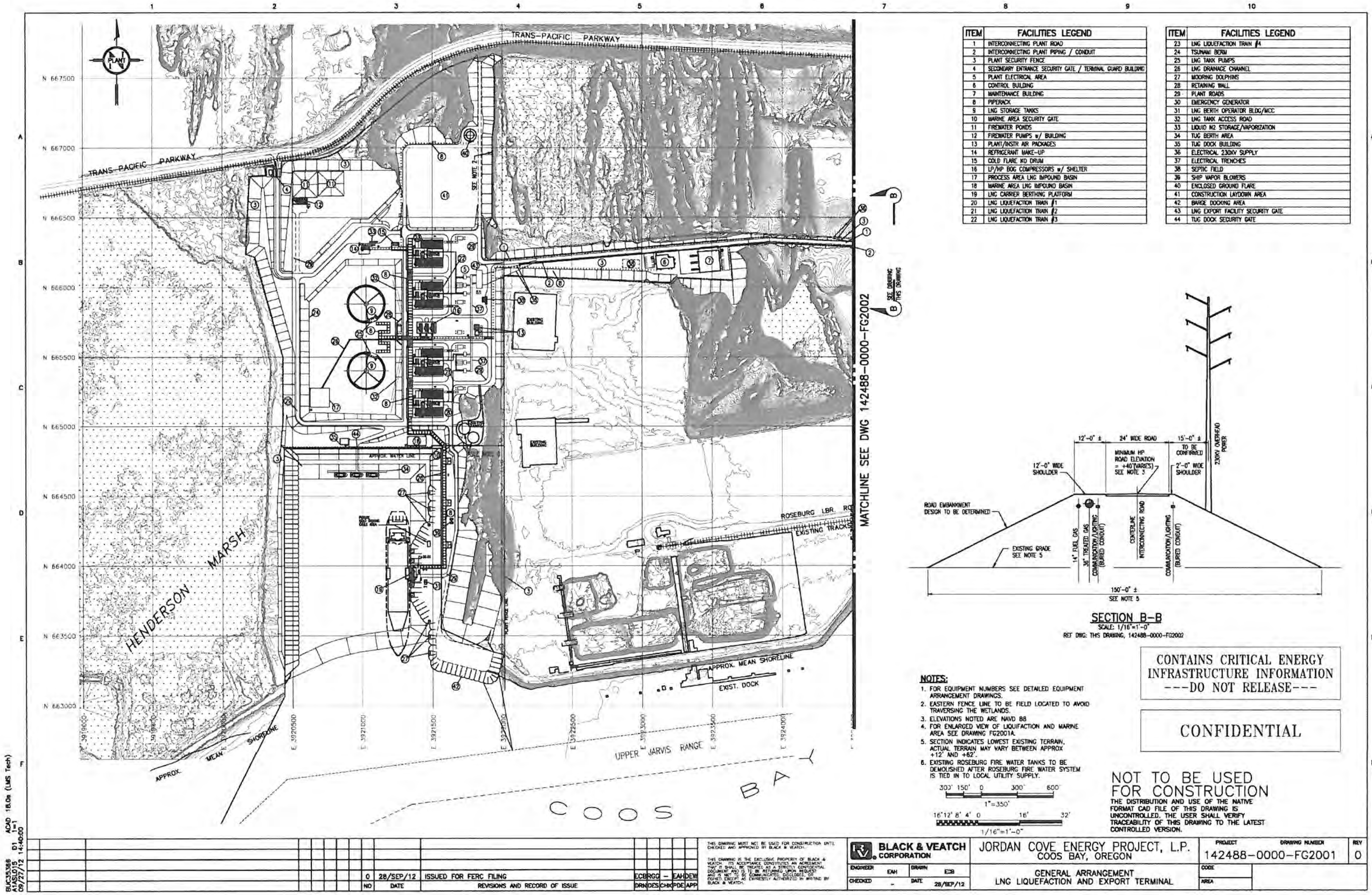


Figure 5-3: Facility Buildings and Stacks for Downwash Analysis

Figure 5-4: Modeled Receptor Grid (Near Grid)

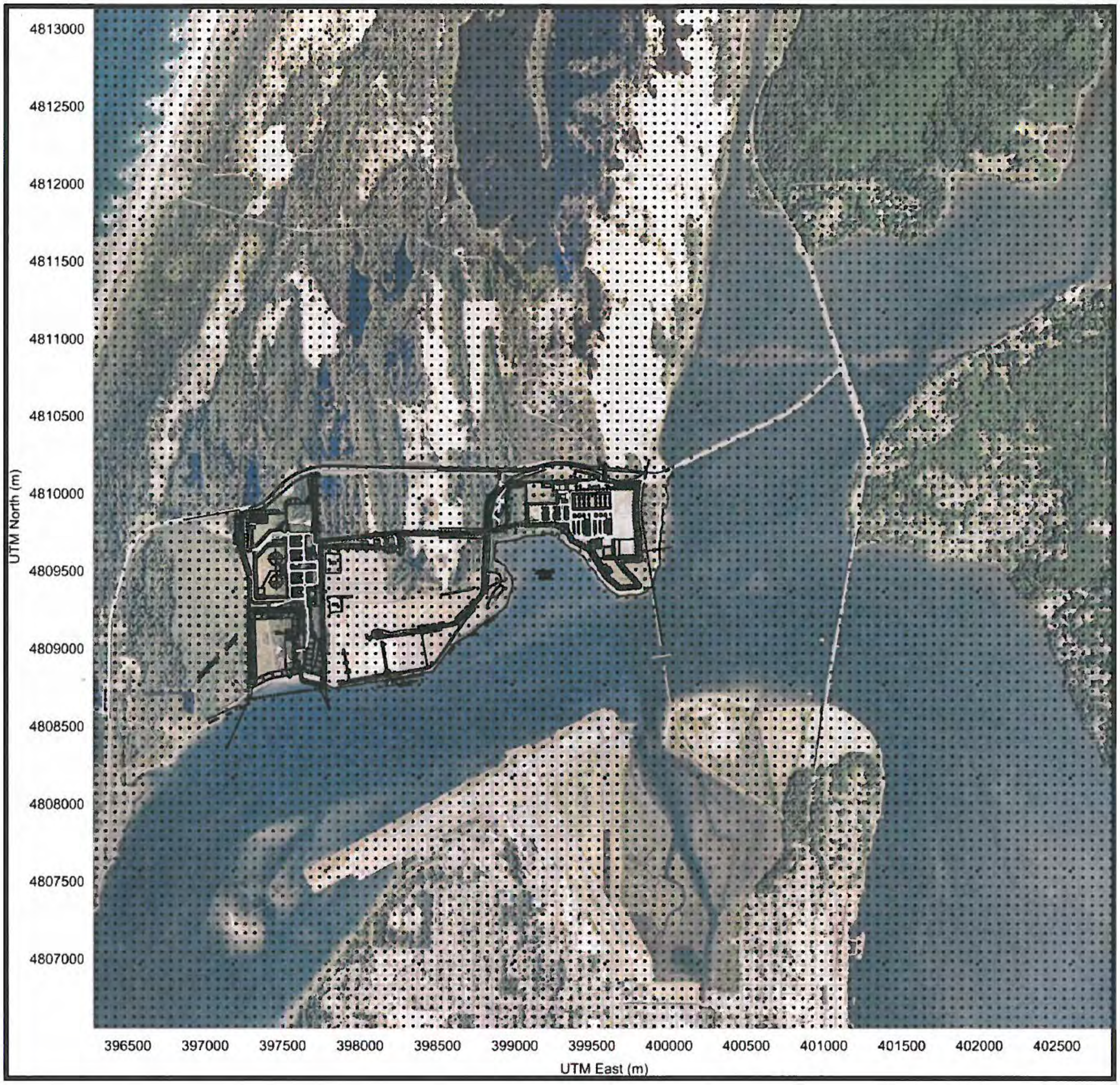


Figure 5-5: Modeled Receptor Grid (Far Grid)

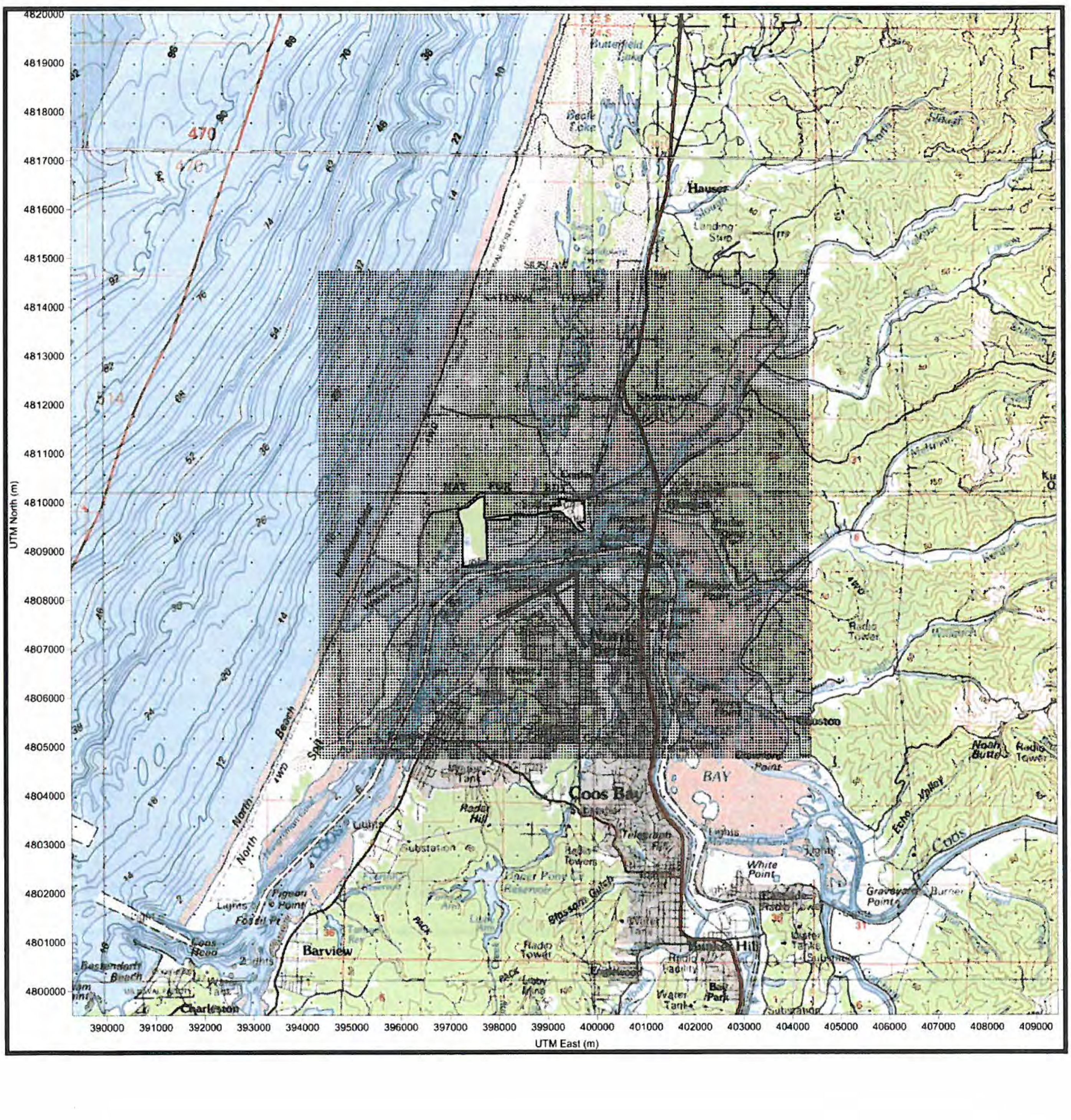


Figure 5-6: Maximum Modeled 1-Hour NO_2 Impacts
(Concentrations in ug/m^3)

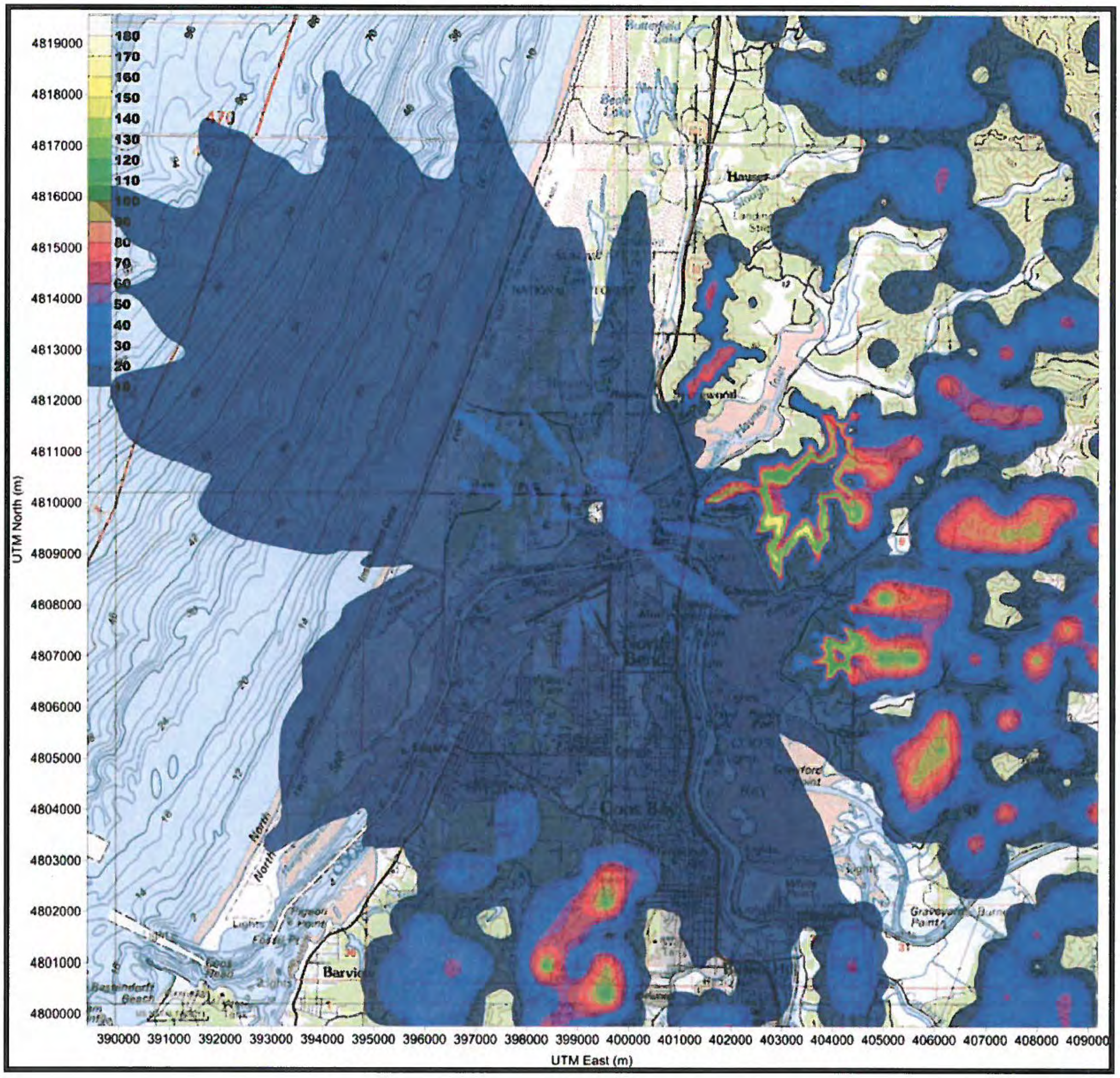


Figure 5-7: Maximum Modeled Annual NO_2 Impacts
(Concentrations in ug/m^3)

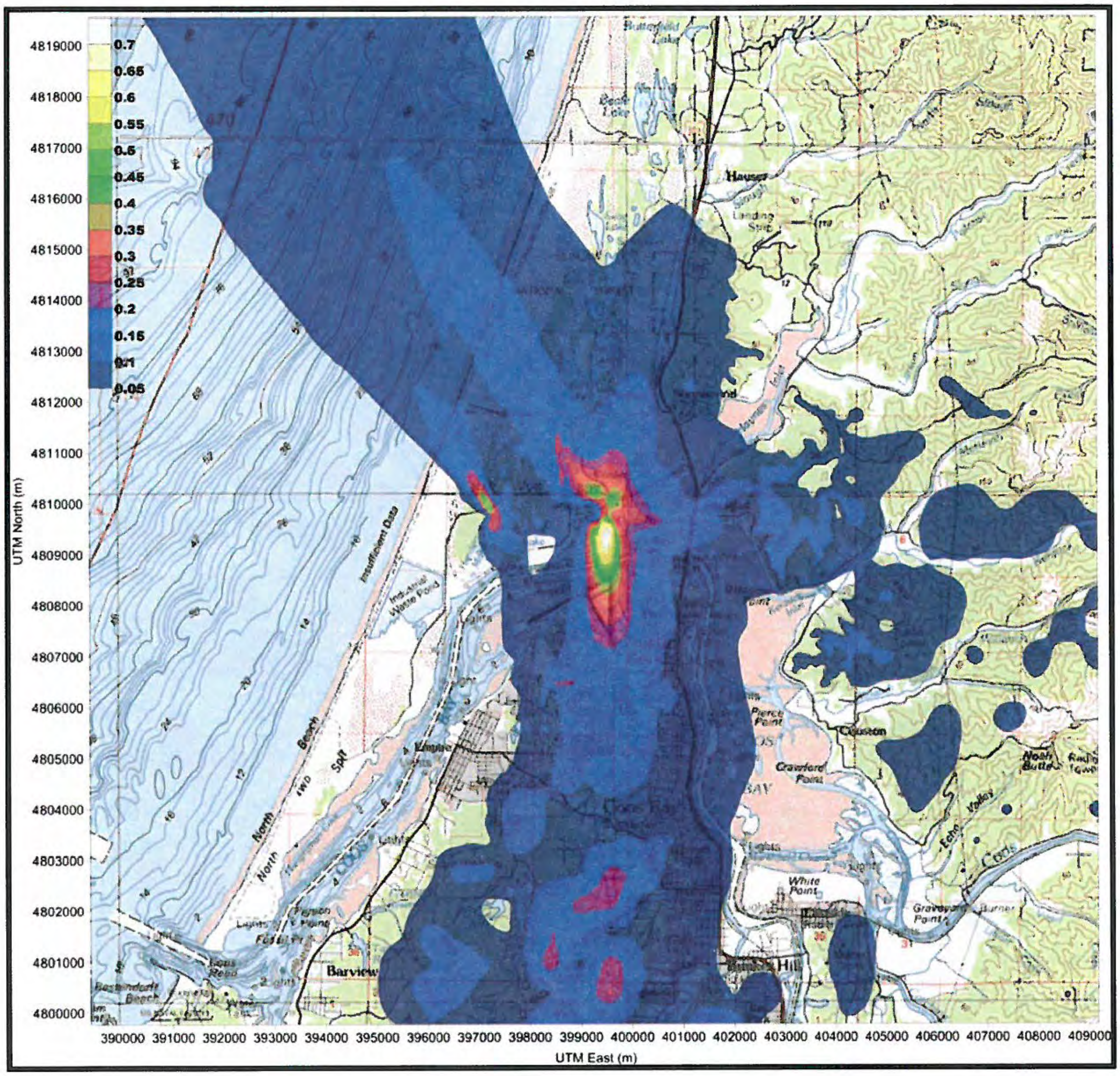


Figure 5-8: Maximum Modeled 1-Hour SO_2 Impacts

(Concentrations in ug/m^3)

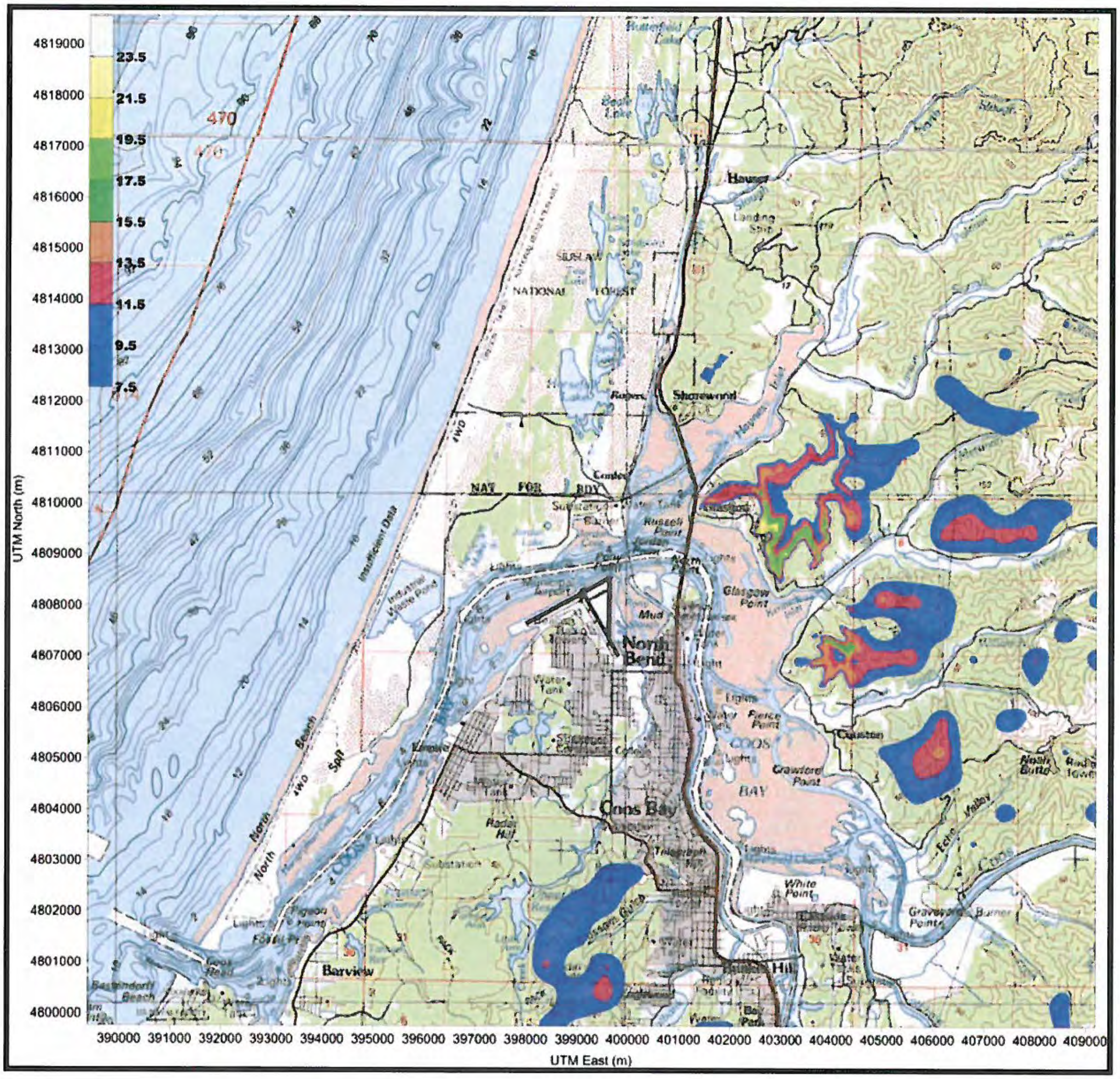


Figure 5-9: Maximum Modeled 3-Hour SO_2 Impacts

(Concentrations in ug/m^3)

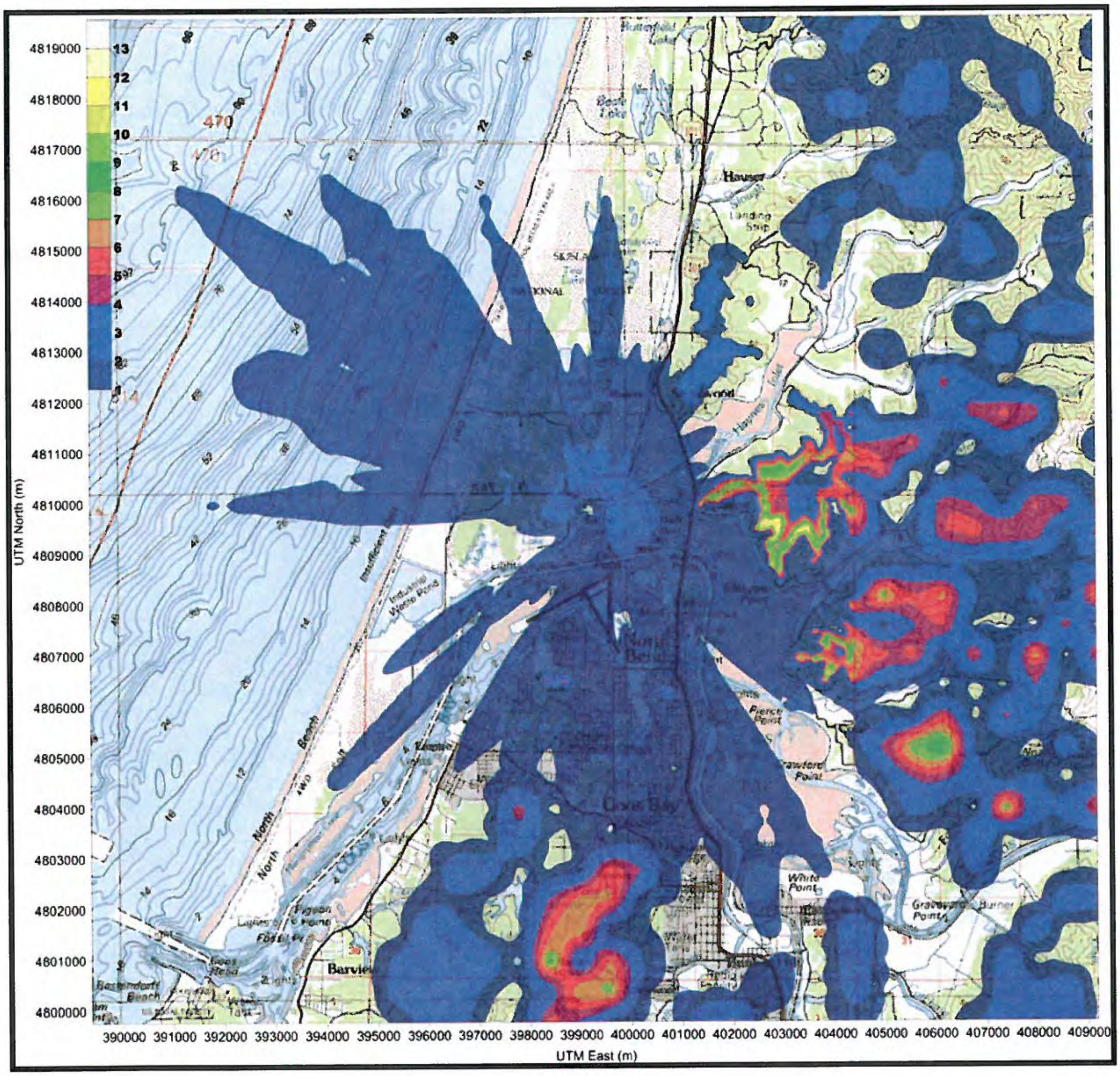


Figure 5-10: Maximum Modeled 24-Hour SO_2 Impacts
(Concentrations in ug/m^3)

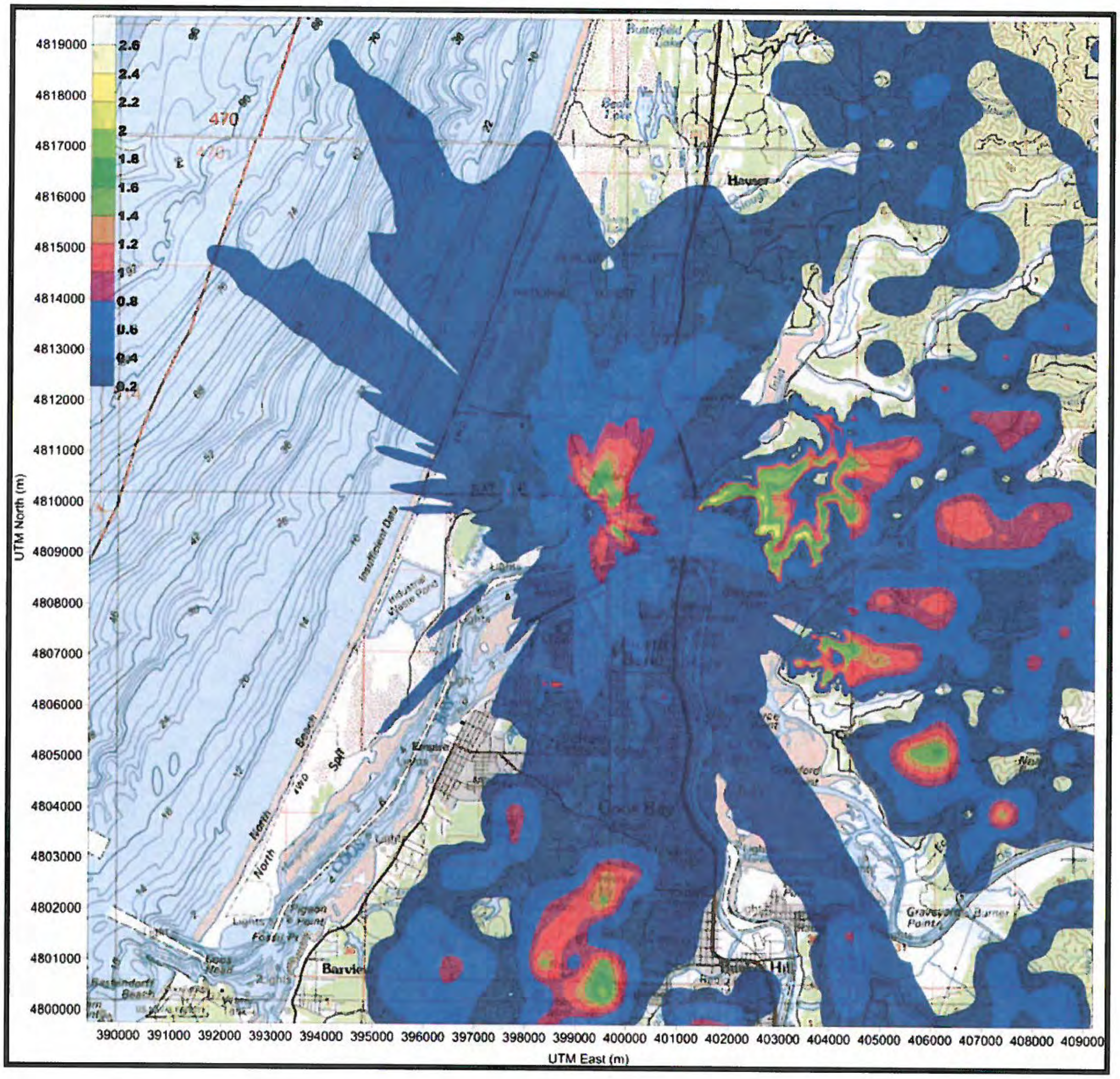


Figure 5-11: Maximum Modeled Annual SO_2 Impacts
(Concentrations in ug/m^3)

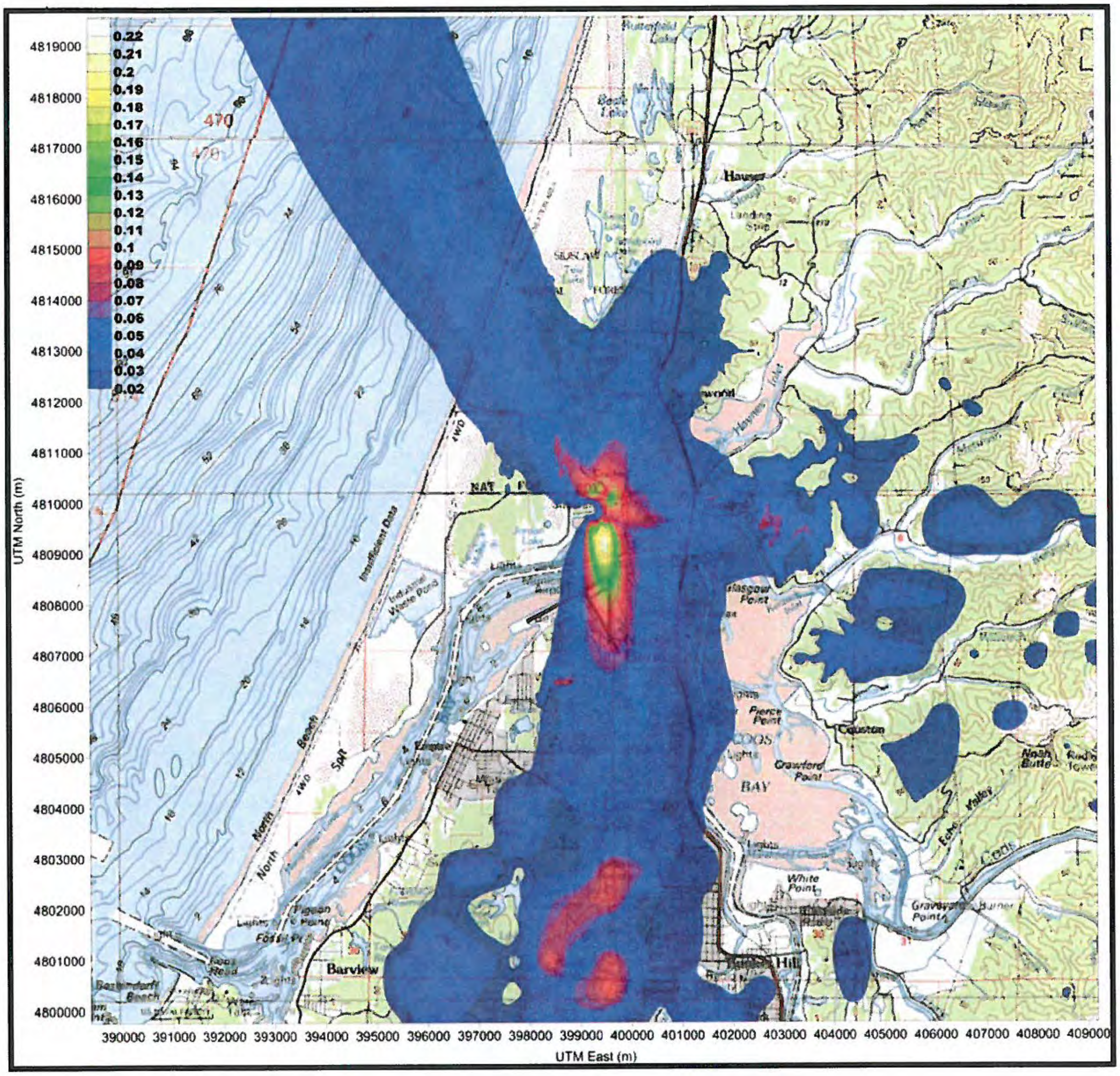


Figure 5-12: Maximum Modeled 24-Hour PM-10 Impacts
(Concentrations in ug/m^3)

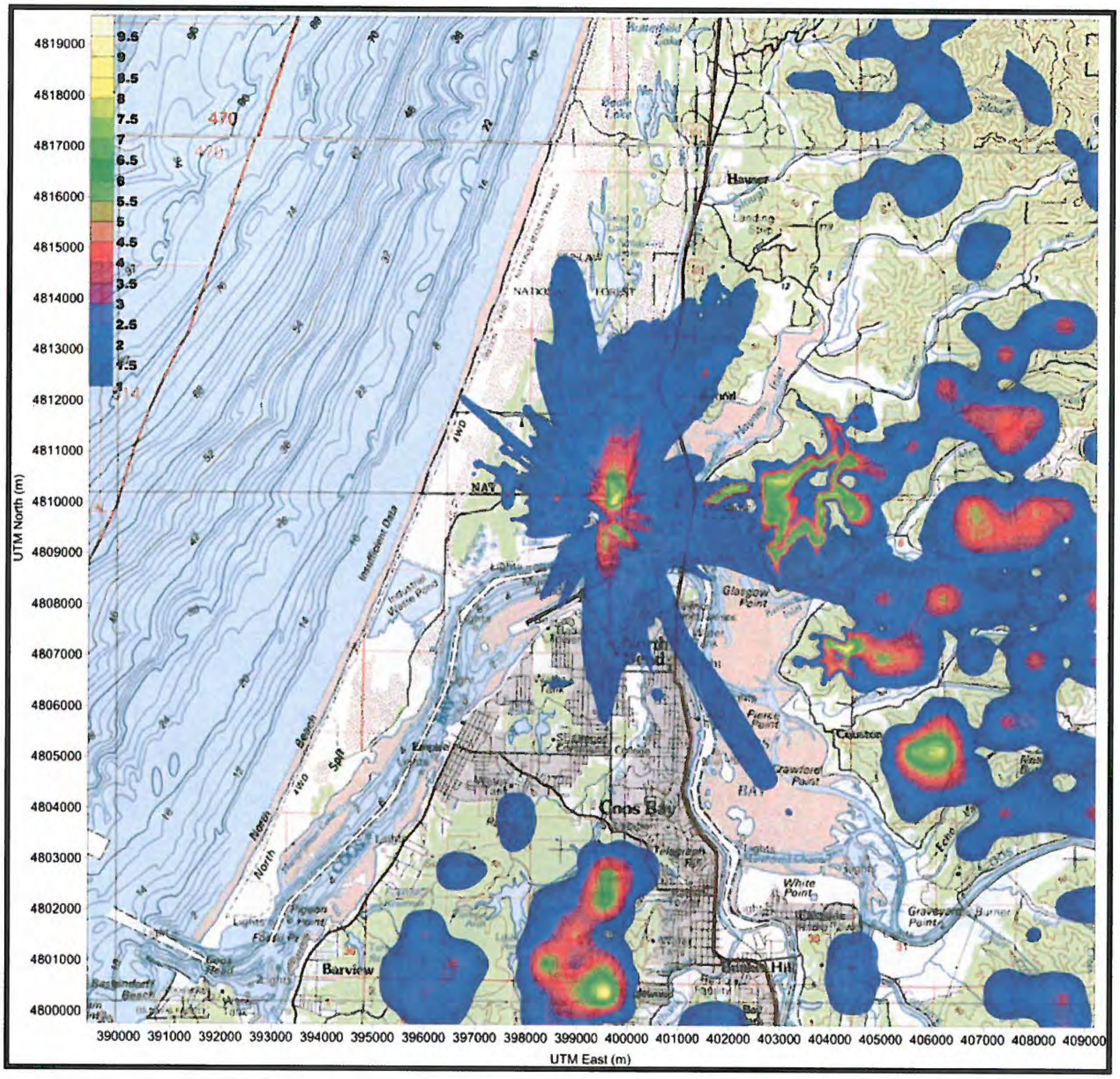


Figure 5-13: Maximum Modeled 24-Hour PM-2.5 Impacts
(Concentrations in ug/m^3)

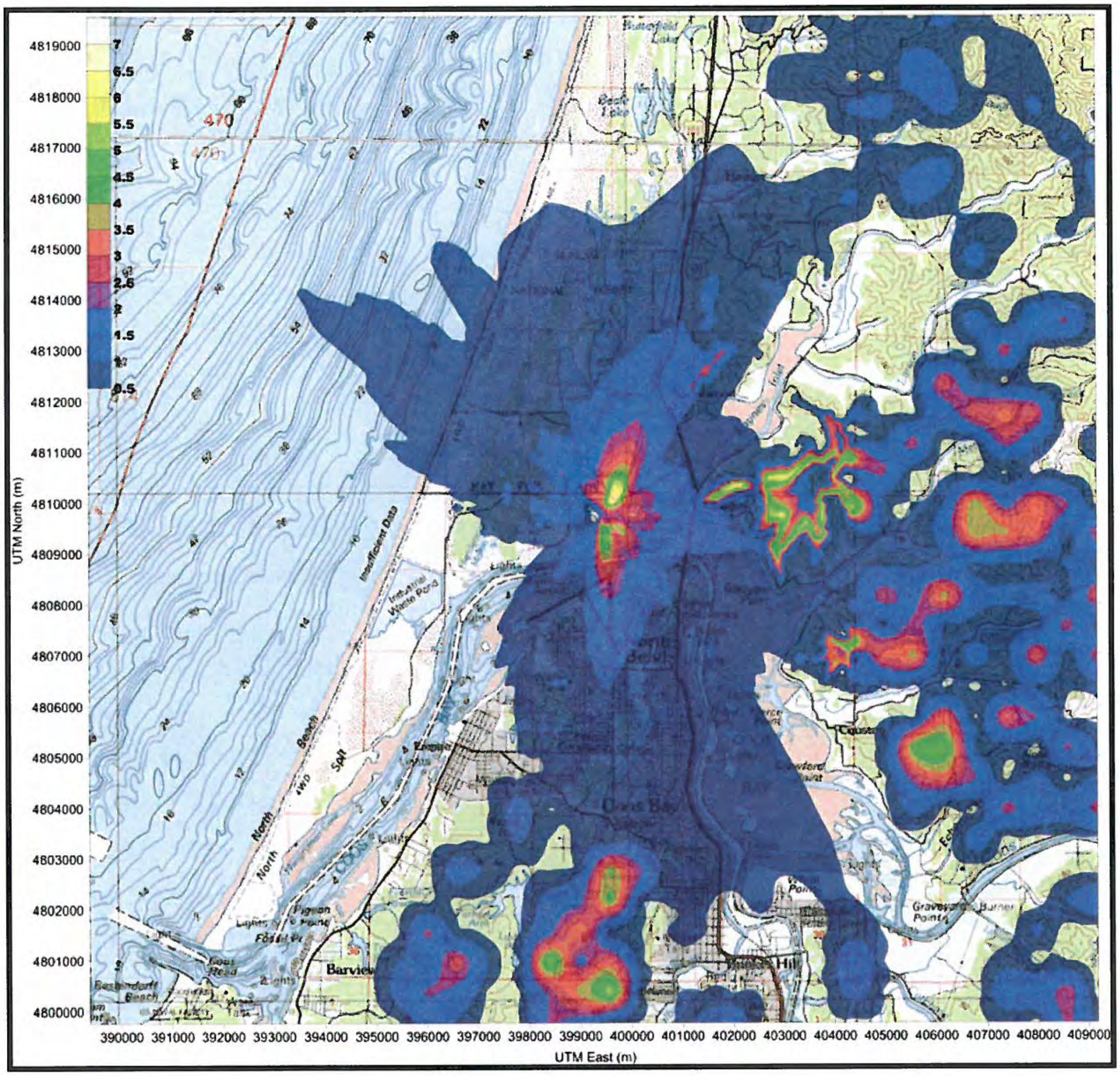


Figure 5-14: Maximum Modeled Annual PM-2.5 Impacts
(Concentrations in ug/m^3)

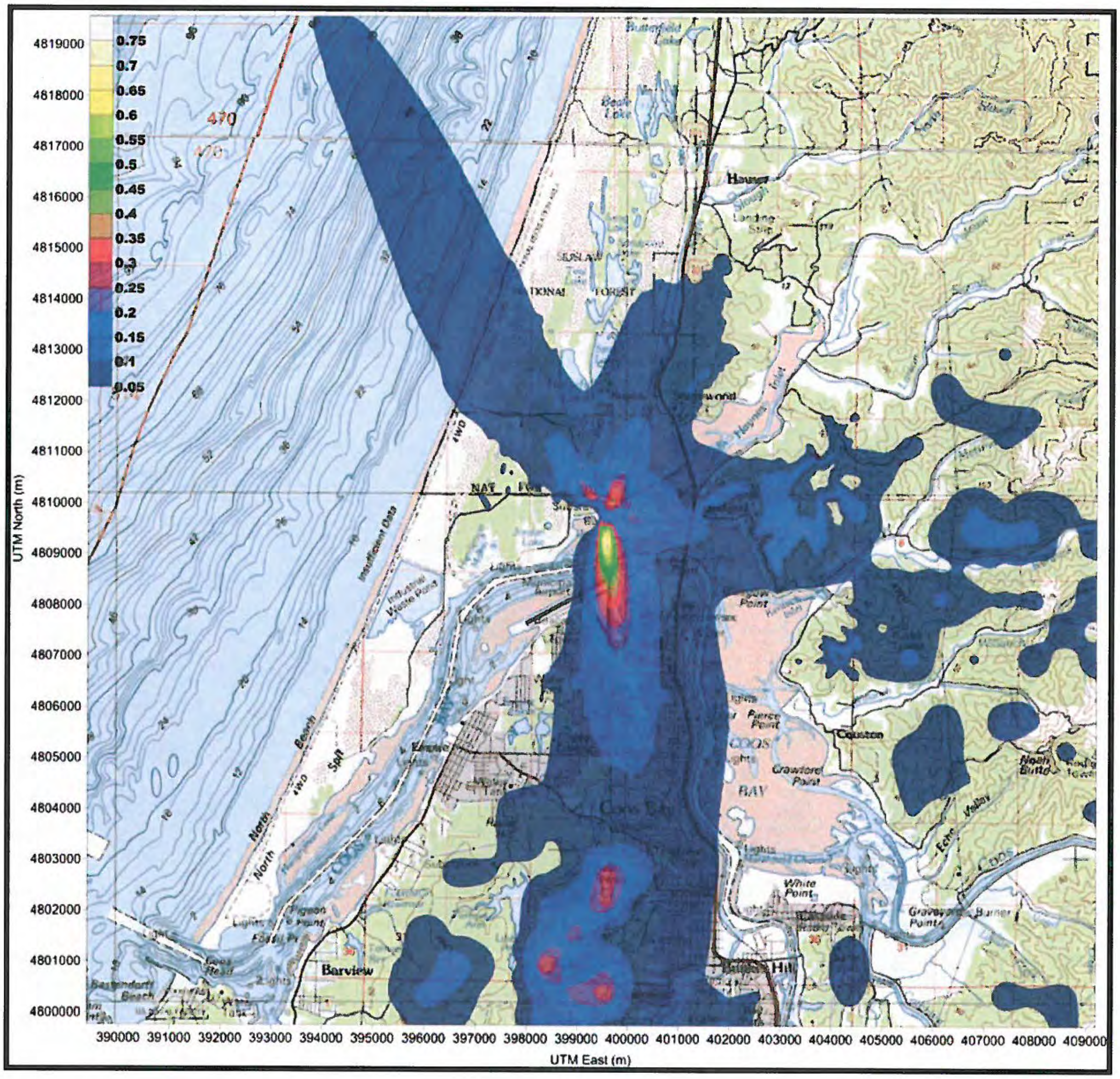


Figure 5-15: Maximum Modeled 1-Hour CO Impacts
(Concentrations in ug/m^3)

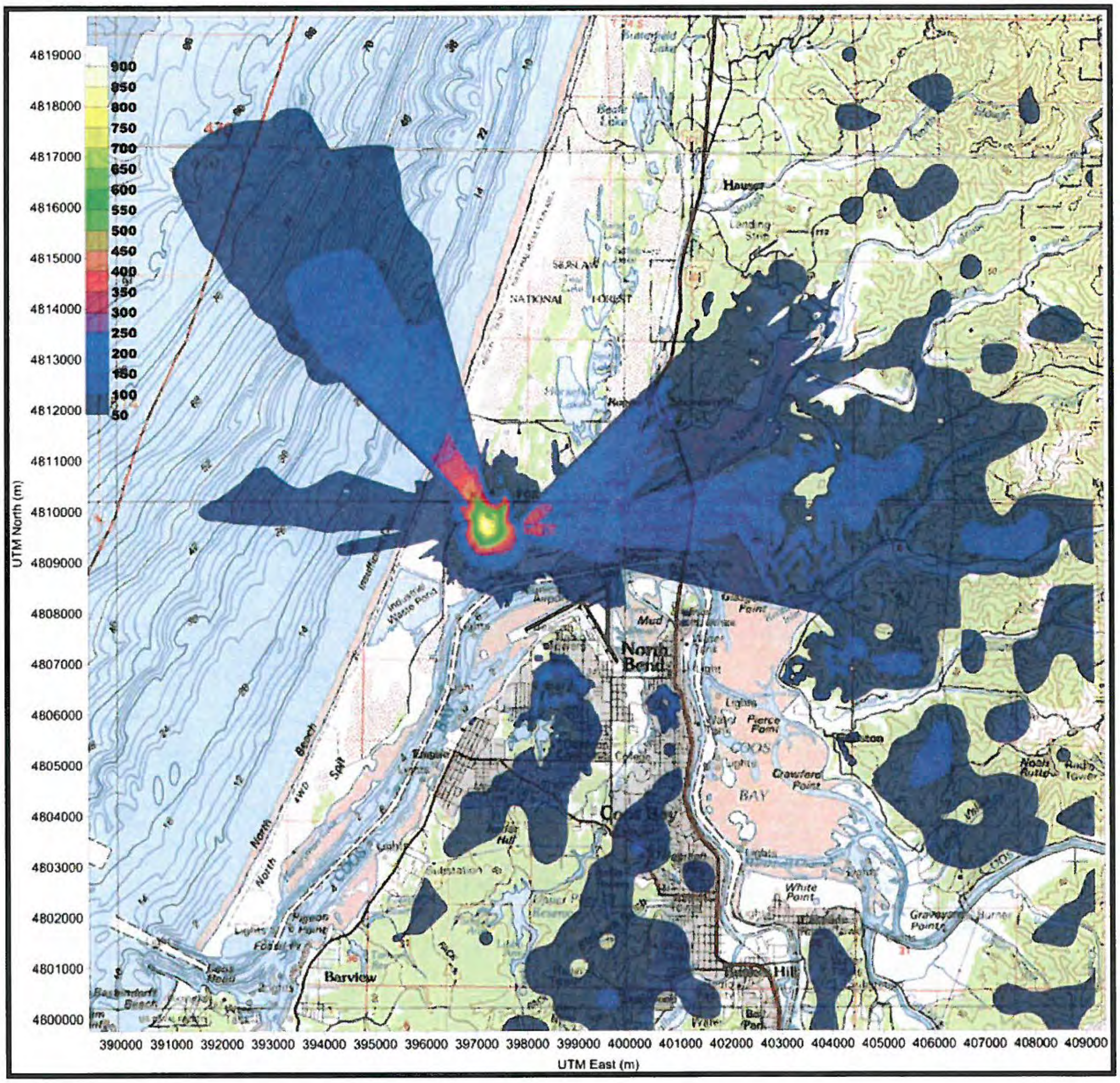


Figure 5-16: Maximum Modeled 8-Hour CO Impacts
(Concentrations in ug/m^3)

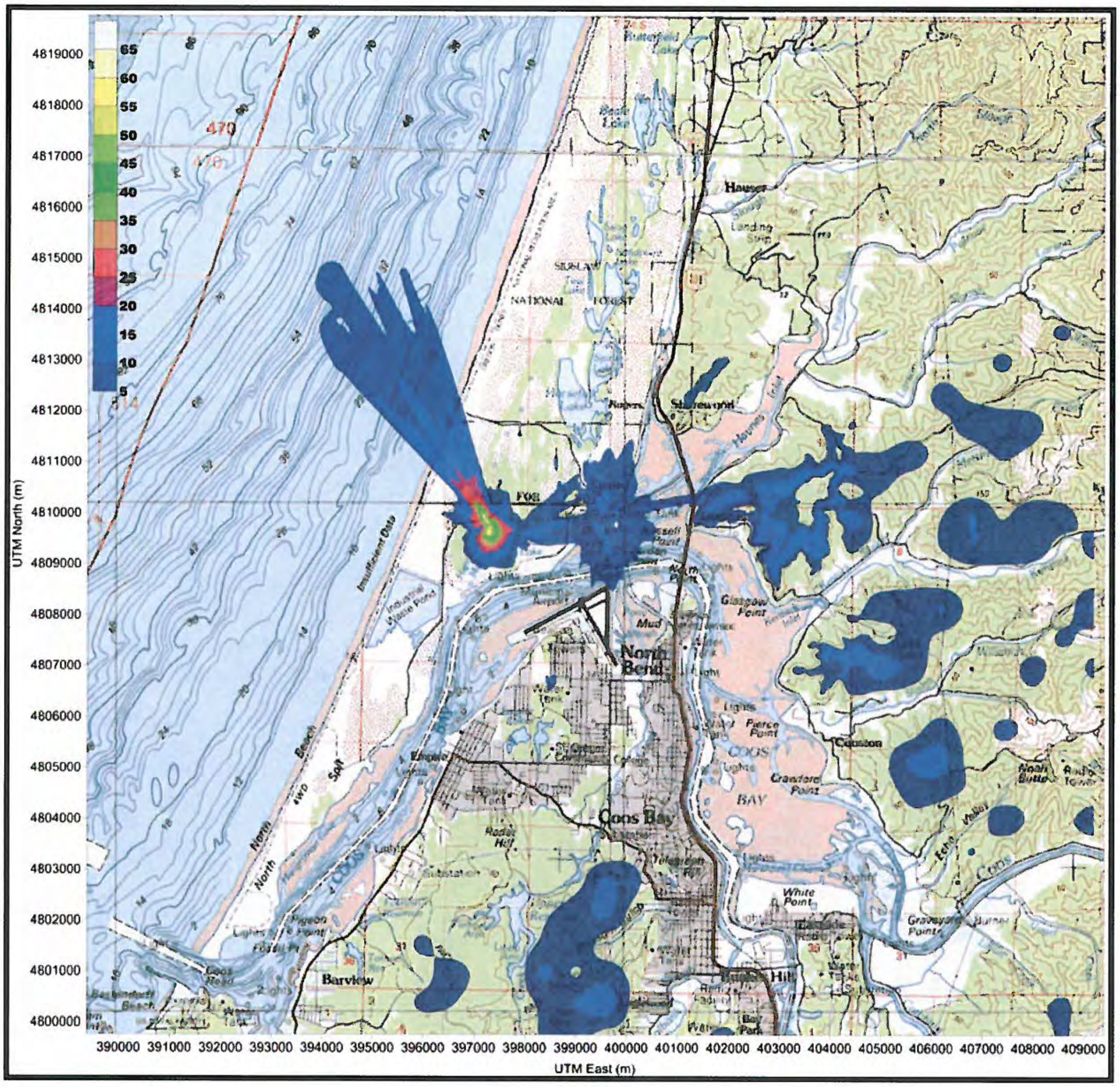
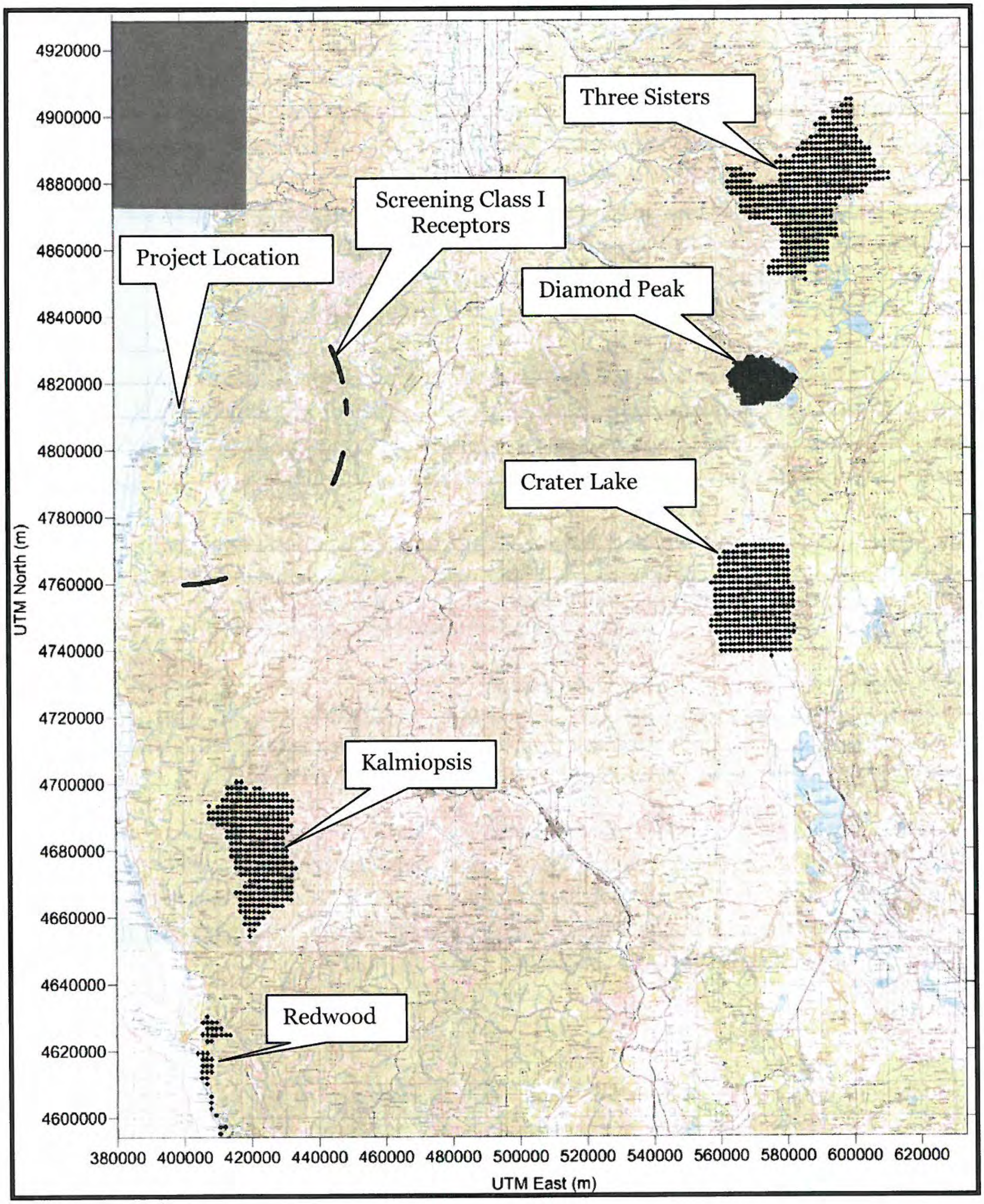


Figure 5-17: Modeled Class I Screening Receptors and Class I Locations



6.0 ENVIRONMENTAL JUSTICE

6.1 Introduction

This environmental justice (EJ) analysis is designed to determine whether the construction and operation of the proposed Project would have a significant adverse and disproportionate effect on an "environmental justice community." The concept of performing an EJ analysis for the Project is related to the issuance of Executive Order 12898 ("EO"), entitled Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations (February 11, 1994). The EO requires federal agencies to consider disproportionately high adverse human health or environmental effects of their actions on minority and low-income populations. Pursuant to the EO, EJ considerations are taken into account during PSD review.

The focus of an environmental justice analysis is the determination of whether the construction and operation of a proposed facility will have both adverse and disproportionately high impacts on an EJ Community. The U.S. EPA Region 2 Interim Environmental Justice Policy (U.S. EPA, 2000) (Interim Policy) provides guidance in making this determination.

The glossary that is included in the Interim Policy defines an "EJ Community" as:

> A minority and/or low income area suffering a disproportionate and adverse environmental burden as a result of the unfair or unequal development, implementation, or enforcement of environmental laws, regulations or policies.

An "adverse environmental burden" is defined as:

> When there is an acknowledged health or welfare standard for the burden in question, the burden is adverse only when it exceeds that standard. When there is no standard, the decision is based on additional site-specific analysis.

Currently, neither Oregon nor EPA Region 10 has formal guidance for identifying potential EJ Communities of Concern (COCs). Therefore, the methodology used in this analysis is based on the National guidance utilized by the U.S. EPA and located in the Council on Environmental Quality's (CEQ) Environmental Justice: Guidance under the National Environmental Policy Act (CEQ, 1997) (National Policy).

6.2 Methodology

The environmental justice analysis contained within this Section is based on the EO and guidance from the Interim Policy and National Policy. According to the Interim Policy, an EJ Assessment consists of the following six steps:

1. Delineate the boundaries of the Community of Concern.
2. Compare the demographics of the community to a statistical reference.
3. Determine whether the community is either minority or low income.
4. Develop a comprehensive environmental load profile for any community that is either minority or low income.
5. Assess whether the burden is disproportionately high or adverse.
6. Summarize and report the results.

Steps one through three must be completed first. If a minority or low-income community is identified based on guidelines set forth by the Interim Policy, then steps four through six must be completed.

6.3 Determination of Environmental Justice Communities

For this analysis, U.S. Census 2010 town boundaries and census tracts were used as boundaries for COCs in the vicinity of the project (i.e., three (3) miles). Pursuant to the National Policy, a community is a potential EJ COC if it is either minority or low-income. The National Policy defines the term "minority" for EJ purposes to include Hispanics, Asian Americans and Pacific Islanders, African Americans, American Indians and Alaskan Natives. A low-income community as defined by the National Policy is below the poverty level as established by the U.S. Census. A summary of the minority and low-income data for the Cities of Coos Bay and North Bend, Coos County, and the State of Oregon is shown in Table 6-1.

Per the National Policy, a geographic population is considered a minority population for EJ analysis purposes when either the minority population exceeds 50% of the population for an affected area or when the minority population of an affected area is meaningfully greater than the minority population of the general population. For this analysis, meaningfully greater is assumed to be 20% and the general population is considered to be the State of Oregon. Similar guidelines were used for identifying potential EJ COCs based upon low-income criteria. An area was considered to be low-income if the percentage of population below the poverty thresholds established by the U.S. Census is 20% greater than the reference population (i.e., the State of Oregon). In other words, the cities of Coos Bay and North Bend would be considered as an EJ COC if either the percent minority or persons in poverty exceed the statewide averages by 20% or more or if the percentages exceed 50%, regardless of the statewide average.

Based upon the methodology described above and on the Census data in Table 6-1, a geographic area could be considered an EJ COC if its minority population exceeds 25.8% and/or its low-income population exceeds 17.8%. The cities of Coos Bay and North Bend have minority and low-income populations less than these thresholds, and thus, would not be considered as EJ COCs on a citywide basis. However, per the National Guidance, the appropriate geographic extent for an EJ COC can be based upon an individual census tract in order to avoid the possibility to artificially dilute a minority or low-income population using a larger geographic area (i.e., entire city or county).

Based upon an assessment of Census tracts within a three mile study radius of the JCEP there are three tracts comprised of eleven census block groups that exceed the EJ threshold criteria for low-income population and/or minority population. A map identifying these areas is shown in Figure 6-1. Thus, these areas can considered to be EJ COCs for the JCEP Project for the purposes of an EJ assessment pertaining to offsite air quality impacts.

6.4 EJ Area Impact Assessment

To evaluate the existing environmental load profile and determine the potential impacts of the proposed Project within the potential EJ COC area, analyses related to air quality were undertaken.

Air dispersion modeling was used to determine which potential EJ COCs have the potential to be significantly impacted by the Project. In order to identify those new sources with the potential to significantly affect air quality, U.S. EPA has adopted ambient air quality standards (NAAQS) for the protection of human health. They have also established significant impact levels (SILs) as a screening level. If a project's impacts are found to be below the SILs, then the project will have an insignificant impact on air quality. If the project's air quality impacts are shown to be insignificant, then there will be no disproportionately high or adverse burden on communities in the area.

The Project was modeled in accordance with the procedures documented in the ODEQ approved Air Quality Modeling Protocol, and maximum calculated Project impacts were determined for various pollutants and averaging periods. Table 6-2 presents the maximum modeled impacts of CO, SO_2, PM-10, PM-2.5 and NO_2 for comparison with SILs that have been established by U.S. EPA. Table 6-2 also presents the sum of maximum Project impacts and background air quality levels so that total modeled concentrations can be compared to the corresponding NAAQS.

All modeled Project impacts, except for 24-hour and annual average PM-2.5, 24-hour PM-10, 1-hour SO_2, and 1-hour NO_2 impacts, are below SILs. The sum of maximum calculated impacts and background levels are below the corresponding NAAQS for all pollutants and averaging periods. Therefore, the Project is not considered to have any adverse air quality impacts. In addition, the Project will be located in an area currently designated as attainment for all of the NAAQS and thus, is not located in area with an existing environmental load burden.

Figures 6-2 through 6-6 provide isopleths plots of maximum modeled Project impacts for each pollutant and averaging period with maximum modeled impacts above the SIL. The outlines of identified EJ COCs and the Project location are also depicted on the plots. The maximum modeled Project impacts are generally modeled to occur at or near to the Project fenceline or located to the east of the facility in elevated terrain and outside of the potential EJ COCs. Therefore, the identified EJ COCs will not receive a disproportionately high share of the maximum Project impacts.

6.5 Evaluation of Toxic Release Inventory Facilities

The U.S. EPA's Office of Prevention, Pesticides, and Toxic Substances internet links to the Toxic Release Inventory (TRI) Community Right to Know – TRI 2011 Data Release was utilized to obtain the most recent 2011 TRI data available for facilities located in Coos County, Oregon. The TRI database provides the yearly emissions/release data for toxic air releases. The TRI data indicates that only one facility in Coos County submitted TRI reports in 2011. The facility is identified as Roseburg Forest Products Plywood and is located in Coquille, Oregon, and approximately 18 miles to the South of the proposed Facility. Thus, there were no reported toxic air emissions within the potential EJ COCs that would contribute to the existing environmental load in the area.

6.6 Environmental Justice Summary

The above analysis shows that three census tracts within a three-mile radius of the Project exceed the U.S. EPA demographic EJ criteria thresholds for minority and/or low-income representation. Therefore, an analysis of potential environmental impacts within the EJ COCs was conducted.

The analysis demonstrates that the Project's potential air emission concentrations are less than the NAAQS within the EJ study area, and therefore are not adverse. Furthermore, the maximum modeled air quality impact locations do not fall within the potential environmental justice areas and thus, are not considered disproportionately high.

Table 6-1: Population Data for Environmental Justice Screening Analysis

Geographic Area	Minority Population (%)	Low-Income Population (%)
State of Oregon	21.5	14.8
Coos County	13.3	16.0
City of Coos Bay	16.6	16.9
City of North Bend	14.2	15.5

Notes: Based upon data obtained from the 2010 U.S. Census.
Minority population includes Hispanics, Asian Americans and Pacific Islanders, African Americans, American Indians and Alaskan Natives.
Low-Income includes population identified as having incomes below the poverty level defined by the U.S. Census.

Table 6-2: Facility Maximum Modeled Concentrations

Pollutant	Averaging Period	Significant Impact Concentration (μg/m3)	NAAQS/ OAAQS (ug/m3)	Maximum Modeled Concentration[a] (μg/m3)	Background Conc. (ug/m3)	Total Conc.[b] (ug/m3)
CO	1-Hour	2,000	40,000	890.3	2,415	3,305
	8-Hour	500	10,000	73.1	1,840	1,913
SO_2	1-Hour	7.8	197	23.8/16.5	22.7	39.2
	3-Hour	25	1,300	13.1/11.0	21.0	32.0
	24-Hour	5	365/262	2.5/2.0	10.5	12.5
	Annual	1	80/52	0.22	4.2	4.4
PM-2.5	24-Hour	1.2	35	7.0/3.9	23.0	26.9
	Annual	0.3	12	0.71/0.80	7.5	8.3
PM-10	24-Hour	5	150	9.3/7.6	55	62.6
NO_2	1-Hour	7.5	188	175.7/92.7	66.4	159.1
	Annual	1	100	0.82	19	19.8

[a]Presented in the form of SIC/NAAQS for short-term standards due to the differing structure of those thresholds.
[b]Represents maximum modeled concentration (NAAQS averaging structure) plus representative background concentration for comparison to the NAAQS/OAAQS.

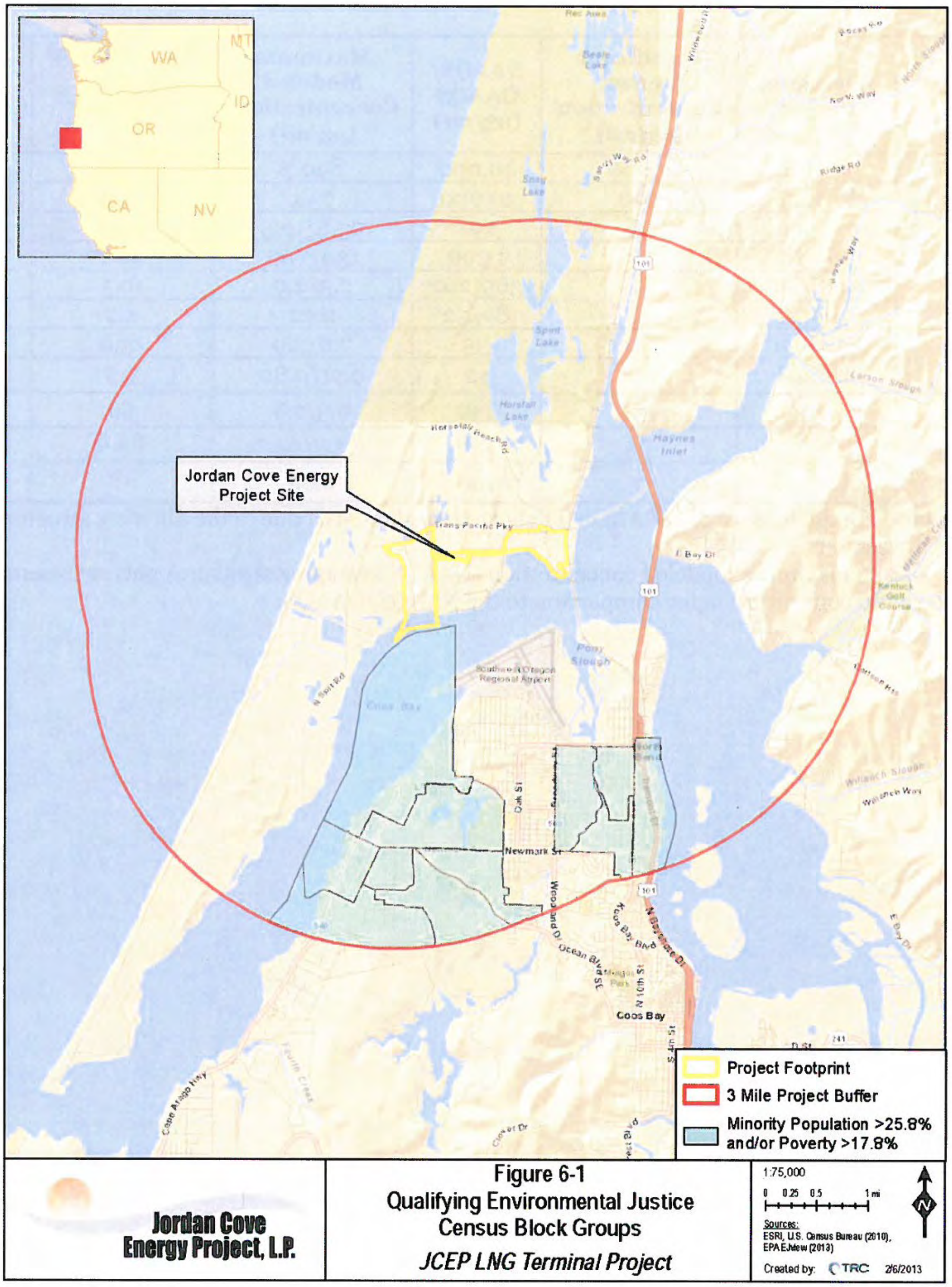


Figure 6-1
Qualifying Environmental Justice Census Block Groups
JCEP LNG Terminal Project

Figure 6-2: Maximum Modeled 1-Hour NO2 Impacts

(Concentrations in ug/m^3)

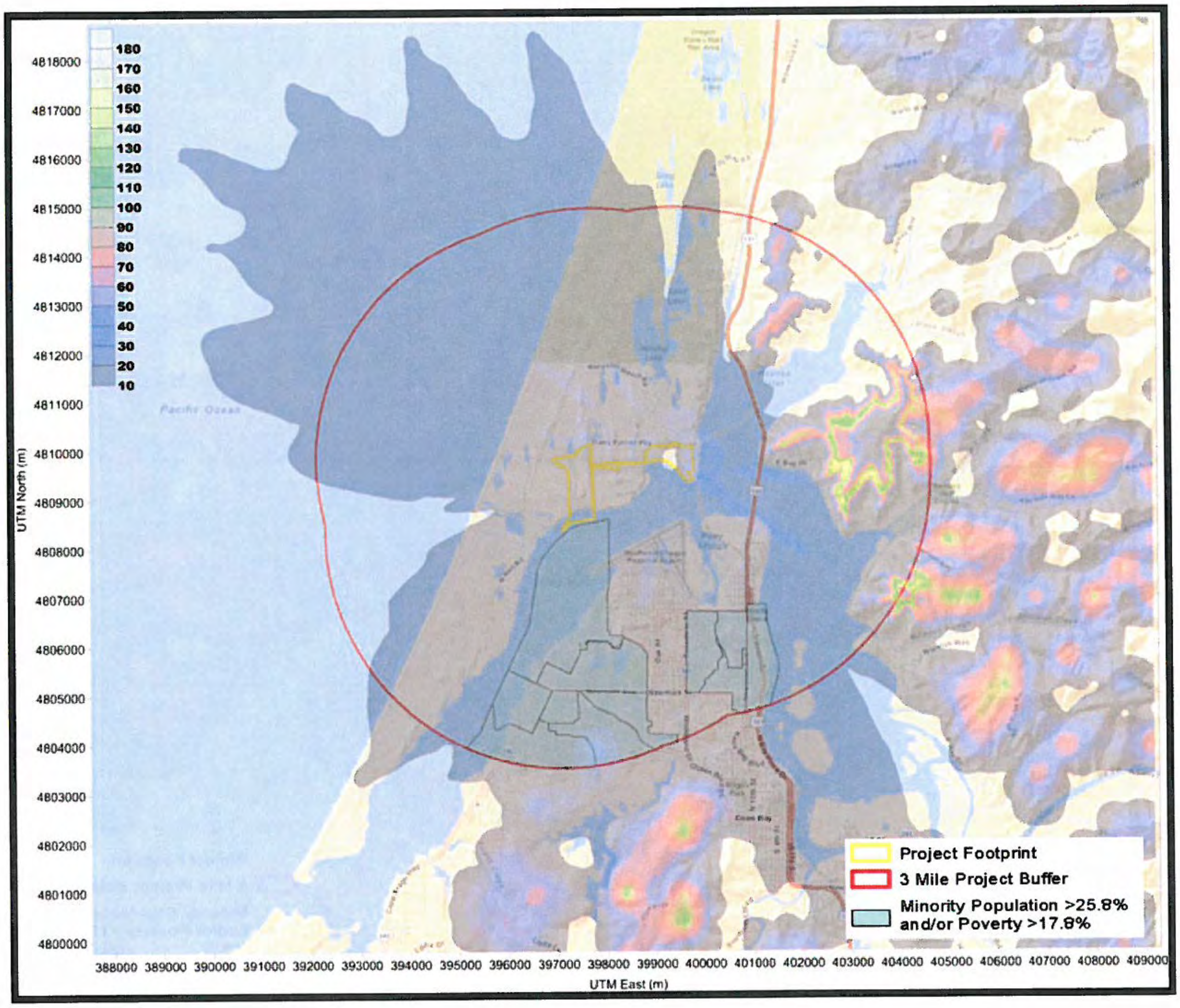


Figure 6-3: Maximum Modeled 1-Hour SO2 Impacts
(Concentrations in ug/m^3)

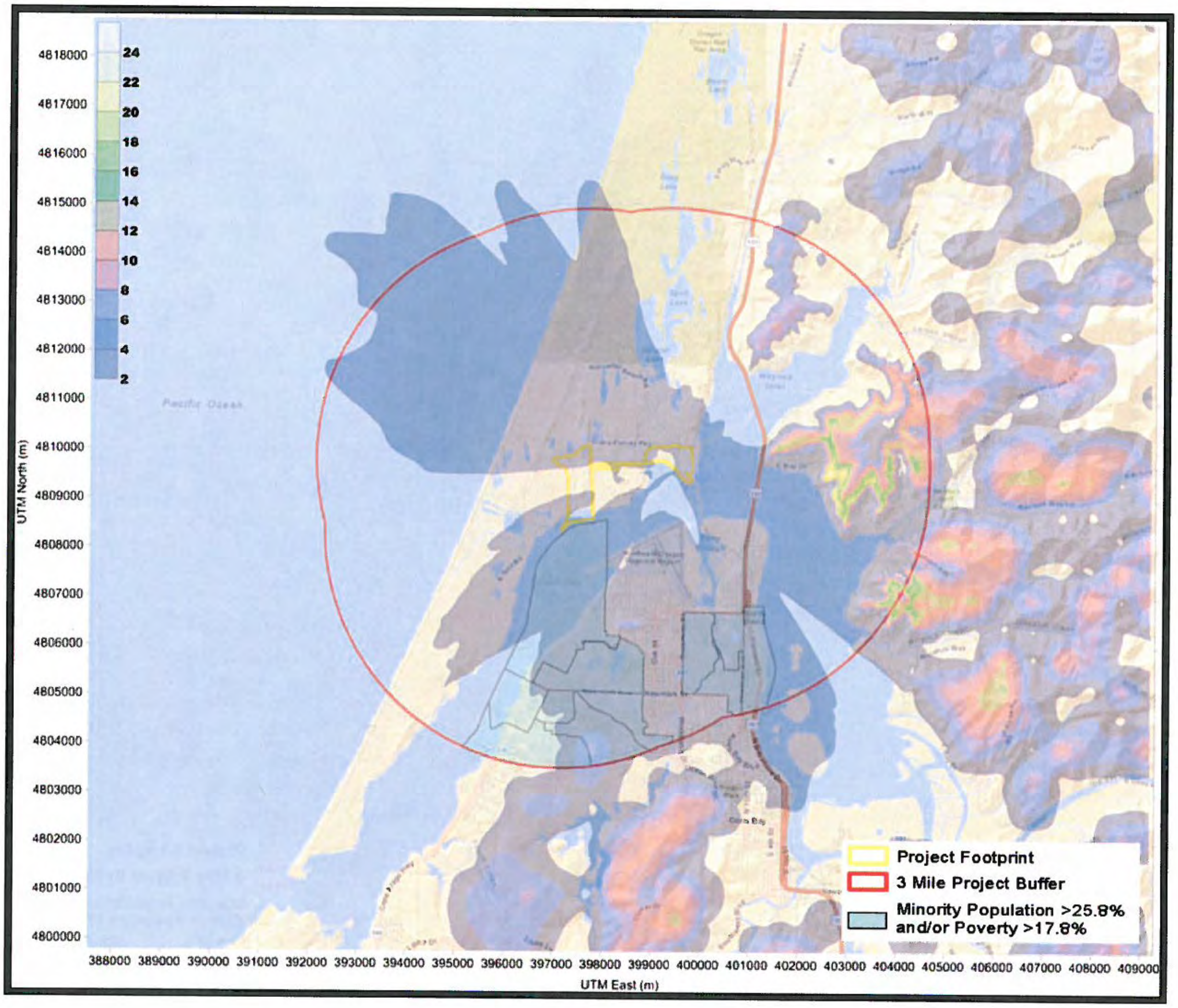


Figure 6-4: Maximum Modeled 24-Hour PM-10 Impacts

(Concentrations in ug/m^3)

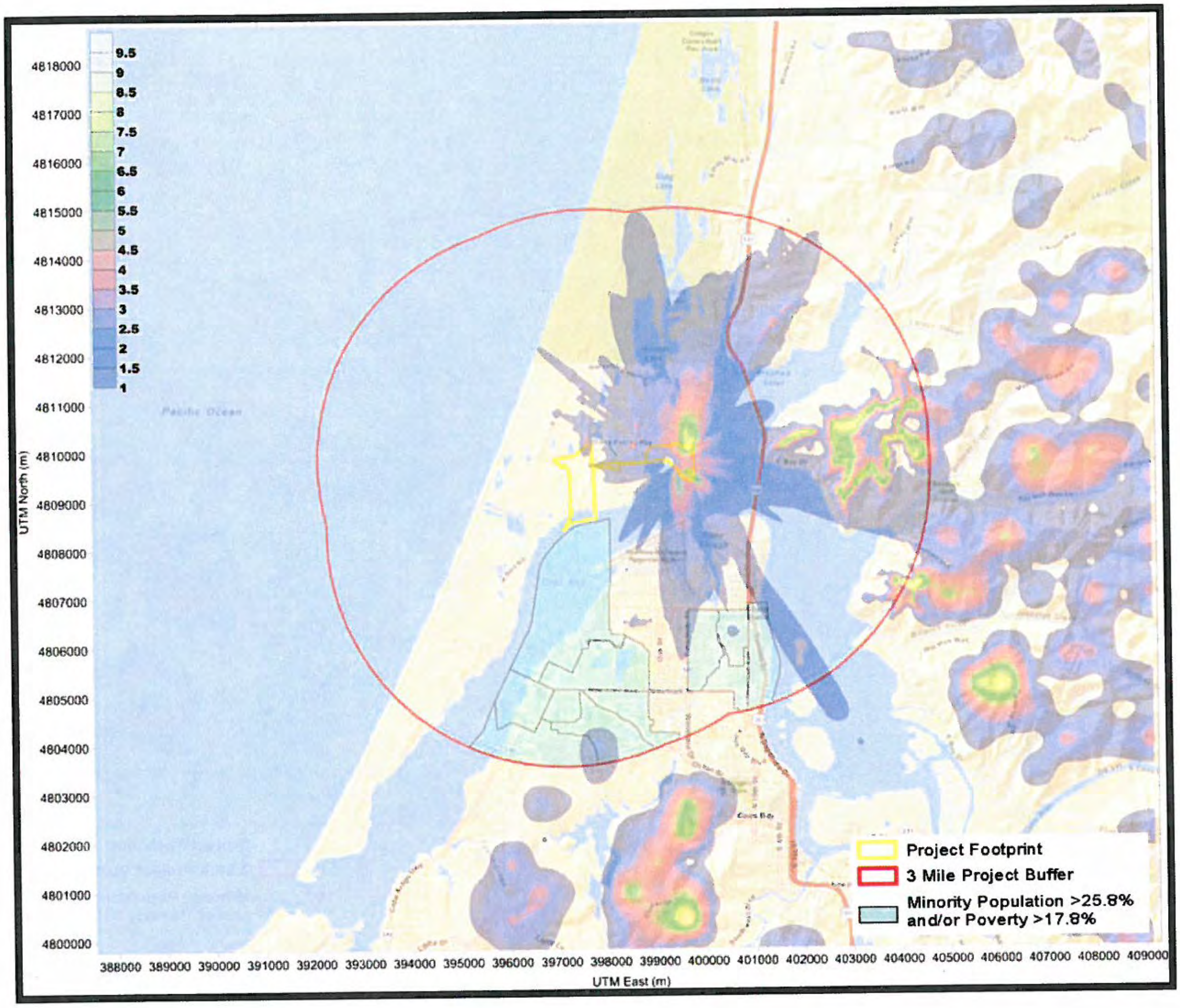


Figure 6-5: Maximum Modeled 24-Hour PM-2.5 Impacts
(Concentrations in ug/m^3)

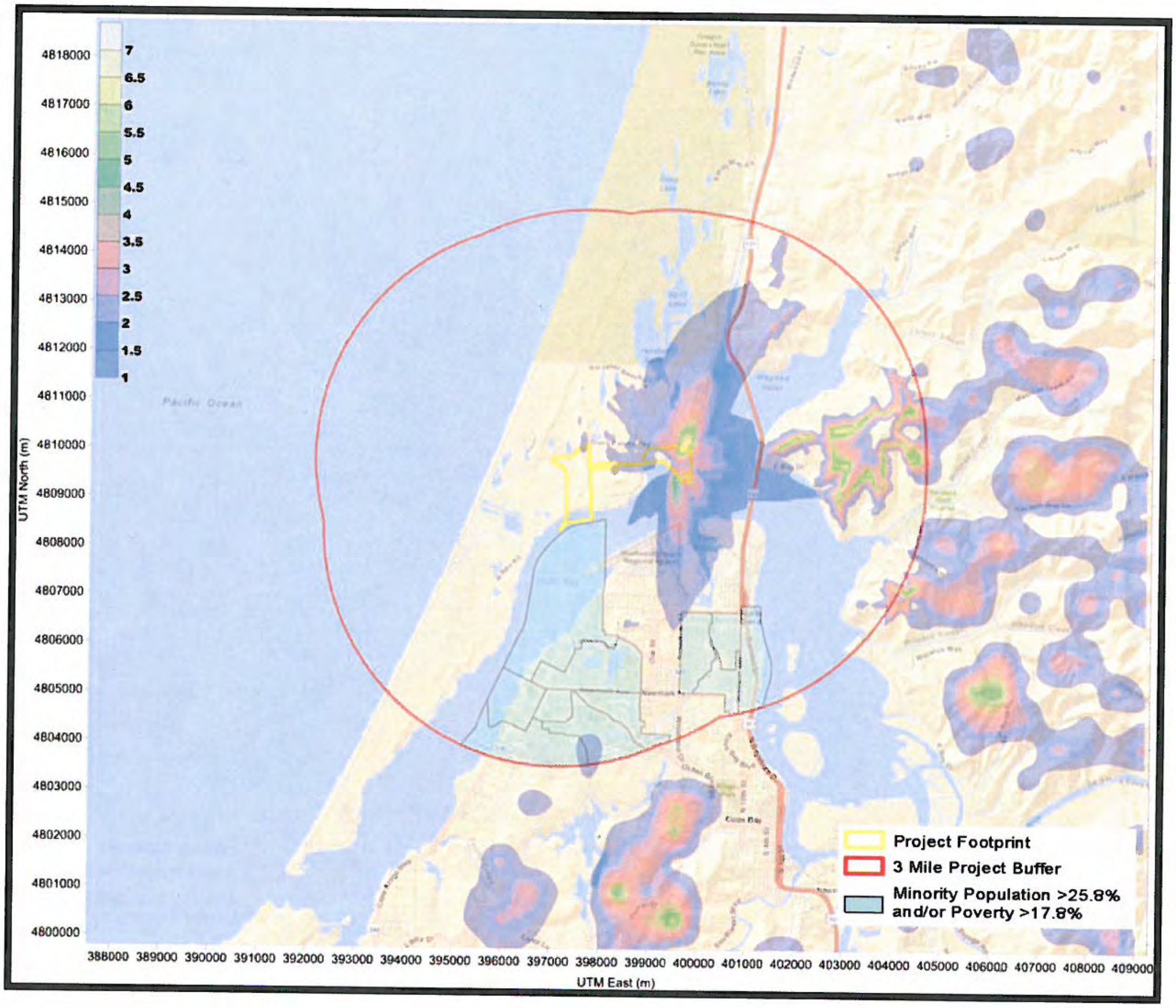
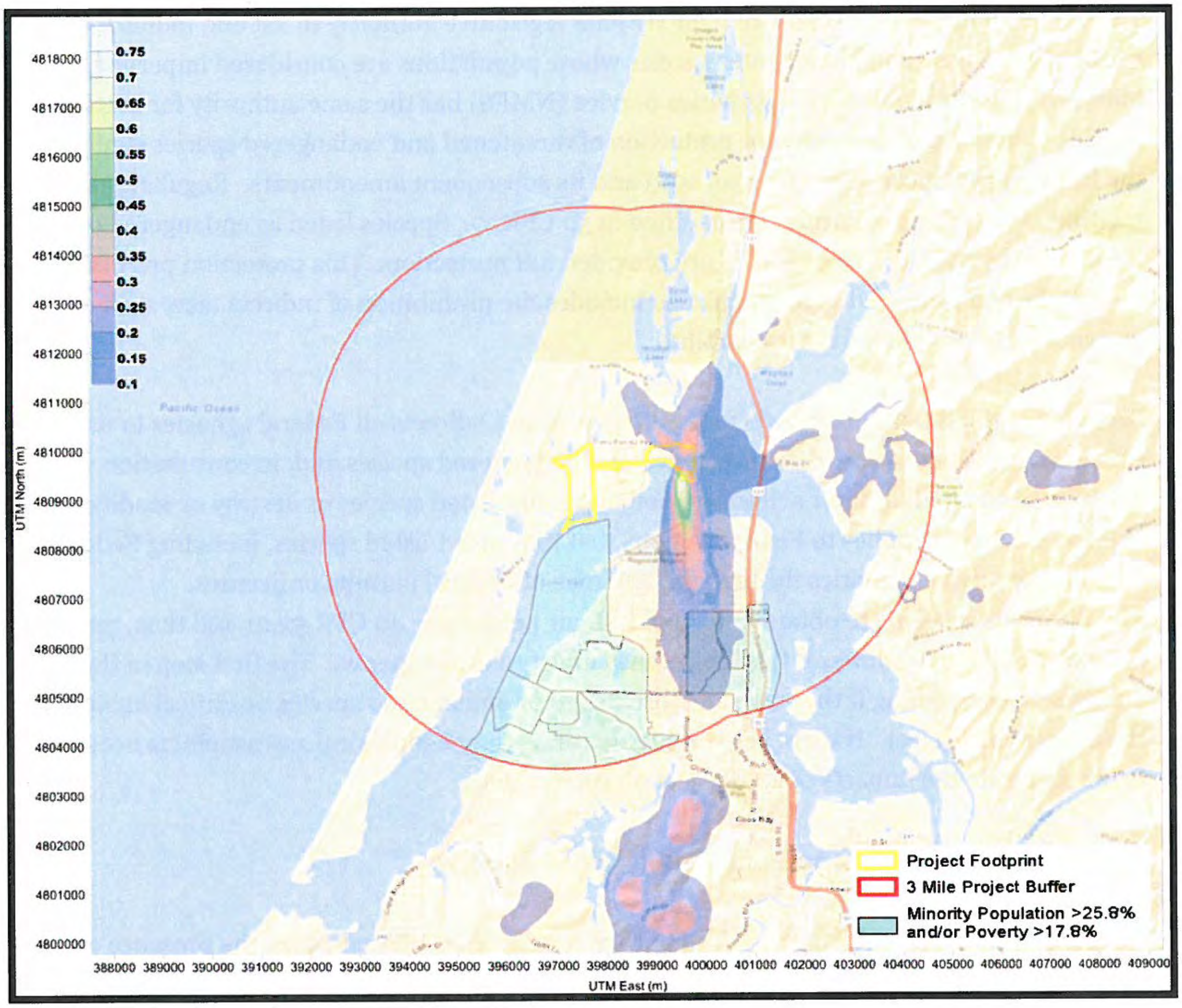


Figure 6-6: Maximum Modeled Annual PM-2.5 Impacts

(Concentrations in ug/m^3)



7.0 ENDANGERED SPECIES ACT

7.1 Introduction

The U.S. Fish and Wildlife Service (USFWS) has legislative authority to list and monitor the status of land-based and freshwater species whose populations are considered imperiled. Similarly, the National Marine Fisheries Service (NMFS) has the same authority for marine species. This federal authority for protection of threatened and endangered species stems from the Endangered Species Act (ESA) of 1973 and its subsequent amendments. Regulations relating to the listing of species are codified in 50 CFR 17. Species listed as endangered or threatened by the USFWS or NMFS are provided full protection. This protection prohibits the direct take of a protected species and also includes the prohibition of indirect take, such as destruction of designated critical habitat.

Section 7 of the ESA as amended (16 U.S.C. 1531 et seq.) directs all Federal agencies to use their existing authorities to conserve threatened and endangered species and, in consultation with the USFWS, to ensure that their actions do not jeopardize listed species or destroy or modify critical habitat. Section 7 applies to Federal actions that may affect listed species, including Federal approval of private activities through the issuance of Federal permits or licenses.
The Project is required to obtain a Federal PSD air permit per 40 CFR 52.21 and thus, requires an analysis that determines if the Project may affect relevant species. The first step in the analysis is determining if there are any threatened or endangered species or critical habitat in the area of the Project. If there are species identified then a biological assessment is necessary to demonstrate the impacts of the Project on such species.

7.2 Federally Threatened and Endangered Species

JCEP has initiated consultation with the USFWS and the NMFS regarding the presence of species that are federally listed or proposed for listing and their critical habitat within the Project site. Appendix D contains correspondence with the USFWS regarding the list of threatened or endangered species that may occur within Coos County. No critical habitat was identified on the Project site with the exception of the green sturgeon, which NMFS has designated critical habitat in the coastal waters from the U.S. Washington and Canadian border southward to Monterey Bay, California.

The Federally listed endangered species nearby or within the Project site are shown in Table 7-1 and summarized below. A more detailed description of the habitat surveys is located in Resource Report 3 of the JCEP LNG Terminal Project application to the Federal Energy Regulatory Commission (FERC) (Docket No. PF12-7-000).

7.2.1 *Botanical Species*

Western Lily

Western lily (*Lilium occidentale*) occurs within four miles of the coast, generally on marine terraces below 300 feet above MSL. Western lily is known to occur from early successional fens and coastal scrub habitat in northwestern California to southwest Oregon. Habitats with which this species is associated include coastal bluff scrub, coastal prairie, and openings in coastal coniferous forest (Sitka spruce dominated) including freshwater marshes and swamps. The closest known western lily occurrence to the Project site is approximately 5.5 miles northeast at Hauser Bog. Surveys conducted on the Project site in 2006 for the majority of the Project area and in 2012 did not result in the detection of western lily.

7.2.2 *Bird Species*

Western Snowy Plover

The only breeding shorebird of Oregon's beaches, the western snowy plover (*Charadrius alexandrinus*) is an uncommon year-round resident on the Oregon coast, including the North Spit, on the south end of which it nests (roughly five miles from the Project area). The North Spit supports the most productive snowy plover population segment on the Oregon coast, accounting for 30 percent of all snowy plovers fledged on the Oregon coast in 2005. Critical habitat for the species on the North Spit includes the ocean beach from Horsfall Road to the jetty and all federal lands at the south end; which excludes the Project site area. There is one record in the Oregon Natural Heritage Database away from the outer coast at the Menasha Spoils near the mouth of Pony Slough, a mile from the Project site. On the coast, it is almost exclusively a bird of open sand beaches. Another population nests inland on alkaline playas. Its typical coastal nesting habitat is at the upper edge of the beach below the foredunes. It also nests on bare spits at small estuary mouths and, on the North Spit, is most prevalent on restored sand habitat east of the foredune. There does not appear to be any typical habitat in the Project site, and while an occasional individual may show up on a mudflat, it is not expected. None were detected during field surveys of the Project site.

Marbled Murrelet

The marbled murrelet (*Brachyramphus marmoratus*) usually nests over 100 feet up on a mossy conifer branch, mostly on the west slopes of the Coast Range but up to more than 30 miles inland where suitable habitat persists. Nesting adults make daily foraging trips to shallow, protected, near-shore coastal waters, feeding mostly on small fish but sometimes on euphausiids (small shrimp-like crustaceans). The species is considered uncommon to rare year-round on the Oregon coast, but Coos Bay is within the zone of highest density. The marbled murrelet nests in Elliott State Forest and probably in the Coos Bay area as well. It is considered an uncommon, year-round, offshore resident on the North Spit. Although none were observed during surveys, it is considered possible that murrelets could occur on the bay within the general Project area and perhaps over the Project site in transit between nesting and feeding sites.

Northern Spotted Owl

The spotted owl (*Strix occidentalis*) is dependent on old-growth components in coniferous forests. In Oregon, it is found in low- and mid-elevation coniferous forests in the Coast, Siskiyou, and Cascade Ranges. There are many spotted owl habitat areas in the forests inland from Coos Bay, the nearest to the Project site area being about five miles away in the Kentuck Creek drainage. However, the species is extremely rare on the immediate coast of Oregon, rare in Coos County, and absent from coastal Coos County. It is thus not expected to occur in the Project site.

Short-tailed Albatross

The short-tailed albatross is a pelagic seabird and is now very rare and only breeds in Japan. It has the potential to occur off Coos County. The short-tailed albatross could potentially be encountered within the LNG ship transit route zones.

7.2.3 Reptiles and Amphibian Species

Leatherback Sea Turtle

Leatherback sea turtle nesting grounds are located around the world, with the largest remaining nesting assemblages found on the coasts of northern South America and West Africa. Adult leatherback sea turtles are capable of tolerating a wide range of water temperatures, and have been sighted along the entire coast of the United States and as far north as the Gulf of Maine and south to Puerto Rico, the U.S. Virgin Islands, and into the Gulf of Mexico. The Pacific subspecies has declined so drastically that a Pacific Leatherback Conservation Area, wherein gillnet fishing is restricted, has been established stretching from central California to central Oregon. Leatherback sea turtles could potentially be encountered within the LNG ship transit route zones.

Green Sea Turtle

Green sea turtles have been sighted from Baja California to southern Alaska, but most commonly occur from San Diego south. Green sea turtles primarily use three types of habitat: oceanic beaches (for nesting), convergence zones in the open ocean, and benthic feeding grounds in coastal areas. Green sea turtles could potentially be encountered within the LNG ship transit route zones.

Loggerhead Sea Turtle

Loggerhead sea turtles occupy three different ecosystems during their lives—the terrestrial zone, the oceanic zone, and the neritic zone. Loggerhead sea turtles are circumglobal in distribution, occurring throughout the temperate and tropical regions of the Atlantic, Pacific, and Indian Oceans. Loggerhead sea turtles are the most abundant species of sea turtle found in U.S. coastal waters. In the U.S., occasional sightings are reported from the coasts of Washington and Oregon, but most records are of juveniles off the coast of California. Loggerhead sea turtles could potentially be encountered within the LNG ship transit route zones.

Olive Ridley Sea Turtle

Important nesting areas for the olive ridley sea turtle include the west coast of Mexico and Central America. Olive ridley sea turtle populations had declined from former times but ridleys are still the most abundantly nesting turtle on the Pacific coast. Olive ridley sea turtles could potentially be encountered within the LNG ship transit route zones.

7.2.4 Marine Mammal Species

Northern Sea Lion

The northern sea lion (*Eumetopias jubatus*), also called Steller sea lion, ranges along the North Pacific coast from Japan to California. It breeds on rocky beaches, often on islands, and at other times is frequently seen hauled out on select coastal rocks, jetties, marinas, and navigation buoys. It forages at sea for fish and invertebrates, sometimes to several hundred miles from land. The Oregon population was estimated at over 5,000 in 2002 and productivity appears to be increasing. There are no rookeries in Coos County. The nearest (one of Oregon's two primary rookeries) is at Orford Reef in Curry County. There is a haul-out site at Cape Arago in Coos County, roughly ten miles from the Project site area. While an occasional Steller sea lion might enter Coos Bay and the species is included on the North Spit wildlife list, there are no suitable haul-out sites within the Project site and the species is not expected to occur there.

Killer Whale

The killer whale (*Orcinus orca*) is a wide-ranging predator of the open ocean, occasionally entering bays in pursuit of salmon and pinnipeds. Killer whales have on occasion penetrated Coos Bay beyond the Project site areas. Grey whales have been seen in Coos Bay at about the same frequency as killer whales.

7.2.5 Mammal Species

Only one federal candidate for listing, the fisher, has a small potential to occur within the Project area. The fisher (*Martes pennanti*) is a large weasel which inhabits mature, closed-canopy coniferous forests with some deciduous components such as riparian corridors. It was nearly extirpated from Oregon by logging and trapping and is now very rare. Reintroductions have been attempted in several inland counties and there have been recent sightings in the mountains east and west of the Willamette Valley. Although the species is considered of potential occurrence on the North Spit, and porcupines, one of the fisher's preferred prey items, are present in the Project site area, there are no records of its presence. It is assumed that there is too much disturbance and that the forest is too immature and fragmented for the site to be used by fishers.

7.2.6 Fish Species

<u>*Pacific Eulachon*</u>

Eulachon (*Thaleichthys pacificus*) are a small, anadromous (migrating up fresh-water rivers to breed) fish endemic to the eastern Pacific Ocean ranging from northern California into the southeastern Bering Sea. NMFS has identified two distinct population segments of Eulachon, the southern range includes Coos Bay and the proposed Project site. Eulachon populations have decreased dramatically since the mid-1990s. On March 18, 2010, NMFS listed the southern segment of eulachon as threatened under the ESA and designated critical habitat for several river systems within Oregon on December 19, 2011. NMFS has designated critical habitat, but not essential fish habitat, for the Coos Bay system.

<u>*Green Sturgeon*</u>

The northern Green Sturgeon (*Acipenser medirostris*) is a large, anadromous fish of North America and ranges in marine waters from Alaska to Mexico and forages in estuaries and bays from the San Francisco Bay to British Columbia. In 2003, it was determined by NOAA's Biological Review Team that green sturgeon is comprised of two segments that qualify as a species under the ESA: (1) a northern population which ranges from the Eel River, California northward and a southern population which ranges from the Eel River southward.

The Southern population of the North American green sturgeon was listed on April 7, 2006 as a threatened species by NMFS under the ESA. North American Green sturgeons are present in Coos Bay, and data indicate spawning occurs within the freshwater habitats upstream of the estuarine Coos Bay system while the bay provides habitat for juvenile rearing. Essential fish habitat has not been designated, however critical habitat does exist. Studies have confirmed the migratory nature of green sturgeon between northern and southern population units; as such NMFS took an inclusive approach when determining the geographical area occupied by the Southern population segment and designated green sturgeon critical habitat from the Bering Sea, AK to the U.S.–California/Mexico border, excluding Canadian waters, including Coos Bay.

<u>*Oregon Coast Coho Salmon*</u>

Coho salmon are one of several anadromous salmonid species that utilize Coos Bay for migration and rearing habitat for adult and juveniles on their way to and from the ocean. In February 2008, NMFS listed the naturally spawning populations within the environmentally sensitive unit of Oregon Coast Coho salmon as a federally threatened species under the ESA.

Critical habitat for this ESU has been designated within several freshwater sub-basins of the Coos Bay system; however, no critical habitat exists within the proposed Project site on Coos Bay.

7.3 Potential Air Quality Impacts to Federally Threatened and Endangered Species

Guidance from the U.S. EPA document: A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (U.S. EPA, 1980) (the Guidance) was followed to assess the impacts to threatened and endangered plants and animals from the JCEP. The Guidance provides minimum levels at which adverse effects have been reported in the literature for use as screening concentrations. These screening concentrations can be concentrations of pollutants in ambient air, in soils, or in aerial plant tissues. A summary of the Guidance requirements is shown below:

Step 1: Estimate the maximum ambient concentrations for averaging times appropriate to the Screening concentration for pollutants emitted by the source. Include background concentrations when appropriate.

Step 2: Determine potential effects from airborne pollutants by checking the maximum predicted ambient concentrations against the corresponding AQRV screening concentration, PSD increments or NAAQS – whichever is most conservative.

Step 3: Determine potential effects from trace metals by calculating the concentration deposited in the soil from the maximum annual average ambient concentrations assuming all deposited metals are soluble and available for uptake by plants.

Step 4: Compare the increase in metal concentration in the soil to the existing endogenous concentrations.

Step 5: Calculate the amount of trace metal potentially taken up by plants

Step 6: Compare the concentrations from Steps 3 and 5 with the corresponding screening concentrations.

The results of the ambient air quality modeling analysis detailed in Section 5 and summarized in Table 7-2 show that the maximum modeled concentrations are much lower than the vegetative screening concentrations identified in the Guidance. Additionally, the modeled concentrations are lower than the PSD Class II increments and the NAAQS. Thus, per the Guidance, the JCEP will not cause significant impacts to soils, water, crops, and wildlife from airborne pollutants.

The Project will emit a small amount of trace metals (Arsenic, Cadmium, Chromium, Lead, Manganese, Mercury, Nickel and Selenium) from the combustion of natural gas. As such, Steps 3 through 6 of the Guidance were conducted to determine the potential effects from trace metals on threatened and endangered species. A summary of these steps is shown in Table 7-3.

The first step of the guidance regarding trace metals (Step 3) is calculating a maximum concentration of heavy metals into soils. This calculation is based upon the maximum modeled trace metal concentrations detailed in Section 5 and on the following equation:

DC (ppmw) = 21.5 (N/d)X

Where: DC = deposited soil concentration (ppmw)
N = expected lifetime of source (assumed to be 50 years)
d = depth of soil through which deposited metals are distributed (assumed to be 3 cm)
X = maximum annual average ambient concentration from the source (ug/m^3)

The following step compares the computed deposited soil concentration to an endogenous concentration. Per the guidance, a less than 10% increase over the endogenous concentration is considered to be inconsequential. As shown in Table 7-3, the calculated maximum percent increase over the endogenous concentration is less than 10% for all of the trace metals.

After the maximum amount of deposited soil concentrations is calculated in Step 3, then the potential concentrations in plant tissue can be calculated by conservatively assuming that all deposited trace metals are fully soluble and available for uptake by plants. With this assumption, the tissue concentration in plants is calculated as shown below:

Tissue Concentration (ppmw) = DC (ppmw) * CR

Where: DC = deposited soil concentration
CR = Plant:Soil Concentration Ratio

The last step in the analysis is to compare the calculated deposited soil concentrations and the tissue concentrations to three screening concentrations identified in the Guidance. Specifically, the calculated deposited soil concentration is compared to the soil screening concentration and the tissue concentration is compared to a tissue screening concentration and a dietary screening concentration (i.e., assuming animals ingest the plants or soils). As shown in Table 7-3, the maximum calculated trace metal deposited soil and tissue concentrations are substantially less than the corresponding screening concentrations. Thus, there are negligible impacts to plants, soils, and animals from the trace metals emitted by the JCEP.

Thus, based upon the results of the analysis shown above for impacts from airborne criteria air pollutants and the potential for deposited heavy metals, the JCEP will not cause significant air quality impacts to threatened and endangered plants or wildlife.

Table 7-1: List of Threatened and Endangered Species in JCEP Area

Species	Federal Status
MAMMALS	
Steller sea lion *Eumatopias jubatus*	Threatened
Killer whale *Orchinus orca*	Endangered
BIRDS	
Western snowy plover *Charadrius alexandrines*	Threatened
Marbled murrelet *Brachyramphus marmoratus*	Threatened
Northern Spotted Owl (Strix occidentalis caurina)	Threatened
Short-tailed Albatross (Diomedea albatrus)	Endangered
AMPHIBIANS and REPTILES	
Leatherback Sea Turtle (*Dermochelys coriacea*)	Endangered
Green Sea Turtle (Chelonia mydas)	Threatened
Loggerhead Sea Turtle (Caretta caretta)	Endangered
Olive Ridley Sea Turtle (Lepidochelys olivacea)	Threatened
FISH	
Eulachon *Thaleichthys pacificus*	Threatened
Northern green sturgeon *Acipenser medirostris*	Threatened
Coho salmon *Onchorhynchus kisutch*	Threatened
PLANTS	
Western lily *Lilium occidentale*	Endangered

Table 7-2: Facility Maximum Modeled Concentrations

Pollutant	Averaging Period	Significant Impact Concentration (µg/m³)	PSD Class II Increment (µg/m³)	Vegetative Screening Concentration (µg/m³)	NAAQS/ OAAQS (ug/m³)	Maximum Modeled Concentration[a] (µg/m³)	Background Conc. (µg/m³)	Total Conc.[b] (µg/m³)
CO	1-Hour	2,000	-	1,800,000	40,000	890.3	2,415	3,305
	8-Hour	500	-	1,800,000	10,000	73.1	1,840	1,913
SO_2	1-Hour	7.8	-	917	197	23.8/NA/16.5	22.7	39.2
	3-Hour	25	512	786	1,300	13.1/11.0/11.0	21.0	32.0
	24-Hour	5	91	-	365/262	2.5/2.0/2.0	10.5	12.5
	Annual	1	20	18	80/52	0.22	4.2	4.4
PM-2.5	24-Hour	1.2	9	-	35	7.0/7.7/3.9	23.0	26.9
	Annual	0.3	4	-	12	0.71/0.80	7.5	8.3
PM-10	24-Hour	5	30	-	150	9.3/7.6/7.6	55	62.6
NO_2	1-Hour	7.5	-	>3,760	188	175.7/NA/92.7	66.4	159.1
	Annual	1	25	94	100	0.82	19	19.8

[a]Presented in the form of SIC/Increment/NAAQS for short-term standards due to the differing structure of those thresholds.
[b]Represents maximum modeled concentration (NAAQS averaging structure) plus representative background concentration for comparison to the NAAQS/OAAQS.

Table 7-3: Screening Analysis of Impacts from JCEP Trace Metals on Plants, Soils, and Animals

Trace Metal	Maximum Modeled Conc. (ug/m^3)	Deposited Soil Concentration (ppmw)	Screening Deposited Soil Concentration (ppmw)	Average Endogenous Soil Concentration (ppmw)[a]	Increase over Average Soil Conc. (%)	Plant:Soil Concentration Ratio[c]	Tissue Conc. (ppmw)	Screening Tissue Conc. (ppmw)	Dietary Screening Conc. (ppmw)
Arsenic	1.06E-05	3.81E-03	3.0	7	0.05%	0.14	5.33E-04	0.25	3
Cadmium	5.84E-05	2.09E-02	2.5	1	2.09%	10.7	2.24E-01	3	15
Chromium	7.44E-05	2.66E-02	8.4	100[b]	0.03%	0.02	5.33E-04	1	-
Lead	2.66E-05	9.52E-03	1000	17	0.06%	0.45	4.28E-03	126	80
Manganese	2.02E-05	7.23E-03	2.5	850[b]	0.00%	0.066	4.77E-04	400	500
Mercury	1.38E-05	4.95E-03	455	0.07	7.07%	0.02	9.90E-05	-	-
Nickel	1.12E-04	4.00E-02	500	40[b]	0.10%	0.045	1.80E-03	60	1000
Selenium	1.27E-06	4.57E-04	13	2	0.02%	1.0	4.57E-04	100	5

[a]Based upon ODEQ suggested default background concentrations for inorganic contaminants in soils (ODEQ Document: Guidance for Assessing Bioaccumulative Chemicals of Concern in Sediment – January 2007)
[b]Based upon Table 3-5 of U.S. EPA, document: A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (U.S. EPA, 1980)
[c]Based upon Table 3-6 of U.S. EPA, document: A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (U.S. EPA, 1980)

8.0 MULTISOURCE MODELING DEMONSTRATION

8.1 Multiple Source Impact Modeling for PM-2.5/PM-10 NAAQS and PSD Increment Compliance

Multiple source modeling was performed to assess the impacts of the Project plus other sources of PM-2.5/PM-10 in the surrounding region, including all identified significant sources of PM-2.5/PM-10 to a distance of 50 km beyond the Project location. Multiple source impacts were modeled using the worst-case operating scenario for the Project emission sources with all other offsite sources at maximum permitted emission rates. A list of offsite sources included in the modeling analysis is discussed in the JCEP Multisource Modeling Protocol (Multisource Protocol) located in Appendix I and approved by the Department on May 10th, 2013. The Multisource Protocol details the information needed to model each of the twelve offsite sources including location coordinates, stack parameters, and emission rates. Additionally, the multisource modeling protocol details the methodology utilized to model the LNG vessel emissions and downwash while the vessels are stationary and being loaded with LNG.

The multisource modeling analysis for both NAAQS and PSD increment demonstrations was conducted for all receptors located within a distance of 50 km from the Project location. Note that the second tier receptor grid methodology discussed in the Multisource Protocol was utilized for a receptor located on the Bay Area Hospital offsite source. The maximum modeled multiple source impacts for PM-2.5/PM-10 are summarized in Table 8-1. As shown in the table, modeled multiple source impacts demonstrate compliance with the NAAQS and the PSD increment for both pollutants. Specifically, the modeled concentration from all sources combined, plus ambient background, is well below the 24-hour and annual NAAQS of 35 $\mu g/m^3$ and 12 $\mu g/m^3$, respectively. Note that the use of the "second-tier" methodology described in the Multisource Protocol was utilized for the 24-Hour PM-2.5 demonstration. The annual PM-2.5 modeling demonstration was conservatively based upon the overall maximum modeled annual concentration rather than the use of the five-year average maximum modeled concentration.

Additionally, the modeled impacts from all sources combined are below the PSD increments of 9.0 ug/m^3 and 4.0 ug/m^3 for 24-hour and annual PM-2.5, respectively. Thus, the results of the multiple source modeling demonstrate that the project will not significantly contribute to a violation of the PM-2.5 NAAQS or PSD increment. Similarly, the modeling results shown in Table 8-1 indicate the maximum modeled 24-hour PM-10 concentrations are much less than the NAAQS and PSD increment for this pollutant. The modeling data files for the multisource modeling are located on DVD-ROM in Appendix J.

8.2 Multiple Source Impact Modeling for SO_2 and NO_2 NAAQS Compliance

The multiple source impact modeling analyses for SO_2 and NO_2 were conducted in accordance with the procedures described in the Multisource Protocol (Appendix I) using "first tier" methodologies. The results of the multiple source modeling analyses include the impacts of the Project emissions including stationary LNG vessels; the approved multisource inventory of all other permitted sources of SO_2 and NO_x emissions in the region; and SO_2 and NO_2 background concentrations that reflect the existing ambient air quality in the region. The modeling was conducted to demonstrate that the total combined concentrations of the Project and the other permitted sources in the region, plus the background concentrations, will comply with the 1-hour average NAAQS for SO_2 and NO_2.

Table 8-1 summarizes the results of the multiple source impact modeling analyses for the 1-hour average SO_2 and NO_2 NAAQS. The results of the multiple source modeling analyses demonstrated compliance with the 1-hour average SO_2 and NO_2 NAAQS at all modeled receptor locations. As such, the multiple source impact modeling analyses demonstrate that the Project will not cause or make a significant contribution to any violations of the 1-hour average SO_2 and NO_2 NAAQS. The modeling data files for the multisource modeling are located on DVD-ROM in Appendix J.

8.3 Air Quality Modeling Summary

The single source modeling analysis detailed in Section 5 indicated potential exceedances of the SILs for 1-hour NO_2, 24-hour and annual PM-2.5, 24-hour PM-10, and 1-hour SO_2. As such, in accordance with OAR 340-225-0050(2)(b), the multisource NAAQS analysis included the JCEP stationary sources, the offsite sources identified by ODEQ, and the representative background concentrations presented in the JCEP Monitoring exemption request, which was approved by the department on March 13, 2013.

Additionally, in order to comply with the PSD Class II increment provisions in accordance with OAR 340-225-0050(b)(1), a PSD Class II increment analysis was necessary for 24-hour and annual PM-2.5, and 24-hour PM-10.

The multisource modeling results summarized in Table 8-1 show that the Project meets the regulatory requirements for a demonstration of compliance with the NAAQS for 1-hour NO_2, 24-hour and annual PM-2.5, 24-hour PM-10, and 1-hour SO_2. Additionally, the modeling results show compliance with the PSD increments for 24-hour and annual PM-2.5, and 24-hour PM-10. Thus, the Project has been demonstrated to comply with the NAAQS and PSD increments for all regulated pollutants and no further modeling analyses are necessary.

8.4 Additional Non-Regulatory Multisource Modeling

While not explicitly required by any Federal or Oregon air regulations, ODEQ has requested that JCEP provide an estimate of LNG carrier emissions and subsequent impact modeling of these emissions while the LNG carrier are mobile (i.e., in transit and berthing). The multisource modeling detailed in Sections 8.1 and 8.2 provides an estimate of the LNG carrier emissions while the LNG carriers are hotelling and loading (i.e., stationary time periods). The additional requested analysis including the transit and berthing/deberthing processes (i.e., time periods when the vessels are mobile and are excluded from ODEQ air permitting) were provided as part of the FERC NEPA licensing process. A copy of the JCEP's Final Resource Report Appendix C.9 (FERC ID CP13-483) detailing the emissions from and impact modeling of the LNG vessels while in transit and stationary is included in Appendix K. Note that the modeling files provided in Appendix J also include those that support the Appendix K results.

Table 8-1: Multisource Maximum Modeled Concentrations

Pollutant	Averaging Period	NAAQS/ OAAQS (μg/m3)	PSD Class II Increment (μg/m3)	Maximum Modeled Concentration[a] (μg/m3)	Background Concentration (μg/m3)	Total Concentration (μg/m3)
PM-2.5	24-Hour[a]	35	9	7.4/7.9	23.0	30.4
	Annual	12	4	2.3/0.8	7.5	9.8
PM-10	24-Hour	150	30	14.3/14.1	55	69.3
NO_2	1-Hour	188	NA	92.7	66.4	159.1
SO_2	1-Hour	197	NA	100.7	22.7	123.4

[a]Presented in the form of NAAQS/PSD Increment due to the differing averaging structures of those thresholds.

Appendix A
ODEQ Application Forms

Print Form

FORM AQ101
ANSWER SHEET

ADMINISTRATIVE INFORMATION

FOR DEQ USE ONLY	
Permit Number:	Type of Application:
Application No:	**RNW** ___ **MOD** ___ **NEW** ___ **EXT** ___
Date Received :	
Regional Office:	**Check No.** **Amount $**

1. Company	**2. Facility Location**
Legal Name: Jordan Cove Energy Project, L.P.	Name: JCEP LNG Terminal Project
Mailing Address: 125 Central Avenue, Suite 380	Street Address: Jordan Cove Road
City, State, Zip Code: Coos Bay, OR 97240	City, County, Zip Code: Unincorporated Coos County, OR
Number of employees:	
3. Site Contact Person	**4. Standard Industrial Classification Code(s)**
Name: Robert L. Braddock	Primary: 1321
Title: Project Manager	Secondary:
Telephone number: (541)266-7510	**5. Other DEQ Permits**
Fax. number: (541)269-1475	
e-mail address: bobbraddock@attglobal.net	

6. Permit Action:

- ☐ New Simple ACDP
- ☐ New Construction ACDP
- ☐ New Standard ACDP
- ☒ New Standard ACDP (PSD/NSR)
- ☐ Renewal of an existing permit without changes (include form AQ403 for Standard ACDPs)
- ☐ Renewal of an existing permit with changes (include form AQ403 for Standard ACDPs)
- ☐ Modification of existing permit

7. Signature

I hereby apply for permission to discharge air contaminants in the State of Oregon, as stated or described in this application, and certify that the information contained in this application and the schedules and exhibits appended hereto, are true and correct to the best of my knowledge and belief.

Robert L. Braddock	Project Manager/Vice President (541)266-7510
Name of official (Printed or Typed)	Title of official and phone number
Robert L Braddock	March 21, 2013
Signature of official	Date

FEE INFORMATION

(Make the check payable to DEQ)

Note: The initial application fees and annual fees specified below (OAR 340-216-0020, Table 2, Parts 1 and 2) are only required for initial permit applications. These fees are not required for an application to renew or modify an existing permit. The appropriate specific activity fee(s) specified below (OAR 340-216-0020, Table 2, Part 3) applies to permit modifications or may be in addition to initial permit application fees.

OAR 340-216-0020, Table 2, Part 1 – INITIAL PERMITTING APPLICATION FEES:	
Short Term Activity ACDP	
Simple ACDP	
Construction ACDP	
Standard ACDP	
Standard ACDP (PSD/NSR)	$42,000
OAR 340-216-0020, TABLE 2, PART 2 - ANNUAL FEES:	
Simple ACDP – Low fee class	
Simple ACDP – High fee class	
Standard ACDP	$7,680
OAR 340-216-0020, TABLE 2, PART 3 - SPECIFIC ACTIVITY FEES:	
Non-technical permit modification	
Non-PSD/NSR basic technical permit modification	
Non-PSD/NSR simple technical permit modification	
Non-PSD/NSR moderate technical permit modification	
Non-PSD/NSR complex technical permit modification	
PSD/NSR modification	
Modeling review (outside PSD/NSR)	
Public hearing at applicant's request	
State MACT determination	
TOTAL FEES	$49,680

SUBMIT TWO COPIES OF THE COMPLETED APPLICATION TO:

New or Modified Permits (include fees):	Permit Renewals (no fees):
Oregon Department of Environmental Quality Business Office 811 SW Sixth Avenue Portland, OR 97204-1390	Oregon Department of Environmental Quality Air Quality Program, Western Region Office 750 Front Street NE, Suite 120 Salem, Oregon 97301-1039

Facility Name: JCEP LNG Terminal Project Permit Number: _________

1. Description of facility and processes:

Liquified natural gas export terminal to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum of LNG.

The following liquefaction facilities are proposed for the Project:
- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/d;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

3. Attach plot plan. See Figures 5-1 and 5-2

4. Attach process flow diagram. See Figures 2-2, 2-3, and 2-4

5. Attach a city map or drawing showing the facility location. See Figure 1-1

Print Form

FORM AQ104

NOTICE OF INTENT TO CONSTRUCT **ANSWER SHEET**

FOR DEQ USE ONLY	
Permit Number:	Regional Office:
Application No:	Date Received :

1. Source Number:	
2. Company	**3. Facility Location**
Legal Name: Jordan Cove Energy Project, L.P.	Name: JCEP LNG Terminal Project
Ownership type: Limited Partnership	Plant start date: 2nd Quarter 2018
Mailing Address: 125 Central Avenue, Suite 380	Street Address: Jordan Cove Road
City, State, Zip Code: Coos Bay, OR 97420	City, County, Zip Code: Unincorporated Coos County, OR
Number of Employees (corporate):	Number of Employees (plant site):

4. Site Contact Person	**5. Industrial Classification Code(s)**
Name: Robert L. Braddock	SIC: 1321-Natural Gas Liquids NAICS:
Title: Project Manager	
Phone number: (541)266-7510	**6. Type of construction/change:** (see instructions)
Fax number: (541) 269-1475	Not applicable
e-mail address: bobbraddock@attglobal.net	

7. Signature

I certify that the information contained in this notice, including any schedules and exhibits attached to the notice, are true and correct to the best of my knowledge and belief.

Robert L. Braddock	Project Manager/Vice President (541)266-7510
Name of official (Printed or Typed)	Title of official and phone number
Robert L Braddock	March 21, 2013
Signature of official	Date

SUBMIT TWO COPIES OF THE COMPLETED NOTICE OF INTENT TO CONSTRUCT TO THE DEPARTMENT REGIONAL OFFICE SHOWN BELOW:

Oregon Department of Environmental Quality
Western Region
750 Front Street NE, Suite 120
Salem, OR 97301

Construction Information

8. Description of proposed construction:

Liquified natural gas export terminal to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum of LNG.

The following liquefaction facilities are proposed for the Project:
- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/d;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

9. Will the construction increase the capacity of the facility? [ ] If yes, how much?

N/A- new facility

10. Will the construction increase pollutant emissions? Y If yes, how much (see question 18)?

See emissions data in 19

11. Will the construction cause new pollutant emissions? Y If yes, which pollutants and how much?

See emissions data in 19

12. Estimated timing of construction.

a. Commence date: 3rd Quarter 2014
b. Begin date: 3rd Quarter 2014
c. Completion date: 2nd Quarter 2018

13. Will tax credits be requested once construction is completed? N

14. Attach relevant forms from Form Series AQ200, Device/Process Forms.

15. Attach relevant forms from Form Series AQ300, Control Device Description Forms, if applicable.

16. Attach process flow diagram.

17. Attach a city map or drawing showing the facility location.

18. If applicable, attach a Land Use Compatibility Statement.

Emissions Data

19. Pre-and Post-Construction emissions summary data

a. Emissions Point	b. Pollutant	c. Pre-Construction Emissions short-term (specify unit)	c. Pre-Construction Emissions Annual (tons/year)	d. Post-Construction Emissions short-term (specify unit)	d. Post-Construction Emissions Annual (tons/year)
See Appendix B of PSD Application					

Facility Name: JCEP LNG Terminal Project

Permit Number:

1. Boiler Information:

Boiler identification	DB1 through DB6			
Manufacturer				
Date manufactured (month/year)				
Date construction commenced (month/year)				
Date installed (month/year)				
Rated design heat input capacity (million Btu per hour)	105.6			
Rated steam production capacity (pounds per hour)	N/A			
Primary fuel type	natural gas			
Max. fuel quantity used per hour (include units)	102924 scf/hr/unit			
Max. fuel quantity used per year (include units)	412 MMscf/yr/unit			
If oil is used, sulfur content (% by wt.)	N/A			
Secondary fuel type	**None**			
Max. fuel quantity used per hour (include units)				
Max. fuel quantity used per year (include units)				
If oil is used, sulfur content (% by wt.)				
Stack identification	CTSTACK1-6			
Stack height (feet)	119			
Stack gas flow rate at maximum load (dscf/minute)				
Control device(s) identification from AQ300 series form(s)	SCR1-6, OXCAT1-6			
Continuous monitoring systems	NOx, CO			

2. Describe how the boiler(s) is operated. (Refer to instructions for guidance)

Duct burner used for supplemental firing of the heat recovery steam generator (HRSG)

Facility Name: JCEP LNG Terminal Project

Permit Number:

Engine Information

1.	Device ID Number	CT1 through CT6
2.	Existing or future?	Future
3.	Date construction commenced	
4.	Date installed/completed	4th Qtr 2017
5.	Special controls (if applicable)	yes
6.	Manufacturer	General Electric
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	554
9.	Control device(s) (y/n; if y, identification number(s))	SCR1-6, OXCAT1-6

10. Description of device:

General Electric (GE) LM6000 PG combustion turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF). The turbines will be equipped with a natural gas-fired duct burner for supplementary firing. The turbine will provide power to the natural gas liquefaction process systems.

Operating Schedule

11.	Projected maximum hours/day	24
12.	Projected maximum hours/year	8760

Fuel Information

13. Fuel usage:

	Type	Hourly usage	Annual usage
Primary	natural gas	539,961 scf/hr/unit	4,730 MMscf/yr/uni
Back-up			
Other			

Stack Information

14.	Exit height (ft)	119
15.	Exit diameter (ft)	10
16.	Design flowrate (dscf)	326,016

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)	Yes	recorder? (y/n)	Yes
engine load (y/n).	Yes	recorder? (y/n)	Yes
other (specify)		recorder? (y/n)	

Facility Name: JCEP LNG Terminal Project Permit Number:

Engine Information

1.	Device ID Number	EDG1, EDG2
2.	Existing or future?	Future
3.	Date construction commenced	
4.	Date installed/completed	
5.	Special controls (if applicable)	
6.	Manufacturer	TBD
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	3350 hp
9.	Control device(s) (y/n; if y, identification number(s))	

10. Description of device:

emergency diesel generators

Operating Schedule

11.	Projected maximum hours/day	2
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:

	Type	Hourly usage	Annual usage
Primary	ultra low sulfur diesel	161 gal/hr/unit	32,101 gal/yr/unit
Back-up			
Other			

Stack Information

14.	Exit height (ft)	15
15.	Exit diameter (ft)	1.0
16.	Design flowrate (dscf)	

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)		recorder? (y/n)	
engine load (y/n).		recorder? (y/n)	
other (specify)	hours of operation	recorder? (y/n)	Yes

Facility Name: JCEP LNG Terminal Project

Permit Number:

Engine Information

1.	Device ID Number	LAFP1 through 4
2.	Existing or future?	Future
3.	Date construction commenced	
4.	Date installed/completed	
5.	Special controls (if applicable)	
6.	Manufacturer	TBD
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	700 hp
9.	Control device(s) (y/n; if y, identification number(s))	

10. Description of device:

Liquefaction area fire water pumps.

Operating Schedule

11.	Projected maximum hours/day	2
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:

	Type	Hourly usage	Annual usage
Primary	ultra low sulfur diesel	34 gal/hr/unit	6708 gal/yr/unit
Back-up			
Other			

Stack Information

14.	Exit height (ft)	15
15.	Exit diameter (ft)	0.5
16.	Design flowrate (dscf)	

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)		recorder? (y/n)	
engine load (y/n).		recorder? (y/n)	
other (specify)	hours of operation	recorder? (y/n)	Yes

Facility Name: JCEP LNG Terminal Project Permit Number:

Engine Information

1.	Device ID Number	SDUNESFP
2.	Existing or future?	Future
3.	Date construction commenced	
4.	Date installed/completed	
5.	Special controls (if applicable)	
6.	Manufacturer	TBD
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	400 hp
9.	Control device(s) (y/n; if y, identification number(s))	

10. Description of device:

South Dunes area fire water pump.

Operating Schedule

11.	Projected maximum hours/day	2
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:

	Type	Hourly usage	Annual usage
Primary	ultra low sulfur diesel	19.2 gal/hr	3833 gal/yr
Back-up			
Other			

Stack Information

14.	Exit height (ft)	15
15.	Exit diameter (ft)	0.5
16.	Design flowrate (dscf)	

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)		recorder? (y/n)	
engine load (y/n).		recorder? (y/n)	
other (specify)	hours of operation	recorder? (y/n)	Yes

Print Form

POWER SUPPLY GENERATORS

FORM AQ 213
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project

Permit Number:

Provide the requested information for each generator used to power the plant. If any one of several generators might be used at the plant at any given time, describe the generator with the highest power rating. If more than one generator is permanently located at the plant, describe all of them.

	Primary generator	**Generator 2**	**Generator 3**
ID No.	CT1 - CT6		
Manufacturer	General Electric		
Year manufactured			
Size (give units[a])	56,049 kW (gross)		
Type of fuels used	natural gas		
Maximum amount of fuel to be used per hour[b]	539,961 scf/hr		
Projected maximum amount of fuel to be used per year[b]	4,730 MMscf/yr		
Projected maximum number of hours to be operated in one year.	8,760		
Maintenance schedule[c]			
Manufacturer's emission rates attached (yes/no)	No		

a. Units for generator size are either kilowatt or horsepower (kW or hp).
b. Provide the units for the amount of fuel (e.g., cubic feet, therms, gallons, etc.).
c. "Maintenance Schedule" refers to regularly scheduled maintenance only, i.e., annual, monthly, weekly, or none.

Emission factors for #2 distillate fuel oil: (EPA FIRE version 6.22, SCC 2010020)

Pollutant	Distillate oil emission factor (lb/1000 gallons)
PM	42.5
PM_{10}	42.5
NO_x	604
CO	130
VOC	49.3
SO_2	39.7

Facility Name: JCEP LNG Terminal Project

Permit Number:

Process Information

1. ID Number: FLARE1 & FLARE2
2. Descriptive name: Flare
3. Existing or future?: Future
4. Date commenced:
5. Date installed/completed: 4th Qtr 2017
6. Description of process:

Two ground flares are included in the project design to handle gas relieved during emergency upset conditions and to relieve and protect equipment in the gas conditioning portion of the plant. The low pressure flare headers are continuously purged with fuel gas. A small pilot (42,500 Btu/hr) on each flare with electronic ignition will be continuously operated.

Operating Schedule

7. Seasonal or year-round?: year round
8. Batch or continuous operation?: continuous
9. Projected maximum hours/day: 24
10. Projected maximum hours/year: 8760
11. Process/device capacity:

	Short term capacity		Annual usage	
Raw materials	amount	units	amount	units
natural gas	42,500	Btu/hr/unit		
Products				

12. Control device(s) (yes/no?) If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

No

Facility Name: JCEP LNG Terminal Project

Permit Number:

Process Information

1. ID Number: TO1 & TO2
2. Descriptive name: Thermal Oxidizers 1 and 2
3. Existing or future?: Future
4. Date commenced:
5. Date installed/completed: 4th Qtr 2017
6. Description of process:

The facility will consist of two thermal oxidizers (TO1 and TO2) to control emissions from the amine treating system and the molecular sieve dehydrators. The thermal oxidizers have destruction efficiencies of greater than 99.5 percent for H2S, VOC and HC.

Operating Schedule

7. Seasonal or year-round?: year round
8. Batch or continuous operation?: continuous
9. Projected maximum hours/day: 24
10. Projected maximum hours/year: 8760
11. Process/device capacity:

Raw materials	Short term capacity		Annual usage	
	amount	units	amount	units
natural gas/waste gas	17.5	MMBtu/hr/unit		
Products				

12. Control device(s) (yes/no?) If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

No

Facility Name: JCEP LNG Terminal Project

Permit Number:

1.	Control Device ID	OXCAT1 through OXCAT6
2.	Process/Device(s) Controlled	CT1 through CT6
3.	Year installed	
4.	Manufacturer/Model No.	TBD
5.	Control Efficiency(%)	97%
6.	Design inlet gas flow rate (acfm)	
7.	Design parameter(s)	
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the Control Device	
	Oxidation catalyst reduces CO emissions from the turbine to 4.0 ppmvd@15%O2.	

Facility Name: JCEP LNG Terminal Project

Permit Number:

1.	Control Device ID	SCR1 through SCR6
2.	Process/Device(s) Controlled	CT1 through CT6
3.	Year installed	
4.	Manufacturer/Model No.	TBD
5.	Control Efficiency(%)	90%
6.	Design inlet gas flow rate (acfm)	
7.	Design parameter(s)	
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the Control Device	

Selective catalytic reduction system reduces NOx emissions from the turbine to 2.0 ppmvd@15%O2

State of Oregon Department of Environmental Quality

Plant Site Emissions Detail Sheet
Current/Future Operations

Form AQ402
Answer Sheet

Facility Name: JCEP LNG Terminal Project *Permit Number:*

1. Emissions Point	Production Rates		4. Pollutant	Emissions Factors			Emissions	
	2. Short-term (Specify units)	3. Annual (Specify units)		5. Short-term	6. Long-term	7. Reference(s)	8. Short-term (Specify units)	9. Annual (tons/year)
Please refer to	Appendix B							
Example	200 tons of rock/hr	400,000 tons	PM	0.04 lb/ton	0.04 lb/ton	DEQ	8.0 lb/hr	8.0

Facility: ____________________

1. Device/process ID	2. PM10 PSEL (tons/year)	3. PM2.5 fraction (f)	4. Reference	5. PM2.5 PSEL (tons/yr)
TOTAL				

Facility Name: JCEP LNG Terminal Project Permit Number: ________

Emissions Data

1. Emissions Point	2. Annual Production Rate (specify units)	3. Pollutant	4. Emission Factor	5. EF reference	6. Annual Emissions (tons/yr)
Please refer to	Appendix B for HAP	emissions data			

Applications for Standard ACDPs must also include the most recent Toxics Release Inventory report, if applicable (see instructions).

SECTION 1 - TO BE COMPLETED BY APPLICANT

A. Applicant Name: Jordan Cove Energy Project L.P.	**B. Project Name:** JCEP LNG Terminal Project
Contact Name: Robert L. Braddock	**Physical Address:** Jordan Cove Road
Mailing Address: 125 Central Avenue, Suite 380	**City, State, Zip:** Unincorporated Coos County, OR
City, State, Zip: Coos Bay, OR 97420	**Tax Lot #:** Not yet partitioned
Telephone: (541)266-7510	**Township:** T25S **Range:** R13W **Section:** 5
Tax Account #:	**Latitude:** 43.434024 N
	Longitude: 124.243219 W

C. Describe the project, include the type of development, business, or facility and services or products provided (attach additional information if necessary):

Liquified natural gas export terminal to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum of LNG. The following liquefaction facilities are proposed for the Project:
- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/d;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

D. Check the type of DEQ permit(s) or approval(s) being applied for at this time.

- ☐ Air Quality Notice of Construction
- ☑ Air Contaminant Discharge Permit *(excludes portable facility permits)*
- ☑ Air Quality Title V Permit
- ☐ Air Quality Indirect Source Permit
- ☐ Parking/Traffic Circulation Plan
- ☐ Solid Waste Land Disposal Site Permit
- ☐ Solid Waste Treatment Facility Permit
- ☐ Solid Waste Compost Facility Registration or Permit
- ☐ Solid Waste Letter Authorization Permit
- ☐ Solid Waste Material Recovery Facility Permit
- ☐ Solid Waste Energy Recovery Facility Permit
- ☐ Solid Waste Transfer Station Permit
- ☐ Waste Tire Storage Site Permit
- ☐ Pollution Control Bond Request
- ☐ Hazardous Waste Treatment, Storage, or Disposal Permit
- ☐ Clean Water State Revolving Fund Loan Request
- ☐ Wastewater/Sewer Construction Plan/Specifications *(includes review of plan changes that require use of new land)*
- ☐ Water Quality NPDES Individual Permit
- ☐ Water Quality WPCF Individual Permit *(for onsite construction-installation permits use the DEQ Onsite LUCS form)*
- ☐ Water Quality NPDES Stormwater General Permit *(1200-A, 1200-C, 1200-CA, 1200-COLS, and 1200-Z)*
- ☐ Water Quality General Permit *(all general permits, except 600, 700-PM, 1700-A, and 1700-B when they are mobile.)*
- ☐ Water Quality 401 Certification for federal permit or license

E. This application is for: ☐ Permit Renewal ☑ New Permit ☐ Permit Modification ☐ Other:

SECTION 2 - TO BE COMPLETED BY CITY OR COUNTY PLANNING OFFICIAL

Instructions: Written findings of fact for all local decisions are required; written findings from previous actions are acceptable. For uses allowed outright by the acknowledged comprehensive plan, DEQ will accept written findings in the form of a reference to the specific plan policies, criteria, or standards that were relied upon in rendering the decision with an indication of why the decision is justified based on the plan policies, criteria, or standards.

A. The project proposal is located: ☐ Inside city limits ☐ Inside UGB ☐ Outside UGB

B. Name of the city or county that has land use jurisdiction *(the legal entity responsible for land use decisions for the subject property or land use)*:

SECTION 2 - TO BE COMPLETED BY CITY OR COUNTY PLANNING OFFICIAL

Applicant Name:	**Project Name:**

C. Is the activity or use allowed under Measure 49? ☐ No, Measure 49 is not applicable ☐ Yes; if yes, then check one:

☐ Express; approved by DLCD order #:

☐ Conditional; approved by DLCD order #:

☐ Vested; approved by local government decision or court judgment docket or order #:

D. Is the activity or use compatible with your acknowledged comprehensive plan as required by OAR 660-031?
Please complete this form to address the activity or use for which the applicant is seeking approval (see 1.C on the previous page). If the activity or use is to occur in multiple phases, please ensure that your approval addresses the phases described in 1.C. For example, if the applicant's project is described in 1.C as a subdivision and the LUCS indicates that only clearing and grading are allowed outright but does not indicate whether the subdivision is approved, DEQ will delay permit issuance until approval for the subdivision is obtained from the local planning official.

☐ The activity or use is not regulated by the acknowledged comprehensive plan; explain:

☐ **YES**, the activity or use is pre-existing nonconforming use allowed outright by *(provide reference for local ordinance)*:

☐ **YES**, the activity or use is allowed outright by *(provide reference for local ordinance)*:

☐ **YES**, the activity or use received preliminary approval that includes requirements to fully comply with local requirements; findings are attached.

☐ **YES**, the activity or use is allowed; findings are attached.

☐ **NO**, see 2.C above, activity or use allowed under Measure 49; findings are attached.

☐ **NO**, *(complete below or attach findings for noncompliance and identify requirements the applicant must comply with before compatibility can be determined)*:

Relevant specific plan policies, criteria, or standards:

Provide the reasons for the decision:

#####

Additional comments (attach additional information as needed): #####

Planning Official Signature: **Title:**

Print Name: **Telephone #:** **Date:**

If necessary, depending upon city/county agreement on jurisdiction outside city limits but within UGB:

Planning Official Signature: **Title:**

Print Name: **Telephone #:** **Date:**

Appendix B
Supporting Emission Calculations

Table B-1
Jordan Cove Energy Project

Total Proposed Equipment Potential-to-Emit (PTE) Summary

Source	Potential Annual Emissions (tons/yr)											
	NO_x	CO	VOC	SO_2	PM-10	PM-2.5	H_2SO_4	CO2e	NH_3	Pb	Maximum Individual HAP	Total HAPs
Combined Cycle Units Steady-State Basis	106.32	129.97	74.78	46.1	180.42	180.42	55.83	1,695,525	196.9	7.8E-03		
Combined Cycle Units Start-Up/Shutdown(1)	47.77	2.31	0.00	N/A	0.00	0.00	N/A	N/A		N/A		
South Dunes Fire Pump	0.24	0.27	0.02	4.08E-04	0.01	0.01	3.13E-05	44		3.8E-06		
Liquefaction Area Fire Pumps	1.71	1.87	0.14	2.86E-03	0.09	0.09	2.19E-04	307		2.6E-05		
Emergency Generators	6.56	3.84	0.53	6.84E-03	0.22	0.22	1.05E-03	1,471		6.3E-05		
Thermal Oxidizers	58.3	17.5	0.48	17.4	1.15	1.15	N/A	447,009				
Thermal Oxidizer Vents	0.0	0.0	1.13	0.0	0.00	0.00	0.000	17,456				
Flares	0.14	0.28	1.12	1.0E-02	2.2E-03	2.2E-03	N/A	555.4				
Fugitives			131.05					3,549				
Total Project PTE	**221.0**	**156.1**	**209.3**	**63.5**	**181.9**	**181.9**	**55.8**	**2,165,917**	**196.9**	**7.8E-03**	**2.5**	**8.9**

Notes:
(1) Combined cycle unit start-up/shutdown emissions are added to the baseline steady-state PTE values if the total start-up/shutdown emissions are more than the steady-state full load equivalent during the period of unit off-line downtime and duration of the start-up (and previous shutdown). For start-up/shutdown emissions noted above as "N/A" for certain pollutants, the start-up/shutdown emissions addition to the baseline steady-state PTE is not applicable since mass emissions of these pollutants are fuel input based (lb/MMBtu) and the full load, steady-state basis represents the worst-case scenario for PTE emissions.

Table B-2
Jordan Cove Energy Project
GE LM6000 PG Combustion Turbines

Steady State Emission Calculations

		Design Scenario - Steady State Emissions															
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Combustion Turbine Parameters																	
CT Fuel Type	--	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Ambient Temperature	°F	90	59	20	90	90	59	20	55	20	20	44	44	55	55	90	90
CT Percent Load Rate	%	100	100	100	100	67	100	100	100	75	50	75	50	75	50	75	50
Evaporative Cooling (Y/N) (Not used)	--	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CT Heat Input Capacity, LHV	MMBtu/hr	426.6	489.6	490.1	426.6	308.2	489.6	490.1	498.6	373.8	281.7	385.1	287.4	381.5	284.9	330.8	250.1
CT Heat Input Capacity, HHV	MMBtu/hr	474.0	544.0	544.6	474.0	342.4	544.0	544.6	554.0	415.4	313.0	427.9	319.4	423.9	316.6	367.5	277.9
Gas-Fired Duct Burner Parameters																	
DB Operation (Y/N)	--	N	N	N	Y	N	Y	Y	N	N	N	N	N	N	N	N	N
DB Heat Input Capacity, HHV	MMBtu/hr	0.0	0.0	0.0	105.6	0.0	25.6	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT/DB Exhaust Composition																	
Ar	% by vol	0.89	0.89	0.91	0.88	0.90	0.89	0.91	0.89	0.92	0.93	0.91	0.92	0.91	0.92	0.90	0.91
N_2	% by vol	70.98	71.32	72.69	70.98	71.68	71.32	72.69	71.34	73.28	74.00	72.91	73.46	72.68	73.24	72.02	72.71
O_2	% by vol	12.45	12.19	12.93	12.45	13.23	12.19	12.93	12.14	13.46	14.13	13.44	13.75	13.37	13.69	13.25	13.85
CO_2	% by vol	3.29	3.46	3.28	3.29	3.00	3.46	3.28	3.49	3.10	2.86	3.05	2.97	3.06	2.97	3.03	2.83
H_2O	% by vol	12.39	12.14	10.20	12.39	11.20	12.14	10.20	12.14	9.25	8.08	9.68	8.89	9.98	9.17	10.79	9.70
Molecular Weight	lb/lbmol	27.90	27.95	28.15	27.90	28.01	27.95	28.15	27.95	28.23	28.34	28.17	28.25	28.15	28.22	28.05	28.16
Exhaust Temperature	°F	252.70	251.80	259.60	245.70	244.60	247.50	250.90	251.90	260.00	260.00	260.00	260.00	260.00	260.00	260.00	260.00
Exhaust Flow Rate	lb/hr	1,048,888	1,145,621	1,219,580	1,053,911	835,320	1,146,838	1,221,801	1,157,084	988,561	810,017	1,031,057	792,359	1,018,389	784,360	888,169	723,018
Total Stack Emission Rates (Controlled)																	
NO_x	ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CO	ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
VOC	ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
NH_3	ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Nox (as NO2)	lb/hr	3.4	3.9	3.9	4.2	2.5	4.1	4.3	4.0	3.0	2.3	3.1	2.3	3.1	2.3	2.7	2.0
CO	lb/hr	4.2	4.8	4.8	5.1	3.0	5.0	5.2	4.9	3.7	2.8	3.8	2.8	3.8	2.8	3.3	2.5
VOC (as CH4)	lb/hr	2.4	2.7	2.7	2.9	1.7	2.9	3.0	2.8	2.1	1.6	2.2	1.6	2.2	1.6	1.9	1.4
SO_2 (without oxydation catalyst)	lb/hr	1.5	1.7	1.7	1.8	1.1	1.8	1.9	1.7	1.3	1.0	1.3	1.0	1.3	1.0	1.2	0.9
PM/PM-10/PM-2.5 - without sulfates	lb/hr	3.8	3.8	3.8	5.4	3.8	4.2	4.5	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
PM/PM-10/PM-2.5 - with sulfates	lb/hr	6.1	6.4	6.1	8.8	5.5	7.3	7.7	6.5	5.5	5.1	5.6	5.3	5.6	5.3	5.6	5.2
SO_3	lb/hr	1.1	1.3	1.1	1.6	0.8	1.5	1.6	1.3	0.8	0.6	0.9	0.7	0.9	0.8	0.9	0.7
H_2SO_4	lb/hr	1.7	1.9	1.7	2.5	1.2	2.3	2.4	2.0	1.3	0.9	1.3	1.1	1.4	1.1	1.4	1.0
NH_3	lb/hr	6.4	7.3	7.3	7.8	4.6	7.6	7.9	7.4	5.6	4.2	5.7	4.3	5.7	4.2	4.9	3.7
CO_2	lb/hr	54,458	62,496	62,569	66,585	39,347	65,432	67,930	63,631	47,723	35,943	49,172	36,692	48,689	36,378	42,220	31,936
N_2O	lb/hr	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CH4	lb/hr	1.0	1.2	1.2	1.3	0.8	1.3	1.3	1.2	0.9	0.7	0.9	0.7	0.9	0.7	0.8	0.6
CO2e	lb/hr	54,512	62,558	62,631	66,651	39,386	65,497	67,998	63,695	47,771	35,979	49,221	36,729	48,738	36,414	42,262	31,968
NO_x	lb/MMBtu	0.0072	0.0072	0.0072	0.0072	0.0073	0.0072	0.0073	0.0072	0.0072	0.0073	0.0072	0.0072	0.0073	0.0073	0.0073	0.0072
CO	lb/MMBtu	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0089	0.0089	0.0089	0.0088	0.0090	0.0088	0.0090	0.0090
VOC	lb/MMBtu	0.0051	0.0050	0.0050	0.0050	0.0050	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0050	0.0052	0.0051	0.0052	0.0050
SO_2	lb/MMBtu	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031
PM/PM-10/PM-2.5 - without sulfates	lb/MMBtu	0.0080	0.0070	0.0070	0.0093	0.0111	0.0074	0.0076	0.0069	0.0091	0.0121	0.0089	0.0119	0.0090	0.0120	0.0103	0.0137
PM/PM-10/PM-2.5 - with sulfates	lb/MMBtu	0.0129	0.0118	0.0112	0.0152	0.0161	0.0128	0.0130	0.0117	0.0132	0.0163	0.0131	0.0166	0.0132	0.0167	0.0152	0.0187
H_2SO_4	lb/MMBtu	0.0035	0.0036	0.0032	0.0043	0.0036	0.0040	0.0040	0.0036	0.0031	0.0030	0.0031	0.0035	0.0032	0.0036	0.0037	0.0037
NH_3	lb/MMBtu	0.0135	0.0134	0.0134	0.0135	0.0134	0.0133	0.0134	0.0134	0.0135	0.0134	0.0133	0.0135	0.0134	0.0133	0.0133	0.0133
CO_2	lb/MMBtu	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
CO_2e	lb/MMBtu	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115

Jordan Cove Energy Project
GE LM6000 PG Combustion Turbines

Steady State Emission Calculations

Constants	Units	Value
Fuel Heating Values		
Natural Gas HHV	Btu/SCF	1,026
Fuel Sulfur Content		
Natural Gas Sulfur Content	grains/100 SCF	1.0
Duct Burner Capacity Rating		
Maximum Heat Input Rating	MMBtu/hr (HHV)	105.60
GHG Global Warming Potentials		
CO_2	1	
N_2O	310	
CH_4	21	
EPA F-Factors :		
Natural Gas	dscf/MMBtu	8,710
Ideal gas conversion:		
NOx (as NO2)	ppm to lb/scf	1.194E-07
CO	ppm to lb/scf	7.270E-08
VOC (as CH4)	ppm to lb/scf	4.16E-08
NH3	ppm to lb/scf	4.42E-08
Molecular Weights		
CO_2	lb/lbmol	44
C	lb/lbmol	12
H_2O	lb/lbmol	18
NO_x (as NO_2)	lb/lbmol	46
CO	lb/lbmol	28
VOC (as CH_4)	lb/lbmol	16
S	lb/lbmol	32
SO_2	lb/lbmol	64
SO_3	lb/lbmol	80
H_2SO_4	lb/lbmol	98
NH_3	lb/lbmol	17
Ammonium Sulfate, $(NH_4)_2SO_4$	lb/lbmol	132
Ammonium Bisulfate, NH_4HSO_4	lb/lbmol	115

Table B-3
Jordan Cove Energy Project
GE LM6000 PG Combustion Turbines

Net PTE Increase Analysis for Start-Up/Shutdown Periods

CC Units Off-Line Period Durations:		
	Natural Gas	
Cold	72	hr (minimum)
Warm	8	hr (minimum)
Hot	0.5	hr (minimum)
Start-Up Event Durations:		
Cold	3.8	hr
Warm	2.2	hr
Hot	1.7	hr
Shutdown Event Duration:	0.6	hr
No. of Start-Up/Shutdown Events:		
Cold	**30**	
Warm	**85**	
Hot	**160**	

Natural Gas

	Units	Sample Calc	Cold S/U Scenario				Warm S/U Scenario				Hot S/U Scenario			
			NO_x	CO	VOC	PM-10/PM-2.5	NO_x	CO	VOC	PM-10/PM-2.5	NO_x	CO	VOC	PM-10/PM-2.5
PTE Baseline Emission Rate - 6 Units	lb/hr	(1)	24.0	29.4	16.8	39.0	24.0	29.4	16.8	39.0	24.0	29.4	16.8	39.0
PTE 'Reduction' for Off-Line Period	lb/event	(2)	1,834.6	2,247.4	1,284.2	2,981.2	260.2	318.7	182.1	422.8	66.2	81.1	46.3	107.6
Start-Up Emissions - 6 Units	lb/event	(3)	760.0	148.0	8.4	100.6	580.0	78.0	6.0	73.8	374.0	34.0	3.8	47.8
Shutdown Emissions - 6 Units	lb/event	(4)	78.0	76.0	6.0	30.0	78.0	76.0	6.0	30.0	78.0	76.0	6.0	30.0
SU/SD Event Total Emissions	lb/event	(5)	838.0	224.0	14.4	130.6	658.0	154.0	12.0	103.8	452.0	110.0	9.8	77.8
PTE 'Increase' per SU/SD Event	ton/event	(6)	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.0	0.0	0.0
Total Annual PTE 'Increase'	ton/yr	(7)	0.0	0.0	0.0	0.0	16.9	0.0	0.0	0.0	30.9	2.3	0.0	0.0

(1) - Steady-State PTE Emission Rate = PTE per Unit (ton/yr) * 2,000 lb/ton * yr/Max Unit hr * No. of Units
(2) - PTE 'Reduction' for Off-Line Period = (1) * (Shutdown Duration + Off-Line Duration + Start-Up Duration)
(3) - Start-Up Emissions per Unit provided by vendor
(4) - Shutdown Emissions per Unit provided by vendor
(5) - SU/SD Event Total Emissions = ((3)+(4)) * No. of Units
(6) - PTE 'Increase per SU/SD Event = zero if (5)-(2) <= 0; or ((5)-(2)) * ton/2,000 lb if (5)-(2) > 0
(7) - Total Annual PTE 'Increase' = (6) * No. of Events per Year per Start-Up Type

Table B-4
Jordan Cove Energy Project

Air Quality Modeling Data Input Parameters

	Units	Steady State Design Scenario											
		1	2	3	4	5	6	7	8	9	10	11	12
Combustion Turbine Parameters													
CT Fuel Type	--	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Ambient Temperature	°F	20	20	20	20	59	59	55	55	90	90	90	90
CT Percent Load Rate	%	100	100	75	50	100	100	75	50	100	100	75	50
Evaporative Cooling (Y/N) (Not used)	Y/N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DB Operation (Y/N)	Y/N	N	Y	N	N	N	Y	N	N	N	Y	N	N
Stack Mass Flow Rate	lb/hr	1,219,580	1,221,801	988,561	810,017	1,145,621	1,146,838	1,018,389	784,360	1,048,888	1,053,911	888,169	723,018
Stack Temperature	°F	259.6	250.9	260.0	260.0	251.8	247.5	260.0	260.0	252.7	245.7	260.0	260.0
Stack Temperature	K	399.6	394.8	399.8	399.8	395.3	392.9	399.8	399.8	395.8	391.9	399.8	399.8
Stack Volumetric Flow Rate	ACFM	379,478	375,572	306,801	250,470	355,123	353,352	317,035	243,507	326,036	324,426	277,428	225,000
Stack Exit Velocity	ft/s	80.53	79.70	65.11	53.15	75.36	74.98	67.28	51.67	69.19	68.85	58.87	47.75
Stack Exit Velocity	m/s	24.54	24.29	19.84	16.20	22.97	22.86	20.51	15.75	21.09	20.98	17.94	14.55
NO_x	g/s	0.491	0.542	0.378	0.290	0.491	0.517	0.391	0.290	0.428	0.529	0.340	0.252
CO	g/s	0.605	0.655	0.466	0.353	0.605	0.630	0.479	0.353	0.529	0.643	0.416	0.315
VOC	g/s	0.340	0.378	0.265	0.202	0.340	0.365	0.277	0.202	0.302	0.365	0.239	0.176
SO_2	g/s	0.215	0.233	0.164	0.123	0.214	0.224	0.168	0.125	0.186	0.229	0.145	0.110
PM/PM-10/PM-2.5	g/s	0.769	0.970	0.693	0.643	0.806	0.920	0.706	0.668	0.769	1.109	0.706	0.655

Stack Parameters		
Height Above Grade =	119.0	ft
Height Above Grade =	36.3	m
Diameter =	10.0	ft
Diameter =	3.05	m

Table B-5
Jordan Cove Energy Project

Combined Cycle Unit(s) Annual Emissions Summary

No. of Combined Cycle Units =	**6**
Total Annual Full Load CT Operation(hrs/yr) =	**8,760**
Total Annual Maximum DB Operation (hrs/yr)=	**4,000**

Pollutant	Steady-State PTE tons/yr	Start-Up & Shutdown PTE Increase tons/yr	PTE Total CC Unit(s) tons/yr
NO_x	106.3	47.8	**154.1**
CO	130.0	2.3	**132.3**
VOC	74.8	0.0	**74.8**
SO_2	46.1		**46.1**
PM-10/PM-2.5	180.4	0.0	**180.4**
NH_3 (24-hr avg)	196.9		**196.9**
H_2SO_4	55.8		**55.8**
CO2e	1695525.2		**1,695,525**

Note:
Potential annual emissions are based on 100% load at the average annual design scenario and the specified annual hour limitations of plant/duct burner operation as noted above.

Table B-6
Jordan Cove Energy Project

Plant Flares Potential Emissions Summary

Emission Unit Parameters

Number of Units	2	Flare
Maximum Annual Operation	8760	hr/yr
Pilot Heat Input	0.0425	MMBtu/hr

Pollutant	lb/hr	g/s	Total Annual (ton/yr)
NO_x	0.02	0.003	0.140
CO	0.04	0.01	0.280
VOC	0.16		1.121
PM	3.19E-04	4.02E-05	0.002
SO_2	0.003	0.0004	0.01
CO_2	78.62	9.91	550.97
N_2O	0.000		0.000
CH_4	0.030		0.210
CO_2e			555.38

(1) Maximum hourly emissions rates of the flares are 125% of the maximum annual emissions.
(2) The vendor has stated that the Flare Pilot has a combustion efficiency >99%.
(3) The values for NO_x and CO for the flare were calculated using TCEQ's method
(4) S. Dunes flare emissions are based on LNG Plant pilot/purge fuel flow rates.

Table B-7
Jordan Cove Energy Project

Thermal Oxidizer Potential Emissions Summary

Emission Unit Parameters

Number of Thermal Oxidizers	2	
Maximum Annual Operation	8760	hr/yr
Thermal Oxidizer Fuel Gas Required	17.5	MMBtu/hr (each)

Pollutant	lb/hr	lb/MMBtu	g/s	Total Annual (ton/yr)
NO_x	6.65	0.380	0.84	58.25
CO	2.00	0.114	0.25	17.52
VOC	0.055	0.003	0.0069	0.48
PM	0.13	0.0075	0.0165	1.15
SO_2	1.99	0.1137	0.25	17.43
CO_2	50,820		6,403	445,186
N_2O	0.000		0.00	0.00
CH_4	9.910		1.25	86.81
CO_2e				447,009

(1) lb/hour calculations include a 10% margin.
(2) TO fuel gas required is equal to 17.5 MMBtu/hr (per each incinerator).
(3) TO includes acid gas and air preheat.
(4) TO exhaust temperature = 980°F and Stack Exit Diameter = 42" ID Refractory.

Thermal Oxidizer Vent Potential Emissions Summary

Emission Unit Parameters

Number of Vents	2	
Maximum Annual Operation	350	hr/yr

Pollutant	lb/hr	g/s	Total Annual (ton/yr)
H2S	0.16	0.02	0.06
VOC	3.22	0.41	1.13
CO_2	48,551	6,117	17012.29
N_2O	0.000	0.00	0.00
CH_4	60.35	7.60	21.15
CO_2e			17,456

(1) lb/hour calculations include a 10% margin.
(2) Per vendor, assume TO reliability is 96%. Therefore, the vent will operate 4% of the time. Annual emissions based on 2 TOs down 4% of the time.
(3) Maximum hourly vent emissions assume only 1 TO is not operating at a given time.
(4) Vent exit temperature = 112°F and Stack Diameter = 12"

Table B-8
Jordan Cove Energy Project

Fugitive Emissions

	Emissions (tons/year)				
Source	**CO2**	**Methane**	**CO2e**	**VOC**	**n-Hexane**
LNG Tanks	9.21E-04	23.06	4.84E+02	1.14E-01	3.49E-03
Marine Vessel Loading	2.45E-04	11.28	2.37E+02	2.94E-02	8.97E-04
Process Component Leaks	13.71	134.03	2.83E+03	130.90	1.32E-02
Total	**13.71**	**168.37**	**3549.48**	**131.05**	**0.02**

Table B-9
Jordan Cove Energy Project
LNG Liquefaction and Export Facility

South Dunes Area Fire Water Pump Diesel Engine Potential Emissions Summary

Engine parameters

Number of Engines	1	Engine
Power output base load	400	hp
Heat Input Capacity (HHV)	2.7	MMBtu/hr
Annual fuel usage	3833.0	gal/yr
Maximum Annual Operation	200	hr/yr

	Potential Emissions (per engine)				
Pollutant	**g/bhp-hr[1]**	**lb/MMBtu**	**lb/hr**	**g/s**	**Total Annual (ton/yr)[5]**
NO_x	2.77	0.9120	2.45	0.31	2.45E-01
CO [2]	3.03	0.9958	2.67	0.337	2.67E-01
VOC	0.23	0.0740	0.20	0.025	1.98E-02
PM	0.15	0.0493	0.13	0.017	1.32E-02
SO_2[3]	0.005	0.0015	0.004	0.0005	4.08E-04
H_2SO_4[3]		1.16E-04	3.13E-04	3.94E-05	3.13E-05
CO_2[4]		163.05	437.50	55.12	4.37E+01
N_2O[4]		0.0013	0.004	0.0004	3.55E-04
CH_4[4]		0.0066	0.018	0.0022	1.77E-03
CO_2e					4.39E+01

[1] NO_x, VOC and PM emissions are based upon Tier 3 emission limits identified in NSPS Subpart IIII. To determine individual limits for NOx and VOC, Tier 3 limit for NO_x+HC was apportioned using AP-42 emission factor ratios.

[2] CO emissions based on AP-42 emission factor, Table 3.3-1.

[3] Emissions of SO_2 and H_2SO_4 based on mass balance of sulfur in fuel:

Sulfur Content	15	ppm by weight
Higher Heating Value	19,719	Btu/lb
	140,005	Btu/gal
Molecular Weight of S =	32	lb/lbmol
Molecular Weight of SO_2 =	64	lb/lbmol
Molecular Weight of H_2SO_4 =	98	lb/lbmol
% SO_2 to SO_3 conversion	5%	

[4] CO_2, N_2O and CH_4 emissions based on 40 CFR Part 98 Appendix C emission factors

[5] Unit will operate only during emergency situations and for limited periods per week for testing/maintenance purposes. Total annual operation due to testing/maintenance is limited to 100 hours per year.

[6] Stack exhaust parameters based on Cummins Diesel fire pump Model CFP15E-F20 data sheet.

Stack Parameters		
Exhaust Temperature	749	degrees F
Exhaust Flow	3,648	acfm
Exit Velocity	309.7	ft/s
	94.4	m/s
Stack Inner Diameter	6.0	in
	0.5	ft
	0.15	m
Stack Height AG	15	ft

Conversion Factors	
g/lb	453.6
lb/ton	2,000

Table B-10
Jordan Cove Energy Project
LNG Liquefaction and Export Facility

Liquefaction Area Fire Water Pump Diesel Engine Potential Emissions Summary

Engine parameters

Number of Engines	4	Engines
Power output base load	700	hp
Heat Input Capacity (HHV)	4.7	MMBtu/hr
Annual fuel usage	6707.7	gal/yr
Maximum Annual Operation	200	hr/yr

Pollutant	Potential Emissions (per engine)					Total Annual (ton/yr) (4 engines)
	g/bhp-hr[1]	lb/MMBtu	lb/hr	g/s	Total Annual (ton/yr)[3]	
NO_x	2.77	0.9120	4.28	0.54	4.28E-01	1.71
CO [2]	3.03	0.9958	4.68	0.589	4.68E-01	1.87
VOC	0.23	0.0740	0.35	0.044	3.47E-02	1.39E-01
PM	0.15	0.0493	0.23	0.029	2.31E-02	9.26E-02
SO_2[3]	0.005	0.0015	0.007	0.0009	7.14E-04	2.86E-03
H_2SO_4[3]		1.16E-04	5.47E-04	6.89E-05	5.47E-05	2.19E-04
CO_2[4]		163.05	765.62	96.47	7.66E+01	3.06E+02
N_2O[4]		0.0013	0.006	0.0008	6.21E-04	2.48E-03
CH_4[4]		0.0066	0.031	0.0039	3.11E-03	1.24E-02
CO_2e					7.68E+01	3.07E+02

[1] NO_x, VOC and PM emissions are based upon Tier 3 emission limits identified in NSPS Subpart IIII. To determine individual limits for NOx and VOC, Tier 3 limit for NO_X+HC was apportioned using AP-42 emission factor ratios.
[2] CO emissions based on AP-42 emission factor, Table 3.3-1.
[3] Emissions of SO_2 and H_2SO_4 based on mass balance of sulfur in fuel:

Sulfur Content	15	ppm by weight
Higher Heating Value	19,719	Btu/lb
	140,005	Btu/gal
Molecular Weight of S =	32	lb/lbmol
Molecular Weight of SO_2 =	64	lb/lbmol
Molecular Weight of H_2SO_4 =	98	lb/lbmol
% SO_2 to SO_3 conversion	5%	

[4] CO_2, N_2O and CH_4 emissions based on 40 CFR Part 98 Appendix C emission factors
[5] Unit will operate only during emergency situations and for limited periods per week for testing/maintenance purposes. Total annual operation due to testing/maintenance is limited to 100 hours per year.
[6] Stack exhaust parameters based on Cummins Diesel fire pump Model CFP15E-F7NL data sheet.

Stack Parameters		
Exhaust Temperature	875	degrees F
Exhaust Flow	3,200	acfm
Exit Velocity	271.6	ft/s
	82.8	m/s
Stack Inner Diameter	6.0	in
	0.5	ft
	0.15	m
Stack Height AG	15	ft

Conversion Factors	
g/lb	453.6
lb/ton	2,000

Table B-11
Jordan Cove Energy Project
LNG Liquefaction and Export Facility

Emergency Diesel Generator Potential Emissions Summary

Engine parameters

Power output base load	2,500	kW
	3350	hp
Heat Input Capacity (HHV)	22.5	MMBtu/hr
	32101.0	gal/yr
Displacement per Cylinder	<10	Liters
Maximum Annual Operation	200	hr/yr

Pollutant	Potential Emissions (per engine) g/bhp-hr	lb/MMBtu	lb/hr	g/s	Total Annual (ton/yr)	Total Annual (ton/yr) (2 engines)
NO_x	4.44	1.4592	32.79	4.13	3.28	6.56
CO	2.60	0.8545	19.20	2.42	1.92	3.84
VOC	0.36	0.1183	2.66	0.34	2.66E-01	5.32E-01
PM	0.15	0.0493	1.11	0.14	1.11E-01	2.22E-01
SO_2		0.0015	0.0342	0.0043	3.42E-03	6.84E-03
H_2SO_4		1.16E-04	2.62E-03	3.30E-04	2.62E-04	1.05E-03
CO_2		163.05	3664.06	461.67	3.66E+02	1.47E+03
N_2O		0.0013	0.030	0.0037	2.97E-03	1.19E-02
CH_4		0.0066	0.149	0.0187	1.49E-02	5.94E-02
CO_2e					3.68E+02	1.471E+03

(1) NO_x, VOC and PM emissions are based upon Tier 2 emission limits identified in NSPS Subpart IIII. To determine individual limits for NOx and VOC, Tier 2 limit for NO_x+HC was apportioned using AP-42 emission factor ratios.

(2) Emissions of SO_2 and H_2SO_4 based on mass balance of sulfur in fuel:

Sulfur Content	15	ppm by weight
Higher Heating Value	19,719	Btu/lb
	140,005	Btu/gal
Molecular Weight of S =	32	lb/lbmol
Molecular Weight of SO_2 =	64	lb/lbmol
Molecular Weight of H_2SO_4 =	98	lb/lbmol
% SO_2 to SO_3 conversion	5%	

(3) CO_2, N_2O and CH_4 emissions based on 40 CFR Part 98 Appendix C emission factors

(43) Unit will operate only during emergency situations and for limited periods per week for testing purposes. The total annual operation restriction is noted above and reflected in the tons/yr PTE values.

Stack Parameters		
Exhaust Temperature	915.0	degrees F
Exhaust Flow	19,582.0	acfm
Exit Velocity	415.5	ft/s
	126.7	m/s
Stack Inner Diameter	12.0	in
	1.0	ft
	0.30	m
Stack Height AG	15	ft

Conversion Factors	
g/lb	453.6
lb/ton	2,000

Table B-12
Jordan Cove Energy Project, L.P.

Potential HAP Emissions Summary

Equipment Parameters:	Heat Input (mmBtu/hr)	Operation (hrs/year)	Number of Units
Combustion Turbine - Gas (max)	554.0	8,760	6
Duct Burner	105.6	4,000	6
Emergency Generators	22.5	200	2
South Dunes Fire Pump	2.7	200	1
Liquefaction Area Fire Pump	4.7	200	4
Thermal Oxidizer	17.5	8,760	2
Flare	0.0425	8,760	2

Fuel Properties:		
Natural Gas Heat Content	1,026	Btu/scf

	New Combustion Turbines		Duct Burners		Emergency Generators		South Dunes Fire Pump		Liquefaction Area Fire Pump		Thermal Oxidizer		Flare		
	Natural Gas Firing		Natural Gas Firing		ULSD Firing		ULSD Firing		ULSD Firing		Gas Firing		Gas Firing		Total
	EF Basis (1)	Max Hourly Per CT	EF Basis (2)	Max Hourly Per DB	EF Basis (3)	Max Hourly Per EDG	EF Basis (4)	Max Hourly Per FP	EF Basis (4)	Max Hourly Per FP	EF Basis (2)	Max Hourly Per TO	EF Basis (2)	Max Hourly Per TO	Facility PTE
Hazardous Air Pollutants (HAPs)	lb/MMBtu	lb/hr	lb/MMCF	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMCF	lb/hr	lb/MMCF	lb/hr	tons/yr
VOC-HAP															
Acetaldehyde	4.00E-05	2.22E-02			2.52E-05	5.66E-04	7.67E-04	2.06E-03	7.67E-04	3.60E-03					5.8E-01
Acrolein	6.40E-06	3.55E-03			7.88E-06	1.77E-04	9.25E-05	2.48E-04	9.25E-05	4.34E-04					9.3E-02
Benzene	1.20E-05	6.65E-03	2.10E-03	2.16E-04	7.76E-04	1.74E-02	9.33E-04	2.50E-03	9.33E-04	4.38E-03	2.10E-03	3.58E-05	2.10E-03	8.70E-08	1.8E-01
1,3-Butadiene	4.30E-07	2.38E-04													6.3E-03
Dichlorobenzene			1.20E-03	1.24E-04							1.20E-03	2.05E-05	1.20E-03	4.97E-08	1.7E-03
Ethylbenzene	3.20E-05	1.77E-02													4.7E-01
Formaldehyde (see note #1)	1.10E-04	6.09E-02	7.50E-02	7.72E-03	7.89E-05	1.77E-03	1.18E-03	3.17E-03	1.18E-03	5.54E-03	7.50E-02	1.28E-03	7.50E-02	3.11E-06	1.7E+00
Hexane			1.80E+00	1.85E-01							1.80E+00	3.07E-02	1.80E+00	7.46E-05	2.5E+00
Naphthalene	1.30E-06	7.20E-04	6.10E-04	6.28E-05	1.30E-04	2.92E-03	8.48E-05	2.28E-04	8.48E-05	3.98E-04	6.10E-04	1.04E-05	6.10E-04	2.53E-08	2.1E-02
Propylene Oxide	2.90E-05	1.61E-02													4.2E-01
Toluene	1.30E-04	7.20E-02	3.40E-03	3.50E-04	2.81E-04	6.31E-03	4.09E-04	1.10E-03	4.09E-04	1.92E-03	3.40E-03	5.80E-05	3.40E-03	1.41E-07	1.9E+00
Xylenes	6.40E-05	3.55E-02			1.93E-04	4.34E-03	2.85E-04	7.65E-04	2.85E-04	1.34E-03					9.3E-01
Polycyclic Organic Compounds (POM)															
Acenaphthene	8.50E-08	4.71E-05	1.80E-06	1.85E-07	4.68E-06	1.05E-04	1.42E-06	3.81E-06	1.42E-06	6.67E-06	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.3E-03
Acenaphthylene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	9.23E-06	2.07E-04	5.06E-06	1.36E-05	5.06E-06	2.38E-05	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.3E-03
Anthracene	1.14E-07	6.32E-05	2.40E-06	2.47E-07	1.23E-05	2.76E-04	1.87E-06	5.02E-06	1.87E-06	8.78E-06	2.40E-06	4.09E-08	2.40E-06	9.94E-11	1.7E-03
Benz(a)anthracene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	6.22E-07	1.40E-05	1.68E-06	4.51E-06	1.68E-06	7.89E-06	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.3E-03
Benzo(a)pyrene	5.69E-08	3.15E-05	1.20E-06	1.24E-07	2.57E-07	5.78E-06	1.88E-07	5.04E-07	1.88E-07	8.83E-07	1.20E-06	2.05E-08	1.20E-06	4.97E-11	8.3E-04
Benzo(b)fluoranthene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	1.11E-06	2.49E-05	9.91E-08	2.66E-07	9.91E-08	4.65E-07	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.2E-03
Benzo(g,h,i)perylene	5.69E-08	3.15E-05	1.20E-06	1.24E-07	5.56E-07	1.25E-05	4.89E-07	1.31E-06	4.89E-07	2.30E-06	1.20E-06	2.05E-08	1.20E-06	4.97E-11	8.3E-04
Benzo(k)fluoranthene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	2.18E-07	4.90E-06	1.55E-07	4.16E-07	1.55E-07	7.28E-07	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.2E-03
Chrysene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	1.53E-06	3.44E-05	3.53E-07	9.47E-07	3.53E-07	1.66E-06	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.3E-03
Dibenzo(a,h)anthracene	5.69E-08	3.15E-05	1.20E-06	1.24E-07	3.46E-07	7.78E-06	5.83E-07	1.56E-06	5.83E-07	2.74E-06	1.20E-06	2.05E-08	1.20E-06	4.97E-11	8.3E-04
7,12-Dimethylbenz(a)anthracene			1.60E-05	1.65E-06							1.60E-05	2.73E-07	1.60E-05	6.63E-10	2.2E-05
Fluoranthene	1.42E-07	7.87E-05	3.00E-06	3.09E-07	4.03E-06	9.06E-05	7.61E-06	2.04E-05	7.61E-06	3.57E-05	3.00E-06	5.12E-08	3.00E-06	1.24E-10	2.1E-03
Fluorene	1.33E-07	7.37E-05	2.80E-06	2.88E-07	1.28E-05	2.88E-04	2.92E-05	7.83E-05	2.92E-05	1.37E-04	2.80E-06	4.78E-08	2.80E-06	1.16E-10	2.1E-03
3-Methylchloranthrene			1.80E-06	1.85E-07							1.80E-06	3.07E-08	1.80E-06	7.46E-11	2.5E-06
2-Methylnaphthalene			2.40E-05	2.47E-06							2.40E-05	4.09E-07	2.40E-05	9.94E-10	3.3E-05
Indeno(1,2,3-cd)pyrene	8.53E-08	4.73E-05	1.80E-06	1.85E-07	4.14E-07	9.30E-06	3.75E-07	1.01E-06	3.75E-07	1.76E-06	1.80E-06	3.07E-08	1.80E-06	7.46E-11	1.2E-03
Phenanthrene	8.06E-07	4.47E-04	1.70E-05	1.75E-06	4.08E-05	9.17E-04	2.94E-05	7.89E-05	2.94E-05	1.38E-04	1.70E-05	2.90E-07	1.70E-05	7.04E-10	1.2E-02
Pyrene	2.37E-07	1.31E-04	5.00E-06	5.15E-07	3.71E-06	8.34E-05	4.78E-06	1.28E-05	4.78E-06	2.24E-05	5.00E-06	8.53E-08	5.00E-06	2.07E-10	3.5E-03
Total POM	2.2E-06	1.2E-03	8.82E-05	9.08E-06	9.26E-05	2.08E-03	8.33E-05	2.23E-04	8.33E-05	3.91E-04	8.82E-05	1.50E-06	8.82E-05	3.65E-09	3.27E-02
Metal-HAPs															
Arsenic	1.96E-07	1.09E-04	2.00E-04	2.06E-05	1.10E-05	2.47E-04	1.10E-05	2.95E-05	1.10E-05	5.17E-05	2.00E-04	3.41E-06	2.00E-04	8.28E-09	3.2E-03
Beryllium	1.18E-08	6.52E-06	1.20E-05	1.24E-06	3.10E-07	6.97E-06	3.10E-07	8.32E-07	3.10E-07	1.46E-06	1.20E-05	2.05E-07	1.20E-05	4.97E-10	1.9E-04
Cadmium	1.08E-06	5.97E-04	1.10E-03	1.13E-04	4.80E-06	1.08E-04	4.80E-06	1.29E-05	4.80E-06	2.25E-05	1.10E-03	1.88E-05	1.10E-03	4.56E-08	1.7E-02
Chromium	1.37E-06	7.60E-04	1.40E-03	1.44E-04	1.10E-05	2.47E-04	1.10E-05	2.95E-05	1.10E-05	5.17E-05	1.40E-03	2.39E-05	1.40E-03	5.80E-08	2.2E-02
Lead	4.90E-07	2.72E-04	5.00E-04	5.15E-05	1.40E-05	3.15E-04	1.40E-05	3.76E-05	1.40E-05	6.57E-05	5.00E-04	8.53E-06	5.00E-04	2.07E-08	7.9E-03
Manganese	3.73E-07	2.06E-04	3.80E-04	3.91E-05	7.90E-04	1.78E-02	7.90E-04	2.12E-03	7.90E-04	3.71E-03	3.80E-04	6.48E-06	3.80E-04	1.57E-08	1.1E-02
Mercury	2.55E-07	1.41E-04	2.60E-04	2.68E-05	1.20E-06	2.70E-05	1.20E-06	3.22E-06	1.20E-06	5.63E-06	2.60E-04	4.43E-06	2.60E-04	1.08E-08	4.1E-03
Nickel	2.06E-06	1.14E-03	2.10E-03	2.16E-04	4.60E-06	1.03E-04	4.60E-06	1.23E-05	4.60E-06	2.16E-05	2.10E-03	3.58E-05	2.10E-03	8.70E-08	3.3E-02
Selenium	2.35E-08	1.30E-05	2.40E-05	2.47E-06	2.50E-05	5.62E-04	2.50E-05	6.71E-05	2.50E-05	1.17E-04	2.40E-05	4.09E-07	2.40E-05	9.94E-10	5.4E-04
Total HAPs		2.40E-01		1.94E-01		5.50E-02		1.26E-02		2.21E-02		3.22E-02			8.94E+00
													Maximum Individual HAP		**2.5**
													Total HAPs		**8.9**

Notes:
Emission Factor References -
(1) U.S. EPA AP-42 Emission Factor Guidance Document, Section 3.1 (Stationary Gas Turbines), Table 3.1-3. Note metal HAPs assumed to be equivalent to natural gas firing of external combustion sources (see Ref #2).
Natural gas formaldehyde emission factor from California Air Resource Board (CARB) emission inventory.
(2) U.S. EPA AP-42 Emission Factor Guidance Document, Section 1.4 (Natural Gas Combustion), Tables 1.4-2, 1.4-3, and 1.4-4.
(3) U.S. EPA AP-42 Emission Factor Guidance Document, Section 3.4 (Large Stationary Diesel Engines), Tables 3.4-3 and 3.4-4. Note metal HAPs assumed to be equivalent to distillate fuel oil firing of combustion turbines.

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Recent RACT/BACT/LAER Determinations for Natural G
Nitrogen Oxi

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION U
LANGLEY GULCH POWER PLANT	PAYETTE, ID	6/25/2010	NO	SIEMENS SGT6-5000F COMBU
CARTY PLANT	MORROW, OR	12/29/2010	NO	COMBINED CYCLE NATURAL G
KING POWER STATION	HARRIS, TX	8/5/2010	NO	TURBINE
THOMAS C. FERGUSON POWER PLANT	LLANO, TX	9/1/2011	NO	(2) GE 7FA COMBUSTION TURI
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TU
FPL WEST COUNTY ENERGY CENTER UNIT 3	PALM BEACH COUNTY, FL	7/30/2008	?	(3) NOMINAL 250 MW CTG (EA
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SIEMENS SGT6-5000F COMBU
CANE ISLAND POWER PARK	OSCEOLA, FL	9/8/2008	?	300 MW COMBINED CYCLE CO
LANGLEY GULCH POWER PLANT	PAYETTE, ID	6/25/2010	NO	COMBUSTION TURBINE, COMB
PATTILLO BRANCH POWER PLANT	FANNIN, TX	6/17/2009	?	ELECTRICITY GENERATION
NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR, TX	6/22/2009	?	ELECTRICITY GENERATION
MADISON BELL ENERGY CENTER	MADISON, TX	8/18/2009	?	ELECTRICITY GENERATION
VEPCO WARREN COUNTY FACILITY	WARREN, VA	1/14/2008	?	ELECTRIC GENERATION - SCE
				ELECTRIC GENERATION - SCE
				ELECTRIC GENERATION SECN
CHOUTEAU POWER PLANT	MAYES, OK	1/23/2009	?	COMBINED CYCLE COGENERA
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBIN
FP&L TURKEY POINT FOSSIL PLANT - UNIT 5	HOMESTEAD, FL	6/1/2004	NO	(4) TURBINE W/ DB, W/ POWEF
VINEYARD ENERGY CENTER, LLC	VINEYARD, UT	5/11/2004	NO	(3) SWPC 501F COMBUSTION
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) COMBINED CYCLE TURBIN
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBU
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	NO	(4) COMBINED CYCLE TURBIN
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBIN
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO	(2) COMBINED CYCLE TURBIN
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	?	TURBINE, COMBINED CYCLE,
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	?	TURBINE, COMBINED CYCLE,
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	(2) TURBINE, COMBINED CYCL
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTIO
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION AE
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	YES	(2) TURBINE, COMBUSTION AE
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCL
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	?	(2) TURBINE, COMBINED CYCL
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	YES	TURBINE, COMBINED CYCLE
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	NO	(3) TURBINE, COMBINED CYCL
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCL
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBU
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURB
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYC
MIRANT BOWLINE LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBIN
				(3) COMBINED CYCLE TURBIN
CONED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, V
				(2) COMBUSTION TURBINES, V
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBU
				(1) COMBINED CYCLE COMBU
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	?	(2) TURBINE, COMBINED CYCL
				(2) TURBINE, COMBINED CYCL
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYC
				(2) TURBINES, COMBINED CYC
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	(2) SIEMENS SGT6-5000F CTG
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SC
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SC
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SC
ATHENS GENERATING PLANT	GREENE, NY	1/19/2007	NO	FUEL COMBUSTION (GAS)
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/16/2005	?	TURBINE, COMBINED CYCLE (
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY, NV	8/17/2005	?	TURBINE, COMBINED CYCLE (
EMPIRE POWER PLANT	RENSSELAER, NY	6/23/2005	?	FUEL COMBUSTION (NATURA
ISLAND END-CABOT POWER	BOSTON, MA	2000	NO	TURBINE, COMBINED CYCLE
HERITAGE STATION	SCRIBA NY	10/12/2000	NO	TURBINE, COMBINED CYCLE
BOWLINE POINT UNIT 3	NEW YORK	2001	NO	TURBINE, COMBINED CYCLE
RAVENSWOOD COGENERATION FACILITY	LONG ISLAND CITY, NY	2001	NO	TURBINE, COMBINED CYCLE
SITHE MYSTIC DEVELOPMENT LLC	EVERETT, MA	1/25/2000	NO	TURBINE, COMBINED CYCLE
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYC
FREE STATE ELECTRIC	MARYLAND	9/27/2001	NO	TURBINE, COMBINED CYCLE
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBU
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCL
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TU
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TU
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TU
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	YES	COMBINED CYCLE NATURAL (
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	YES	TURBINE, COMBINED CYCLE
PINNACLE WEST ENERGY CORP./REDHAWK	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE [
KYRENE GENERATING STATION, SALT RIVER	PHOENIX, AZ	3/14/2001	YES	TURBINE, COMBINED CYCLE [
MOUNTAINVIEW POWER	SAN BERNARDINO, CA	5/22/2001	YES	(4) TURBINE, COMBINED CYCL
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, C
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBU
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE

Appendix C
RACT/BACT/LAER Clearinghouse Review

Table C-1
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYLE, W/ AND W/O DB	1,600	DLN COMBUSTORS WITH SCR	2.5	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	DLN COMBUSTORS & SCR	2.5	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	LNB, SCR	2.5	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	LNB, SCR	2.5	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	DLN COMBUSTOR AND SCR SYSTEM	2.5	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	SCR	2.5	LAER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	SCR AND DLN BURNERS	2.5	LAER
CAROLINA POWER & LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	DLN COMBUSTORS AND SCR	2.5	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	DLN AND SCR	2.5	BACT-PSD
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	DLN AND SCR	2.5	BACT-PSD
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE W/ AND W/O DB (GE, MHI, SW)	1,400	DLN AND SCR	2.5	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	LNB WITH SCR	2.5	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LNB WITH SCR	2.5	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE, W/ AND W/O DB	2,964	SCR - AMMONIA FLOW RATE AT 11.46 GAL/H	2.5	OTHER
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE (60%-100% LOAD) W/ AND W/O DB	2,181	SCR - 29% AQUEOUS AMMONIA, DLN	2.5	OTHER
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	?	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	SCR, DLN COMBUSTION AND GCP	2.5	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	DLN COMBUSTORS, AND SCR	2.5	BACT-PSD
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	DLN COMBUSTION, SCR	2.5	BACT-PSD
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	SCR	2.5	LAER
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	SCR, DLN COMBUSTION	2.5	LAER
CONECTIV BETHLEHEM, INC.	PENNSYLVANIA	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	SCR, DLN COMB, CLEAN FUEL WI NG DIFFUSION MODE	2.5	LAER
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	?	(2) TURBINE, COMBINED CYCLE	2,240	LNB, SCR	2.5	LAER
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	DLN BURNERS WITH SCR	2.5	BACT-PSD
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	DLN & SCR	2.5	LAER
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	LEAN PRE-MIX DLN AND GCP. SCR SYSTEM AND CEM	2.5	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	2,325	DLN BURNERS SCR W/ CEM DEVICES	2.5	BACT-PSD
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	2,470	SCR AND LNB. GCP	2.5	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	SCR	2.5	BACT-OTHER
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	SCR	2.5	BACT-OTHER
BLACK HILLS CORP./NEIL SIMPSON TWO	GILLETTE, WY	4/4/2003	?	TURBINE, COMBINED CYCLE & DUCT BURNER	320	DLN BURNERS AND SCR	2.5	BACT-OTHER
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	SCR	2.5	BACT-PSD
				TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,923		3.1	
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	DLN COMBUSTION AND SCR W/CEM	2.5	BACT-PSD
				(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		3.3	
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	THE USE OF DLN COMBUSTOR AND SCR	2.5	BACT-PSD
				(4) COMBUSTION TURBINE COMBINED CYCLE, W/ STEAM INJ	2,010		3.5	
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	LNB AND GCP. SCR USING AMMONIA INJECTION. CEM	2.5	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, 70% LOAD	1,492		4.5	
HINES POWER BLOCK 4	POLK, FL	6/8/2005	?	COMBINED CYCLE TURBINE	4,240	SCR	2.5	BACT-PSD
SEPCO	RIO LINDA, CA	10/5/1994	?	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920	SCR AND DLN COMBUSTION	2.6	BACT
EMPIRE POWER PLANT	RENSSELAER, NY	6/23/2005	?	FUEL COMBUSTION (NATURAL GAS) DUCT BURNING	646	DLN IN COMBINATION W/ SCR	3.0	LAER
S.W.E.C, LLC	FALLS TWP, PA	2001	NO	COMBUSTION TURBINE			3.0	LAER
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO, CA	8/19/1994	YES	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	1,257	SCR AND DRY LOW NOX COMBUSTION	3.0	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,876	SCR AND DLN	3.0	BACT-PSD
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	SCR	3.0	BACT-PSD
SALT RIVER/DESERT BASIN GENERATING PROJECT	PHOENIX, AZ	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	SCR	3.0	BACT-PSD
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO, CA	8/19/1994	?	TURBINE, GAS COMBINED CYCLE LM6000	421	SCR AND WATER INJECTION	3.0	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO, CA	8/19/1994	?	TURBINE GAS COMBINE CYCLE SIEMENS V84.2	1,257	SCR AND DLN COMBUSTION	3.0	BACT
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	YES	(2) COMBINED-CYCLE TURBINE	2,311	LN COMB (POLLUTION PREVENTION) AND SCR (CONTROL)	3.0	BACT-PSD
AUGUSTA ENERGY CENTER	GEORGIA	10/28/2001	YES	(3) TURBINE, COMBINED CYCLE	2,000	SCR	3.0	BACT-PSD
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	LNB AND SCR	3.0	BACT-PSD
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	DLN BURNERS AND SCR	3.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE, GA	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	DLN COMBUSTORS SCR	3.0	
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	YES	(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400	SCR WITH DLN COMBUSTION	3.0	BACT-PSD
ROQUETTE AMERICA	KEOKUK, IA	1/31/2003	?	TURBINE, COMBINED CYCLE	587	SCR	3.0	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	SCR	3.0	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	SCR	3.0	BACT-PSD
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION, W/ AND W/O DB	1,735	SCR (80-90%), DLN BURNERS AND GCP	3.0	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE, W/ AND W/O DB	1,944	DLN BURNERS AND GOOD COMBUSTION: SCR	3.0	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,491	DLN BURNERS AND SCR. NATURAL GAS IS ONLY FUEL	3.0	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	YES	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	SCR AND LNB	3.0	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	YES	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883	DLN BURNERS AND SCR	3.0	BACT-PSD
CONTINENTAL ENERGY SVC, SILVER BOW GEN	BUTTE, MT	6/7/2002	NO	(4) COMBINED CYCLE CT	1,400	SCR	3.0	BACT-PSD
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON/OFF	1,440	DLN & LNB & SCR	3.0	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	YES	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON/OFF	1,376	DLN BURNERS AND SCR	3.0	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	DLN BURNERS, SCR	3.0	LAER
RELIANT ENERGY- CHANNELVIEW COGEN	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	3.0	BACT
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	SCR	3.0	LAER
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	SCR SYSTEM UNIT	3.0	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	SCR, CEM	3.0	BACT-PSD
TRANSALTA CENTRALIA GENERATION LLC	CENTRALIA, WA	2/22/2002	?	(4)TURBINE/HRSG	1,504	WATER INJECTION AND SCR	3.0	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	ADVANCED DLN TECHNOLOGY AND SCR	3.0	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	7/25/2001	YES	(2) GAS TURBINES COMBINED CYCLE	2,205	DLN STAGED COMB SCR MODE: W/ STEAM INJECTION	3.0	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE	2,200	DLN BURNERS AND SCR	3.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE W/ DB, POWER AUG.	2,200		3.5	
HAY ROAD POWER COMPLEX UNITS 5-8	WILMINGTON, DE	10/17/2000	YES	TURBINES (3) COMBINED CYCLE PREMIXED MODE, BASELOAD	1,333	DLN BURNERS WITH SCR	3.0	LAER
				TURBINES (3) COMBINED CYCLE PREMIXED MODE, PEAKLOAD	1,333		9.0	
				TURBINES (3) COMBINED CYCLE NG DIFFUSION MODE	1,333		14.0	
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMB WITH SCR ADD-ON NOX CONTROL	3.1	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	SCR & DLN	3.1	BACT-OTHER
SOUTHERN ENERGY, INC.	ZEELAND, MI	3/16/2000	NO	COMBINED CYCLE TURBINE ELECTRICAL GENERATING UNITS		SELECTIVE CATALYTIC REDUCTION (SCR)	3.5	BACT-PSD
PIKE GENERATION FACILITY	MCCOMB, MS	11/14/2000	NO	COMBUSTION TURBINE	1,259	DLN, SCR	3.5	BACT-PSD
CPV GULFCOAST LTD	MANATEE CO, FL	2/6/2001	NO	COMBUSTION TURBINE	1,960	SCR	3.5	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMB WITH SCR ADD-ON NOX CONTROL	3.5	BACT-PSD

Table C-1

JCEP LNG Terminal Project

Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW

Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	NO	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000	NONE INDICATED	3.5	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	DLN W/SCR	3.5	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	ALABAMA	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	DLN COMBUSTION & SCR	3.5	BACT-PSD
DUKE ENERGY DALE, LLC	ALABAMA	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	DLN AND SCR	3.5	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	ALABAMA	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	SCR	3.5	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	DLN COMBUSTORS + SCR	3.5	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	SCR/DLN	3.5	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	DLN BURNERS AND SCR	3.5	BACT-PSD
HOT SPRINGS POWER PROJECT	ARKANSAS	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	DLN BURNERS W/ SCR	3.5	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	ARKANSAS	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	SCR AND DLN COMBUSTORS	3.5	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	SCR	3.5	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (GE, SWH OR MHI)	1,360	DLN COMBUSTOR/SCR	3.5	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,696	DLN BURNERS	3.5	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	DLN WET INJECTION	3.5	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	DLN COMBUSTORS & SCR	3.5	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	SCR (DLN 2.6). WET INJECTION	3.5	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA, FL	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	SCR	3.5	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	DLN BURNERS	3.5	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	GOOD COMBUSTION AND SCR	3.5	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	DUCT BURNER, SCR	3.5	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD, ME	5/1/1998	YES	TURBINE GENERATOR COMBUSTION	1,906	SCR	3.5	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	SCR	3.5	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	DLN BURNERS AND SCR	3.5	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE, W/ AND W/O DB	2,096	DLN BURNER AND SCR	3.5	BACT-PSD
INDECK-NILES, LLC	NILES, MI	12/2/2001	?	(4) GAS TURBINES COMBINED CYCLE, W/ AND W/O DB	2,152	LNB AND SCR	3.5	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	DLN BURNERS STAGED COMB OF NATURAL GAS + SCR	3.5	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	DLN COMBUSTORS + SCR	3.5	BACT-PSD
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	SCR	3.5	BACT-PSD
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	LNB AND SCR UNIT	3.5	BACT-PSD
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	DLN BURNERS AND SCR	3.5	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	DLN COMBUSTORS, SCR	3.5	BACT-PSD
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	NO	(2) TURBINE, COMBINED CYCLE	640	LNB AND SCR	3.5	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	SCR AND COMBUST ONLY PIPELINE QUALITY NATURAL GAS	3.5	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE W/ AND W/O DUCT FIRING	1,360	DLN COMBUSTION BURNERS AND SCR	3.5	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,360	DLN COMBUSTION BURNERS AND SCR	3.5	BACT-PSD
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DB	2,440	SCR WITH DLN COMBUSTION	3.5	BACT-PSD
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/ AND W/O DB	1,440	SCR AND DLN BURNERS	3.5	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/ AND W/O DB	1,374	SCR AND DLN BURNERS	3.5	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	COMBUSTION TURBINE & DUCT BURNERS (GE OR MHI)	1,705	SCR WITH DLN COMBUSTORS	3.5	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	SCR, DLN COMBUSTORS	3.5	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	SCR WITH DLN BURNERS	3.5	BACT-PSD
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	?	(3) TURBINE, COMBINED CYCLE, W/ AND W/O DB	1,798	DLN COMBUSTION TECHNOLOGY AND SCR	3.5	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000	DLN COMBUSTORS, SCR	3.5	LAER
LOWER MOUNT BETHEL ENERGY, LLC	FAIRFAX	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	SCR, DLN LEAN BURN COMBUSTORS	3.5	LAER
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	DLN LEAN BURNERS & SCR	3.5	LAER
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNERS, SCR	3.5	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TENNESSEE	2/1/2002	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,990	DLN BURNERS, SCR	3.5	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	SCR AND LNB	3.5	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	SCR	3.5	LAER
CHANNEL ENERGY FACILITY	HOUSTON, TX	3/22/2000	?	(3) TURBINE	1,440	SCR	3.5	LAER
CHAMBERS ENERGY L.P./AMERICAN NATIONAL POWER	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	DLN COMBUSTORS AND SCR SYSTEM H2O INJECTION	3.5	LAER
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	DLN COMBUSTION AND SCR	3.5	LAER
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	SCR, DLN BURNERS	3.5	LAER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACK	1,400	SCR	3.5	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	SCR	3.5	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	DLN COMBUSTORS & SCR	3.5	BACT-OTHER
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,937	WATER INJECTION SCR AND CEM	3.5	LAER
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION + SCR ADD-ON NOX CONTROLS	3.5	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	LNB + SCR	3.5	BACT-PSD
				(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DB	1,900		3.7	
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	DLN BURNERS AND SCR	3.5	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		4.4	
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	DLN COMBUSTOR & SCR NOX CONTROL	3.6	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	CLEAN BURNERS AND SCR	3.6	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	DLN BURNERS AND SCR	3.6	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	DLN BURNER AND SCR	3.6	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GEN UNITS	1,384	DLN AND SCR	3.6	BACT-PSD
BEAR MOUNTAIN LIMITED	BAKERSFIELD, CA	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	STEAM INJECTION AND SCR	3.6	BACT-OTHER
SWEPCO ARSENAL HILL POWER PLANT	CADDO, LA	3/20/2008	?	TWO COMBINED CYCLE GAS TURBINES	2,110	LOW NOX TURBINES, DUCT BURNERS COMBINED WITH SCR	3.9	BACT
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	DLN BURNER & SCR ON TURBINE. LNB ON DUCT BURNER	4.0	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	DLN COMBUSTION AND SCR USING AMMONIA INJECTION	4.0	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	SCR OF NOX	4.0	BACT-OTHER
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224	DRY LNB WITH SCR	4.0	LAER
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	LNB, SCR	4.0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	5/31/1994	YES	TURBINES, NATURAL GAS (2)	1,720	SCR	4.5	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO, NY	11/24/1992	YES	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133	SCR AND DRY LOW NOX	4.5	BACT-OTHER
FAIRBAULT ENERGY PARK	RICE, MN	6/5/2007	?	COMBINED CYCLE COMBUSTION TURBINE W/DUCT BURNER	1,758	DLN COMBUSTION FOR NG; WATER INJ FOR OIL; SCR	4.5	BACT-PSD
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	LNB, SCR	4.5	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	SCR	4.5	BACT-OTHER
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	DLN BURNERS AND SCR	4.5	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	SCR WITH A NOX CEM AND A NOX PEM	4.5	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GEN STATION	BURNSVILLE, MN	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	DLN COMBUSTORS PLUS SCR	4.5	95.9
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	DLN BURNERS, SCR	4.5	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	DLN COMBUSTOR	4.5	BACT-PSD
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	DRY COMBUSTION CONTROLS AND SCR	4.5	BACT-PSD

Table C-1
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	(2) COMBUSTION TURBINES #1 & #2	1,836	SCR	4.5	BACT-PSD
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	LNB, AND/OR SCR GOOD OPER & NATURAL GAS AS FUEL	4.5	BACT-PSD
				(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		12.5	
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	NO	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	SCR, LOW NOX COMBUSTORS	4.5	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166		15.0	
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	DLN COMBUSTOR IN CT LNB IN DUCT BURNER, SCR	4.9	BACT-PSD
CROCKETT COGENERATION - C&H SUGAR	CROCKETT, CA	10/5/1993	YES	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	1,920	DRY LOW-NOX COMBUSTERS AND A MITSUBISHI HEAVY INDUSTRIES AMERICAN SCR	5.0	BACT-OTHER
GEISMAR PLANT	GEISMAR, LA	2/26/2002	?	(2) COGENERATION UNITS W/ AND W/O DB	320	LNB AND A SCR SYSTEM	5.0	BACT-PSD
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	DLN BURNERS, SCR	5.0	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	SCR & DLN BURNERS	5.0	BACT-PSD
SAM RAYBURN GENERATION STATION	NURSERY	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	SCR AND GOOD COMBUSTION"	5.0	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(6) GAS FUELED TURBINES, STACK 1-6	2,200	SCR, DLN BURNERS	5.0	BACT-PSD
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE W/ AND W/O POWER AUGMENTATION	2,000	DLN COMBUSTORS & SCR	5.0	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	DLN BURNERS & SCR SYSTEM	5.0	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	DLN BURNERS, FIRING WITH NATURAL GAS, USE OF SCR	5.0	BACT-PSD
				(4) GAS TURBINES TURBINE ONLY FIRING	1,360		9.0	
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	SCR & DLN COMBUSTORS	5.1	BACT-PSD
BRIDGEPORT ENERGY, LLC	BRIDGEPORT, CT	6/29/1998	YES	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	2,080	DRY LOW NOX BURNER WITH SCR	6.0	BACT-PSD
HERMISTON POWER PARTNERSHIP	OREGON	4/13/1999	?	(2) TURBINE	1,853	SCR	6.0	OTHER
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	SCR AND DLN BURNERS	6.0	BACT-OTHER
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	TURBINE/HRSG (CG-3)	1,280	SCR, DLN COMBUSTORS	6.0	LAER
				TURBINE/HRSG (CG-2)	1,280		9.0	
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	STEAM/WATER INJECTION AND SCR	7.0	BACT-PSD
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	SCR	7.5	BACT
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	STEAM INJECTION AND SCR	8.0	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TWP, NJ	4/1/1991	YES	TURBINES (NATURAL GAS) (2)	1190	SCR, DRY LOW NOX BURNER	8.9	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP	VA	5/4/1990	YES	TURBINE, COMBUSTION	1261	DRY COMBUSTOR TO 25 PPM SCR TO 9 PPM USING NAT GAS	9.0	OTHER
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	FL	10/15/1999	NO	TURBINE-GAS, COMBINED CYCLE	4,000	DLN GE DLN2.6 BURNERS	9.0	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN, GA	4/3/1996	YES	COMBUSTION TURBINE (2), NATURAL GAS	928	SCR	9.0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE, RI	4/13/1992	YES	TURBINE, GAS AND DUCT BURNER	1,360	SCR	9.0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	YES	TURBINE, COMBUSTION GAS (150 MW)	1,146	DRY LOW NOX	9.0	BACT-OTHER
SARANAC ENERGY COMPANY	PLATTSBURGH, NY	7/31/1992	YES	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123	SCR	9.0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK, NY	6/18/1992	YES	COMBUSTION TURBINES (2) (252 MW)	1,173	STEAM INJECTION AND SCR	9.0	BACT-OTHER
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	?	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	DLN BURNER ON TURBINE AND LNB ON DUCT BURNER	9.0	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	DLN GE DLN2.6 BURNERS	9.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	DLN 2.6 GE ADVANCED DLN BURNERS	9.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	DLN TECHNOLOGY AND WET INJECTION	9.0	BACT-PSD
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945	SCR	9.0	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE, LA	3/2/1995	?	TURBINE/HRSG, GAS COGENERATION	450	DLN BURNER/COMBUSTION DESIGN AND CONTROL	9.0	LAER
FORMOSA PLASTICS CORP, BATON ROUGE PLANT	BATON ROUGE, LA	3/7/1997	YES	TURBINE/HSRG, GAS COGENERATION	450	DLN BURNER/COMBUSTION DESIGN AND CONSTRUCTION	9.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	?	(2) GAS TURBINES	1,908	DLN COMBUSTORS AND BURNERS	9.0	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	?	(2) COGENERATION UNITS COMBINED CYCLE	320	SCR	9.0	BACT-PSD
CARVILLE ENERGY CENTER	NORTHBROOK, IL	5/16/2001	?	(2) GAS TURBINES (1-98A, 2-98A)	1,908	DLN COMBUSTOR AND BURNERS	9.0	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	9.0	OTHER
CHAMPION INTL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	DLN BURNER	9.0	BACT-OTHER
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINTS AA-001, 002, 003	2,248	SCR	9.0	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINES COMB CYCLE W/ & W/O DB	2,400	SCR AND DLN BURNERS	9.0	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	DLN COMBUSTORS	9.0	BACT-PSD
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	DLN COMBUSTOR	9.0	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNERS	9.0	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	DLN BURNER WITH NATURAL GAS	9.0	BACT-PSD
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	SCR ON TURBINES & DBS AND DRY LNB'S ON TURBINES	9.0	BACT-PSD
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	SCR	9.0	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	LOW NOX COMBUSTORS, SCR	9.0	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	SCR	9.0	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	NONE INDICATED	9.0	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	SCR	9.0	NSPS
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINES GT-HRSG 1-4 W/ AND W/O DB	2,000	DLN BURNERS	9.0	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	SCR	9.0	NSPS
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	DLN COMBUSTORS	9.0	BACT-PSD
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HRSG	2,800	NONE INDICATED	9.0	BACT-OTHER
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	9.0	NSPS
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	DLN COMBUSTION DESIGN	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE DUCT BURNER	1,488		9.4	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	DLN BURNERS	9.0	BACT-PSD
				(3) COMBUSTION TURBINES W/O DB, W/ STEAM INJECTION	1,440		12.0	
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		13.4	
BASTROP CLEAN ENERGY CENTER		3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	LNB, FIRING ONLY NAT GAS	9.0	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		12.6	
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	DLN COMBUSTORS	9.0	BACT-PSD
				(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		13.0	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	DLN BURNERS	9.0	BACT-PSD
				(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		13.0	
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	DLN COMBUSTORS	9.0	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		13.4	
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	DLN BURNERS	9.0	BACT-PSD
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		14.0	
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE	1,698	DLN COMBUSTORS	9.0	BACT-PSD
				(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698		15.0	
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/O DUCT FIRING	1,698	DLN COMBUSTION	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698		15.0	
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	SCR, WATER INJECTION	9.0	BACT-PSD
				COMBUSTION TURBINE, W/O DUCT BURNER	908		24.5	
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	DLN COMBUSTION (DLN MODE)	9.0	BACT-PSD

Table C-1
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	INTERNAL COMBUSTION CONTROLS	25.0	BACT-OTHER
				(2) GAS TURBINES UNITS 1 & 2 W/O DUCT BURNER	602		11.2	
				(2) GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602		21.7	
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) COMBINED CYCLE GENERATION UNIT	1,464	LNB, SCR	11.6	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC.	PRYOR, OK	3/24/1999		ELECTRIC GENERATION, TURBINE, NATURAL GAS	4,240	DRY LOW NOX COMBUSTOR	12.0	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	DLN COMBUSTORS	12.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	DLN BURNERS VERSION 2.6 BY GE	12.0	BACT-OTHER
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	DLN BURNERS WITH SCR	12.0	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	DLN BURNERS	12.0	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO.1, 2, 3	3,168	DLN BURNERS	12.2	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	SCR	12.5	BACT-PSD
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	DLN BURNERS USE OF STEAM INJECTION AS NECESSARY	12.8	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	12/14/1992		TURBINE,GAS	1,214	DRY LOW NOX COMBUSTOR	15.0	BACT-PSD
TIGER BAY LP	FL	5/17/1993		TURBINE, GAS	1,615	DRY LOW NOX COMBUSTOR	15.0	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION (ABB OR GE)	600	DLN BURNER	15.0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB STAGED COMBUSTION	15.0	BACT-PSD
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	?	(2) TURBINES, COMBINED CYCLE	1,280	DLN COMBUSTOR	15.0	BACT-PSD
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	LNB	15.0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	SCR WITH LOW NOX COMBUSTORS	15.0	BACT-OTHER
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	15.0	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/ AND W/O DUCT BURNER FIRING	672	DLN BURNERS	15.0	BACT-OTHER
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	LOW NOX COMBUSTORS, WATER INJECTION & SCR	15.0	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	LNB	15.0	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		15.8	
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	DLN COMBUSTORS FOR TURBINE AND DUCT BURNER	15.0	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464		16.7	
GREGORY POWER FACILITY	TEXAS	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	DLN BURNERS	15.0	BACT-PSD
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		16.8	
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE	457	LNB	15.0	BACT-PSD
				COMBUSTION TURBINE W/ DUCT BURNER	623		19.0	
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	DLN BURNERS	15.0	BACT-OTHER
				(4) GAS TURBINE/HRSG 1-4, EPN1-4, W/ DUCT BURNER	970		25.0	
COLORADO SPRINGS UTILITIES	FOUNTAIN, CO	4/19/1999	YES	TURBINE, COMBINED (70%-100% LOAD)	264	DLN COMBUSTION, < 70% LOAD OPERATION IS MINIMIZED	15.0	BACT-PSD
				TURBINE, COMBINED (<70% LOAD)	264		65.0	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	CASE I: TURBINE E-1 W/O HRSG	720	NONE INDICATED	15.0	NSPS
				CASE I: TURBINE E-2 W/O HRSG	720		15.0	
				CASE II: TURBINE E-1 W/ HRSG	720		85.4	
				CASE II: TURBINE E-2 W/ HRSG	720		74.5	
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	SCR	15.3	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY, DE	3/30/1998	YES	(2) TURBINES, COMBINED CYCLE	827	NITROGEN INJECTION WHILE FIRING GAS	16.0	LAER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	DLN COMBUSTION FOR TURBINES AND DUCT BURNERS	17.0	BACT-PSD
MANSFIELD MILL	MANSFIELD, LA	8/14/2001	?	GAS TURBINE/HRSG	654	DLN BURNER	21.7	BACT-PSD
PLAQUEMINE COGENERATION FACILITY	IBERVILLE, LA	7/23/2008		(4) GAS TURBINES/DUCT BURNERS	2,876	DLN, SCR	22.6	BACT/LAER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	SCR	23.0	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	?	COMBINED CYCLE TURBINE (25 MW)	568	DLN COMBUSTOR DESIGN	25.0	BACT-PSD
WRIGHTSVILLE POWER FACILITY	WRIGHTSVILLE, AR	2/28/2000	?	(6)TURBINE, COMBUSTION GE LM6000	368	STEAM INJECTION	25.0	BACT-PSD
KENTUCKY PIONEER ENERGY, LLC - TRAPP	KENTUCKY	6/7/2001	?	(2) TURBINES, COMBINED CYCLE	1,765	STEAM INJECTION	25.0	BACT-PSD
INTERNATIONAL PAPER	MANSFIELD, LA	2/24/1994	?	TURBINE/HRSG, GAS COGEN	338	DLN COMBUSTOR/COMBUSTION CONTROL	25.0	BACT-OTHER
PINE STATE POWER"	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	WI "QUIET COMBUSTOR" MULTI FUEL NOZZLE CAP ; LNB DB	25.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	TURBINE, COMBINED CYCLE	984	LNB	25.0	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	DILUTION PRIOR TO COMB & DILUTION INJ. IN COMB ZONE	25.0	BACT-PSD
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	SCR	25.0	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	WATER/STEAM INJECTION, COMBUSTION MODIFICATION	25.0	BACT-PSD
SWEENY COGENERATION LIMITED PARTNERS	DALLAS, TX	9/9/1996	?	(3) COMBINED CYCLE TURBINES	970	DLN BURNERS	25.0	BACT-OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	DLN BURNERS	25.0	RACT
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	LOW NOX COMBUSTORS	25.0	BACT-OTHER
SUNLAW COGEN. (FEDERAL COLD STORAGE COGEN)	VERNON, CA	1/15/1994	?	TURBINE, COMBINED CYCLE AND COGEN	224	WI AND SCONOX (MOD 2) CATALYST SYSTEM AFTERHRSG	25.8	BACT-OTHER
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	STACK EMISSIONS (TURBINE & DUCT BURNER)	610	WATER INJECTION	36.0	BACT-OTHER
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848	LNB W/ STEAM INJECTION	42.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(11) TURBINE, COMBINED CYCLE	984	EXISTING STEAM INJECTION	42.0	BACT-PSD
LEDERLE LABORATORIES	PEARL RIVER, NY	9/15/1994	?	(2) GAS TURBINES (EP #S 00101&102)	110	STEAM INJECTION	42.0	BACT-PSD
BORDEN CHEMICALS AND PLASTICS	GEISMAR, LA	5/29/2001	?	COGEN II	471	STEAM INJECTION	51.0	BACT-PSD
BORDEN CHEMICALS AND PLASTICS OPERATING, LP	GEISMAR, LA	5/29/2001	?	COGEN III UNIT	473	STEAM INJECTION	62.0	RACT
HOFFMAN-LA ROCHE, NUTLEY COGEN FACILITY	NUTLEY, NJ	5/8/1995	YES	TURBINE, GM LM500	87	NONE INDICATED	92.1	RACT
GULF STATES UTILITIES COMPANY - LOUISIANA STA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	NONE INDICATED	100.0	OTHER
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	CEM, DLN COMBUSTORS AND GCP	102.0	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, CEMS, CONTINUOUS EMISSION MONITOR, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Table C-2
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SIEMENS SGT6-5000F COMBUSTION TURBINE WITH 445 MMBTU/HR NATURAL GAS DUCT BURNER	2,142	CO CATALYST	0.9	BACT
VIRGINIA ELECTRIC AND POWER COMPANY	WARREN COUNTY, VA	12/17/2010	NO	(3) COMBINED CYCLE TURBINE GENERATORS W/ HRSG & DUCT BURNERS	2996	GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST.	1.5 w/out DB 2.4 w/ DB	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	OXIDATION CATALYST AND GCP	1.3	BACT
				(2) COMBINED CYCLE TURBINES W/ POWER AUGMENTATION, GE 7FA	1,717		1.8	
				(2) COMBINED CYCLE TURBINES W/ DUCT BURNER, GE 7FA	2,217		2.5	
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	YES	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	1.5	LAER
SOUTHERN COMPANY/GEORGIA POWER	COBB COUNTY, GA	1/7/2008	NO	COMBINED CYCLE COMBUSTION TURBINE, NG with Fuel oil backup	2032	OXIDATION CATALYST	9.0	BACT
				COMBINED CYCLE COMBUSTION TURBINE, NG only	2032	OXIDATION CATALYST	1.8	BACT
PATTILLO BRANCH POWER COMPANY LLC	FANNIN, TX	6/17/2009	NO	ELECTRICITY GENERATION	2800	OXIDATION CATALYST	2.0	BACT
BP CHERRY POINT COGENERATION PROJECT	WHATCOM CO., WA	1/11/2005	?	GE 7FA COMBUSTION TURBINE	1,392	LEAN PRE-MIX CT BURNER & OXIDATION CATALYST	2.0	BACT-PSD
LANGLEY GULCH POWER PLANT	PAYETTE, ID	6/25/2010	NO	SIEMENS SGT6-5000F COMBUSTION TURBINE	2,375	OXIDATION CATALYST AND GCP	2.0	BACT/LAER
KING POWER STATION	HARRIS, TX	8/5/2010	NO	TURBINE	2,700	OXIDATION CATALYST AND GCP	2.0	BACT/LAER
WANAPA ENERGY CENTER	UMATILLA, OR	8/8/2005	?	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	2384.1	OXIDATION CATALYST	2.0	BACT-PSD
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	OXIDATION CATALYST	2.0	BACT
LAKELAND C.D. MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	OXIDATION CATALYST	2.0	BACT
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	NO	(2) COMBINED CYCLE TURBINES	2,160	OXIDATION CATALYST AND EFFICIENT COMBUSTION	2.0	BACT
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	CATALYTIC REDUCTION	2.0	OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	2.0	BACT
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	OXIDATION CATALYST	2.0	BACT
AUGUSTA ENERGY CENTER	AUGUSTA, GA	10/28/2001	?	(3) TURBINE, COMBINED CYCLE	2,000	CATALYTIC OXIDATION	2.0	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	CATALYTIC OXIDATION	2.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	GCP	2.0	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	OXIDATION CATALYST AND GCP	2.0	BACT-PSD
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	OXIDATION CATALYST	2.0	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	OXIDATION CATALYST	2.0	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE W/ AND W/O DB	2,964	CO CATALYST	2.0	OTHER
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	CATALYTIC OXIDATION	2.0	BACT-PSD
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	?	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	CATALYTIC OXIDATION	2.0	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	OXIDATION CATALYST	2.0	BACT-OTHER
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	OXIDATION CATALYST	2.0	BACT-OTHER
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	OXIDATION CATALYST	2.0	BACT-PSD
LIVE OAKS COMPANY, LLC	GLYNN, GA	4/8/2010	?	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	4800	GOOD COMBUSTION PRACTICES AND CATALYTIC OXIDATION	2.0	BACT
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	?	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2375.28	CATALYTIC OXIDATION (CATOX), DLN, GCP	2.0	BACT
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	OXIDATION CATALYST	2.0	BACT-PSD
Mirant Bowline, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	CO CATALYST AND EFFICIENT COMBUSTION TECHNIQUES	2.0	BACT
				(3) COMBINED CYCLE TURBINES	2,049		2.8	
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	?	(2) TURBINE, COMBINED CYCLE	1,360	CATALYTIC OXIDIZER	2.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955		3.0	
Keyspan Ravenswood Generating Station	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	OXIDATION CATALYST	2.0	OTHER
				(1) COMBINED CYCLE COMBUSTION TURBINE, W/ DUCT BURNER	2,423		3.9	
ConEd East River Repowering Project	NEW YORK, NY	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OXIDATION CATALYST	2.0	LAER
				(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		4.0	
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440	GCP AND OXIDATION CATALYST	2.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440		10.0	
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION TECHNOLOGY	2.0	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181	OXIDATION CATALYST	2.3	NSPS
				(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		2.4	
				(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		2.5	
				(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181		3.1	
NYPA Poletti Power Project	ASTORIA, NY	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	OXIDATION CATALYST	2.5	LAER
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	NONE INDICATED	2.5	BACT-PSD
CONECTIV BETHLEHEM, INC	PENNSYLVANIA	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	GCP	2.5	BACT-OTHER
El Paso Manatee Energy Center	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	2.5	BACT
				(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742		4.0	
El Paso Belle Glade Energy Center	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	2.5	BACT
				(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742		4.0	
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	OXIDATION CATALYST	2.8	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	OXIDATION CATALYST	2.6	LAER
				(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DUCT BURNER	1,900		3.5	
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, COMBUSTION ABB GT-24 #1 &#2 WITH 2 CHILLERS (100% LOAD)	1,965	OXIDATION CATALYST	3.0	BACT-PSD
				(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS (50-99% LOAD	1,965		11.8	
CALPINE CORP	WELD, CO	5/2/2006	YES	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	2,400	GOOD COMBUSTION CONTROL PRACTICES AND CATALISTIC OXIDATION	3.0	BACT-PSD
NINEMILE POINT ELECTRIC GENERATING PLANT	JEFFERSON, LA	8/16/2011	NO	COMBINED CYCLE TURBINES	3,573	OXIDATION CATALYST AND GCP	3.0	BACT/LAER
Vineyard Energy Center, LLC	VINEYARD, UT	5/11/2004	NO	(3) SWPC 501F COMBUSTION TURBINES	1,738	OXIDATION CATALYST	3.0	BACT
Dome Valley Energy Partners, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	OXIDATION CATALYST	3.0	BACT-OTHER
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	CATALYTIC OXIDIZER	3.0	LAER
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	CATALYTIC OXIDIZER	3.0	LAER
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	OXIDATION CATALYST	3.0	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FORMER SWEC-FALLS TOWNSH	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	3.0	LAER
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	OXIDATION CATALYST	3.0	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	CATALYTIC OXIDIZER	3.0	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE (50%-100% LOAD)	2,010	THE USE OF OXIDATION CATALYST SYSTEM	3.0	BACT-PSD
Lake Road Generating Company, L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (100% LOAD)	2,181	OXIDATION CATALYST	3.0	BACT
				(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (75% LOAD)	2,181		4.0	
				(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3 (50% LOAD)	2,181		20.0	
ANP Bellingham Energy Company	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYCLE ABB GT-24 (75%-100%) W/ STEAM NJECTIO	1,815	OXIDATION CATALYST	3.0	BACT-PSD
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (50%-75%)	1,361		4.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (<50%)	908		20.0	
ANP Blackstone Energy Company	MARLBOROUGH, MA	4/16/1999	?	(2) TURBINES, COMBINED CYCLE ABB GT-24 (75%-100%) W/ STEAM NJECTIO	1,815	OXIDATION CATALYST	3.0	BACT-PSD
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (50%-75%)	1,361		4.0	
				(2) TURBINES, COMBINED CYCLE ABB GT-24 (<50%)	908		20.0	
Brookhaven Energy, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, W/ STEAM INJECTION	1,897	OXIDATION CATALYST	3.0	OTHER
				(4) COMBINED CYCLE TURBINES, 75%-100%	1,897		4.0	
				(4) COMBINED CYCLE TURBINES, 50%-74%	1,404		20.0	
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	GCP AND OXIDATION CATALYST	3.0	BACT-PSD
				(3) TURBINES, STATIONARY GAS COMBINED CYCLE, W/ POWER AUG.	1,360		5.0	
BLUE MOUNTAIN POWER, LP	RICHLAND, PA	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224	OXIDATION CATALYST	3.1	OTHER
				COMBUSTION TURBINE W/ HEAT RECOVERY BOILER (75% LOAD)	1,224		22.1	
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE (70%-100%)	2,132	GCP	3.1	BACT-PSD
				(2) TURBINE, COMBINED CYCLE (<70%)	1,492		16.0	
SIERRA PACIFIC POWER COMPANY	STOREY, NV	8/16/2005	NO	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNE	2,448	OXIDATION CATALYST SYSTEM	3.5	BACT-PSD
				TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNE	2,448	OXIDATION CATALYST	3.5	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE (75%-100%)	1,440	GOOD COMBUSTION AND OXIDATION CATALYST	3.5	BACT-PSD

Table C-2
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS
BERKSHIRE POWER DEVELOPMENT, INC	AGAWAM, MA	9/22/1997	?
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES
KYRENE GENERATING STATION, SALT RIVER PROJECT	PHOENIX, AZ	3/14/2001	YES
CRESENT CITY POWER, LLC	ORLEANS, LA	6/6/2005	YES
CAITHNESS BLYTHE II, LLC	RIVERSIDE, CA	4/25/2007	NO
THOMAS C. FERGUSON POWER PLANT	LLANO, TX	9/1/2011	NO
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	?
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	?
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?
FLORIDA POWER AND LIGHT	DADE, FL	2/8/2005	NO
PROGRESS ENERGY FLORIDA (PEF)	PINELLAS, FL	1/26/2007	NO
FP&L Turkey Point Fossil Plant - Unit 5	HOMESTEAD, FL	6/1/2004	NO
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	?
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?
Towantic Energy, LLC	OXFORD, CT	10/2/2002	?
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	?
CHAMBERS ENERGY L.P./ANP	SAN ANTONIO, TX	3/6/2000	NO
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO
INDECK-NILES, LLC	NILES, MI	12/2/2001	?
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES
FREMONT ENERGY CENTER, LLC	OHIO	8/6/2001	YES
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES
CONTINENTAL ENERGY SVCS, SILVER BOW GEN	BUTTE, MT	6/7/2002	NO
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	YES
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	YES
MOUNTAINVIEW POWER	SAN BERNARDINO, CA	5/22/2001	YES
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?
LOWER MOUNT BETHEL ENERGY, LLC	FAIRFAX	10/20/2001	?
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?
DUKE ENERGY HANGING ROCK ENERGY	OHIO	12/13/2001	?
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES
TPS - DELL, LLC	DELL, AR	8/8/2000	YES
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES
TECO BAYSIDE POWER STATION	TAMPA, FL	3/30/2001	YES
TECO BAYSIDE POWER STATION	TAMPA, FL	1/8/2002	?
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?
FPL ENERGY MARCUS HOOK, L.P.	JUNO BEACH, FL	5/4/2003	?
PROGRESS ENERGY	POLK, FL	6/8/2005	YES
FLORIDA POWER AND LIGHT COMPANY	WEST PALM BEACH, FL	1/10/2007	NO
CPV PIERCE	FLORIDA	8/7/2001	?
CPV CANA	FLORIDA	1/17/2002	?
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?
El Paso Broward Energy Center	BROWARD CO., FL	2001	?
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	NO
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	?
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	NO
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?
MINNESOTA MUNICIPAL POWER AGENCY	RICE, MN	6/5/2007	NO
ROCKY MOUNTAIN ENERGY CENTER, LLC	LITTLETON, CO	8/11/2002	YES
CPV GULFCOAST POWER GENERATING	PINEY POINT, FL	2/5/2001	YES
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	?
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES
CHAMPION INTERNATL CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?
CAROLINA POWER AND LIGHT - RICHMOND CO	RALEIGH, NC	12/21/2000	?
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES
SANTEE COOPER RAINEY GEN STATION	MONKS CORNER, SC	4/3/2000	YES
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?

EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)
TURBINE, COMBINED CYCLE (50%-75%)	1,440
TURBINE, COMBUSTION ABB GT24	1,792
(2) TURBINE, COMBINED CYCLE	2,200
(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200
TURBINE, COMBINED CYCLE DUCT BURNER	1,400
NEW 600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	2,006
520 MW NATURAL GAS-FIRED POWER PLANT	680
NATURAL GAS FIRED TURBINES	1,560
TURBINE, COMBINED CYCLE, DUCT BURNER	1,360
(2) GAS TURBINES	1,611
(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883
TURBINE, COMBINED CYCLE	1,923
TURBINE, COMBINED CYCLE W/ DUCT BURNER	1,923
THE PROPOSED A "4 ON 1" COMBINED CYCLE UNIT 5, WHICH WILL CONSIST	1,360
COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	493
(4) COMBUSTION TURBINE	1,608
(4) COMBUSTION TURBINE W/ DUCT BURNER	2,103
(4) COMBUSTION TURBINE W/ DUCT BURNER, W/ POWER AUG.	2,103
(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600
(2) TURBINES, COMBINED CYCLE	1,338
(2) GE PG7241 FA COMBUSTION TURBINE	1,706
(2) GAS TURBINES WITH DUCT BURNERS	2,097
(3) TURBINE, COMBINED CYCLE	2,400
(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420
(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920
(2) TURBINE, COMBINED CYCLE	2,240
(8) ABB GT-24 COMBUSTION TURBINES	1,440
(2) GAS TURBINE W/ AND W/O POWER AUGMENTATION	2,000
(4) GAS TURBINES COMBINED CYCLE	2,152
(4) GAS TURBINES COMBINED CYCLE W/ DUCT BURNER	2,152
(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650
(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300
(3) TURBINE, COMBINED CYCLE AND DUCT BURNER, POWER AUG.	2,300
(6) GAS FUELED TURBINES, 1-6	2,133
(6) GAS FUELED TURBINES, 1-6 W/STEAM INJECTION OR EVAP COOLING	2,133
(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440
(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440
(2) TURBINE, COMBINED CYCLE	2,046
(4) COMBINED CYCLE CT	1,400
(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400
TURBINE, COMBINED CYCLE COMBUSTION, ABB	600
(2) TURBINE, COMBINED CYCLE, DUCT BURNER CC4, CC5	2,640
(4) TURBINE, COMBINED CYCLE	1,991
(2) COMBUSTION TURBINE, COMBINED CYCLE	816
(4) TURBINE, COMBINED CYCLE	477
(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071
(2) TURBINE, COMBINED CYCLE	1,480
TURBINE	1,984
(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360
(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945
(3) TURBINES, COMBINED CYCLE	1,944
(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944
(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376
(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376
(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374
(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374
(2) TURBINE	2,560
(4) TURBINE, COMBINED CYLE	1,600
(4) TURBINE, COMBINED CYCLE	1,600
TURBINE, NO DUCT BURNER FIRING	1,937
TURBINE, COMBINED CYCLE, DUCT BURNER	1,937
(7) TURBINE, COMBINED CYCLE	1,360
(11) TURBINE, COMBINED CYCLE	1,360
(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360
(3) TURBINE, COMBINED CYCLE	1,798
(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191
COMBINED CYCLE POWER PLANT. THIS IS THE 4TH BLOCK OF POWER ADDI	4,240
COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	389
TURBINE, COMBINED CYCLE	1,680
TURBINE, COMBINED CYCLE	1,680
(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440
(1) COMBINED CYCLE GAS TURBINE	1,742
(1) COMBINED CYCLE GAS TURBINE, W/ POWER AUGMENTATION	1,742
(2) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,737
(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062
(3) TURBINE, COMBINED CYCLE	1,467
(2) TURBINE, COMBINED CYCLE (GE)	1,360
GE COMBUSTION TURBINE & DUCT BURNERS	1,705
GE COMBUSTION TURBINE W/O DUCT BURNERS	1,705
COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400
COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400
(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000
(4) TURBINE, COMBINED CYCLE W/ DUCT FIRING (70%-100%)	2,200
COMBINED CYCLE COMBUSTION TURBINE GENERATOR WITH 249 MMBTU/H	1,758
(2) COMBINED-CYCLE TURBINE	2,311
TURBINE, COMBINED CYCLE	1,700
(2) TURBINE, COMBINED CYCLE	1,480
TURBINE, COMBINED CYCLE	1,360
TURBINE, COMBINED CYCLE	1,400
(2) TURBINES, COMBINED CYCLE	1,628
(2) TURBINE, COMBINED CYCLE	1,628
(2) TURBINE, COMBINED CYCLE	1,384
(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440
(2) TURBINES, COMBINED CYCLE	1,360
(4) GAS TURBINES TURBINE W/ AND W/O DUCT BURNER	1,384

CONTROL DESCRIPTION
DLN COMBUSTION TECHNOLOGY
CATALYTIC OXIDATION SYSTEM
OXIDATION CATALYST
CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES
None
OXIDATION CATALYST AND GCP
OXIDATION CATALYST
GOOD COMBUSTION CONTROL
CATALYTIC OXIDATION AND USE OF GCP
OXIDATION CATALYST
CO WILL BE MINIMIZED BY THE EFFICIENT COMBUSTION OF NATURAL GAS AND D
GOOD COMBUSTION
GCP
CO CATALYST AND GCP
COMBUSTION CATALYST
OXIDATION CATALYST
NONE INDICATED
NONE INDICATED
OXIDATION CATALYST
CATALYTIC OXIDATION
OXIDATION CATALYST
GCP CO CATALYST OXIDATION CATALYST
GCP
NONE INDICATED
CATALYTIC OXIDATION
GCP
OXIDATION CATALYST SYSTEM
CATALYTIC OXIDATION
NONE INDICATED
CATALYTIC OXIDATION
NONE INDICATED
OXIDATION CATALYST
OXIDATION CATALYST
OXIDATION CATALYST
GOOD COMBUSTION
GCP
OXIDATION CATALYST
OXIDATION CATALYST
GOOD COMBUSTION
GCP
NONE INDICATED
NONE INDICATED
DLN/GOOD COMBUSTION
GOOD COMBUSTION DESIGN AND PRACTICES
GOOD COMBUSTION DESIGN AND PRACTICES
NONE INDICATED
GOOD COMBUSTION DESIGN AND OPERATING PRACTICES
GOOD COMBUSTION DESIGN AND OPERATING PRACTICES
GOOD COMBUSTION
GCP
GOOD COMBUSTION
None
COMBUSTION CONTROLS
COMBUSTION CONTROLS
CATALYTIC AFTERBURNER
OXIDATION CATALYST
GCP
OXIDATION CATALYST
GCP
COMBUSTION CONTROL
STATE OF THE ART COMBUSTER DESIGN AND GOOD OPERATING PRACTICES
NONE INDICATED
CLEAN FUEL, GOOD COMBUSTION AND DESIGN
GOOD COMBUSTION
GOOD COMBUSTION CONTROL PRACTICES (PREVENTION) AND OXIDATION CATA
COMBUSTION CONTROLS
GCP
GOOD COMBUSTION
NONE INDICATED
COMBUSTION CONTROL
COMBUSTION CONTROL
COMBUSTION CONTROL
GOOD COMBUSTION
COMBUSTION TECHNOLOGY/CLEAN FUELS
LNB, GCP

EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
10.0	
3.6	BACT-PSD
3.6	BACT-PSD
3.8	
3.9	LAER
4.0	BACT-PSD
4.0	BACT-PSD
4.0	BACT/LAER
4.0	BACT-PSD
4.0	LAER
4.0	BACT-PSD
4.0	BACT-PSD
5.0	
4.1	BACT-PSD
4.1	BACT-PSD
4.1	BACT-OTHER
7.6	
14.0	
4.9	BACT-PSD
4.9	BACT-PSD
5.0	BACT
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
5.0	BACT-PSD
7.5	
5.0	BACT-PSD
10.0	
20.0	
5.0	BACT-PSD
25.0	
5.0	BACT-PSD
25.0	
5.2	BACT-OTHER
5.3	OTHER
5.4	BACT-OTHER
5.6	BACT-OTHER
6.0	LAER
6.0	LAER
6.0	LAER
8.0	BACT-PSD
6.0	BACT-PSD
6.0	LAER
6.0	BACT-PSD
6.0	BACT-PSD
9.0	
6.0	BACT-PSD
9.0	
6.0	BACT-PSD
9.0	
6.0	BACT-PSD
13.5	
7.0	BACT-PSD
7.4	BACT-PSD
7.4	BACT-PSD
7.4	BACT-PSD
14.5	
7.8	BACT-PSD
7.8	BACT-PSD
7.8	BACT-PSD
7.8	BACT-PSD
13.4	
8.0	BACT-PSD
8.0	BACT-PSD
8.0	BACT-PSD
8.0	BACT-PSD
8.0	BACT-PSD
8.0	BACT
12.0	
8.0	BACT-PSD
13.8	
8.1	BACT-PSD
8.2	BACT-PSD
8.2	BACT-PSD
11.4	
8.2	BACT-PSD
13.8	
8.2	BACT-PSD
8.5	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-OTHER
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD
9.0	BACT-PSD

Table C-2
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINE W/ AND W/O DUCT BURNERS GT-HRSG 1-4	2,000	GCP	9.0	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	GCP & OXIDATION CATALYST SYSTEM	9.0	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE	1,973	GCP	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		12.0	
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	GCP	9.0	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		13.7	
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	GCP, NATURAL GAS AS FUEL	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791		14.0	
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	GCP AND DESIGN	9.0	BACT-PSD
				(2) TURBINES, COMBINED CYCLE DUCT BURNERS	1,985		14.0	
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE	1,827	GCP	9.0	BACT-PSD
				(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		14.6	
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	COMB DESIGN & GOOD OPER PRACTICE. DLN COMBUSTION	9.0	BACT-PSD
				TURBINE, COMBINED CYCLE DUCT BURNER	1,488		15.0	
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE INDICATED	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		15.0	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	GCP	9.0	BACT-PSD
				(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3) W/ STEAM INJECTI	1,440		15.0	
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		16.3	
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,698	GCP	9.0	BACT-PSD
				(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698		15.4	
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/O DUCT FIRING	1,698	DLN COMBUSTORS, GCP	9.0	BACT-PSD
				(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698		15.4	
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION	1,735	GCP	9.0	BACT-PSD
				(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735		16.4	
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	COMBUSTION CONTROLS	9.0	BACT-PSD
				COMBINED CYCLE COMBUSTION TURBINE, W/ POWER AUG	1,700		20.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE GE	1,400	GCP	9.0	BACT-PSD
				(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		20.0	
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	LNB	9.0	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		25.0	
NORTHERN STATES POWER CO. DBA XCEL ENERGY	RAMSEY, MN	8/12/2005	YES	2 COMBINED-CYCLE COMBUSTION TURBINES	2,640	GOOD COMBUSTION PRACTICES	10.0	BACT-PSD
NORTHERN STATES POWER CO. DBA XCEL ENERGY	RAMSEY, MN	5/16/2006	YES	TWO COMBUSTION TURBINES	1,885	GOOD COMBUSTION PRACTICES	10.0	BACT-PSD
SOUTHWEST ELECTRIC POWER COMPANY	SHREVEPORT, LA	3/20/2008	YES	(2) COMBINED CYCLE GAS TURBINES	1,055	PROPER OPERATING PRACTICES	10.0	BACT-PSD
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	NO	TURBINE, COMBINED CYCLE	1,876	GCP	10.0	BACT-PSD
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	YES	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	GCP, DLN COMBUSTORS	10.0	BACT-PSD
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	OXIDATION CATALYST	10.0	BACT-OTHER
BEAR MOUNTAIN LIMITED"	BAKERSFIELD, CA	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	OXIDATION CATALYST	10.0	BACT-OTHER
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION DESIGN GCP	10.0	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	GOOD COMBUSTOR DESIGN, ONLY "SWEET" NATURAL GAS	10.0	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	COMBUSTION CONTROLS	10.0	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	COMBUSTION CONTROL	10.0	BACT-PSD
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	NONE INDICATED	10.0	BACT-OTHER
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	CATALYTIC CONTROL	10.0	LAER
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	10.0	BACT-PSD
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4, W/ AND W/O DUCT BURNER	970	PROPER COMBUSTION CONTROL	10.0	BACT-PSD
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	PROPER COMBUSTION	10.0	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	TURBINES OPERATE BASE LOAD AT LEAST 75% OF TIME	10.0	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		13.9	
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	NONE INDICATED	10.0	BACT-PSD
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		14.0	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	?	(4) TURBINES, COMBINED CYCLE MHI/SW	1,400	GCP	10.0	BACT-PSD
				(4) TURBINES, COMBINED CYCLE MHI/SW @ 75% LOAD	1,400		15.0	
				(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		20.6	
KANSAS CITY POWER & LIGHT CO HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED (70%-100% LOAD)	1,360	OXIDATION CATALYST	10.0	BACT-OTHER
				(2) TURBINE, COMBINED (>70% LOAD)	1,360		25.0	
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	GCP/CO OXIDATION CATALYST	10.2	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	?	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	CATALYTIC OXIDATION	10.2	BACT-PSD
SWEENY COGENERATION LIMITED PARTNERS	DALLAS, TX	9/9/1996	?	(3) COMBINED CYCLE TURBINES	970	LNB	10.3	BACT-PSD
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	GCP	10.3	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	11.0	BACT-PSD
				(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		17.0	
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	GOOD OPERATING PRACTICE	11.5	BACT-PSD
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	THREE COMBINED-CYCLE COMBUSTION TURBINE GENERATORS, EACH WIT	1,844	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN	11.6	BACT-PSD
				TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844	GOOD COMBUSTION PRACTICES AND EFFICIENT PROCESS DESIGN	25.9	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE	1,844	GCP AND EFFICIENT PROCESS DESIGN	11.6	BACT-PSD
				(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844		25.9	
HOT SPRINGS POWER PROJECT	ARKANSAS	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	CATALYTIC OXIDIZER	12.0	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	GOOD COMBUSTION	12.0	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	GOOD COMBUSTION	12.0	BACT-PSD
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	GCP	12.0	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(12) TURBINE, COMBINED CYCLE	984	GOOD COMBUSTION TECHNIQUES	12.0	BACT-PSD
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	?	(2) TURBINES, COMBINED CYCLE	1,280	NONE INDICATED	12.0	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	COMBUSTION CONTROLS	12.0	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE	1,696	GCP	12.0	BACT-PSD
				TURBINE, COMBINED CYCLE & DUCT BURNER	1,696		20.0	
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	NONE INDICATED	12.2	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	GOOD COMBUSTION	12.2	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000	GCP	12.9	OTHER
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	GCP	13.0	BACT-PSD
				(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		18.4	
TENASKA FRONTIER GENERATION STATION	TEXAS	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	GCP	13.2	BACT-PSD
				(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464		20.2	
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	13.3	OTHER
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	DLN COMBUSTORS	13.3	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	EFFICIENT COMBUSTION	13.4	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	EFFICIENT COMBUSTION	13.4	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP	13.4	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE NO DUCT BURNER	1,400	GOOD COMBUSTION	14.0	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	OXIDATION CATALYST	14.0	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	14.0	LAER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	GCP	14.4	BACT-PSD
INEOS USA LLC	BRAZORIA, TX	8/29/2006	YES	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS)	140	BP AMOCO PROPOSES PROPER COMBUSTION CONTROL	15.0	BACT-PSD
DUKE ENERGY DALE, LLC	ALABAMA	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	EFFICIENT COMBUSTION	15.0	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	ALABAMA	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	EFFICIENT COMBUSTION	15.0	BACT-PSD

Table C-2
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	EFFICIENT COMBUSTION	15.0	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD, ME	5/1/1998	YES	TURBINE GENERATOR COMBUSTION	1,906	GE DLN COMBUSTOR DESIGN, GOOD COMBUSTION CONTROL	15.0	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	USING 15 % EXCESS AIR	15.0	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE	2,096	NONE INDICATED	15.0	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	LNB WITH GCP	15.0	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LNB WITH GCP	15.0	BACT-PSD
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	GOOD COMBUSTION	15.0	BACT-PSD
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	?	(2) COMBUSTION TURBINES #1 & #2	1,836	NONE INDICATED	15.0	BACT-PSD
HERMISTON POWER PARTNERSHIP	OREGON	4/13/1999	?	(2) TURBINE	1,853	NONE INDICATED	15.0	NSPS
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	PROPER COMBUSTION CONTROL	15.0	BACT-OTHER
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP	15.0	OTHER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	OXIDATION CATALYST	15.0	BACT-PSD
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	GCP	15.0	BACT-PSD
				(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		16.0	
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE	457	LNB	15.0	BACT-PSD
				COMBUSTION TURBINE W/ DUCT BURNER	623		20.0	
GEISMAR PLANT	GEISMAR, LA	2/26/2002	?	(2) COGENERATION UNITS POINT # 720-99 AND 721-99, W/O DUCT BURNER	320	GCP WITH NATURAL GAS AS FUEL	15.0	BACT-PSD
				(2) COGENERATION UNITS POINT # 720-99 AND 721-99, W/ DUCT BURNER	320		24.8	
Athens Generating Company, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	CLEAN BURNING FUELS AND EFFICIENT COMBUSTION TECHNIQUES	15.0	BACT
				(3) SWPC 510G COMBUSTION TURBINES (75% LOAD)	2,880		30.0	
SALT RIVER PROJECT/ DESERT BASIN GEN	PHOENIX, AZ	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	GCP	15.3	BACT-PSD
				TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		24.0	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	TURBINES E-1+E-2 W/O HRSG	720	NONE INDICATED	15.2	OTHER
				TURBINES E-1+E-2 W/ HRSG	720		31.7	
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	COMBUSTION DESIGN, GCP	16.0	BACT-PSD
ENERGETIX	COMANCHE, OK	12/12/2006	YES	COMBUSTION TURBINE AND DUCT BURNER	Not Reported	GOOD COMBUSTION PRACTICES	16.4	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	16.6	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	GOOD COMBUSTION	17.0	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	GOOD COMBUSTION CONTROLS	17.0	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	GCP/DESIGN	17.2	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	17.4	BACT-OTHER
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	NONE INDICATED	17.4	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP AND CLEAN BURNING FUEL, DLN	17.4	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	GCP	17.8	BACT-PSD
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	GCP	17.8	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	EFFICIENT COMBUSTION	17.8	BACT-PSD
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	GOOD COMBUSTION CONTROL	18.0	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GEN	BURNSVILLE, MN	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	COMBUSTOR DESIGN AND OPERATION	18.0	BACT-PSD
				COMBUSTION TURBINE WITH HRSG W/ DUCT BURNER	2,427		25.0	
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GCP	18.3	BACT-PSD
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	NO	(2) TURBINE, COMBINED CYCLE	640	GOOD COMBUSTION & CATALYTIC OXIDATION	18.4	BACT-OTHER
PPG INDUSTRIES	LAKE CHARLES, LA	12/2/1999	?	COGENERATION UNIT 5 AND 6 (EACH)	1,320	GOOD DESIGN,PROPER OPERATION AND MAINTENANCE PRACTICES	19.0	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480	GCP	19.7	BACT-PSD
				TURBINE, COMBINED CYCLE (<75% LOAD)	1,480		68.2	
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	YES	TURBINE, COMBINED CYCLE	2,040	NONE INDICATED	20.0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DLNB, GCP	20.0	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	YES	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	GCP	20.0	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	15% EXCESS AIR	20.0	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	GOOD COMBUSTION CONTROL	20.0	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	LOW NOX COMBUSTOR, GCP	20.0	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	OXIDATION CATALYST	20.0	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	NONE INDICATED	20.0	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	GCP	20.0	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1& -2	2,080	GCP	20.0	BACT-PSD
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	20.0	BACT-OTHER
GREGORY POWER FACILITY	TEXAS	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	GOOD COMBUSTION	20.0	BACT-PSD
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		26.2	
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	EFFICIENT COMBUSTION	20.1	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(3) TURBINE/HRSG NO 1, 2, 3	888	GOOD COMBUSTION	20.2	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	BEST COMBUSTION CONTROL PRACTICES	21.0	BACT-PSD
GULF STATES UTILITIES COMPANY - LOUISIANA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	NONE INDICATED	22.1	OTHER
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	GCP	22.3	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN	PHOENIX, AZ	12/2/2000	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	GOOD COMBUSTION	23.0	BACT-PSD
RELIANT ENERGY- CHANNELVIEW COGENERATION	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	23.0	OTHER
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	(2) GAS TURBINES UNITS 1 & 2 W/O DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	23.0	BACT-OTHER
				(2) GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602		35.7	
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	GCP	23.2	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GCP	23.2	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	HOUSTON, TX	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	GOOD OPERATING PRACTICE	23.6	BACT-PSD
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	GOOD COMBUSTION AND OXIDATION CATALYST	23.6	BACT-PSD
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	GOOD COMBUSTION AND CO CATALYST	23.6	BACT-PSD
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION TECHNOLOGY, CLEAN FUELS	23.7	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP	24.4	BACT-PSD
PUBLIC SERVICE CO OF OKLAHOMA	CADDO, OK	2/9/2007	YES	GAS-FIRED TURBINES	Not Reported	COMBUSTION CONTROL	25.0	BACT-PSD
FRONT RANGE POWER COMPANY, LLC	FOUNTAIN, CO	11/13/2000	?	TURBINES, COMBINED CYCLE	1,384	GOOD COMBUSTION CONTROL PRACTICES TO MINIMIZE EMISSIONS	25.0	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	GOOD COMBUSTION CONTROL PRACTICES	25.0	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	COMBUSTION CONTROLS	25.0	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	GOOD COMBUSTION OF CLEAN FUELS	25.0	BACT-OTHER
CIPS - GRAND TOWER POWER STATION	ILLINOIS	2/25/2000	YES	(2) COMBINED CYCLE COMBUSTION TURBINE (UNITS 1&2)	2,365	GCP	25.0	BACT-PSD
KENTUCKY PIONEER ENERGY, LLC - TRAPP	KENTUCKY	6/7/2001	?	(2) TURBINES, COMBINED CYCLE	1,765	GOOD COMBUSTION	25.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	?	(2) GAS TURBINES	1,908	GCP, GOOD DESIGN AND OPERATING PRACTICES, NATURAL GAS AS FUEL	25.0	BACT-PSD
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	GCP	25.0	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	?	(2) COGENERATION UNITS COMBINED CYCLE	320	GCP	25.0	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	5/16/2001	?	(2) GAS TURBINES (1-98A, 2-98A)	1,908	GOOD DESIGN AND PRACTICES NATURAL GAS AS FUEL WITH DLN BURNERS	25.0	BACT-PSD
PINE STATE POWER"	JAY, ME	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	DILUENT WATER INJECTION SYTEM BY USING A "QUIET COMBUSTOR" MULTI FUE	25.0	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	NONE INDICATED	25.0	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	OXIDATION CATALYST	25.0	LAER
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	PROPER COMBUSTION	25.0	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	(2) TURBINE/HRSG (CG-2, CG-3)	1,280	PROPER COMBUSTION CONTROL	25.0	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/ AND W/O DUCT BURNER FIRING	672	LNB	25.0	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	GCP	25.0	BACT-PSD
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	DLN BURNERS	25.0	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	NONE INDICATED	25.0	BACT-OTHER
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	25.0	OTHER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACKS 1-8	1,400	CO CATALYST	25.0	BACT-PSD

Table C-2
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
DEER PARK ENERGY CENTER	HOUSTON	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	EFFICIENT & COMPLETE COMBUSTION	25.0	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	25.0	OTHER
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	GCP	25.0	BACT-PSD
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	PROPER OPERATION AND COMBUSTING NAT GAS &/OR BYPRODUCT FUEL GAS	25.0	BACT-PSD
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		30.0	
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	LNB	25.0	BACT-PSD
				(4) COMBINED CYCLE GENERATION UNIT	1,464		33.0	
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	GOOD OPERATING PRACTICES, USE OF CLEAN BURNING FUEL, LNB	25.0	BACT-PSD
				(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		35.5	
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE, LA	3/2/1995	?	TURBINE/HRSG, GAS COGENERATION	450	PROPER OPERATION	25.5	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	NONE INDICATED	26.0	OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC	MOSELL, MS	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,299	GOOD COMBUSTION CONTROLS	26.3	BACT-PSD
Pedricktown Cogeneration Plant (PCLP)	MAYS LANDING, NJ	9/19/1995	?	COMBUSTION TURBINE, W/O DUCT BURNER	908	NONE INDICATED	26.7	BACT-PSD
				TURBINE WITH DUCT BURNER	1,048		31.1	
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	NO	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	GCP AND COMBUSTION CONTROL	27.0	BACT-PSD
				TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166		64.0	
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB TURB	1,384	EFFICIENT COMBUSTION	27.2	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	?	COMBINED CYCLE TURBINE (25 MW)	568	PROPER DESIGN AND GCP	28.0	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	FLORIDA	2/1/2002	?	TURBINE, COMBINED CYCLE W AND W/O DUCT FIRING	1,990	GCP	28.3	BACT-PSD
GENOVA ARKANSAS I, LLC	ARKANSAS	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (SWH)	1,360	GCP	30.0	BACT-PSD
BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/25/1997	?	(3) TURBINE, EMISSION POINTS AA-001, 002, 003	2,248	NONE LISTED	30.3	BACT-PSD
				(3) TURBINE, EMISSION POINTS AA-001, 002, 003 (<75% LOAD)	1,686		200.0	
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	?	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	PROPER COMBUSTION	31.2	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	31.2	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	COMBUSTION CONTROLS	33.0	BACT-PSD
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP	36.0	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	NONE LISTED	37.0	BACT-PSD
BLACK HILLS CORP./NEIL SIMPSON TWO	GILLETTE, WY	4/4/2003	?	TURBINE, COMBINED CYCLE & DUCT BURNER	320	GCP	37.2	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	EFFICIENT COMBUSTION	38.4	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	EFFICIENT COMBUSTION PRACTICES	40.0	BACT-PSD
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	COMBUSTION CONTROLS	40.0	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	GOOD COMBUSTION CONTROL	40.0	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	EFFICIENT COMBUSTION	44.6	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	GOOD COMBUSTION CONTROL PRACTICES	48.0	BACT-PSD
LEDERLE LABORATORIES	PEARL RIVER, NY	9/15/1994	?	(2) GAS TURBINES (EP #S 00101&102)	110	NONE LISTED	48.0	BACT-OTHER
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	YES	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	NONE LISTED	60.0	BACT-PSD
WRIGHTSVILLE POWER FACILITY	WRIGHTSVILLE, AR	2/28/2000	?	(6)TURBINE, COMBUSTION GE LM6000	368	STEAM INJECTION/GOOD COMBUSTION	66.0	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE	BATON ROUGE, LA	3/7/1997	YES	TURBINE/HSRG, GAS COGENERATION	450	COMBUSTION DESIGN AND CONSTRUCTION	69.0	BACT-PSD
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	GOOD DESIGN, PROPER COMBUSTION TECHNIQUES 2% EXCESS O_2	88.3	BACT-PSD
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848	EFFICIENT COMBUSTION	100.0	BACT-PSD
FULTON COGEN PLANT	FULTON, NY	9/15/1994	?	GAS TURBINE	500	NONE INDICATED	107.0	BACT-OTHER
				STACK EMISSIONS (TURBINE & DUCT BURNER)	610		156.0	
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	GCP	132.0	BACT-PSD
INTERNATIONAL PAPER	MANSFIELD, LA	2/24/1994	?	TURBINE/HRSG, GAS COGEN	338	COMBUSTION CONTROL	161.2	BACT-OTHER
PONCA CITY MUNICIPAL ELECTRICAL GENERATING	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	DESIGN	188.7	BACT-PSD

Table C-3
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	NO	COMBINED CYCLE COGENERATION	1,882	GOOD COMBUSTION	0.3	BACT
CHAMBERS ENERGY L.P./ANP	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	GOOD COMBUSTION DESIGN/OPERATIONS CO CATALYST	0.4	LAER
HARRIS ENERGY FACILITY	8/31/2000	NO	(8) COMBUSTION GS TURBINE GENERATORS STACK (100% LOAD)	1,400	GOOD COMBUSTION AND DESIGN	0.4	BACT-PSD
			(8) COMBUSTION GS TURBINE GENERATORS STACK (50%-100% LOAD)	1,400		0.7	
WEST TEXAS ENERGY FACILITY	7/28/2000	NO	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	GOOD COMBUSTION DESIGN AND OPERATIONS	0.4	BACT-PSD
			(2) GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		3.0	
VIRGINIA ELECTRIC AND POWER COMPANY			(3) COMBINED CYCLE TURBINE GENERATORS W/ HRSG & DUCT BURNERS		GOOD COMBUSTION PRACTICES AND OXIDATION CATALYST.	0.7 w/out DB	BACT
	12/17/2010	NO		2996		1.6 w/DB	BACT
ASSOCIATED ELECTRIC COOPERATIVE INC - CHOUTEAU POWER PLANT	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	COMBUSTION CONTROLS	0.57	BACT-PSD
CPV WARREN, LLC	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	OXIDATION CATALYST	0.7	BACT
			(2) COMBINED CYCLE TURBINES W/ DUCT BURNER, GE 7FA	2,217		1.0	
			(2) COMBINED CYCLE TURBINES W/ POWER AUG, W/ DB, GE 7FA	2,217		1.4	
MANTUA CREEK GENERATING FACILITY	6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181	OXIDATION CATALYST	0.7	NSPS
			(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		0.8	
			(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		0.8	
			(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181		1.8	
PANDA-BRANDYWINE	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.8	OTHER
BEAR MOUNTAIN LIMITED	8/19/1994	?	TURBINE, GE COGENERATION 48 MW	384	OXIDATION CATALYST	0.6	OTHER
MEMPHIS GENERATION, LLC	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.8	BACT-PSD
PDC EL PASO MILFORD LLC	4/16/1999	?	(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (75-99% LOAD, ALL TEMPS)	1,965	OXIDATION CATALYST FOR CO	0.9	BACT
			(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (50-74% LOAD, ALL TEMPS)	1,965		1.2	
			(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP < 60°F)	1,965		1.2	
			(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP 61-70°F)	1,965		1.3	
			(2) TURBINES, ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP 71-80°F)	1,965		1.5	
			(2) TURBINES,ABB GT-24 #1&2 W/ 2 CHILLERS (100% LOAD, TEMP > 81°F)	1,965		3.0	
EMPIRE GENERATING CO. LLC	6/23/2005	NO	(2) GE FRAME 7FA COMB TURBINES, HRSGS & STG.	2,099	OXIDATION CATALYST	1.0	LAER
			FUEL COMBUSTION (NATURAL GAS)	646	OXIDATION CATALYST	7.0	LAER
FAIRBAULT ENERGY PARK	7/15/2004	NO	(2) TURBINE, COMBINED CYCLE	1,876	GCP	1.0	BACT-PSD
SITHE EDGAR DEV. LLC - FORE RIVER	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	OXIDATION CATALYST	1.0	BACT
			(2) MHI 501G COMBUSTION TURBINE W/ DUCT FIRING	2,955		1.7	
LIBERTY GENERATING STATION	3/28/2002	NO	(3) COMBINED CYCLE TURBINE	2,964	CO CATALYST	1.0	OTHER
			(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202		1.7	
SITHE MYSTIC DEVELOPMENT LLC	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	CLEAN FUEL	1.0	LAER
			(2) TURBINE, COMBINED CYCLE, DUCT FIRING	2,699		1.7	
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	11/12/2003	NO	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	1.0	BACT-PSD
			(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955		4.0	
MIRANT GASTONIA POWER FACILITY	5/28/2002		(4) TURBINES, COMBINED CYCLE MHI/SW	1,400	GCP	1.0	BACT-PSD
		?	(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		4.6	
AES LONDONDERRY, LLC	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	GCP	1.0	SIP
MILLENNIUM POWER PARTNER, LP	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	1.0	BACT-PSD
MANSFIELD MILL	8/14/2001	?	GAS TURBINE/HRSG	654	OPERATION/MAINTENANCE, VENDOR GUARANTEE	1.0	BACT-PSD
CRESENT CITY POWER, LLC	6/6/2005	NO	NEW 600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	2,006	CO OXIDATION CATALYST AND GCP	1.1	BACT-PSD
EL PASO MANATEE ENERGY CENTER	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	1.1	BACT
EL PASO BELLE GLADE ENERGY CENTER	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	OXIDATION CATALYST	1.1	BACT
BROOKHAVEN ENERGY, LP	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	OXIDATION CATALYST	1.1	OTHER
			(4) COMBINED CYCLE TURBINES, 50%-74%	1,404		1.9	
SOUTH SHORE POWER LLC	1/30/2003	?	(2) TURBINE, COMBINED CYCLE	1,376	OXIDATION CATALYST	1.1	BACT-OTHER
			(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,883		2.5	
LAKE ROAD GENERATING COMPANY,L.P.	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	OXIDATION CATALYST FOR CO	1.1	BACT
WESTBROOK POWER LLC	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	1.1	BACT-PSD
FLORIDA POWER AND LIGHT COMPANY (FP&L) - West County Energy Center						1.2 w/out DB	
	7/30/2008	YES	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	2,333	SCR & DLN when firing natural gas	1.5 w/DB	PSD-BACT
PROGRESS ENERGY FLORIDA (PEF) - Bartow Plant						1.2 w/out DB	
	12/23/2009	YES	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	493	SCR & DLN when firing natural gas	1.5 w/DB	BACT-PSD
TRANSGAS ENERGY SYSTEMS	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	OXIDATION CATALYST	1.2	LAER
ONETA GENERATING STA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	NONE INDICATED	1.2	BACT-PSD
CONECTIV BETHLEHEM, INC.	1/16/2002	?	(6) TURBINE, COMBINED CYCLE	976	NONE INDICATED	1.2	BACT-OTHER
ODESSA-ECTOR GENERATING STATION	11/18/1999	NO	(4) TURBINE W/ AND W/O DUCT BURNERS GT-HRSG 1-4	1,360	GOOD COMBUSTION DESIGN & OPERATIONS	1.2	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	5/9/2000	YES	(6) GAS FUELED TURBINES, STACK 1-6	2,200	GOOD COMBUSTION DESIGN AND OPERATIONS	1.2	BACT-PSD
			(6) GAS FUELED TURBINES, STACK 1-6, W/ EVAP COOLER OR STEAM INJ.	2,200		3.0	
BADGER GENERATING CO LLC	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE (75% LOAD)	2,010	THE USE OF OXIDATION CATALYST	1.2	LAER
			(4) COMBUSTION TURBINE COMBINED CYCLE (50% LOAD)	2,010		3.0	
VA POWER - POSSUM POINT	11/18/2002	YES	TURBINE, NO DUCT BURNER FIRING	1,937	GOOD AIR POLLUTION CONTROL PRACTICES	1.2	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		2.3	
PARIS GENERATING STATION	10/28/1998	?	(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360	GOOD AIR POLLUTION CONTROL PRACTICES	1.2	BACT-PSD
			(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000		2.3	
MIRANT BOWLINE, LLC	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	CO CATALYST & EFFICIENT COMBUSTION TECHNIQUES	1.2	LAER
			(3) COMBINED CYCLE TURBINES	2,049		2.4	
DUKE ENERGY, VIGO LLC	6/6/2001	NO	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360	GOOD COMBUSTION, NATURAL GAS ONLY	1.2	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945		6.2	
KEYSPAN RAVENSWOOD GENERATING STATION	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE	1,779	OXIDATION CATALYST	1.2	OTHER
			(1) COMBINED CYCLE COMBUSTION TURBINE, W/ DUCT BURNER	2,423		7.6	
APS WEST PHOENIX	5/26/2000	YES			OXIDATION CATALYST		LAER
			TURBINE, COMBINED CYCLE, NO DUCT BURNER CC4	1,040		1.9	
			TURBINE, COMBINED CYCLE, DUCT BURNER CC4	1,040		2.1	
TOWANTIC ENERGY, LLC	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	OXIDATION CATALYST FOR CO	1.2	BACT
FLORIDA POWER AND LIGHT	2/8/2005	NO	(4) GE MODEL FA TURBINES (170 MW EACH), (4) HRSGS, (1) STG	1,360	EFFICIENT COMBUSTION	1.3	None

Table C-3
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
DUKE ENERGY WYTHE, LLC	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE	1,627	GCP	1.3	BACT-PSD
			(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		6.6	
EL PASO BROWARD ENERGY CENTER	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	EFFICIENCT COMBUSTION	1.3	BACT
NYPA POLETTI POWER PROJECT	10/1/2002	NO (2-2008)	(2) COMBINED CYCLE TURBINES	1,779	OXIDATION CATALYST	1.3	LAER
TECO BAYSIDE POWER STATION	3/30/2001	YES	(7) TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	1.3	BACT-PSD
CEDAR BLUFF POWER PROJECT	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	GCP AND OXIDATION CATALYST	1.3	LAER
MONTGOMERY COUNTY POWER PROJECT	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	GOOD COMBUSTION AND VOC CATALYST	1.3	BACT-PSD
NORTON ENERGY STORAGE, LLC	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	DLN & SCR	1.3	BACT-PSD
			(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		2.3	
FPL MARTIN PLANT	4/16/2003	?	(4) TURBINE, COMBINED CYLE	1,600	GCP	1.3	BACT-PSD
			(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,095		4.0	
FPL MANATEE PLANT - UNIT 3	4/15/2003	?	(4) TURBINE, COMBINED CYCLE	1,600	GCP	1.3	BACT-OTHER
			(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER OR POWER AUG.	1,360		4.0	
MIRANT GASTONIA POWER FACILITY	5/28/2002	?	(4) TURBINES, COMBINED CYCLE GE	1,400	GCP	1.3	BACT-PSD
			(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		4.9	
TENASKA FRONTIER GENERATION STATION	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/O DUCT BURNER	1,464	GOOD COMBUSTION DESIGN AND OPERATIONS	1.3	BACT-PSD
			(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464		5.6	
PINE BLUFF ENERGY CENTER	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	GCP WITH DLN COMBUSTORS (NAT GAS)	1.3	BACT-PSD
PINE BLUFF ENERGY LLC	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	GCP	1.3	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	1.3	BACT-PSD
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	CATALYTIC REDUCTION	1.4	OTHER
NINEMILE POINT ELECTRIC GENERATING PLANT	8/16/2011	NO	COMBINED CYCLE TURBINES	3,573	OXIDATION CATALYST	1.4	BACT/LAER
GENOVA ARKANSAS I, LLC	8/23/2002	NO	(2) TURBINE, COMBINED CYCLE (GE)	1,360	GCP	1.4	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	12/14/2000	YES	TURBINE, COMBINED CYCLE	2,040	NONE INDICATED	1.4	BACT-PSD
GILA BEND POWER GENERATING STATION	5/15/2002	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	OXIDATION CATALYST AND GCP	1.4	BACT-PSD
MOUNTAINVIEW POWER	5/22/2001	YES	(4) TURBINE, COMBINED CYCLE	1,991	OXIDATION CATALYST	1.4	LAER
SACRAMENTO MUNICIPAL UTILITY DISTRICT	9/1/2003	?	(2) GAS TURBINES	1,611	NONE INDICATED	1.4	
FPL SANFORD PLANT	9/14/1999	YES	(4) COMBUSTION TURBINES COMBINED CYCLE	1,776	GCP	1.4	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	COMBUSTION CONTROLS	1.4	BACT-OTHER
CPV ATLANTIC POWER GENERATING FACILITY	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	GCP	1.4	BACT-OTHER
CP & L - RICHMOND CO. FACILITY	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	COMBUSTION CONTROL	1.4	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	COMBUSTION CONTROL	1.4	BACT-PSD
CLOVIS ENERGY FACILITY	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	PIPELINE QUAL NAT GAS, GOOD ENGINEERING PRACTICE	1.4	BACT-PSD
PALESTINE ENERGY FACILITY	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP	1.4	BACT-PSD
ARCHER GENERATING STATION	1/3/2000	?	(4) GAS TURBINES TURBINE W/ AND W/O DUCT BURNER	1,360	GCP	1.4	BACT-PSD
GATEWAY POWER PROJECT	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	GOOD COMBUSTION DESIGN AND OPERATIONS	1.4	BACT-PSD
			(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		2.4	
ANP BELLINGHAM ENERGY COMPANY	8/4/1999	?	(2) TURBINES, COMBINED CYCLE (50%-100%)	3,630	CLEAN FUEL - NATURAL GAS	1.4	LAER
			(2) TURBINES, COMBINED CYCLE (<50%)	3,630		2.5	
			(2) TURBINES, COMBINED CYCLE, W/ STEAM INJECTION	3,630		3.5	
BASTROP CLEAN ENERGY CENTER	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP	1.4	BACT-PSD
			(2) TURBINES AND DUCT BURNERS COMBINED	1,288		3.0	
FPL ENERGY MARCUS HOOK, L.P.	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	GCP	1.4	LAER
			(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191		3.1	
ANP BLACKSTONE ENERGY COMPANY	4/16/1999	?	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL - NATURAL GAS	1.4	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ STEAM INJECTION	1,815		3.5	
JAMES CITY ENERGY PARK	12/1/2003	?	TURBINE, COMBINED CYCLE	1,973	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	1.4	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		4.0	
CANE ISLAND POWER PARK /KUA - UNIT 3	11/24/1999	?	TURBINE, COMBINED CYCLE	1,696	GOOD COMBUSTION	1.4	BACT-PSD
			TURBINE, COMBINED CYCLE & DUCT BURNER	1,696		4.0	
GENOVA OK I POWER PROJECT	6/13/2002	?	GE COMBUSTION TURBINE W/O DUCT BURNERS	1,705	GCP AND DLN COMBUSTOR	1.4	BACT-PSD
			GE COMBUSTION TURBINE & DUCT BURNERS	1,705		4.1	
PERRYVILLE	8/25/2000	?	(4) GAS TURBINES IN COMBINED CYCLE MODE	1,774	LNB	1.4	BACT-PSD
			(4) COMBINED CYCLE GENERATION UNIT	1,464		4.8	
CONED EAST RIVER REPOWERING PROJECT	8/30/2001	NO	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	OXIDATION CATALYST	1.4	LAER
			(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		5.0	
PERRYVILLE POWER STATION	3/8/2002	?	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	GOOD OPER PRACTICES & USE OF NATURAL GAS AS FUEL	1.4	BACT-PSD
			(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		5.2	
BERRIEN ENERGY, LLC	10/10/2002	?	(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650	CATALYTIC OXIDIZER PROVIDES SOME CONTROL FOR VOC	1.4	BACT-PSD
			(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300		5.4	
			(3) TURBINE, COMBINED CYCLE AND DUCT BURNER, POWER AUG.	2,300		12.4	
PANDA CULLODEN GENERATING STATION	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	STATE OF THE ART COMBUSTER DESIGN, GCP	1.4	BACT-PSD
			COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		5.7	
FORNEY PLANT	3/6/2000	NO	(6) TURBINES	1,358	GCP	1.4	BACT-PSD
			(6) COMBINED TURBINE & DUCT BURNER	1,358		20.0	
SPRINGDALE TOWNSHIP STATION	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP	1.4	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	1.4	OTHER
BP CHERRY POINT COGENERATION	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	OXIDATION CATALYST	1.4	BACT
FLORIDA POWER AND LIGHT COMPANY	1/10/2007	NO	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	389	None	1.5	BACT-PSD
MINNESOTA MUNICIPAL POWER AGENCY	6/5/2007	NO	COMBINED CYCLE COMB TURBINE GENERATOR W/ 249 MMBTU/H DB	1,758	None	1.5	BACT-PSD
BERRIEN ENERGY, LLC	4/13/2005	YES	3 COMBUSTION TURBINES AND DUCT BURNERS	1,584	CATALYTIC OXIDIZER	1.6	BACT-PSD
NEWINGTON ENERGY LLC	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	GCP	1.6	OTHER
FAIRLESS ENERGY LLC	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	OXIDATION CATALYST	1.6	LAER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	OXIDATION CATALYST	1.6	LAER
COGENTRIX LAWRENCE CO., LLC	10/5/2001	?	(3) TURBINES, COMBINED CYCLE	1,944	GCP	1.6	BACT-PSD
			(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944		2.9	
TEXAS CITY OPERATIONS	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	GCP	1.6	BACT-OTHER
GUADALUPE GENERATING STATION	2/15/1999	?	(4) TURBINES - ONLY CTG-1 TO 4	1,360	GOOD COMBUSTION DESIGN AND OPERATIONS	1.6	BACT-PSD
			(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000		2.2	
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	1.7	BACT-OTHER
BELL ENERGY FACILITY	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	GCP	1.7	BACT-OTHER

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Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	5/1/1996	YES	(2) COMBINED CYCLE TURBINES	1,884	GOOD COMBUSTION CONTROL PRACTICES	1.7	BACT-PSD
RAINEY GENERATING STATION	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION TECHNOLOGY, CLEAN FUEL	1.7	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	COMBUSTION TECHNOLOGY/CLEAN FUELS	1.7	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	SCR HAS SOME CONTROL OF VOC	1.7	BACT-PSD
			(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		11.2	
SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	NO	6 TURBINES, 254 MW EACH (NOT INCLUDING STEAM RECOVERY).	2,032	OXIDATION CATALYST	1.8	LAER
KING POWER STATION	8/5/2010	NO	TURBINE	2,700	OXIDATION CATALYST	1.8	BACT/LAER
MUSTANG ENERGY PROJECT	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	GOOD COMBUSTION CONTROL	1.8	BACT-PSD
CALPINE CONSTRUCTION FINANCE CO., LP	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	NONE INDICATED	1.8	LAER
CALPINE BERKS ONTELAUNEE POWER PLANT	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	2 CATALYTIC CONTROL DEVICES	1.8	BACT-OTHER
CPV CUNNINGHAM CREEK	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE, 70% LOAD	1,492	GCP	1.8	BACT-PSD
			(2) TURBINE, COMBINED CYCLE	2,132		2.0	
CASCO BAY ENERGY CO	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,937	GCP	1.8	BACT-PSD
DRESDEN ENERGY LLC	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	NONE INDICATED	1.8	BACT-PSD
			(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		3.7	
GARNET ENERGY, MIDDLETON FACILITY	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707	GCP	1.8	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097		3.8	
PSEG WATERFORD ENERGY LLC	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE INDICATED	1.8	BACT-PSD
			(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		3.9	
LONGVIEW ENERGY DEVELOPMENT	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMBUSTION CLEAN FUELS	1.9	BACT-OTHER
RIO NOGALES POWER PROJECT	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	GOOD COMBUSTION DESIGN & OPERATION	1.9	BACT-PSD
IDAHO POWER COMPANY	6/25/2010	?	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,375	CATALYTIC OXIDATION (CATOX),DLN, GCP	2	BACT
LIVE OAKS COMPANY, LLC	4/8/2010	?	COMBINED CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	4,800	GOOD COMBUSTION PRACTICES, CATALYTIC OXIDATION	2.0	BACT
PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	NO	ELECTRICITY GENERATION	2,800	OXIDATION CATALYST	2	BACT
NORTHERN STATES POWER CO. DBA XCEL ENERGY	8/12/2005	YES	2 COMBINED-CYCLE COMBUSTION TURBINES	2,640	GOOD COMBUSTION PRACTICES.	2.0	BACT-PSD
APS WEST PHOENIX	5/26/2000	YES	TURBINE, COMBINED CYCLE, DUCT BURNER CC5	4,240	OXIDATION CATALYST	2.0	BACT-OTHER
UMATILLA GENERATING COMPANY, L.P.	5/11/2004	?	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	CATALYTIC OXIDATION AND GCP	2.0	BACT-OTHER
MIRANT SUGAR CREEK LLC	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	GCP, NATURAL GAS FUEL	2.0	BACT-PSD
			TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791		2.3	
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	8/19/1994	?	TURBINE GAS COMBINE CYCLE SIEMENS V84.2	1,257	OXIDATION CATAYLST	2.0	BACT
LANGLEY GULCH POWER PLANT	6/25/2010	NO	SIEMENS SGT6-5000F COMBUSTION TURBINE	2,375	OXIDATION CATALYST	2.0	BACT/LAER
THOMAS C. FERGUSON POWER PLANT	9/1/2011	NO	NATURAL GAS FIRED TURBINES	1,560	OXIDATION CATALYST	2.0	BACT/LAER
CABOT POWER CORPORATION	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	COMBUSTION CONTROLS AND OXIDATION CATALYST	2.0	BACT-PSD
VALERO REFINING COMPANY	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	OXIDATION CATAYLST	2.0	LAER
HINES ENERGY COMPLEX, POWER BLOCK 2	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	COMBUSTION DESIGN, GCP	2.0	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	COMBUSTION DESIGN, GCP	2.0	BACT-PSD
AUGUSTA ENERGY CENTER	10/28/2001	?	(3) TURBINE, COMBINED CYCLE	2,000	CATALYTIC OXIDATION	2.0	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	4/17/2003	NO	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	CATALYTIC OXIDATION	2.0	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	1/15/2002	?	(2) TURBINE, COMBINED CYCLE	1,336	GCP	2.0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES"	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	GCP	2.0	BACT-OTHER
CHANNELVIEW COGENERATION FACILITY	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	PROPER COMBUSTION CONTROL	2.0	LAER
SAM RAYBURN GENERATION STATION	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	GOOD COMBUSTION PRACTICES	2.0	BACT-OTHER
WISE COUNTY POWER	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	FIRING PIPELINE NAT GAS AND OXIDATION CATALYST	2.0	BACT-OTHER
KAUFMAN COGEN LP	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	NONE INDICATED	2.0	OTHER
HIDALGO ENERGY FACILITY	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-PSD
JACK COUNTY POWER PLANT	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	GOOD COMBUSTION DESIGN AND OPERATIONS	2.0	BACT-OTHER
ENNIS TRACTEBEL POWER	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	2.0	OTHER
GENPOWER EARLEYS, LLC	1/9/2002	?	(2) TURBINES, COMBINED CYCLE	1,715	GCP AND DESIGN	2.0	BACT-PSD
			(2) TURBINES, COMBINED CYCLE DUCT BURNERS	1,985		3.7	
GREGORY POWER FACILITY	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	GOOD COMBUSTION DESIGN AND PRACTICES	2.0	BACT-PSD
			(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		4.9	
UCC SEADRIFT OPERATIONS	10/20/1999	?	COGEN STACK COMBINED GT/HRSG&DB 1180	310	GCP	2.0	BACT-OTHER
			COGEN STACK TURBINE ONLY	310		7.0	
ROCKY MOUNTAIN ENERGY CENTER, LLC.	8/11/2002	YES	(2) COMBINED-CYCLE TURBINE	2,311	GOOD COMB CONTROL & OXIDATION CATALYST	2.0	BACT-PSD
SACRAMENTO COGENERATION AUTHORITY P&G	8/19/1994	?	TURBINE, GAS COMBINED CYCLE LM6000	421	OXIDATION CATALYST	2.0	BACT
FREMONT ENERGY CENTER, LLC	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440	NONE INDICATED	2.1	BACT-PSD
			(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440		16.3	
MIRANT SUGAR CREEK, LLC	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION. NATURAL GAS ONLY	2.1	BACT-PSD
LOST PINES 1 POWER PLANT	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	GCP	2.1	BACT-PSD
EL DORADO ENERGY, LLC	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	FIRING OF NATURAL GAS ONLY IN THE CTG/HRSGS AND THE	2.1	BACT-PSD
			(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DUCT BURNER	1,900	USE OF GOOD COMBUSTION CONTROL	2.7	
NORTH AMERICAN POWER GP -KIOWA CREEK	1/17/2001	?	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	GOOD COMBUSTION CONTROL PRACTICES	2.2	BACT-PSD
EMERY GENERATING STATION	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	CATALYTIC OXIDATION	2.2	BACT-OTHER
FORT PIERCE REPOWERING	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	GOOD COMBUSTION AND OXIDATION CATALYST	2.2	
LIBERTY ELECTRIC POWER , LLC	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	2,000	GCP	2.2	LAER
CALPINE CORP.	5/2/2006	YES	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	2,400	GCP AND OXIDATION CATALYST.	2.3	BACT-PSD
ASTORIA ENERGY, LLC	12/5/2001	NO	(4) COMBINED CYCLE TURBINES	2,000	OXIDATION CATALYST	2.3	LAER
LAWRENCE ENERGY	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440	COMBUSTION CONTROLS AND OXIDATION CATALYST	2.3	BACT-PSD
			(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440		9.4	
FREEPORT COGENERATION FACILITY	6/26/1998	?	TURBINE/HRSG W/O DUCT BURNER FIRING	672	GOOD COMBUSTION	2.4	BACT-OTHER
			TURBINE/HRSG W/ DUCT BURNER FIRING	672		18.5	
CR WING COGENERATION PLANT	10/12/1999	NO	(2) CASE I: TURBINES E-1+E-2 W/O HRSG	720	NONE INDICATED	2.4	OTHER
			(2) CASE II: TURBINES E-1+E-2 W/ HRSG	720		6.7	
LIMERICK PARTNERS, LLC	4/9/2002	NO	(3) TURBINE, COMBINED CYCLE	1,467	OXIDATION CATALYST	2.4	LAER
ELECTRIC GENERATING STATION	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	GCP	2.4	LAER
COB ENERGY FACILITY, LLC	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	CATALYTIC OXIDATION AND GCP	2.4	BACT-PSD
MADISON BELL PARTNERS LP	8/18/2009	NO	ELECTRICITY GENERATION	2,200	GOOD COMBUSTION PRACTICES	2.5	BACT
RIVER ROAD GENERATING PROJECT	10/25/1995	?	TURBINE	1,984	PIPELINE QUALITY NAT GAS	2.6	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	GCP	2.7	SIP
MIRANT AIRSIDE INDUSTRIAL PARK	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	GCP	2.7	BACT-PSD
JACKSON COUNTY POWER, LLC	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	NONE INDICATED	2.7	BACT-PSD

Table C-3
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
BERKSHIRE POWER DEVELOPMENT, INC.	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	2.7	BACT-PSD
SALT RIVER PROJ./ DESERT BASIN GENERATING PROJ.	9/10/1999	YES	TURBINE, COMBINED CYCLE	2,320	GCP	2.8	BACT-PSD
			TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		5.7	
HARQUAHALA GENERATING PROJECT	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	COMBUSTION CONTROL AND USE OF NATURAL GAS	2.8	BACT-OTHER
PANDA GILA RIVER	2/23/2001	YES	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	2.8	BACT-PSD
AES WOLF HOLLOW LP	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	2.8	OTHER
SATSOP COMBUSTION TURBINE PROJECT	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	OXIDATION CATALYST	2.8	BACT-PSD
PINNACLE WEST ENERGY CORP/REDHAWK GEN. FACILITY	12/2/2000	YES	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	GOOD COMBUSTION	2.8	BACT-PSD
HENRY COUNTY POWER	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	CLEAN FUEL, GOOD COMBUSTION AND DESIGN	2.9	BACT-PSD
			(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		6.1	
RELIANT ENERGY HOPE GENERATING FACILITY	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	VOC AS NMHC	2.9	BACT-PSD
KLAMATH GENERATION, LLC	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	CATALYTIC OXIDATION	2.9	BACT-PSD
CHEHALIS GENERATION FACILITY	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	CATALYTIC OXIDATION	3.0	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION	3.0	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	OXIDATION CATALYST	3.0	BACT-OTHER
GENOVA ARKANSAS I, LLC	8/23/2002	?	(2) TURBINE, COMBINED CYCLE (SWH)	1,360	GCP	3.0	BACT-PSD
OLEANDER POWER PROJECT	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	3.0	BACT-PSD
LOWER MOUNT BETHEL ENERGY, LLC	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	OXIDATION CATALYST	3.0	LAER
PINE STATE POWER	6/30/1994	?	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	EFFECTIVE FUEL COMBUSTION	3.1	BACT-PSD
AEC - MCWILLIAMS PLANT	3/3/2000	YES	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	EFFICIENT COMBUSTION	3.1	BACT-PSD
FULTON COGEN PLANT	9/15/1994	?	GAS TURBINE	500	NONE INDICATED	3.1	BACT-OTHER
			STACK EMISSIONS (TURBINE & DUCT BURNER)	610		31.2	
SEPCO	10/5/1994	?	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920	OXIDATION CATALYST	3.1	BACT
AES RED OAK LLC	10/24/2001	?	(3) 501F TURBINES WITH HRSG	1,967	NONE INDICATED	3.2	BACT-PSD
SWEENY COGENERATION FACILITY	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	NONE INDICATED	3.2	OTHER
LAKE WORTH GENERATION, LLC	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	COMBUSTION DESIGN AND GOOD OPERATING PRACTICE	3.3	BACT-OTHER
KALKASKA GENERATING, INC	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	OXIDATION CATALYST	3.5	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	3.5	LAER
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	COMBUSTION CONTROLS	3.5	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	2/1/2002	?	TURBINE, COMBINED CYCLE W/ AND W/O DUCT FIRING	1,990	GCP	3.5	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC	2/25/2008	NO	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS FIRED) V	2,142	CO CATALYST	3.6	BACT
WHITING CLEAN ENERGY, INC.	7/20/2000	YES	(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735	GCP	3.6	BACT-PSD
			(2) TURBINES, COMBUSTION	1,735		12.5	
KM POWER COMPANY	6/26/2000	YES	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	NONE INDICATED	3.7	BACT-PSD
MIDDLETON FACILITY	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	NONE INDICATED	3.8	BACT-PSD
TPS - DELL, LLC	8/8/2000	YES	(2) TURBINE	2,560	GCP	3.8	BACT-PSD
KM POWER COMPANY	6/26/2000	YES	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	NONE INDICATED	3.9	BACT-PSD
LAMAR POWER PARTNERS II LLC	6/22/2009	NO	ELECTRICITY GENERATION	2,000	GOOD COMBUSTION PRACTICES	4	BACT
SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	?	COMBINED CYCLE COMBUSTION TURBINE	2,032	OXIDATION CATALYST	4.0	BACT
		?	COMBINED CYCLE COMBUSTION TURBINE	2,032	OXIDATION CATALYST	1.8	BACT
NEW ATHENS GENERATING CO. LLC	1/19/2007	NO	3 WESTINGHOUSE MODEL 501G GAS COMBINED CYCLE TURBINES	3,100	GOOD COMBUSTION CONTROL	4.0	LAER
SIERRA PACIFIC POWER COMPANY	8/16/2005	NO	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG & DB	2,448	OXIDATION CATALYST	4.0	BACT-PSD
			TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG & DB	2,448	OXIDATION CATALYST	4.0	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	EFFICIENT COMBUSTION TECHNIQUES	4.0	LAER
HOT SPRINGS POWER PROJECT	11/9/2001	?	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	CATALYTIC OXIDIZER	4.0	BACT-PSD
SALT RIVER PROJECT/SANTAN GEN. PLANT	3/7/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	CATALYTIC OXIDIZER	4.0	LAER
RENAISSANCE POWER LLC	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	GCP, OXIDATION CATALYST	4.0	BACT-PSD
CHOCTAW GAS GENERATION, LLC	12/13/2001	?	(2) TURBINE, COMBINED CYCLE	2,737	GCP	4.0	BACT-PSD
EXXON-MOBIL BEAUMONT REFINERY	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	FIRING NAT GAS, AND DLN BURNERS	4.0	BACT-OTHER
ENNIS TRACTEBEL POWER	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	GCP	4.0	BACT-OTHER
INDECK-NILES, LLC	12/2/2001	?	(4) GAS TURBINES COMBINED CYCLE	2,152	NONE INDICATED	4.0	BACT-PSD
			(4) GAS TURBINES COMBINED CYCLE W/ DUCT BURNER	2,152		5.2	
BLUE MOUNTAIN POWER, LP	7/31/1996	YES	COMBUSTION TURBINE W/ HEAT RECOVERY BOILER	1,224	OXIDATION CATALYST	4.0	LAER
			COMBUSTION TURBINE W/ HEAT RECOVERY BOILER (75% LOAD)	1,224		7.6	
MIDLAND COGENERATION	7/26/2001	?	(2) GAS TURBINE COMBINED CYCLE	2,096	NONE INDICATED	4.2	BACT-PSD
		?	TWO COMBINED CYCLE GAS TURBINES	2,110	PROPER OPERATING PRACTICES	4.5	BACT
MURRAY ENERGY FACILITY	10/23/2002	?	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	GCP	4.5	BACT-PSD
NORTHERN STATES POWER CO. DBA XCEL ENERGY	5/16/2006	YES	TWO COMBUSTION TURBINES	1,885	GOOD COMBUSTION PRACTICES	4.6	BACT-PSD
HIDALGO ENERGY FACILITY	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	COMBUSTION CONTROL	4.6	BACT-OTHER
MOBILE ENERGY LLC	1/5/1999	YES	TURBINE, GAS COMBINED CYCLE	1,344	GCP	4.7	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	GCP	4.7	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	1/8/2001	?	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GCP	4.7	BACT-PSD
PEDRICKTOWN COGENERATION PLANT (PCLP)	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	NONE INDICATED	4.7	BACT-PSD
CIPS - GRAND TOWER POWER STATION	2/25/2000	YES	(2) COMBINED CYCLE COMBUSTION TURBINE (UNITS 1+2)	2,347	GCP	4.8	BACT-PSD
SOUTHWEST ELECTRIC POWER COMPANY	3/20/2008	YES	(2) COMBINED CYCLE GAS TURBINES	1,055	PROPER OPERATING PRACTICES	4.9	BACT-PSD
PORT WESTWARD PLANT	1/16/2002	?	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	CO CATALYST, GOOD COMBUSTION	4.9	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	GOOD COMBUSTION. NATURAL GAS ONLY	4.9	BACT-PSD
GENPOWER KELLEY LLC	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	EFFICIENT COMBUSTION	4.9	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC	2/25/2008	NO	(2) SIEMENS SGT6-5000F TURBINES (HRSG & NG DUCT BURNER)	1,071	EMISSION RATES NOT BASED ON RED. FROM CO CAT.	5.0	BACT-PSD
ECOELECTRICA, L.P.	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	COMBUSTION CONTROLS	5.0	BACT-PSD
WALLULA POWER PLANT	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	GCP	5.0	BACT-OTHER
SUMAS ENERGY 2 GENERATION FACILITY	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	GCP	5.2	BACT-PSD
MESQUITE GENERATING STATION	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	OXIDATION CATALYST	5.2	BACT-PSD
PANDA-KATHLEEN, L.P.	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	5.2	BACT-OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	4/9/1996	YES	COMBUSTION TURBINE COMBINED CYCLE	1,299	GOOD COMBUSTION CONTROLS	5.2	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	12/31/2002	?	(2) HRSG/TURBINES 001&002	1,400	GOOD COMBUSTION CONTROLS	5.3	LAER
DUKE ENERGY FAYETTE, LLC	1/30/2002	?	(2) TURBINE, COMBINED CYCLE	2,240	OXIDATION CATALYST	5.3	LAER
REDBUD POWER PLANT	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	GCP/DESIGN	5.3	BACT-PSD
TENASKA ALABAMA GENERATING STATION	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	EFFICIENT COMBUSTION	5.5	BACT-PSD
COLUMBIA ENERGY LLC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GCP WITH DLN COMBUSTOR	5.6	BACT-PSD

Table C-3
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (PPM)	PERMIT LIMIT BASIS
TENASKA GATEWAY GENERATING STATION	5/7/1999	NO	(3) TURBINE/HRSG NO.1,2,3	3,168	GOOD COMBUSTION DESIGN AND OPERATIONS	5.6	OTHER
BARTON SHOALS ENERGY	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GCP	5.6	BACT-PSD
FORSYTH ENERGY PROJECTS, LLC	9/29/2005	YES	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844	GCP AND EFFICIENT PROCESS DESIGN	5.7	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GEN STATION	11/17/2000	?	COMBUSTION TURBINE WITH HRSG	1,917	USE OF NATURAL GAS AS THE EXCLUSIVE FUEL	5.7	BACT-PSD
BLACK DOG GENERATING PLANT	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	GOOD COMBUSTION CONTROL	5.7	BACT-PSD
FORSYTH ENERGY PLANT	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844	GCP AND EFFICIENT PROCESS DESIGN	5.7	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	12/31/2002	?	(2) HRSG/TURBINES 003&004	1,400	GOOD COMBUSTION CONTROLS	5.7	LAER
WYANDOTTE ENERGY	2/8/1999	YES	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	NONE INDICATED	6.0	BACT-PSD
HORSESHOE ENERGY PROJECT	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	CATALYTIC OXIDATION	6.0	BACT-PSD
GOLDENDALE ENERGY PROJECT	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	OXIDATION CATALYST AND GCP	6.0	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	EFFICIENT COMBUSTION	6.1	BACT-PSD
PASADENA 2 POWER FACILITY	9/30/1998	?	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	PROPER COMBUSTION PRACTICES	6.2	LAER
GPC - GOAT ROCK COMBINED CYCLE PLANT	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	EFFICIENT COMBUSTION PRACTICES	6.2	BACT-PSD
LSP - COTTAGE GROVE, L.P.	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NATURAL GAS COMBUSTION	6.2	BACT-PSD
DUKE ENERGY DALE, LLC	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	EFFICIENT COMBUSTION	6.4	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	EFFICIENT COMBUSTION	6.4	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	CLEAN FUEL -- NATURAL GAS ONLY	6.6	BACT-PSD
PANDA-KATHLEEN, L.P.	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	7.0	BACT-OTHER
INTERNATIONAL PAPER	2/24/1994	?	TURBINE/HRSG, GAS COGEN	338	COMBUSTION CONTROLS, FUEL SELECTION	7.0	BACT-OTHER
FAYETTEVILLE GENERATION, LLC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	COMBUSTION CONTROL	7.0	BACT-PSD
REDBUD POWER PLT	8/15/2001	?	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	OPERATIONAL CONTROLS	7.0	BACT-PSD
THUNDERBIRD POWER PLT	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	DLN COMBUSTION	7.0	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	GCP/DESIGN	7.0	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	NONE INDICATED	7.0	OTHER
ROCHE VITAMINS	10/8/1997	?	COMBUSTION TURBINE	457	LNB	7.2	BACT-PSD
			COMBUSTION TURBINE W/ DUCT BURNER	623		10.0	
TENASKA ARKANSAS PARTNERS, LP	10/9/2001	NO	TURBINE, COMBINED CYCLE (<75% LOAD)	1,480	GCP	7.3	BACT-PSD
			TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480		13.5	
RELIANT ENERGY- CHANNELVIEW COGENERATION	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	7.4	OTHER
BASF CORPORATION	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	NONE INDICATED	7.5	BACT-PSD
SILAS RAY POWER STATION UNIT 9	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	NONE INDICATED	8.4	BACT-PSD
			UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		10.1	
DUKE ENERGY-JACKSON FACILITY	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION CONTROL	8.4	BACT-PSD
GENOVA ARKANSAS I, LLC	8/23/2002	?	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	GCP/CO OXIDATION CATALYST	8.4	BACT-PSD
GENOVA OK I POWER PROJECT	6/13/2002	?	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	CATALYTIC OXIDATION	8.4	BACT-PSD
LIMA ENERGY COMPANY	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	NONE INDICATED	8.6	BACT-PSD
CALEDONIA POWER LLC	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	8.9	BACT-OTHER
EDINBURG ENERGY LIMITED PARTNERSHIP	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	9.0	BACT-PSD
BATESVILLE GENERATION FACILITY	11/25/1997	?	(3) TURBINE, EMISSION POINT AA-001,002,003 (75%-100% LOAD)	2,248	NONE INDICATED	9.3	BACT-PSD
			(3) TURBINE, EMISSION POINT AA-001,002,003 (<75% LOAD)	2,248		10.0	
TENASKA ALABAMA II GENERATING STATION	2/16/2001	?	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	EFFICIENT COMBUSTION	9.4	BACT-PSD
BLUEWATER ENERGY CENTER LLC	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	CATALYTIC AFTERBURNER	9.4	BACT-PSD
CONTINENTAL ENERGY SERVICES, INC., SILVER BOW GEN	6/7/2002	NO	(4) COMBINED CYCLE CT	1,400	NONE INDICATED	9.5	OTHER
LSP NELSON ENERGY, LLC	1/28/2000	?	TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166	GCP AND COMBUSTION CONTROL	9.6	BACT-PSD
			TURBINE, COMBINED CYCLE W DUCT BURNER	2,516		12.6	
LSP- BATESVILLE GENERATION FACILITY	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	NONE INDICATED	9.6	OTHER
BAYTOWN COGENERATION PLANT	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	PROPER COMBUSTION CONTROL	9.7	LAER
SMITH POCOLA ENERGY PROJECT	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	GOOD OPERATING PRACTICE	9.7	BACT-PSD
MIRANT WYANDOTTE LLC	7/25/2001	YES	(2) GAS TURBINES COMBINED CYCLE	2,205	CAT-OX SYSTEM	10.0	BACT-PSD
MIRANT WYANDOTTE LLC	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200	CATALYTIC OXIDIZER & GOOD COMBUSTION TECHNIQUES	10.0	BACT-OTHER
DECATUR ENERGY CENTER	6/6/2000	YES	(3) TURBINES, COMBINED CYCLE	1,867	EFFICIENT COMBUSTION	10.2	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376	NONE INDICATED	11.6	BACT-PSD
ALABAMA POWER CO. - THEODORE COGENERATION	3/16/1999	YES	TURBINE, W/ DUCT BURNER	1,360	EFFICIENT COMBUSTION	12.5	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP	13.6	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STATION	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	GCP	13.7	BACT-OTHER
MCWILLIAMS PLANT	4/14/1995	YES	TURBINE COMBINED CYCLE UNIT	848	EFFICIENT COMBUSTION	15.0	BACT-PSD
TENASKA FLUVANNA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	BEST COMBUSTION CONTROL PRACTICES	15.5	BACT-PSD
CHOCOLATE BAYOU PLANT	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP	17.1	BACT-OTHER
DEER PARK ENERGY CENTER	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	EFFICIENT & COMPLETE COMBUSTION	19.3	LAER
PLANT NO. 2	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	GOOD COMBUSTION DESIGN AND OPERATIONS	19.7	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	GOOD COMBUSTION AND DLN TECHNOLOGY	20.9	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	5/2/1994	NO	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	22.6	BACT-OTHER
PIKE GENERATION FACILITY	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	EFFICIENT COMBUSTION PRACTICES	22.8	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GENERATING PLANT	9/6/1996	?	COMBUSTION TURBINE	360	DESIGN	24.9	BACT-PSD
MAGIC VALLEY GENERATION STATION	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	PROPER COMBUSTION	28.4	BACT-PSD
INEOS USA LLC	8/29/2006	YES	COGENERATION TRAIN 2 AND 3 (TURBINE AND DUCT BURNER EMISSIONS	140	PROPER COMBUSTION CONTROL	34.2	BACT-PSD

SCR = SELECTIVE CATALYTIC REDUCTION, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Table C-4
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	(2) COMBINED CYCLE TURBINES, 75% LOAD	2,160	CLEAN BURNING FUEL AND EFFICIENT COMBUSTION	0.00130	BACT
			(2) COMBINED CYCLE TURBINES	2,160	CLEAN BURNING FUEL AND EFFICIENT COMBUSTION	0.00930	
			(2) COMBINED CYCLE TURBINES, 60% LOAD	2,160	CLEAN BURNING FUEL AND EFFICIENT COMBUSTION	0.01280	
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TWP, NJ	4/1/1991	TURBINES (NATURAL GAS) (2)	1190	TURBINE DESIGN	0.0023	BACT-OTHER
COYOTE SPRINGS PLANT	BOARDMAN, OR	10/13/1998	(2) COMBUSTION TURBINES #1 & #2	1,836	NONE INDICATED	0.00245	BACT-PSD
TRANSALTA CENTRALIA GENERATION LLC	CENTRALIA, WA	2/22/2002	(4)TURBINE/HRSG	1,504	GCP	0.00273	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC. - CHOUTEAU POV	MAYES, OK	3/24/1999	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	USE OF LOW ASH FUEL (NAT GAS) COMBUSTION CONTROLS	0.00300	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	(2) TURBINES, COMBINED CYCLE	2,640	GCP LOW SULFUR FUEL	0.00306	BACT-PSD
TENASKA TALLADEGA GENERATING STATION	OMAHA, AL	10/3/2001	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	EFFICIENT COMBUSTION	0.00350	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE, INC. - CHOUTEAU POV	MAYES, OK	1/23/2009	COMBINED CYCLE COGENERATION >25MW	1,882	NATURAL GAS FUEL	0.00350	BACT
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE INDICATED	0.00353	OTHER
NINEMILE POINT ELECTRIC GENERATING PLANT	JEFFERSON, LA	8/16/2011	COMBINED CYCLE TURBINES	3,573	USE OF PIPELINE QUALITY NATURAL GAS	0.00367	BACT
FORSYTH ENERGY PLANT	NC	9/29/2005	TURBINE, COMBINED CYCLE NATURAL GAS (3)	1844.3		0.0037	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	(2) TURBINES, COMBINED CYCLE	1,915	CLEAN BURNING FUELS, GCP	0.00381	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	(2) TURBINES, COMBINED CYCLE	1,338	CLEAN FUEL -- NATURAL GAS ONLY	0.00390	BACT-PSD
INDECK-NILES, LLC	NILES, MI	12/2/2001	(4) GAS TURBINES COMBINED CYCLE	2,152	NONE INDICATED	0.00395	BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK, NY	6/18/1992	COMBUSTION TURBINES (2) (252 MW)	1173	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	0.0040	BACT-OTHER
KING POWER STATION	HARRIS, TX	8/5/2010	TURBINE	2,700	USE OF LOW SULFUR FUEL	0.0041	BACT
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	NATURAL GAS < 1 GR S/100 SCF OF GAS	0.00420	BACT-PSD
UMATILLA GENERATING COMPANY, L.P.	OREGON	5/11/2004	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	2,007	GOOD COMBUSTION AND FIRING NATURAL GAS	0.00420	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	COMBUSTION TURBINE COMBINED CYCLE	2,320	GOOD COMBUSTION AND CLEAN FUELS	0.00431	BACT-OTHER
THOMAS B. FITZHUGH GENERATING STATION	OZARK, AR	2/15/2002	TURBINE, COMBINED CYCLE, SWPC 501D5A	1,365	LOW ASH FUELS, GCP	0.00432	BACT-PSD
PINE STATE POWER	JAY, ME	6/30/1994	(2) COMBINED CYCLE TURBINES #1 & #2	1,127	CLEAN FUEL	0.00444	BACT-PSD
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	(2) TURBINES, COMBUSTION, W/ AND W/O DUCT BURNER	1,735	GCP AND NATURAL GAS FUEL	0.00450	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	TURBINE	1,984	PIPELINE QUALITY NAT GAS	0.00454	BACT-PSD
CITY OF GAINESVILLE REGIONAL UTILITIES	GAINESVILLE, FL	2/24/2000	ELECTRIC GENERATION TURBINE COMBINED CYCLE	1,083	CLEAN FUELS	0.00462	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	NONE INDICATED	0.00474	LAER
			(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN, W/ DB	1,900		0.006105	
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE, CO	5/1/1996	(2) COMBINED CYCLE TURBINES	1,884	PIPELINE QUALITY GAS, CLOSE MONITORING/CONTROL/COMB	0.00478	BACT-PSD
PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	TURBINE, COMBINED CYCLE	1,360	CLEAN FUELS	0.00490	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2,534	DLN TECHNOLOGY IN CONJUNCTION WITH SCR	0.0050	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE, RI	4/13/1992	TURBINE, GAS AND DUCT BURNER	1,360	USE OF NATURAL GAS	0.0050	BACT-PSD
DECATUR ENERGY CENTER	DECATUR, AL	6/6/2000	(3) TURBINES, COMBINED CYCLE	1,867	NATURAL GAS ONLY EFFICIENT COMBUSTION	0.00500	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	0.00500	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	0.00500	BACT-PSD
			(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		0.00542	
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	TURBINE, COMBINED CYCLE, DUCT BURNER CC5	4,240	USE OF NATURAL GAS AND GOOD COMBUSTION	0.00510	LAER
CPV WARREN	VA	1/14/2008	ELECTRIC GENERATION - SCENARIO 2	1,717	WITHOUT DUCT FIRING	0.0051	UNKNOWN
			ELECTRIC GENERATION - SCENARIO 1			0.0073	N/A
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	SIEMENS SGT6-5000F TURBINE #1 AND #2 W/ 445 MMBTU/HR DUCT BURNER	2,142	NONE INDICATED	0.00514	BACT
VINEYARD ENERGY CENTER, LLC	VINEYARD, UT	5/11/2004	(3) SWPC 501F COMBUSTION TURBINES	1,738	NONE INDICATED	0.00518	BACT
			(3) SWPC 501F COMBUSTION TURBINES, W/ DUCT BURNER	2,400		0.00631	
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	COMBUSTION TURBINE (1 OR 2)	1,700	GCP	0.00529	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	GCP. USE OF NG/LPG	0.00530	BACT-PSD
APS WEST PHOENIX	PHOENIX, AZ	5/26/2000	TURBINE, COMBINED CYCLE, DUCT BURNER CC4	1,040	USE OF NATURAL GAS AND GCP	0.00550	LAER
CAROLINA POWER AND LIGHT - RICHMOND CO. FACILITY	RALEIGH, NC	12/21/2000	(2) TURBINES, COMBINED CYCLE	1,628	COMBUSTION CONTROL	0.00550	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	(2) TURBINE, COMBINED CYCLE	1,628	COMBUSTION CONTROL	0.00550	BACT-PSD
CON ED EAST RIVER REPOWERING PROJECT	NEW YORK, NY	8/30/2001	(2) COMBUSTION TURBINES, W/O DUCT BURNER	2,054	NONE INDICATED	0.00554	LAER
			(2) COMBUSTION TURBINES, W/ DUCT BURNER	3,165		0.00786	
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	(2) GAS TURBINES	1,611	GOOD COMBUSTION CONTROL	0.00559	LAER
TIGER BAY LP	FT. MEADE, FL	5/17/1993	TURBINE, GAS	1,615	GOOD COMBUSTION PRACTICES	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH, FL	6/5/1991	TURBINE, GAS, 4 EACH	400	COMBUSTION CONTROL	0.0056	BACT-PSD
PANDA GILA RIVER	GILA BEND, AZ	2/23/2001	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	0.00560	BACT-PSD
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	GCP	0.00600	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	GOOD COMBUSTION AND FIRING NATURAL GAS	0.00609	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	GCP	0.00610	LAER
SARANAC ENERGY COMPANY	PLATTSBURGH, NY	7/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123	COMBUSTION CONTROLS	0.0062	BACT-OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL, MS	4/9/1996	COMBUSTION TURBINE COMBINED CYCLE	1,299	GOOD COMBUSTION CONTROLS	0.00624	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	TURBINE, COMBINED CYCLE COMBUSTION	1,120	DRY LNB, GOOD COMBUSTION	0.00625	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TENNESSEE	2/1/2002	TURBINE, COMBINED CYCLE W/O DUCT FIRING	1,990	CLEAN FUELS, GCP	0.00628	BACT-PSD
			TURBINE, COMBINED CYCLE W/ DUCT FIRING	1,990		0.00879	
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	(1) COMBINED CYCLE GAS TURBINE	1,742	CLEAN FUELS, GCP	0.00631	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS, COMBUSTION CONTROLS	0.00631	BACT
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS, COMBUSTION CONTROLS	0.00631	BACT
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	FIRING NAT GAS	0.00643	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	TURBINE, COMBINED CYCLE	1,700	COMBUSTION CONTROLS, LOW SULFUR FUELS	0.00647	BACT-PSD
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	COMBINED CYCLE COMBUSTION TURBINE	1,700	INHERENTLY CLEAN FUELS	0.00647	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.00650	BACT
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	TURBINE, COMBINED CYCLE	1,360	GCP, CLEAN FUEL	0.00650	BACT-PSD
ROCKY MOUNTAIN ENERGY CENTER, LLC.	LITTLETON, CO	8/11/2002	(2) COMBINED-CYCLE TURBINE	2,311	USE OF PIPELINE QUALITY NATURAL GAS AND GCP	0.00650	BACT-PSD
CPV PIERCE	FLORIDA	8/7/2001	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS GOOD COMBUSTION	0.00655	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS GOOD COMBUSTION	0.00655	BACT-PSD
SALT RIVER / DESERT BASIN GENERATING PROJECT	PHOENIX, AZ	9/10/1999	TURBINE, COMBINED CYCLE	2,320	GCP	0.00659	BACT-PSD
			TURBINE, COMB'D CYCLE W/ DUCT BURNERS	2,320		0.00991	
CHUGACH ELECTRIC ASSOCIATION, INC.	ANCHORAGE, AK	12/20/2010	GE LM6000PF-25 Turbines (4)	358	GOOD COMBUSTION PRACTICES.	0.00660	BACT
			GE LM6000PF-25 Turbines (4)	358	GOOD COMBUSTION PRACTICES.	0.00660	BACT
			GE LM6000PF-25 Turbines (4)	358	GOOD COMBUSTION PRACTICES.	0.00660	BACT
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	(2) COMBUSTION TURBINES COMB CYCLE W/O DUCT BURNER	1,440	NONE INDICATED	0.00660	BACT-PSD
			(2) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	1,440		0.00910	
LORDSBURG L.P.	LORDSBURG, NM	6/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	800	OIL (LESS THAN 0.05% BY WT.)	0.0066	BACT-PSD
ONETA GENERATING STA	OKLAHOMA	1/21/2000	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW ASH FUELS	0.00662	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY, AL	3/12/1997	COMBINED CYCLE TURBINE (25 MW)	568	EFFICIENT OPERATION OF THE COMBUSTION TURBINE	0.00680	BACT-PSD
TENASKA FLUVANNA	VIRGINIA	1/11/2002	(3) TURBINES, COMBINED CYCLE	2,375	USE OF NATURAL GAS/CLEAN FUEL	0.00682	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	CASE I: TURBINE E-1 W/O HRSG	720	NONE INDICATED	0.00694	OTHER
			CASE II: TURBINE E-1 W/ HRSG	720		0.00750	
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	USE OF NO-ASH FUEL AND EFFICIENT COMBUSTION	0.00700	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON, AL	12/11/2001	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL	0.00720	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	HOUSTON, AL	10/23/2001	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	EFFICIENT COMBUSTION	0.00720	BACT-PSD
KYRENE GENERATING STATION, SALT RIVER PROJECT	PHOENIX, AZ	3/14/2001	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	NONE INDICATED	0.00720	LAER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	(2) TURBINE, COMBINED CYCLE	2,046	LOW ASH FUEL, NG	0.00720	BACT-OTHER
GULF STATES UTILITIES COMPANY - LOUISIANA STATION	BATON ROUGE, LA	2/7/1996	NO.4 TURBINE/HRSG	1,573	NONE INDICATED	0.00725	OTHER

Table C-4
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.00740	BACT
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-ASH FUEL - NATURAL GAS	0.00750	BACT-OTHER
			COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		0.00929	
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	7/25/2001	(2) GAS TURBINES COMBINED CYCLE	2,205	NONE INDICATED	0.00762	BACT-PSD
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	(2) TURBINE, COMBINED CYCLE WITH DUCT BURNER, POWER AUG.	2,200	GCP AND USE OF PIPELINE QUALITY NATURAL GAS	0.00764	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	(3) TURBINE/HRSG NO.1,2,3	3,168	FIRING NAT GAS	0.00783	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	GOOD COMBUSTION	0.00787	BACT-PSD
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	FIRING NAT GAS	0.00795	BACT-PSD
			(2)GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		0.00910	
WALLULA POWER PLANT	WASHINGTON	1/3/2003	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	NONE INDICATED	0.00800	BACT-OTHER
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	FIRING NAT GAS	0.00805	BACT-PSD
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	COMBUSTION CONTROL & PIPELINE-QUALITY NAT GAS	0.00809	BACT-OTHER
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	(3) COMBUSTION TURBINES 7,8,9	360	GCP	0.00833	BACT-PSD
MANSFIELD MILL	MANSFIELD, LA	8/14/2001	GAS TURBINE/HRSG	654	NATURAL GAS FIRING	0.00840	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE, MI	2/8/1999	(2) TURBINE, COMBINED CYCLE POWER PLANT	2,000	NONE INDICATED	0.00850	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	(2) COMBUSTION TURBINES	1,840	GOOD COMBUSTION	0.00858	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	FIRING NAT GAS	0.00865	BACT-PSD
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	(4) TURBINES, COMBINED CYCLE GE (50%-100%)	1,400	GCP	0.00876	BACT-PSD
			(4) TURBINES, COMBINED CYCLE GE (100%)	1,400		0.01007	
			(4) TURBINES, COMBINED CYCLE GE DUCT BURNERS	1,400		0.01204	
MOBILE ENERGY LLC	MOBILE, AL	1/5/1999	TURBINE, GAS COMBINED CYCLE	1,344	COMBUSTION OF CLEAN FUELS	0.00890	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	COMBUSTING NATURAL GAS	0.00890	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON, RI	2/13/1998	COMBUSTION TURBINE, NATURAL GAS	2,120	GOOD COMBUSTION	0.0089	BACT-PSD
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	(8) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NATURAL GAS ONLY	0.00900	BACT-PSD
AUTAUGAVILLE COMBINED CYCLE PLANT	PRATTVILLE, AL	1/8/2001	(4) COMBUSTION TURBINES COMBINED CYCLE	1,384	GCP	0.00900	BACT-PSD
MCINTOSH COMBINED-CYCLE FACILITY	RINCON, GA	4/17/2003	(4) TURBINE, COMBINED CYCLE, DUCT BURNER	1,902	NATURAL GAS	0.00900	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	(2) TURBINE, COMBINED CYCLE	1,488	NONE INDICATED	0.00900	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	0.00900	BACT-OTHER
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	NONE INDICATED	0.00900	BACT-PSD
			UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		0.01025	
SPRINGDALE TOWNSHIP STATION	GREENSBURG, PA	7/12/2001	TURBINE, COMBINED CYCLE	2,094	GCP	0.00907	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,973	GOOD COMBUSTION/DESIGN AND CLEAN FUEL	0.00912	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	2,325		0.01062	
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	NONE INDICATED	0.00915	BACT-OTHER
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	(2) TURBINE, COMBINED CYCLE	1,962	GCP. DRIFT ELIMINATORS	0.00917	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707	GCP	0.00926	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097		0.00939	
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.00932	OTHER
MIDDLETON FACILITY	BOISE, ID	10/19/2001	(2) GAS TURBINES WITH DUCT BURNERS	2,097	REASONABLE POLLUTION PREVENTION PRECAUTIONS	0.00939	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION TECHNOLOGY	0.00942	BACT-PSD
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	TURBINE, NO DUCT BURNER FIRING	1,937	NONE INDICATED	0.00945	BACT-PSD
			TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		0.01146	
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	PIPELINE QUALITY NATURAL GAS AND GCP	0.00955	BACT-PSD
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	(2) TURBINE, COMBINED CYCLE	1,827	GCP	0.00958	BACT-PSD
			(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470		0.00960	
LAWRENCE ENERGY	OHIO	9/24/2002	(3) TURBINES, COMBINED CYCLE DUCT BURNERS OFF	1,440	BURNING NATURAL GAS	0.00960	BACT-PSD
			(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON	1,440		0.01010	
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	0.00971	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	(2) TURBINE, COMBINED CYCLE & DUCT BURNER	1,955	NONE INDICATED	0.00972	BACT-PSD
			(2) TURBINE, COMBINED CYCLE	1,360		0.01103	
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN	6/15/2001	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	0.00980	BACT-OTHER
			(3) COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	2,400		0.01060	
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	USE OF LOW ASH FUEL	0.00994	BACT-PSD
LAKE ROAD GENERATING COMPANY, L.P.	KILLINGLY, CT	11/30/2001	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	NONE INDICATED	0.01000	BACT
FAIRBAULT ENERGY PARK	RICE CO., MN	7/15/2004	TURBINE, COMBINED CYCLE	1,876	CLEAN FUEL AND GCP	0.01000	BACT-PSD
GENERAL ELECTRIC PLASTICS	BURKVILLE, AL	5/27/1998	TURBINE & DUCT BURNER COMBINED CYCLE	1,200	CLEAN FUEL - NATURAL GAS/HYDROGEN	0.01000	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	EFFICIENT COMBUSTION	0.01000	BACT-PSD
SALT RIVER PROJECT/SANTAN GEN. PLANT	PHOENIX, AZ	3/7/2003	TURBINE, COMBINED CYCLE, DUCT BURNER	1,400	NONE INDICATED	0.01000	LAER
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	CLEAN FUEL/NATURAL GAS ONLY	0.01000	BACT-PSD
REDBUD POWER PLT	TULSA, OK	8/15/2001	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	USE OF LOW ASH FUEL, EFFIECIENT COMBUSTION	0.01000	BACT-PSD
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	USE OF LOW ASH FUEL	0.01000	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01000	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	MHI COMBUSTION TURBINE & DUCT BURNERS	1,767	LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01000	BACT-PSD
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP	0.01000	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	(2) NEW TURBINES, STACK 5 & 6	2,000	FIRING NAT GAS	0.01000	BACT-PSD
			(4) GAS FUELED TURBINES, STACK 1-4	2,200		0.01091	
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	TURBINE, COMBINED CYCLE (<75% LOAD)	1,480	GCP	0.01000	BACT-PSD
			TURBINE, COMBINED CYCLE (75%-100% LOAD)	1,480		0.01100	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000	FIRING NAT GAS	0.01000	BACT-PSD
			(4) TURBINES - ONLY CTG-1 TO 4	1,360		0.01324	
MURRAY ENERGY FACILITY	DALTON, GA	10/23/2002	(4) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,480	GCP, CLEAN FUEL	0.01008	BACT-PSD
RELIANT ENERGY- CHANNELVIEW COGENERATION	HOUSTON, TX	10/29/2001	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	0.01009	BACT-PSD
PINNACLE WEST ENERGY CORP./REDHAWK GEN.	PHOENIX, AZ	12/2/2000	TURBINE, COMBINED CYCLE DUCT BURNER	1,400	NONE INDICATED	0.01010	BACT-PSD
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000	FIRING NAT GAS	0.01015	BACT-PSD
			(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360		0.01346	
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	COMBINED CYCLE NATURAL GAS	2,362	GOOD COMBUSTION CONTROL	0.01016	BACT-OTHER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.01017	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP	0.01025	BACT-PSD
			(2) TURBINES AND DUCT BURNERS COMBINED	1,288		0.01258	
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	TURBINE, GE 7EA FRAME COMBINED CYCLE	896	NONE INDICATED	0.01027	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	12/9/1999	(2) GAS TURBINES	1,908	GCP GOOD DESIGN AND CLEAN BURNING NATURAL GAS	0.01034	BACT-PSD
CARVILLE ENERGY CENTER	LOUISIANNA	5/16/2001	(2) GAS TURBINES (1-98A, 2-98A)	1,908	GCP GOOD DESIGN AND CLEAN BURNING NATURAL GAS	0.01034	BACT-PSD
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	TURBINE/HRSG W/O DUCT BURNER FIRING	672	NATURAL GAS AS FUEL	0.01042	BACT-OTHER
			TURBINE/HRSG W/ DUCT BURNER FIRING	672		0.01871	
MIRANT GASTONIA POWER FACILITY	NORTH CAROLINA	5/28/2002	(4) TURBINES, COMBINED CYCLE MHI/SW @ 75% LOAD	1,400	GCP	0.01056	BACT-OTHER
			(4) TURBINES, COMBINED CYCLE MHI/SW	1,400		0.01342	
			(4) TURBINES, COMBINED CYCLE MHI/SW DUCT BURNERS	1,400		0.01523	
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	FIRING NAT GAS	0.01050	BACT-PSD
			(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360		0.01346	
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360	NATURAL GAS. GOOD COMBUSTION	0.01070	BACT-PSD
			(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945		0.01200	
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	(4) TURBINES, COMBINED CYCLE	1,372	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01071	BACT-PSD

Table C-4
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
GREATER DES MOINES ENERGY CENTER	PLEASANT HILL, IA	4/10/2002	(2) COMBUSTION TURBINES - COMBINED CYCLE	1,400	NONE INDICATED	0.01080	BACT-PSD
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	NONE INDICATED	0.01080	BACT
BEATRICE POWER STATION	GAGE CO., NE	6/22/2004	(2) COMBUSTION TURBINES W/ DUCT BURNER	1,000	NONE INDICATED	0.01080	BACT-OTHER
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376	NONE INDICATED	0.01090	BACT-PSD
			(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376		0.01693	
SITHE EDGAR DEVELOPMENT, LLC - FORE RIVER	WEYMOUTH, MA	3/10/2000	(2) MHI 501G COMBUSTION TURBINE	2,676	NONE INDICATED	0.01100	BACT
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	(3) SWPC 510G COMBUSTION TURBINES	2,880	CLEAN BURNING FUELS & EFFICIENT COMBUSTION	0.01100	BACT
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS	1,965	NAT GAS AS PRIMARY FUEL	0.01100	BACT-PSD
WANSLEY COMBINED CYCLE ENERGY FACILITY	ROOPVILLE, GA	1/15/2002	(2) TURBINE, COMBINED CYCLE	1,336	GCP, LOW SULFUR FUEL	0.01100	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	(2) TURBINE, COMBINED CYCLE	2,699	NATURAL GAS FUEL	0.01100	BACT-PSD
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	0.01100	BACT-OTHER
PSO NORTHEASTERN POWER STA	OKLAHOMA	10/18/1999	(2) TURBINES, COMBINED CYCLE	1,280	COMBUSTION CONTROL	0.01100	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791	NONE INDICATED	0.01128	BACT-PSD
			(4) TURBINE, COMBINED CYCLE	1,491		0.01200	
CHOCTAW GAS GENERATION, LLC	MISSISSIPPI	12/13/2001	(2) TURBINE, COMBINED CYCLE	2,737	LOW ASH FUEL AND GCP	0.01136	BACT-PSD
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	TWO COMBINED CYCLE GAS TURBINES	2,110	GOOD COMBUSTION DESIGN/ PROPER OPERATING PRACTICES/ PIPELINE QUALITY NATURAL GAS AS FUEL	0.01148	BACT
GREGORY POWER FACILITY	TEXAS	6/16/1999	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	FIRING NAT GAS	0.01149	BACT-PSD
			(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		0.01486	
THE DOW CHEMICAL COMPANY	IBERVILLE, LA	7/23/2008	(4) GAS TURBINES/DUCT BURNERS	2,876	USE OF CLEAN BURNING FUELS	0.01165	BACT
PLAQUEMINE, IBERVILLE PARISH	LOUISIANNA	12/26/2001	(4) GAS TURBINES/DUCT BURNERS	2,876	USE OF CLEAN BURNING FUELS	0.01165	BACT-PSD
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	TURBINES AND DUCT BURNERS	2,480	LOW ASH FUEL (NATURAL GAS)	0.01170	BACT-PSD
KM POWER COMPANY	FORT LUPTON, CO., MI	6/26/2000	(6) TURBINE GE LM 6000 COMBINED CYCLE	416	NONE INDICATED	0.01178	BACT-PSD
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	(2) TURBINE, COMBINED CYCLE	2,132	NONE INDICATED	0.01190	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	(3) COMBINED CYCLE TURBINES	2,049	CLEAN BURNING FUEL & EFFICIENT COMBUSTION	0.01200	BACT
ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE, AL	3/16/1999	TURBINE, W/ DUCT BURNER	1,360	COMBUSTION OF NATURAL GAS ONLY	0.01200	BACT-PSD
AEC - MCWILLIAMS PLANT	GANTT, AL	3/3/2000	(2) TURBINES, COMBINED CYCLE COMBUSTION	1,328	GCP ALONG WITH USE OF NATURAL GAS	0.01200	BACT-PSD
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	GCP	0.01200	BACT-PSD
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL	0.01200	BACT-PSD
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	(2) TURBINES, COMBINED CYCLE	3,630	NATURAL GAS FUEL	0.01200	BACT-PSD
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	TURBINE, COMBINED CYCLE	2,493	CLEAN FUEL - NATURAL GAS	0.01200	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	0.01200	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.01200	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	NONE INDICATED	0.01202	BACT-OTHER
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	0.01233	BACT-OTHER
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	NONE INDICATED	0.01238	BACT-PSD
LIBERTY ELECTRIC POWER , LLC	PENNSYLVANIA	5/3/2000	(2) TURBINE, COMBINED CYCLE	2,000	NONE INDICATED	0.01244	LAER
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (SWH)	1,360	GCP/CLEAN FUEL	0.01250	BACT-PSD
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NG < 0.8 GR/100SCF	0.01250	BACT-PSD
KAUFMAN COGEN LP	TEXAS	1/31/2000	(2) GAS TURBINES HRSG-1 & -2	1,440	PIPELINE QUALITY NAT GAS	0.01250	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	(4) TURBINES, COMBINED CYCLE	1,515	NONE INDICATED	0.01254	BACT-PSD
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.01276	BACT
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	0.01278	BACT-OTHER
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	TURBINE, COMBINED CYCLE	1,923	NONE INDICATED	0.01280	BACT-PSD
GENPOWER EARLEYS, LLC	NORTH CAROLINA	1/9/2002	(2) TURBINES, COMBINED CYCLE	1,715	GCP AND DESIGN	0.01283	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	GCP AND USE OF NATURAL GAS	0.01286	BACT-PSD
PERRYVILLE	ALEXANDRIA, LA	8/25/2000	(4) GAS TURBINES IN COMBINED CYCLE MODE, W/ DUCT BURNER	1,774	GCP, USING CLEAN NATURAL GAS	0.01297	BACT-PSD
			(4) COMBINED CYCLE GENERATION UNIT, W/O DUCT BURNER	1,464		0.01783	
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	(2) GE7121EA GAS TURBINES	1,079	NONE INDICATED	0.01297	OTHER
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	(2) COMBINED CYCLE TURBINE	1,464	NATURAL GAS WITH LOW ASH CONTENT	0.01298	BACT-PSD
VIRGINIA ELECTRIC AND POWER COMPANY	WARREN, VA		ELECTRIC GENERATION - SCENARIO 1	1,717	GOOD COMBUSTION PRACTICES	0.01300	BACT
			ELECTRIC GENERATION - SCENARIO 2	1,944	GOOD COMBUSTION PRACTICES	0.00643	BACT
		1/14/2008	ELECTRIC GENERATION SECNARIO 3	2,204	GOOD COMBUSTION PRACTICES.	0.00449	BACT
CPV Warren, LLC	FRONT ROYAL, VA	7/30/2004	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	LOW SULFUR GAS < 0.002%	0.01300	BACT
MCWILLIAMS PLANT	ANDALUSIA, AL	4/14/1995	TURBINE COMBINED CYCLE UNIT	848	EFFICIENT COMBUSTION	0.01300	BACT-PSD
HOT SPRINGS POWER PROJECT	ARIZONA	11/9/2001	(2) COMBUSTION TURBINE, HRSG, DUCT BURNER	2,800	CLEAN FUELS	0.01300	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	COMBUSTION TURBINE	360	LOW ASH FUEL	0.01300	BACT-PSD
HENRY COUNTY POWER	VIRGINIA	11/21/2002	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	GOOD COMBUSTION DESIGN AND CLEAN FUEL	0.01300	BACT-PSD
			(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		0.01400	
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	(3) COMBUSTION TURBINE W/ AND W/O DUCT BURNER	2,181	NONE INDICATED	0.01300	NSPS
			(3) COMBUSTION TURBINE W/O DUCT BURNER 75%LOAD	1,636		0.01540	
			(3) COMBUSTION TURBINE W/O DUCT BURNER 60% LOAD	1,309		0.01730	
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	PORPER COMBUSTION	0.01302	BACT-PSD
PLANT NO. 2	LUBBOCK, TX	1/8/1999	(2) TURBINE/DUCT BURNER STGT1 & T2	336	FIRING NAT GAS	0.01310	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY	ARLINGTON, AZ	12/14/2000	TURBINE, COMBINED CYCLE	2,040	NONE INDICATED	0.01324	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	TURBINE, COMBINED CYCLE	1,360	GOOD COMBUSTION	0.01324	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	USE OF CLEAN BURNING FUELS	0.01324	BACT-PSD
DRESDEN ENERGY LLC	OHIO	10/16/2001	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	NONE INDICATED	0.01332	BACT-PSD
			(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		0.01587	
FORNEY PLANT	HOUSTON, TX	3/6/2000	(6) TURBINES	1,358	GCP	0.01325	BACT-PSD
			(6) COMBINED TURBINE & DUCT BURNER	1,358		0.09526	
GATEWAY POWER PROJECT	TEXAS	3/20/2000	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	GCP	0.01340	BACT-PSD
			(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		0.01735	
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NATURAL GAS FUEL USED	0.01352	BACT-PSD
NORTH AMERICAN POWER GP -KIOWA CREEK	GREENWOOD VILLAGE, CO	1/17/2001	(4) COMBINED-CYCLE GAS TURBINES - GENERATORS	2,000	PIPELINE QUALITY NATURAL GAS AND GCP	0.01360	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE, FL	12/14/1992	TURBINE,GAS	1,214	GOOD COMBUSTION PRACTICES	0.0136	BACT-PSD
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (MHI)	1,360	GCP	0.01360	BACT-PSD
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	EXCLUSIVE USE OF NATURAL GAS	0.01361	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	NONE INDICATED	0.01397	BACT-PSD
			(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		0.02059	
GILA BEND POWER GENERATING STATION	ARIZONA	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER	1,360	NONE INDICATED	0.01400	BACT-PSD
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	(4) TURBINES, COMBINED CYCLE	2,380	NONE INDICATED	0.01400	BACT-PSD
FAIRLESS WORKS ENERGY CENTER	GLEN ALLEN, PA	8/7/2001	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.01400	BACT-PSD
LIMERICK PARTNERS, LLC	LIMERICK, PA	4/9/2002	(3) TURBINE, COMBINED CYCLE	1,467	NONE INDICATED	0.01400	BACT-OTHER
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	(3) TURBINES, COMBINED CYCLE & DUCT BURNERS	1,944	NONE INDICATED	0.01400	BACT-PSD
			(3) TURBINES, COMBINED CYCLE	1,944		0.01700	
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	(3) TURBINE/HRSGS CTG1-3	2,000	GCP & FIRING NON-ASH CONTAINING GASEOUS FUELS	0.01415	BACT-PSD
GENOVA ARKANSAS I, LLC	ARIZONA	8/23/2002	(2) TURBINE, COMBINED CYCLE (GE)	1,360	GCP/CLEAN FUEL	0.01434	BACT-PSD
EFFINGHAM COUNTY POWER, LLC	GEORGIA	12/27/2001	(2) TURBINE, COMBINED CYCLE	1,480	GCP/CLEAN FUEL	0.01459	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	FIRING NATURAL GAS	0.01467	BACT-PSD
			(4) GAS TURBINES TURBINE ONLY FIRING	1,360		0.01493	
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	(2) CTG-HRSG STACKS STACK1 & 2	1,440	FIRING PIPELINE-QUALITY NAT GAS	0.01476	BACT-PSD

Table C-4
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
NYPA Poletti Power Project	ASTORIA, NY	10/1/2002	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.01500	BACT
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	(2) TURBINES, COMBINED CYCLE	1,701	CLEAN FUEL AND EFFICIENT COMBUSTION	0.01500	BACT-OTHER
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191	LOW SULFUR FUEL	0.01500	BACT-PSD
			(3) TURBINE, COMBINED CYCLE	1,798		0.01600	
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	(3) COMBINED CYCLE TURBINE W/O DUCT BURNER	2,964	NONE INDICATED	0.01500	BACT-PSD
			(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202		0.01700	
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	GCP & FIRING NON-ASH CONTAINING GASEOUS FUELS	0.01515	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	GCP AND THE USE OF NATURAL GAS	0.01517	BACT-PSD
TENASKA FRONTIER GENERATION STATION	OMAHA, TX	8/7/1998	(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464	FIRING NATURAL GAS IN THE TURBINES AND DUCT BURNERS	0.01530	BACT-PSD
XCEL ENERGY, BLACK DOG ELECTRIC GENERATING STA	BURNSVILLE, MN	11/17/2000	COMBUSTION TURBINE WITH HRSG	1,917	USE OF NATURAL GAS AS THE EXCLUSIVE FUEL	0.01534	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE INDICATED	0.01544	BACT-PSD
			(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360		0.01838	
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	GCP AND FIRING ONLY GASEOUS FUELS	0.01547	BACT-PSD
DUKE ENERGY FAYETTE, LLC	MASONTOWN, PA	1/30/2002	(2) TURBINE, COMBINED CYCLE	2,240	NONE INDICATED	0.01554	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	CLEAN FUEL AND GCP	0.01570	BACT-PSD
BASF CORPORATION	GEISMAR, LA	12/30/1997	(2) TURBINE, COGEN UNIT GE FRAME 6	339	GOOD DESIGN & OPERATING PRACTICES USE GASEOUS FUELS	0.01592	BACT-PSD
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	NONE INDICATED	0.01600	OTHER
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	COGEN STACK TURBINE ONLY	310	FIRING NAT GAS	0.01615	BACT-PSD
			COGEN STACK COMBINED GT/HRSG&DB 1180	310		0.02590	
PPG INDUSTRIES	LAKE CHARLES, LA	12/2/1999	COGENERATION UNIT 5 AND 6 (EACH)	1,320	GCP, CLEAN BURNING FUEL	0.01621	BACT-PSD
SHELL CHEMICAL COMPANY - GEISMAR PLANT	GEISMAR, LA	5/10/2000	(2) COGENERATION UNITS COMBINED CYCLE	320	GCP	0.01625	BACT-PSD
TENASKA ALABAMA II GENERATING STATION	ALABAMA	2/16/2001	(3) COMBINED CYCLE COMBUSTION TURBINE UNITS	1,360	CLEAN FUELS	0.01660	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN STA	KANSAS CITY, MO	8/19/1999	(2) TURBINE, COMBINED	1,360	GCP	0.01662	BACT-OTHER
BEATRICE POWER STATION	BEATRICE, NE	5/29/2003	(2) TURBINE, COMBINED CYCLE	640	NONE INDICATED	0.01688	BACT-OTHER
PERRYVILLE POWER STATION	ALEXANDRIA, LA	3/8/2002	(2) GAS TURBINES, EPNS 1-1, 1-2	1,360	LNB, PROPER OPERATING INSTRUCTIONS & USE OF NATL GAS	0.01691	BACT-PSD
			(2) GAS TURBINE/HRSG UNITS, EPNS 1-1, 1-2	1,360		0.01919	
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	(4) COMBINED CYCLE GAS TURBINE STACK1-4	1,400	FIRING NAT GAS	0.01714	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	(2) TURBINE, COMBINED CYCLE	1,376	USE OF NATURAL GAS & STATE OF THE ART COMBUSTION	0.01744	BACT-PSD
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	FIRING PIPELINE QUALITY NAT GAS	0.01781	NSPS
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	LOW SULFUR FUELS	0.01820	OTHER
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	TURBINE, COMBINED CYCLE W DUCT BURNER	2,516	GCP WITH USE OF NATURAL GAS	0.01832	BACT-PSD
			TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166		0.01910	
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP, USE OF GASEOUS FUELS CONTAINING NO ASH	0.01882	BACT-PSD
SC ELECTRIC AND GAS COMPANY - URQUHART STATION	COLUMBIA, SC	9/22/2000	(2) TURBINES, COMBINED CYCLE	1,795	NONE INDICATED	0.01894	BACT-PSD
GENOVA OK I POWER PROJECT	OKLAHOMA	6/13/2002	GE COMBUSTION TURBINE & DUCT BURNERS	1,705	LOW SULFUR FUEL AND EFFICIENT COMBUSTION	0.01900	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	(3) TURBINE, COMBINED CYCLE	1,844	USE OF ONLY CLEAN-BURNING LOW-SULFUR FUELS AND GCP	0.01900	BACT-PSD
			(3) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,844		0.02100	
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	USE OF NATURAL GAS AS FUEL	0.01905	BACT-PSD
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	FIRING NAT GAS	0.01918	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN, GA	4/3/1996	COMBUSTION TURBINE (2), NATURAL GAS	928	CLEAN FUEL	0.0194	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	(3) TURBINE & DUCT BURNER	1,360	EFFICIENT COMBUSTION	0.02000	BACT-PSD
ROQUETTE AMERICA	KEOKUK, IA	1/31/2003	TURBINE, COMBINED CYCLE	587	GCP, NATURAL GAS ONLY	0.02000	BACT-PSD
MIDLAND COGENERATION	MIDLAND, MI	7/26/2001	(2) GAS TURBINE COMBINED CYCLE	2,096	NONE INDICATED	0.02000	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	TURBINE, NG, 3 AT 170MW EA W/ DUCTBURNER	1,360	EFFICIENT COMBUSTION	0.0200	BACT-PSD
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	LOW ASH FUEL AND GCP	0.02039	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	FIRING PIPELINE NAT GAS	0.02043	BACT-PSD
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	(1) COMBINED CYCLE COMBUSTION TURBINE, W/ AND W/O DB	1,779	CLEAN FUELS	0.02100	OTHER
TPS - DELL, LLC	DELL, AR	8/8/2000	(2) TURBINE	2,560	GCP	0.02100	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	(2) TURBINES, COMBINED CYCLE	1,360	GCP, CLEAN FUEL	0.02154	BACT-PSD
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	FIRING PIPELINE NAT GAS	0.02163	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	NONE INDICATED	0.02222	BACT-OTHER
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	(2) TURBINE, COMBINED CYCLE	1,384	COMBUSTION CONTROL	0.02262	BACT-PSD
CONTINENTAL ENERGY SVCS, INC., SILVER BOW GEN	BUTTE, MT	6/7/2002	(4) COMBINED CYCLE CT	1,400	NONE INDICATED	0.02314	OTHER
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING PIPELINE-QUALITY NAT GAS	0.02354	BACT-PSD
DUKE ENERGY-JACKSON FACILITY	ARIZONA	4/1/2002	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION CONTROL CLEAN FUEL	0.02368	BACT-PSD
FULTON COGEN PLANT	FULTON, NY	9/15/1994	STACK EMISSIONS (TURBINE & DUCT BURNER)	610	NONE INDICATED	0.02400	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP	VA	5/4/1990	TURBINE, COMBUSTION	1,261	FUEL SPEC: CLEAN BURNING FUEL, NAT GAS & DIST. #2 OIL	0.0262	OTHER
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	COMBUSTION TURBINE W/ DUCT BURNER	623	LNB	0.02700	BACT-PSD
			COMBUSTION TURBINE W/O DUCT BURNER	457		0.03300	
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(2) COMBUSTION GS TURBINE GENERATORS STACK7&8	1,400	FIRING NAT GAS	0.02714	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	(4) HRSG/TURBINES 001,002,003,004	1,400	GOOD COMBUSTION CONTROLS	0.02757	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(6) COMBUSTION GS TURBINE GENERATORS STACK	1,400	FIRING NAT GAS	0.02907	BACT-PSD
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	(4) GAS TURBINES & WHB - COMBINED	114	FIRING NAT GAS	0.03345	BACT-OTHER
GEISMAR PLANT	GEISMAR, LA	2/26/2002	(2) COGENERATION UNITS W/ AND W/O DB	320	USE OF CLEAN NATURAL GAS WITH GCP	0.03375	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP & FIRING ONLY GASEOUS FUELS CONTAINING NO ASH	0.03582	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	(3) TURBINE, COMBINED CYCLE AND DB, W/ AND W/O POWER AUG.	2,300	STATE OF THE ART COMBUSTION & NATURAL GAS	0.03616	BACT-PSD
			(3) TURBINE, COMBINED CYCLE W/O DUCT BURNER	1,650		0.05041	
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	(4) TURBINE, COMBINED CYCLE	477	GOOD COMBUSTION	0.04406	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	0.06000	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	0.06000	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	0.06000	BACT-OTHER
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	0.06000	BACT-PSD
PORT WESTWARD PLANT	PORTLAND, OR	1/16/2002	(2) COMBUSTION TURBINES WITH DUCT BURNER	2,600	USE OF PIPELINE QUALITY NATURAL GAS	0.14000	BACT-OTHER

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Table C-5
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CPV WARREN	WARREN, VA	1/14/2008	NO	(2) GE 207FA NG COMBINED-CYCLE TURBINES, W/ HRSG & DB	1,944	CEMS, GOOD COMB. PRAC. 2 STAGE LEAN PREMIX	0.0002	NA
				(2) GE MODEL 7FA NATURAL GAS COMBINED-CYCLE	1,717		0.0003	
				(2) SIEMENS MODEL SGT6-5000	2,204		0.0003	
VIRGINIA ELECTRIC AND POWER COMPANY	WARREN, VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 1	1,717	GOOD COMBUSTION PRACTICES	0.0003	BACT
				ELECTRIC GENERATION - SCENARIO 2	1,944		0.0002	
				ELECTRIC GENERATION SECNARIO 3	2,204		0.0003	
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	PIPELINE QUALITY NAT GAS AND GCP	0.0005	BACT-PSD
EL DORADO ENERGY, LLC	CLARK CO., NV	8/19/2004	?	(2) COMBUSTION TURBINE COMBINED CYCLE & COGEN	1,900	NONE INDICATED	0.0005	BACT-OTHER
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	?	COMBINED CYCLE COGENERATION >25MW	1,882	NATURAL GAS FUEL	0.0006	BACT
FORSYTH ENERGY PROJECTS, LLC	FORSYTH, NC	9/29/2005	YES	3 COMBINED-CYCLE COMBUSTION TURBINES W/ DB	1,844	USE OF VERY LOW-SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
				TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	1,844	LOW SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	YES	(2) COMBUSTION TURBINES COMBINED CYCLE	1,783	SULFUR CONTENT IN GAS	0.0006	OTHER
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	NO	(3) TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,844	USE OF VERY LOW-SULFUR FUEL (NATURAL GAS)	0.0006	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	NO	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.0006	BACT
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(2) COMBINED CYCLE COMB.TURB.	1,384	USE OF NATURAL GAS ONLY	0.0006	OTHER
PINE BLUFF ENERGY CENTER	PINE BLUFF, AR	5/5/1999	YES	TURBINE, COMBINED CYCLE	1,360	COMBUSTION OF LOW SULFUR FUELS, NO FUEL > 0.5% S	0.0006	BACT-PSD
PINE BLUFF ENERGY LLC	PINE BLUFF, AR	2/27/2001	YES	TURBINE, COMBINED CYCLE	1,360	LOW SULFUR FUEL - < 0.05% S BY WT	0.0006	BACT-PSD
CAROLINA POWER & LIGHT - RICHMOND CO.	RALEIGH, NC	12/21/2000	?	(2) TURBINES, COMBINED CYCLE	1,628	NONE INDICATED	0.0006	BACT-PSD
CP&L ROWAN CO TURBINE FACILITY	RALEIGH, NC	3/14/2001	?	(2) TURBINE, COMBINED CYCLE	1,628	NONE INDICATED	0.0006	BACT-PSD
FAYETTEVILLE GENERATION, LLC	SANFORD, NC	1/10/2002	?	(2) TURBINE, COMBINED CYCLE	1,384	NONE INDICATED	0.0006	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	?	COMBUSTION TURBINE COMBINED CYCLE	2,320	LOW SULFUR FUELS	0.0006	BACT-OTHER
TOWANTIC ENERGY, LLC	OXFORD, CT	10/2/2002	?	(2) GE PG7241 FA COMBUSTION TURBINE	1,706	FUEL SULFUR LIMITED TO < 8 PPMV FOR NG	0.0007	BACT
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	NEW GAS TURBINE PHASE 3 ONLYSTK-701	1,360	FIRING SWEET PIPELINE-QUALITY NAT GAS	0.0007	BACT-OTHER
GRAYS FERRY COGEN PARTNERSHIP	PHILADELPHIA, PA	3/21/2001	?	COMBUSTION TURBINE COMBINED CYCLE, W/ DUCT BURNER	1,515	GCP, LOW SULFUR FUEL	0.0008	BACT-PSD
NORTON ENERGY STORAGE, LLC	OHIO	5/23/2002	YES	(9) COMBUSTION TURBINE COMB CYCLE W/O DUCT BURNER	2,400	NONE INDICATED	0.0008	BACT-PSD
				(9) COMBUSTION TURBINES COMB CYCLE W/ DUCT BURNER	2,400		0.0011	
FREEPORT COGENERATION FACILITY	FREEPORT, TX	6/26/1998	?	TURBINE/HRSG W/O DUCT BURNER FIRING	672	NATURAL GAS	0.0008	NSPS
				TURBINE/HRSG W/ DUCT BURNER FIRING	672		0.0012	
DUKE ENERGY WYTHE, LLC	VIRGINIA	2/5/2004	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,470	GCP & SULFUR IN NG LIMITED TO 0.3 GR/100 DSCF	0.0008	BACT-PSD
				(2) TURBINE, COMBINED CYCLE	1,827		0.0010	
VA POWER - POSSUM POINT	GLENN ALLEN, VA	11/18/2002	YES	TURBINE, NO DUCT BURNER FIRING	1,937	NONE INDICATED	0.0009	BACT-PSD
				TURBINE, COMBINED CYCLE, DUCT BURNER	1,937		0.0011	
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	TURBINE WITH DUCT BURNER	1,048	NONE INDICATED	0.0009	BACT-PSD
				COMBUSTION TURBINE, W/O DUCT BURNER	908		0.0400	
EXXON-MOBIL BEAUMONT REFINERY	BEAUMONT, TX	3/14/2000	?	(3) COMBUSTION TURBINES W/DUCT BURN 61STK001-003	1,464	FIRING NAT GAS	0.0010	BACT-OTHER
CAITHNESS BELLPORT, LLC	SUFFOLK, NY	5/10/2006	NO	COMBINED CYCLE WITH DUCT FIRING UP TO 494 MMBTU/H	2,221	LOW SULFUR FUEL	0.0011	BACT-PSD
MEMPHIS GENERATION, LLC	MEMPHIS, TN	4/9/2001	NO	TURBINE, COMBINED CYCLE DUCT BURNER	1,698	NONE INDICATED	0.0011	BACT-PSD
MESQUITE GENERATING STATION	ARLINGTON, AZ	3/22/2001	?	TURBINE, COMBINED CYCLE	1,923	PIPELINE QUALITY NATURAL GAS	0.0011	BACT-OTHER
TransGas Energy Systems	BROOKLYN, NY	6/4/2003	NO	(4) COMBUSTION TURBINES	2,200	CLEAN FUELS	0.0011	BACT
DRESDEN ENERGY LLC	OHIO	10/16/2001	YES	(2) COMBUSTION TURBINE COMB. CYCLE W/O DUCT BURNER	1,374	MAX SULFUR CONTENT OF NG </= 0.3 GRAINS/100 SCF	0.0012	BACT-PSD
				(2) COMBUSTION TURBINE COMB. CYCLE W DUCT BURNER	1,374		0.0013	
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	FIRING LOW S NAT GAS	0.0014	BACT-PSD
				(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360		0.0018	
KLAMATH FALLS COGENERATION FACILITY	PORTLAND, OR	1/27/1998	?	COMBUSTION TURBINE (1 OR 2)	1,700	BURN ONLY PIPELINE QUALITY NATURAL GAS	0.0014	BACT-OTHER
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES, ALL LOADS	2,049	LOW SULFUR FUEL < 0.5 GR/100SCF	0.0014	BACT
PARIS GENERATING STATION	DALLAS, TX	10/28/1998	?	(4) GAS TURBINES W/DUCT BURNERSGT-HRSG#1-#4	2,000	FIRING NAT GAS W/ SULFUR CONTENT OF 5 GR S/100 DSCF	0.0014	BACT-PSD
				(4) GAS TURBINES GE7241FA GT-HRSG#1-#4	1,360		0.0018	
GUADALUPE GENERATING STATION	TEXAS	2/15/1999	?	(4) TURBINES W/ DUCT BURNERS CTG-1 TO 4	2,000	FIRING LOW S NAT GAS	0.0014	BACT-PSD
				(4) TURBINES - ONLY CTG-1 TO 4	1,360		0.0018	
MUSTANG ENERGY PROJECT	OKLAHOMA	2/12/2002	?	COMBUSTION TURBINES W/ DUCT BURNERS	2,480	2 GRAINS S PER 100 SCF NATURAL GAS	0.0014	BACT-PSD
PONCA CITY MUNICIPAL ELECTRICAL GEN PLANT	OKLAHOMA	9/6/1996	?	COMBUSTION TURBINE	360	LOW-SULFUR NATURAL GAS </= 4 PPM S IN NATURAL GAS	0.0015	BACT-PSD
RELIANT ENERGY HUNTERSTOWN, LLC	JOHNSTOWN, PA	6/15/2001	?	(3) COMBUSTION TURBINE COMBINED CYCLE	2,400	NONE INDICATED	0.0015	BACT-OTHER
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUEL	0.0015	BACT-PSD
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0015	BACT-PSD
SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO, CA	9/1/2003	?	(2) GAS TURBINES	1,611	LOW SULFUR NATURAL GAS	0.0016	LAER
CPV Warren, LLC	FRONT ROYAL, VA	7/30/2004	NO	(2) COMBINED CYCLE TURBINES, GE 7FA	1,717	LOW SULFUR GAS < 0.002%	0.0016	BACT
TENASKA FLUVANNA	VIRGINIA	1/11/2002	YES	(3) TURBINES, COMBINED CYCLE	2,375	USE OF CLEAN FUEL/NATURAL GAS	0.0017	BACT-PSD
KEYSPAN SPAGNOLI ROAD ENERGY CENTER	MELVILLE, NY	4/30/2003	NO	(1) COMBINED CYCLE COMBUSTION TURBINE	1,788	LOW SULFUR FUELS	0.0017	OTHER
WEST TEXAS ENERGY FACILITY	HOUSTON, TX	7/28/2000	NO	(2) GAS TURBINE NO POWER AUGMENTATION CASE I	2,000	LOW S FUEL	0.0017	BACT-OTHER
				(2)GAS TURBINES W/POWER AUGMENTATION CASE II	2,000		0.0020	
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	LOW - SULFUR FUEL: NATURAL GAS	0.0017	BACT-OTHER
BASF CORPORATION	GEISMAR, LA	12/30/1997	?	(2) TURBINE, COGEN UNIT GE FRAME 6	339	NONE INDICATED	0.0017	OTHER
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW SULFUR NATURAL GAS	0.0018	BACT-PSD
SATSOP COMBUSTION TURBINE PROJECT	WASHINGTON	1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NONE INDICATED	0.0020	BACT-PSD
GENPOWER KELLEY LLC	QUINTON, AL	1/12/2001	?	(4) TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NONE INDICATED	0.0020	BACT-PSD
TPS - DELL, LLC	DELL, AR	8/8/2000	YES	(2) TURBINE	2,560	LOW SULFUR FUEL	0.0020	BACT-PSD
FAIRLESS ENERGY LLC	GLEN ALLEN, PA	3/28/2002	?	(4) TURBINES, COMBINED CYCLE	2,380	LOW SULFUR FUEL	0.0020	OTHER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	YES	TURBINE, COMBINED CYCLE	1,344	NONE INDICATED	0.0020	BACT-OTHER
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(2) NEW TURBINES, STACK 5 & 6	2,000	PIPELINE-QUALITY NAT GAS 0.8 GR S/100 DSCF	0.0020	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	USE OF PIPELINE QUALITY LOW-SULFUR NATURAL GAS	0.0020	BACT-PSD
				(4) GAS TURBINES TURBINE ONLY FIRING	1,360		0.0021	
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM, ME	12/4/1998	?	(3) TURBINE, COMBINED CYCLE	2,400	NONE INDICATED	0.0020	BACT-PSD
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	LOW SULFUR FUEL; S CONTENT OF FUEL IS 0.75 GR/100 SCF	0.0021	BACT-PSD
LAKE ROAD GENERATING CO., L.P.	KILLINGLY, CT	11/30/2001	?	(3) TURBINE, COMBUSTION ABB GT-24 #1,#2,#3	2,181	LOW SULFUR FUEL < 0.05% S	0.0022	BACT

Table C-5
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
PDC EL PASO MILFORD LLC	MILFORD, CT	4/16/1999	?	(2) TURBINE, COMBUSTION ABB GT-24 #1&#2 WITH 2 CHILLERS	1,965	NAT GAS AS PRIMARY FUEL 0.8 GR/100 SCF	0.0022	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	YES	(2) TURBINE, COMBINED CYCLE	2,046	LOW SULFUR FUEL NG. NATURAL GAS < 0.8 GR/100SCF	0.0022	BACT-OTHER
CABOT POWER CORPORATION	EVERETT, MA	5/7/2000	?	TURBINE, COMBINED CYCLE	2,493	CLEAN FUEL - NG WITH .8 GRAINS SULFUR/100 SCF	0.0022	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM, MA	9/22/1997	?	TURBINE, COMBUSTION ABB GT24	1,792	DLN COMBUSTION TECHNOLOGY	0.0022	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	SULFUR CONTENT OF FUEL.	0.0022	BACT-PSD
KLEEN ENERGY SYSTEMS, LLC	MIDDLESEX, CT	2/25/2008	NO	SIEMENS SGT6-5000F COMBUSTION TURBINE #1 AND #2 (NATURAL GAS	2,142	NONE INDICATED	0.0023	BACT
PANDA CULLODEN GENERATING STATION	CULLODEN, WV	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.0023	BACT-PSD
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400		0.0026	
MIDLOTHIAN ENERGY PROJECT	VENUS, TX	5/9/2000	YES	(4) GAS FUELED TURBINES, STACK 1-4	2,200	LOW S FUEL	0.0023	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	?	TURBINE, COMBUSTION ABB GT11N2	1,327	DLN COMBUSTION TECHNOLOGY	0.0023	BACT-PSD
SITHE - FORE RIVER STATION	WEYMOUTH, MA	3/10/2000	YES	(2) MHI 501G COMBUSTION TURBINE	2,676	NONE INDICATED	0.0023	BACT
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	?	(2) COMBUSTION TURBINE W/ DUCT BURNER	2,480	PIPELINE QUALITY NATURAL GAS < 0.75 grains/100 SCF	0.0023	BACT-OTHER
MILLENNIUM POWER PARTNER, LP	CHARLTON, MA	2/2/1998	?	TURBINE, COMBUSTION WESTINGHOUSE MODEL 501G	2,534	DLN COMBUSTION TECHNOLOGY	0.0023	BACT-PSD
ANP BLACKSTONE ENERGY COMPANY	BLACKSTONE, MA	4/16/1999	?	(2) TURBINE, COMBINED CYCLE	1,815	CLEAN FUEL	0.0023	BACT-PSD
ANP BELLINGHAM ENERGY COMPANY	MARLBOROUGH, MA	8/4/1999	?	(2) TURBINES, COMBINED CYCLE	3,630	NATURAL GAS FUEL	0.0023	BACT-PSD
AES LONDONDERRY, LLC	LONDONDERRY, NH	4/26/1999	?	(2) SWPC 501G TURBINE, COMBINED CYCLE #1 & #2	2,849	LOW SULFUR FUELS	0.0023	BACT-PSD
HARQUAHALA GENERATING PROJECT	TONOPAH, AZ	2/15/2001	?	COMBINED CYCLE NATURAL GAS	2,362	USE OF PIPELINE QUALITY NATURAL GAS ONLY	0.0025	BACT-OTHER
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	TURBINE, COMBINED CYCLE AND DUCT BURNER	1,791	LOW S NAT GAS: < .007 %S BY WT (2 GR/100 SCF) GCP	0.0025	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	?	(3) COMBUSTION TURBINE W/ & W/O DB (ALL LOADS)	2,181	NATURAL GAS AS FUEL WITH <= 0.8% SULFUR BY WEIGHT	0.0025	NSPS
WISE COUNTY POWER	HOUSTON, TX	7/14/2000	NO	(2) COMBUSTION TURBINES STACK 1 & 2	1,840	BURN NATURAL GAS	0.0026	BACT-OTHER
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	FIRING PIPELINE NAT GAS < 0.5 GRAINS/100 DSCF	0.0026	BACT-OTHER
LOWER MOUNT BETHEL ENERGY, LLC	PENNSYLVANIA	10/20/2001	?	(2) TURBINE, COMBINED CYCLE	1,480	LOW SULFUR FUEL	0.0027	LAER
SPRINGDALE TOWNSHIP STATION	GREENSBURG	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GCP, LOW SULFUR FUEL	0.0027	BACT-PSD
SILAS RAY POWER STATION UNIT 9	BROWNSVILLE, TX	7/30/1997	NO	UNIT NO. 9 CASE II SHORT-TERM, W/O DUCT BURNER	400	LOW SULFUR FUEL	0.0028	BACT-PSD
				UNIT NO. 9 CASE III SHORT-TERM, W/ DUCT BURNER	400		0.0030	
EDINBURG ENERGY LIMITED PARTNERSHIP	HOUSTON, TX	1/8/2002	NO	(4) COMBINED CYCLE GAS TURBINE ABB MODEL GT24	1,440	NONE INDICATED	0.0028	BACT-PSD
MIRANT SUGAR CREEK LLC	WEST TERRE HAUTE, IN	7/24/2002	?	(4) TURBINE, COMBINED CYCLE	1,491	LOW S NAT GAS: 0.007 % S BY WT (2 GR/100 SCF) GCP	0.0028	BACT-PSD
CLOVIS ENERGY FACILITY	NEW MEXICO	6/27/2002	?	(4) TURBINES, COMBINED CYCLE	1,515	PIPELINE QUALITY NAT GAS	0.0028	BACT-PSD
ELECTRIC GENERATING STATION	HOUSTON, TX	8/31/2000	?	(8) ELECTRIC GENERATION TURBINES	2,000	GCP (LOW S FUEL - 0.8 GR/100 DSCF)	0.0029	LAER
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	YES	(2) TURBINE, COMBINED CYCLE	2,699	LOW S CONTENT IN FUEL - .8 GRAINS PER 100 CU FT	0.0029	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	LOW S FUEL: < 2 GR/100 CF, 7 DAY AVG 1.1 GR/100 CF, 12 MO AVG	0.0030	BACT-PSD
REDBUD POWER PLANT	LUTHER, OK	3/18/2002	?	(4) COMBUSTION TURBINE AND DUCT BURNERS	1,832	VERY LOW SO2 EMISSION RATE-LOW SULFUR FUEL	0.0030	BACT-PSD
MIRANT SUGAR CREEK, LLC	WEST TERRE HAUTE, IN	5/9/2001	YES	TURBINE, COMBINED CYCLE	1,360	LOW S NATURAL GAS ONLY (LESS THAN 0.8% BY WEIGHT)	0.0031	BACT-PSD
MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) GAS TURBINES WITH DUCT BURNERS	2,097	NAT GAS W/ MAX S CONTENT OF 1 GR/100 SCF	0.0031	BACT-PSD
GARNET ENERGY, MIDDLETON FACILITY	BOISE, ID	10/19/2001	?	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	2,097	LOW SULFUR FUEL, 1 GR/100 SCF	0.0031	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,707		0.0032	
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(2) COMBUSTION GS TURBINE GENERATORS STACK7&8	1,400	NAT GAS CONTAINING NOT MORE THAN 0.8 GR S/100 DSCF	0.0033	BACT-PSD
LAKELAND C.D. - MCINTOSH POWER PLANT	LAKELAND, FL	1999	YES	(1) COMBINED CYCLE GAS TURBINE	2,407	CLEAN FUELS, GOOD COMBUSTION	0.0033	OTHER
ALLEGHENY ENERGY SUPPLY CO. LLC	INDIANA	12/7/2001	?	(2) CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	2,071	USE OF LOW SULFUR NATURAL GAS AS SOLE FUEL	0.0034	BACT-PSD
MIDLOTHIAN ENERGY PROJECT	HOUSTON, TX	10/2/1998	?	(4) COMBINED CYCLE GAS TURBINE STACK1-4	1,400	LOW S FUEL	0.0036	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	(2) TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUELS.	0.0036	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.0036	BACT-PSD
OLEANDER POWER PROJECT	FLORIDA	11/22/1999	NO	TURBINE-GAS, COMBINED CYCLE	1,520	CLEAN FUELS AND GCP	0.0036	BACT-PSD
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	FUEL SULFUR CONTENT	0.0038	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, ABB	600	NONE INDICATED	0.0040	BACT-OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE W/ AND W/O DUCT BURNER	3,202	NONE INDICATED	0.0040	OTHER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	NO	(6) COMBUSTION GS TURBINE GENERATORS STACK	1,400	NAT GAS CONTAINING NOT MORE THAN 0.8 GR S/100 DSCF	0.0041	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND, FL	6/1/1995	NO	TURBINE, COMBINED CYCLE COMBUSTION, GE	600	NONE INDICATED	0.0042	BACT-OTHER
KLEEN ENERGY SYSTEMS, LLC (DRAFT)	MIDDLESEX, CT	2/25/2008	NO	(2) SIEMENS SGT6-5000F TURBINES (HRSG & NG DUCT BURNER)	1,071	NONE INDICATED	0.0048	BACT-PSD
JACK COUNTY POWER PLANT	HOUSTON, TX	3/14/2000	NO	(2) GE-7241FA TURBINES, HRSG-1&-2	2,080	FIRING PIPELINE NAT GAS	0.0048	BACT-PSD
JAMES CITY ENERGY PARK	VIRGINIA	12/1/2003	?	TURBINE, COMBINED CYCLE, DUCT BURNER	2,325	LOW SULFUR FUELS	0.0049	BACT-PSD
				TURBINE, COMBINED CYCLE	1,973		0.0058	
HAYWOOD ENERGY CENTER, LLC	TAMPA	2/1/2002	?	TURBINE, COMBINED CYCLE W/O DUCT FIRING	1,990	LOW SULFUR FUEL (<2.0 GR SULFUR PER 100 SCF OF NATURAL GAS)	0.0049	BACT-PSD
				TURBINE, COMBINED CYCLE W/ DUCT FIRING	1,990		0.0059	
CRESENT CITY POWER, LLC	ORLEANS, LA	6/6/2005	YES	600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	2,006	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	0.0050	BACT-PSD
REDBUD POWER PLT	TULSA, OK	8/15/2001	?	(4) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	1,698	LOW SULFUR FUEL - PIPELINE QUALITY NATURAL GAS	0.0050	BACT-PSD
THUNDERBIRD POWER PLT	TULSA, OK	5/17/2001	?	(3) TURBINES, COMBINED CYCLE, W/ DUCT FIRING	1,698	PIPELINE QUALITY NATURAL GAS	0.0050	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002,003,004	1,400	FIRING NAT GAS < 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0051	BACT-PSD
RELIANT ENERGY HOPE GENERATING FACILITY	JOHNSTON, RI	5/3/2000	?	(2) TURBINE, COMBINED CYCLE	1,488	CLEAN FUEL - NATURAL GAS	0.0054	BACT-PSD
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.0055	BACT
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE	2,200	SWEET NAT GAS W/ MAX S CONTENT 0.8 GR/100 SCF	0.0055	BACT-PSD
FLORIDA POWER AND LIGHT COMPANY (FP&L)	PALM BEACH CO., FL	7/30/2008	?	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HR	2,333	NONE INDICATED	0.0056	BACT
FLORIDA MUNICIPAL POWER AGENCY (FMPA	OSCEOLA, FL	9/8/2008	?	300 MW COMBINED CYCLE COMBUSTION TURBINE	1,860	FUEL SPECIFICATIONS.	0.0056	BACT
PROGRESS ENERGY FLORIDA (PEF)	PINELLAS, FL	1/26/2007	NO	COMBINED CYCLE COMBUSTION TURBINE SYSTEM (4-ON-1)	493	NONE INDICATED	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT COMPANY	WEST PALM BEACH, FL	1/10/2007	NO	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	389	LOW SULFUR FUELS	0.0056	BACT-PSD
PROGRESS ENERGY	POLK, FL	6/8/2005	YES	COMBINED CYCLE POWER PLANT (4TH POWER BLOCK) TOTAL GEN CAPACITY OF FACILITY 2090 MW.	4,240	CLEAN FUELS	0.0056	BACT-PSD
FLORIDA POWER AND LIGHT	DADE, FL	2/8/2005	YES	4 GE MODEL FA GAS TURBINES (170 MW EACH), 4 HRSGS, 1 STEAM TURBINE-ELECTRICAL GENERATOR (470 MW)	1,360	GAS AND RESTRICTING THE AMOUNTS OF ULTRA LOW SULFUR DISTILLATE OIL.	0.0056	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	TEXAS	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	PIPELINE-QUALITY, SWEET NAT GAS 2.0 GR S/100 DSCF	0.0056	NSPS
HORSESHOE ENERGY PROJECT	OKLAHOMA	2/12/2002	?	TURBINES AND DUCT BURNERS	2,480	LOW SULFUR FUEL (NATURAL GAS)	0.0056	BACT-PSD
CALPINE CONSTRUCTION FINANCE CO., LP	ONTELAUNEE TWP., PA	10/10/2000	?	TURBINE, COMBINED CYCLE	1,456	GCP BASED ON SULFUR CONTENT (2 GR/DSCF)	0.0056	BACT-OTHER
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	?	TWO COMBINED CYCLE GAS TURBINES	2,110	USE LOW-SULFUR PIPELINE-QUALITY NATURAL GAS AS FUEL	0.0057	BACT

Table C-5
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW SULFUR FUELS	0.0057	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON, AL	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL.	0.0057	BACT-PSD
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE DUCT BURNERS ON/OFF	1,440	BURNING NATURAL GAS	0.0057	BACT-PSD
FREMONT ENERGY CENTER, LLC	OHIO	8/9/2001	YES	(2) COMBUSTION TURBINES COMB CYCLE W/ & W/O DB	1,440	NONE INDICATED	0.0057	BACT-PSD
DUKE ENERGY, VIGO LLC	WEST TERRE HAUTE, IN	6/6/2001	YES	(2) TURBINE, COMBINED CYCLE, W/ DUCT BURNER	1,945	GOOD COMBUSTION. NATURAL GAS ONLY	0.0057	BACT-PSD
				(2) TURBINE, COMBINED CYCLE, W/O DUCT BURNER	1,360		0.0083	
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	CLEAN FUELS. < 0.0065 % S GAS COMBUSTION CONTROLS	0.0059	BACT-PSD
TENASKA ARKANSAS PARTNERS, LP	OMAHA, AR	10/9/2001	NO	TURBINE, COMBINED CYCLE	1,480	FUEL SPECIFICATION: LOW SULFUR FUELS	0.0060	BACT-PSD
COGENTRIX LAWRENCE CO., LLC	INDIANA	10/5/2001	?	(3) TURBINES, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,944	GCP	0.0060	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	?	(2) TURBINE, COMBINED CYCLE	2,112	NONE INDICATED	0.0060	BACT-PSD
CASCO BAY ENERGY CO	VEAZIE, ME	7/13/1998	?	(2) TURBINE, COMBINED CYCLE	1,360	NONE INDICATED	0.0060	BACT-PSD
GREEN COUNTRY ENERGY PROJECT	OKLAHOMA	10/1/1999	?	(3) TURBINES W/ DUCT BURNERS, COMBINED CYCLE	2,133	USE OF NATURAL GAS	0.0060	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OKLAHOMA	12/10/2001	?	(2) TURBINES, COMBINED CYCLE	1,701	PIPELINE-QUALITY NATURAL GAS (VERY LOW SULFUR FUEL) MAXIMUM 0.8 % S BY WT.	0.0060	BACT-PSD
LSP NELSON ENERGY, LLC	NELSON, IL	1/28/2000	?	TURBINE, COMBINED CYCLE W/O DUCT BURNERS	2,166	CLEAN FUEL	0.0060	BACT-PSD
				TURBINE, COMBINED CYCLE W DUCT BURNER	2,516		0.0062	
HENRY COUNTY POWER	VIRGINIA	11/21/2002	?	(4) TURBINE, COMBINED CYCLE 100%LOAD, W/ DUCT FIRING	2,200	LOW SULFUR FUELS AND GOOD COMBUSTION DESIGN	0.0060	BACT-PSD
				(4) TURBINE, COMBINED CYCLE 70%LOAD, W/ DUCT FIRING	958		0.0135	
SAM RAYBURN GENERATION STATION	NURSERY, TX	1/17/2002	?	(3) COMBUSTION TURBINES 7,8,9	360	FIRING NAT GAS, 1.25 GR/100SCF	0.0061	BACT-OTHER
JACKSON COUNTY POWER, LLC	OHIO	12/27/2001	YES	(4) COMBUSTION TURBINES COMBINED CYCLE, W/ DUCT BURNER	2,440	LOW SULFUR FUEL (2) GR/100 SCF	0.0063	BACT-PSD
MCCLAIN ENERGY FACILITY	OKLAHOMA	1/19/2000	?	COMBUSTION TURBINES W/ NON-FIRED HEAT RECOVERY	1,360	NONE INDICATED	0.0067	BACT-PSD
VALERO REFINING COMPANY	BENICIA, CA	1/11/2000	YES	(2) COMBUSTION TURBINE, COMBINED CYCLE	816	AMINE SCRUBBER	0.0069	LAER
ENNIS TRACTEBEL POWER	ENNIS, TX	1/31/2002	NO	COMBUSTION TURBINE W/HEAT RECOVERY STEAM GENERATOR	2,800	PIPELINE QUALITY NAT GAS < 2.5 GR S/100 DSCF SHORT-TERM, AND 0.2 GR S/100 DSCF 12 MO ROLLING AV	0.0069	NSPS
KAUFMAN COGEN LP	TEXAS	1/31/2000	NO	(2) GAS TURBINES HRSG-1 & -2	1,440	PIPELINE QUALITY NAT GAS < 2.0 GR S/100 DSCF	0.0069	BACT-PSD
ATHENS GENERATING COMPANY, L.P.	ATHENS, NY	6/12/2000	?	(3) SWPC 510G COMBUSTION TURBINES	2,880	LOW S FUELS AND EFFICIENT COMBUSTION TECHNIQUES		BACT
BARTON SHOALS ENERGY	ENGLEWOOD, AL	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	NATURAL GAS ONLY	0.0070	BACT-PSD
ROCHE VITAMINS	BELVIDERE, NJ	10/8/1997	?	COMBUSTION TURBINE W/ AND W/O DUCT BURNER	623	LNB	0.0070	BACT-PSD
FPL ENERGY MARCUS HOOK, L.P.	MARCUS HOOK, PA	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	LOW SULFUR FUEL	0.0070	BACT-OTHER
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191		0.0080	
CALEDONIA POWER LLC	CALEDONIA, MS	3/27/2001	?	ELECTRIC POWER GENERATION TURBINE & DUCT BURNER	1,700	NONE INDICATED	0.0071	BACT-OTHER
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	YES	(1) COMBINED CYCLE COMBUSTION TURBINE, W/ & W/O DB	2,423	CLEAN FUELS	0.0071	OTHER
LSP- BATESVILLE GENERATION FACILITY	MISSISSIPPI	11/13/2001	?	COMBINED CYCLE COMBUSTION TURBINE GENERATION	2,100	NATURAL GAS A FUEL	0.0071	BACT-PSD
BELL ENERGY FACILITY	TEMPLE, TX	6/26/2001	NO	(2) GAS TURBINES (HRSG-1 AND HRSG-2)	1,400	LOW SULFUR FUEL	0.0071	BACT-PSD
CEDAR BLUFF POWER PROJECT	CEDAR BLUFF, TX	12/21/2000	NO	(2) COMBUSTION TURBINES W/HRSG STACK1&2	2,640	NAT GAS W/ S CONTENT OF 0.2 GR S/100 DSCF ANNUALLY AND 2.5 GR S/100 DSCF HOURLY	0.0072	BACT-OTHER
PIKE GENERATION FACILITY	MISSISSIPPI	9/24/2002	NO	(4) TURBINES, COMBINED CYCLE, WITH DUCT BURNER	2,168	LOW SULFUR FUEL	0.0072	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	HOUSTON, TX	5/2/1994	NO	GAS TURBINES UNITS 1 & 2 W/ DUCT BURNER	602	INTERNAL COMBUSTION CONTROLS	0.0073	BACT-OTHER
HIDALGO ENERGY FACILITY	SAN ANTONIO, TX	12/22/1998	NO	(2) GE-7241FA TURBINES HRSG-1 & -2	1,400	FIRING NAT GAS	0.0076	BACT-PSD
RENAISSANCE POWER LLC	MICHIGAN	6/7/2001	?	(3) TURBINES, STATIONARY GAS COMBINED CYCLE	1,360	PIPELINE QUALITY NATURAL GAS OF NGT 0.5 GR/100 CF	0.0079	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	OHIO	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS OFF	1,376	LOW SULFUR FUEL: MAXIMUM S CONTENT OF NATURAL GAS < 2 GRAINS/100 SCF	0.0080	BACT-PSD
				(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376		0.0105	
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	LOW S NATURAL GAS 2 GR/100 SCF	0.0082	BACT-PSD
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360		0.0107	
MIRANT AIRSIDE INDUSTRIAL PARK	VIRGINIA	12/6/2002	?	(2) TURBINE, COMBINED CYCLE	1,962	LOW SULFUR FUELS AND GCP	0.0085	BACT-PSD
CHAMPION INTL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT, ME	9/14/1998	?	TURBINE, COMBINED CYCLE	1,400	NONE INDICATED	0.0086	BACT-OTHER
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY, OK	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	PIPELINE NAT GAS S CONTENT < 2 GR/100 SCF OR 65 PPMW	0.0101	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360	NONE INDICATED	0.0103	BACT-PSD
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	(2) TURBINE/HRSG NO.1,2	3,168	PIPELINE NG; SHORT-TERM MAX 5 GR S/100CF; < 2 GR S/100 CF	0.0106	BACT-PSD
GREGORY POWER FACILITY	COSTA MESA, TX	6/16/1999	NO	(2) COMBUSTION TURBINES NO DUCT BURN EPN 101&102	1,480	PIPELINE QUALITY NAT GAS, CONTAINING < 3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0106	NSPS
				(2) COMBUSTION TURBINES W/DUCT BURN EPN101&102	1,480		0.0133	
SOUTHWEST ELECTRIC POWER COMPANY	SHREVEPORT, LA	3/20/2008	YES	(2) COMBINED CYCLE GAS TURBINES	1,055	USE LOW-SULFUR PIPELINE-QUALITY NATURAL GAS	0.0114	BACT-PSD
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	NAT GAS, < 3 GR S/100 DSCF (SHORT-TERM)& 0.25 GR S/100 DSCF 12 MO ROLLING AV	0.0119	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	ST. MARKS, FL	5/29/1998	?	TURBINE, COMBINED CYCLE	1,468	NONE INDICATED	0.0124	BACT-OTHER
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.0129	NSPS
MONTGOMERY COUNTY POWER PROJECT	TEXAS	6/27/2001	NO	(2) CTG-HRSG STACKS STACK1 & 2	1,440	PIPELINE-QUALITY NAT GAS CONTAINING < 0.2 GR S/100 DSCF ON AN ANNUAL AV AND 2.5 GR S/100 DSCF ON A MAX H BASIS	0.0131	BACT-OTHER
WHITING CLEAN ENERGY, INC.	WHITING, IN	7/20/2000	YES	(2) TURBINES, COMBUSTION	1,735	GCP AND LOW SULFUR FUEL (0.8 % BY WT SULFUR)	0.0131	NSPS
				(2) TURBINES, COMBUSTION W/DUCT BURNER	1,735		6.0000	
PLANT NO. 2	LUBBOCK, TX	1/8/1999	?	(2) TURBINE/DUCT BURNER STGT1 & T2	336	LOW S FUEL	0.0134	BACT-OTHER
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	PIPELINE QUALITY NATURAL GAS	0.0140	BACT-PSD
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	GCP & FIRING LOW S-CONTENT FUELS	0.0141	BACT-OTHER
THE DOW CHEMICAL COMPANY	IBERVILLA, LA	7/23/2008	?	(4) GAS TURBINES/DUCT BURNERS	2,876	LOW SULFUR FUELS WITH MAXIMUM SULFUR CONTENT OF 5 GR/100 SC	0.0142	BACT
PLAQUEMINE, IBERVILLE PARISH	LOUISIANA	12/26/2001	?	(4) GAS TURBINES/DUCT BURNERS	2,876	LOW SULFUR FUELS MAX S CONTENT OF 5 GR/100 SCF	0.0142	BACT-PSD
PANDA-BRANDYWINE	BRANDYWINE, MD	6/17/1994	YES	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	LOW SULFUR FUEL	0.0146	OTHER
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.0152	BACT-PSD
EL PASO MERCHANT ENERGY CO.	MISSISSIPPI	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	LOW SULFUR FUEL	0.0156	BACT-PSD
RELIANT ENERGY- CHANNELVIEW COGEN	HOUSTON, TX	10/29/2001	NO	(4) TURBINE/HRSG #1-#4	2,350	NONE INDICATED	0.0165	BACT-PSD
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	USE OF PIPELINE QUALITY NATURAL GAS., S<0.5%	0.0173	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	GCP, LOW SULFUR FUEL	0.0176	BACT-OTHER
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	GC,P FIRE ONLY NAT GAS W/ S CONTENT < 5.0 GR/100 DSCF	0.0190	BACT-PSD
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	FIRING LOW SULFUR PIPELINE NAT GAS	0.0194	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358		0.0487	

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Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	OPER STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES WITHOUT DB CTG (1), (2), (3)	1,440	FIRING NAT GAS	0.0208	BACT-OTHER
				(3) COMBUSTION TURBINES & DUCTBURNERS CTG (1), (2), (3)	1,360		0.0250	
BASTROP CLEAN ENERGY CENTER	BASTROP, TX	3/21/2000	NO	(2) COMBUSTION TURBINE GENERATORS ONLY	1,288	GCP. LOW S FUEL: < 5.0 GR S/100 DSCF (SHORT-TERM) + 1.0 GR TOTAL S/100 DSCF (ANNUAL AVG)	0.0211	BACT-PSD
				(2) TURBINES AND DUCT BURNERS COMBINED	1,288		0.0244	
DEER PARK ENERGY CENTER	HOUSTON, TX	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING LOW-S FUELS	0.0222	BACT-OTHER
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	GCP, LOW SULFUR FUELS (NAT GAS W/< 5 GR S/100 DSCF ON H AVER & 0.25 GR S/100 DSCF FOR AN ANN. AVER)	0.0224	BACT-OTHER
TENASKA FRONTIER GENERATION STATION	TEXAS	8/7/1998	NO	(3) TURBINE/HRSG#1-#3 CASE 1, W/DUCT BURNER	1,464	FIRING NATURAL GAS IN THE TURBINES AND DUCT BURNERS	0.0229	BACT-PSD
PSEG LAWRENCEBURG ENERGY FACILITY	LAWRENCEBURG, IN	6/7/2001	YES	(4) TURBINE, COMBINED CYCLE	477	LOW SULFUR NATURAL GAS (LESS THAN 2 G/DSCF)	0.0231	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	(2) TURBINE/HRSG (CG-2,CG-3)	1,280	LOW SULFUR FUEL (<5 GR/100 SCF) AND PROPER COMBUSTION	0.0232	BACT-PSD
RIVER ROAD GENERATING PROJECT	VANCOUVER, WA	10/25/1995	?	TURBINE	1,984	PIPELINE QUALITY NAT GAS	0.0258	BACT-PSD
LIMA ENERGY COMPANY	CINCINNATI, OH	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	USE OF SOLVENT BASED ABSORPTION TECHNOLOGY WITH TAIL GAS RECIRCULATION PRIOR TO COMBUSTION	0.0284	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD, PA	4/22/1994	?	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360	FUEL SPEC: 0.1 % SULFUR IN FUEL	0.0314	BACT-OTHER
VH BRAUNIG A VON ROSENBERG PLANT	SAN ANTONIO, TX	10/14/1998	NO	(2) COMBUSTION TURBINES & HRSG W/ DUCT BURN E5&6	1,488	PIPELINE QUALITY NAT GAS WITH NO > 1.0 GR S/100 DSCF	0.0392	NSPS
UCC SEADRIFT OPERATIONS	PORT LAVACA, TX	10/20/1999	?	COGEN STACK TURBINE ONLY	310	FIRING PIPELINE QUALITY NAT GAS	0.0481	BACT-OTHER
				COGEN STACK COMBINED GT/HRSG&DB 1180	310		0.0757	
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	NO	(2) CASE I: TURBINES E-1+E-2 W/O HRSG	720	NONE INDICATED	0.0411	NSPS
				(2) CASE II: TURBINES E-1+E-2 W/ HRSG	720		0.0438	
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	GCP & LOW S FUEL GASES < 0.5 GRAINS/DSCF	0.0452	BACT-OTHER
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	NONE INDICATED	0.0460	SIP
TEXAS CITY OPERATIONS	TEXAS CITY, TX	1/23/2003	?	(4) GAS TURBINES & WHB - COMBINED	114	PRIMARY FUEL GAS OR PIPELINE QUALITY SWEET NATURAL GAS WITH NO > 5 GR/100	0.0528	NSPS
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	S & H2S LIMITATIONS IN FUEL SPECIFIED AT THE FACILITY LEVEL	0.0796	BACT-OTHER
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	USE OF PIPELINE QUALITY GAS AND GCP	0.0842	BACT-PSD
INEOS USA LLC	BRAZORIA, TX	8/29/2006	YES	COGENERATION TRAIN 2 AND 3 (TURBINE & DB)	140	TURBINES & DB WILL FIRE NATL GAS & COMPLEX GAS W/ S CONTENT < 5 GR/100 SCF ON AN HOURLY BASIS	0.0904	BACT-PSD
KANSAS CITY POWER & LIGHT CO. - HAWTHORN	KANSAS CITY, MO	8/19/1999	YES	(2) TURBINE, COMBINED	1,360	NONE INDICATED	0.2000	BACT-OTHER
SC ELECTRIC AND GAS COMPANY - URQUHART	COLUMBIA, SC	9/22/2000	?	(2) TURBINES, COMBINED CYCLE	1,795	S CONTENT OF FUEL LESS THAN OR EQUAL TO 0.2% BY WEIGHT	0.4028	BACT-PSD
GULF STATES UTILITIES COMPANY - LOUISIANA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	MAX H2S CONC OF 33.53 PPM @ 15% O2 IN FLUE GAS (DRY BASIS)	1.0212	OTHER
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	?	(1) COMBINED CYCLE GAS TURBINE	1,742	PIPELINE NATURAL GAS < 1.5 GR/100 SCF	--	BACT
DUKE ENERGY-JACKSON FACILITY	ARKANSAS	4/1/2002	NO	(2) TURBINES, COMBINED CYCLE	1,360	CLEAN FUEL	--	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN, FL	1/1/1996	?	TURBINE, COMBINED CYCLE COMBUSTION	1,120	FUEL SPEC: NATURAL GAS FUEL; COMBUSTION OF CLEAN FUELS	--	BACT-PSD
CANE ISLAND POWER PARK /KUA - UNIT 3	INTERCESSION CITY, FL	11/24/1999	?	TURBINE, COMBINED CYCLE, W/ AND W/O DUCT BURNER	1,696	NATURAL GAS	--	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	NEW SMYRNA BEACH, FL	10/15/1999	?	(2) TURBINE, COMBINED CYCLE	2,000	NATURAL GAS ONLY	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 2	ST. PETERSBURG, FL	6/4/2001	YES	(2) TURBINES, COMBINED CYCLE	1,915	PERMIT LIMIT IS LOW SULFUR FUELS	--	
CPV ATLANTIC POWER GENERATING FACILITY	PORT ST. LUCIE, FL	5/3/2001	?	COMBINED CYCLE COMBUSTION TURBINE	1,700	LOW SULFUR FUELS: GAS < .0065 % SULFUR;NO EMISSION LIMITS	--	BACT-PSD
LAKE WORTH GENERATION, LLC	LAKE WORTH, FL	11/4/1999	NO	TURBINE, COMBINED CYCLE	1,488	NATURAL GAS 1 GR/100 SCF OF GAS	--	BACT-PSD
OUC STANTON ENERGY CENTER	PENSACOLA, FL	9/21/2001	YES	(2) TURBINE, COMBINED CYCLE	2,402	CLEAN FUELS	--	BACT-PSD
JEA/BRANDY BRANCH	JACKSONVILLE, FL	3/27/2002	YES	(2) TURBINES, COMBINED CYCLE	1,911	CLEAN FUELS SULFUR FUEL LIMIT	--	BACT-OTHER
CPV PIERCE	FLORIDA	8/7/2001	?	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS - < .0065 % S	--	BACT-PSD
CPV CANA	FLORIDA	1/17/2002	?	TURBINE, COMBINED CYCLE	1,680	CLEAN FUELS, FUEL SULFUR LIMIT: .0065% S	--	BACT-PSD
FPL MARTIN PLANT	JUNO BEACH, FL	4/16/2003	?	(4) TURBINE, COMBINED CYLE	1,600	LOW SULFUR FUELS	--	BACT-PSD
FPL MANATEE PLANT - UNIT 3	PARRISH, FL	4/15/2003	?	(4) TURBINE, COMBINED CYCLE	1,600	LOW SULFUR FUELS	--	BACT-PSD
FORT PIERCE REPOWERING	FORT PIERCE, FL	8/15/2001	?	TURBINE, COMBINED CYCLE	1,440	NAT GAS W/ MAX OF 2.0 GRAINS OF SULFUR PER 100 SCF	--	BACT-PSD
HINES ENERGY COMPLEX, POWER BLOCK 3	ST. PETERSBURG, FL	9/8/2003	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,830	PERMIT LIMIT IS LOW SULFUR FUELS	--	BACT-PSD
SOUTH SHORE POWER LLC	BRIDGEMAN, MI	1/30/2003	?	(2) TURBINE, COMBINED CYCLE	1,376	PIPELINE QUALITY NAT GAS W/ 0.2 GR S/100 CF	--	BACT-PSD
MIDLAND COGENERATION (MCV)	MIDLAND, MI	4/21/2003	NO	(11) TURBINE, COMBINED CYCLE	984	NAT GAS W/S CONTENT OF 0.2 GRAINS/100 CF OF GAS	--	BACT-PSD
BLACK DOG GENERATING PLANT	BURNSVILLE, MN	1/12/2001	?	TURBINE, COMBINED CYCLE	2,320	MAX S CONTENT 0.004 GR/DSCF USING 12-MONTH ROLLING AVG	--	BACT-PSD
COB ENERGY FACILITY, LLC	OREGON	12/30/2003	?	(4) TURBINE, COMBINED CYCLE DUCT BURNER	2,300	LOW SULFUR FUEL: < 0.8 % S BY WT	--	NSPS
KLAMATH GENERATION, LLC	PORTLAND, OR	3/12/2003	NO	(2) TURBINE, COMBINED CYCLE DUCT BURNER	1,920	FUEL NOT TO EXCEED 0.8 % S BY WT	--	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS, PR	10/1/1996	YES	(2) SWPC 501F TURBINES, COMBINED-CYCLE COGENERATION	1,844	FUEL SPEC: LNG/LPG AS PRIMARY FUEL	--	BACT-PSD
CHAMBERS ENERGY L.P./AMERICAN NATIONAL POWER	SAN ANTONIO, TX	3/6/2000	NO	(8) ABB GT-24 COMBUSTION TURBINES	1,440	LOW SULFUR FUEL	--	BACT-PSD
CHANNELVIEW COGENERATION FACILITY	HOUSTON, TX	12/9/1999	YES	(4) TURBINE COGENERATION FACILITY	1,600	NG W/ S CONT <5.0 GRAINS/100 DSCF (HRLY), <0.2 GRAINS/100 DSCF (ANNUAL), GCP	--	BACT-OTHER

S = SULFUR, GCP = GOOD COMBUSTION PRACTICES, DLN = DRY LOW NOX, LNB = LOW NOX BURNERS

Table C-6
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO,LA	3/20/2008	?	TWO COMBINED CYCLE GAS TURBINES	2,110	USE OF LOW-SULFUR PIPELINE QUALITY NATURAL GAS AS FUEL AND PI	0.00008	BACT
NORTON ENERGY STORAGE, LLC	HOUSTON	5/23/2002	YES	(9) COMBUSTION TURBINES COMB CYCLE W/O DB	2,400	NONE LISTED	0.00008	SIP
				(9) COMBUSTION TURBINE COMB CYCLE W/ DB	2,400	NONE LISTED	0.00011	SIP
VIRGINIA ELECTRIC AND POWER COMPANY	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 1	1,717	GOOD COMBUSTION PRACTICES	0.00010	BACT
				ELECTRIC GENERATION - SCENARIO 2	1,944	GOOD COMBUSTION PRACTICES.	0.00020	BACT
				ELECTRIC GENERATION SECNARIO 3	2,204	GOOD COMBUSTION PRACTICES.	0.00010	BACT
CPV WARREN	WARREN,VA	1/14/2008	NO	ELECTRIC GENERATION - SCENARIO 1	1,717	GOOD COMBUSTION PRACTICES	0.00010	N/A
				ELECTRIC GENERATION - SCENARIO 2	1,944	GOOD COMBUSTION PRACTICES	0.00020	N/A
				ELECTRIC GENERATION SECNARIO 3	2,204	GOOD COMBUSTION PRACTICES	0.00010	N/A
GOLDENDALE ENERGY PROJECT	KIRKLAND, WA	2/23/2001	?	COMBINED CYCLE UNIT (TURBINE/HRSG)	1,990	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.00010	BACT-OTHER
DRESDEN ENERGY LLC	RICHMOND	10/16/2001	YES	(2) COMBUSTION TURBINE W/ & W/O DB	1,374	NONE LISTED	0.00015	SIP
RAINEY GENERATING STATION	STARR, SC	4/3/2000	?	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.00018	BACT-OTHER
SANTEE COOPER RAINEY GENERATION STATION	MONKS CORNER, SC	4/3/2000	YES	(2) TURBINES, COMBINED CYCLE	1,360	LOW SULFUR FUELS	0.00018	BACT-PSD
NYPA POLETTI POWER PROJECT	ASTORIA, NY	10/1/2002	?	(2) COMBINED CYCLE TURBINES	1,779	NONE INDICATED	0.00020	BACT
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	YES	GENERATOR, COMBUS TURBINE & DUCT BURNER	2,258	NATURAL GAS COMBUSTION	0.00020	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	NO	(4) TURBINES (ONLY) HR LIMITS ONLY GT-HRSG 1-4	1,360	FIRING LOW-S NATURAL GAS	0.00020	SIP
				(4) TURBINE & DUCT BURNERS GT-HRSG 1-4	2,000	NONE INDICATED	0.00015	SIP
ONETA GENERATING STA	OKLAHOMA	1/21/2000	?	(4) COMBUSTION TURBINES, COMBINED CYCLE	1,360	USE OF LOW SULFUR NATURAL GAS FUEL	0.00021	BACT-PSD
PANDA CULLODEN GENERATING STATION	CULLODEN	12/18/2001	?	COMBUSTION TURBINE, 300 MW, W/O DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.00026	BACT-OTHER
				COMBUSTION TURBINE, 300 MW, W/ DUCT BURNER	2,400	USE OF LOW-SULFUR FUEL - NATURAL GAS	0.00030	BACT-OTHER
CALPINE BERKS ONTELAUNEE POWER PLANT	READING, PA	10/10/2000	?	(2) TURBINES, COMBINED CYCLE	2,176	NONE LISTED	0.00030	SIP
SPRINGDALE TOWNSHIP STATION	GREENSBURG	7/12/2001	YES	TURBINE, COMBINED CYCLE	2,094	GOOD COMBUSTION PRACTICES, LOW SULFUR FUEL	0.00033	BACT-PSD
MIRANT BOWLINE, LLC	WEST HAVERSTRAW, NY	3/22/2002	NO	(3) COMBINED CYCLE TURBINES	1,815	LOW SULFUR FUEL < 0.5 GR/100SCF	0.00033	BACT
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	YES	(3) TURBINES, COMBINED CYCLE W/O DUCT FIRING	1,360	NONE LISTED	0.00035	SIP
				(3) TURBINES, COMBINED CYCLE W/ DUCT FIRING	1,360	NONE LISTED	0.00041	SIP
LIMA ENERGY COMPANY	CINCINNATI	3/26/2002	?	(2) COMBUSTION TURBINE COMBINED CYCLE	1,360	NONE LISTED	0.00039	SIP
CAITHNESS BELLPORT ENERGY CENTER	SUFFOLK,NY	5/10/2006	?	COMBUSTION TURBINE	2,221	LOW SULFUR FUEL	0.00040	BACT-PSD
TRACY SUBSTATION EXPANSION PROJECT	STOREY COUNTY,NV	8/16/2005	?	TURBINE, CC COMBUSTION #1 WITH HRSG & DB	2,448	BEST COMBUSTION PRACTICES	0.00041	BACT-PSD
WEATHERFORD ELECTRIC GENERATION FACILITY	ATLANTA	3/11/2002	NO	(2) GE7121EA GAS TURBINES	1,079	PIPELINE-QUALITY NAT GAS	0.00046	OTHER
JACKSON COUNTY POWER, LLC	CHARLOTTE	12/27/2001	YES	(4) COMBUSTION TURBINES W/ DUCT BURNER	2,440	NONE LISTED	0.00048	BACT-PSD
CPV WARREN LLC	WARREN,VA	7/30/2004	?	TURBINE, COMBINED CYCLE (2)	1,717	MAX. 0.002% BY WT MAX S CONTENT	0.00050	
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	4/17/2003	NO	(2) TURBINES, COMBINED CYCLE	2,640	LOW SULFUR FUEL: < 2 GR/100 CF 7 DAY AVG 1.1 GR/100 CF 12 MO AVG	0.00062	BACT-PSD
COLUMBIA ENERGY LLC	COLUMBIA, SC	4/9/2001	?	(2) TURBINES, COMBINED CYCLE	1,360	GOOD COMBUSTION PRACTICES CLEAN BURNING LOW SULFUR FUELS	0.00066	BACT-PSD
DUKE ENERGY DALE, LLC	HOUSTON	12/11/2001	?	(2) GE 7FA COMB. CYCLE W/DB	1,928	NATURAL GAS AS EXCLUSIVE FUEL	0.00070	BACT-PSD
DUKE ENERGY AUTAUGA, LLC	HOUSTON	10/23/2001	?	(2) GE COM. CYCLE UNITS W/HRSG & 550 MMBTU/HR DB	2,407	NATURAL GAS AS EXCLUSIVE FUEL	0.00070	BACT-PSD
WALLULA POWER PLANT	WASHINGTON	1/3/2003	NO	(4) TURBINE, COMBINED CYCLE NATURAL GAS	2,600	EXCLUSIVE USE OF NATURAL GAS	0.00073	BACT-OTHER
BROOKHAVEN ENERGY, LP	YAPHANK, NY	7/18/2002	NO	(4) COMBINED CYCLE TURBINES, 75%-100%	1,897	NONE LISTED	0.00078	
SUMAS ENERGY 2 GENERATION FACILITY	SUMAS, WA	9/6/2002	?	(2) TURBINES, COMBINED CYCLE	1,338	LOW SULFUR FUEL -- NATURAL GAS ONLY	0.00080	BACT-PSD
ENNIS TRACTEBEL POWER	ENNIS	1/31/2002	NO	COMBUSTION TURBINE W/HRSG	2,800	NONE INDICATED	0.00085	OTHER
ARSENAL HILL POWER PLANT	CADDO,LA	3/20/2008	NO	TWO COMBINED CYCLE GAS TURBINES	2,110	USE OF PIPELINE QUALITY NAT GAS AND PROPER SCR DESIGN	0.00088	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	RICHMOND, TX	12/31/2002	?	(4) HRSG/TURBINES 001,002, 003 & 004	1,400	FIRING PIPELINE QUALITY NATURAL GAS	0.00093	BACT-OTHER
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	?	(4) COMBINED CYCLE TURBINES	2,000	CLEAN FUELS	0.00100	BACT
TENASKA GATEWAY GENERATING STATION	TEXAS	5/7/1999	NO	TURBINE/HRSG NO.1, 2 & 3	3,168	NAT GAS	0.00104	BACT-PSD
PASADENA 2 POWER FACILITY	TEXAS	9/30/1998	?	TURBINE/HRSG (CG-2) & (CG-3)	1,280	PROPER COMBUSTION CONTROL & LOW S FUELS	0.00106	BACT-PSD
DICKERSON	MONTGOMERY,MD	11/5/2004	?	UNIT 4 -GE FRAME 7F COMB. TURBINES W/HRSG - NG CC	1,568	NONE LISTED	0.00108	BACT-PSD
CHEHALIS GENERATION FACILITY	WASHINGTON	6/18/1997	YES	(2) COMBUSTION TURBINES	1,840	LOW-SULFUR FUELS	0.00109	BACT-PSD
TENASKA ALABAMA GENERATING STATION	BILLINGSLY, AL	11/29/1999	YES	(3) TURBINE & DUCT BURNER	1,360	INHERENTLY LIMITED BY LOW SULFUR IN FUEL	0.00110	BACT-PSD
BARTON SHOALS ENERGY	ENGLEWOOD	7/12/2002	?	(4) COMBINED CYCLE COMBUSTION TURBINE UNITS W/ DB	1,384	NATURAL GAS ONLY	0.00110	BACT-PSD
EL PASO MERCHANT ENERGY CO.	HOUSTON	6/24/2002	?	(2) TURBINE, COMBINED CYCLE DUCT BURNER	2,062	USE OF LOW SULFUR FUEL	0.00111	BACT-PSD
CPV GULFCOAST POWER GENERATING STATION	PINEY POINT, FL	2/5/2001	YES	TURBINE, COMBINED CYCLE	1,700	NATURAL GAS < 0.0065 %S	0.00118	BACT-PSD
ENNIS TRACTEBEL POWER	TEXAS	1/31/2003	NO	(2) COMBUSTION TURBINE/HRSG STACKS	1,840	NONE INDICATED	0.00118	OTHER
CPV CUNNINGHAM CREEK	SILVER SPRING, VA	9/6/2002	NO	(2) TURBINE, COMBINED CYCLE	2,132	GOOD COMBUSTION PRACTICES	0.00120	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	?	(4) TURBINES COMBINED CYCLE DUCT BURNERS ON	1,376	NONE LISTED	0.00122	BACT-PSD
					1,376	NONE LISTED	0.00160	
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	YES	(2) TURBINE COMBINED CYCLE NO DUCT FIRING	1,360	NONE LISTED	0.00125	SIP
				(2) TURBINE COMBINED CYCLE DUCT FIRING	1,360	NONE LISTED	0.00162	SIP
MIRANT WYANDOTTE LLC	WYANDOTTE, MI	1/28/2003	YES	(2) TURBINE, COMBINED CYCLE W/ DB, POWER AUG.	2,200	USE OF NATURAL GAS. LOW SULFUR FUEL	0.00128	BACT-OTHER
SATSOP COMBUSTION TURBINE PROJECT"		1/2/2003	NO	(2) COMBINED CYCLE COMBUSTION TURBINES	1,671	NONE LISTED	0.00130	BACT-OTHER
LAWRENCE ENERGY	OHIO	9/24/2002	YES	(3) TURBINES, COMBINED CYCLE W/ & W/O DB	1,440	NONE LISTED	0.00130	BACT-PSD
MANTUA CREEK GENERATING FACILITY		6/26/2001	?	(3) COMBUSTION TURBINE W/O DUCT BURNER	2,181	NONE	0.00138	NSPS
				(3) COMBUSTION TURBINE W/ DUCT BURNER	2,181	NONE	0.00156	NSPS
				(3) COMBUSTION TURBINE W/O DB 75%LOAD	1,636	NONE	0.00150	NSPS
				(3) COMBUSTION TURBINE W/O DB 60% LOAD	1,309	NONE	0.00160	NSPS
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	?	(4) COMBUSTION TURBINE COMBINED CYCLE	2,010	THE USE OF NATURAL GAS ONLY	0.00139	BACT-PSD
PANDA-BRANDYWINE	MARYLAND	6/17/1994	?	(2) COMBUSTION TURBINES, COMBINED CYCLE	1,984	NONE LISTED	0.00151	OTHER

Table C-6
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Sulfuric Acid Mist Emissions

FACILITY	LOCATION	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
RIO NOGALES POWER PROJECT	TEXAS	12/3/1999	?	(3) TURBINES/HRSG 1-3 CTG1-3	2,133	FIRING NAT GAS	0.00155	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	NO	(2) GAS TURBINES GFRAME W/HRSG NORMAL OP EC-ST1&2	3,228	NONE INDICATED	0.00158	OTHER
TENASKA TALLADEGA GENERATING STATION	OMAHA	10/3/2001	?	(6) COMBINED CYCLE COMB. TURB. UNITS W/ DUCT FIRING	1,360	PIPELINE QUALITY NATURAL GAS	0.00170	BACT-PSD
BP CHERRY POINT COGENERATION	WHATCOM CO., WA	3/1/2004	NO	(3) COMBINED CYCLE COMBUSTION TURBINE	1,614	NATURAL GAS FUEL	0.00173	BACT
KALKASKA GENERATING, INC	RAPID RIVER TWP, MI	2/4/2003	?	(2) TURBINE, COMBINED CYCLE, WITH DUCT BURNER	2,420	USE OF LOW SULFUR FUEL	0.00186	BACT-OTHER
BERRIEN ENERGY, LLC	BENTON HARBOR, MI	10/10/2002	?	(3) TURBINE, COMBINED CYCLE AND DUCT BURNER	2,300	USE OF PIPELINE QUALITY GAS	0.00187	BACT-PSD
FREMONT ENERGY CENTER, LLC	BOSTON	8/9/2001	YES	(2) COMBUSTION TURBINES W/O DUCT BURNER	1,440	NONE LISTED	0.00188	BACT-PSD
				(2) COMBUSTION TURBINES W/ DUCT BURNER			0.00257	
KEYSPAN RAVENSWOOD GENERATING STATION	QUEENS, NY	10/25/2001	?	(1) COMBINED CYCLE COMBUSTION TURBINE W & W/O DB	1,779	CLEAN FUELS	0.00220	OTHER
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	?	(4) GAS TURBINES TURBINE ONLY FIRING	1,360	USE OF PIPELINE QUALITY LOW-SULFUR NATURAL GAS	0.00206	BACT-PSD
				(4) GAS TURBINES WITH HRSG (COMBINED FIRING)	1,384	USE OF PIPELINE QUALITY LOW-SULFUR CONTENT NATURAL GAS	0.00023	BACT-PSD
HAYWOOD ENERGY CENTER, LLC	TAMPA	2/1/2002	?	TURBINE, COMBINED CYCLE W/ & W/O DUCT FIRING	1,990	LOW SULFUR FUEL (<2.0 GR SULFUR PER 100 SCF OF NAT GAS)	0.00231	BACT-PSD
BAYTOWN COGENERATION PLANT	TEXAS	2/11/2000	?	(3) TURBINE/HRSGS CTG1-3	2,000	USE OF LOW SULFUR CONTENT FUELS	0.00240	OTHER
FPL ENERGY MARCUS HOOK, L.P.	JUNO BEACH, FL	5/4/2003	?	(3) TURBINE, COMBINED CYCLE	1,798	LOW SULFUR FUEL	0.00240	BACT-OTHER
				(3) TURBINE, COMBINED CYCLE W/ DUCT BURNER	2,191	LOW SULFUR FUEL	0.00300	BACT-OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	?	(3) COMBINED CYCLE TURBINE	2,964	NONE LISTED	0.00243	OTHER
				(3) COMBINED CYCLE TURBINE W/ DUCT BURNER	3,202	NONE	0.00244	OTHER
MAGIC VALLEY GENERATION STATION	TEXAS	12/31/1998	NO	(2) TURBINE/HRSG CTG-1 & CTG-2	1,920	NONE LISTED	0.00292	BACT-OTHER
FORNEY PLANT	HOUSTON, TX	3/6/2000	NO	(6) TURBINES	1,358	FIRING LOW SULFUR PIPELINE NAT GAS	0.00297	BACT-PSD
				(6) COMBINED TURBINE & DUCT BURNER	1,358	LOW SULFUR PIPELINE NAT GAS	0.03266	BACT-PSD
LOST PINES 1 POWER PLANT	AUSTIN, TX	9/30/1999	?	(2) COMBINED CYCLE TURBINE	1,464	LOW SULFUR FUEL	0.00301	BACT-OTHER
DEER PARK ENERGY CENTER	HOUSTON	8/22/2001	?	(4) CTG1-4 & HRSG1-4, ST-1 THRU -4	1,440	FIRING LOW-S FUELS	0.00340	BACT-OTHER
PALESTINE ENERGY FACILITY	PALESTINE, TX	12/13/2000	NO	(6) TURBINES, COMBINED CYCLE & HRSG	1,360	NONE LISTED	0.00346	BACT-OTHER
SMITH POCOLA ENERGY PROJECT	OKLAHOMA CITY"	8/16/2001	?	(4) TURBINES, COMBINED CYCLE	1,372	LOW SULFUR FUEL	0.00350	BACT-PSD
GATEWAY POWER PROJECT	TEXAS	3/20/2000	?	(3) COMBUSTION TURBINES & DB (1), (2), (3)	1,360	FIRING NAT GAS	0.00382	BACT-OTHER
CRESCENT CITY POWER	ORLEANS,LA	6/6/2005	?	GAS TURBINES - 187 MW (2)	2,006	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	0.00424	BACT-PSD
FLORIDA MUNICIPAL POWER AGENCY (FMPA	OSCEOLA, FL	9/8/2008	?	300 MW COMBINED CYCLE COMBUSTION TURBINE	1,860	FUEL SPECIFICATIONS	0.00429	BACT
DUKE ENERGY HANGING ROCK ENERGY FACILITY	LAWRENCE,OH	12/28/2004	?	TURBINES (4) (MODEL GE 7FA) DUCT BURNERS OFF	344	NONE LISTED	0.00488	BACT-PSD
BLUEWATER ENERGY CENTER LLC	MICHIGAN	1/7/2003	?	(3) TURBINE, COMBINED CYCLE WITH DUCT BURNER	1,440	EXCLUSIVE USE OF NATURAL GAS	0.00569	BACT-PSD
SWEENY COGENERATION FACILITY	DALLAS, TX	9/30/1998	NO	(4) GAS TURBINE/HRSG 1-4, EPN1-4	970	FUEL SULFUR AND H2S CONTENT LIMITS	0.00608	BACT-OTHER
INEOS CHOCOLATE BAYOU FACILITY	BRAZORIA,TX	8/29/2006	?	COGEN TRAIN 2 AND 3 (TURBINE & DB)	280	NATURAL GAS & COMPLEX GAS W/ MAX S CONTENT 5GR/100SCF	0.00693	BACT-PSD
CHOCOLATE BAYOU PLANT	ALVIN, TX	3/24/2003	NO	(2) COMBUSTION TURBINE W/ DUCT BURNER	280	LOW SULFUR FUEL	0.00693	OTHER
GPC - GOAT ROCK COMBINED CYCLE PLANT	SMITHS, AL	4/10/2000	YES	(6) COMBINED CYCLE ELECTRIC GENERATING UNITS	1,384	NATURAL GAS ONLY	0.00900	BACT-PSD
(PCLP)	MAYS LANDING, NJ	9/19/1995	?	COMBUSTION TURBINE, W/O DUCT BURNER	908	N/A	0.01000	BACT-PSD
NEWINGTON ENERGY LLC	NEWINGTON, NH	4/26/1999	NO	TURBINES, COMBINED CYCLE	1,280	LOW SULFUR FUELS	0.01746	BACT-PSD
GULF STATES UTILITIES COMPANY - LOUISIANA STA	BATON ROUGE, LA	2/7/1996	?	NO.4 TURBINE/HRSG	1,573	NONE LISTED	0.04406	OTHER

Table C-7
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Greenhouse Gas Emissions

FACILITY	LOCATION	PERMIT STATUS	PERMIT DATE	OPERATING STATUS	EMISSION UNIT DESCRIPTION	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	PERMIT LIMIT BASIS
TAYLORVILLE ENERGY CENTER	ILLINOIS	DRAFT	10/17/2011	NO	COMBINED CYCLE COMBUSTION TURBINES	HIGH EFFICIENCY CTGS	2,307,110	TONS/YR	BACT
							1,200	LB/MWH	
CRICKET VALLEY ENERGY CENTER	NEW YORK	FINAL	9/27/2012	NO	GE 7FA COMBINED CYCLE COMBUSTION TURBINES	HIGH EFFICIENCY CTGS	7,605	BTU/KWH	BACT
							3,576,943	TONS/YR	
							120	LB/MMBTU	
LOWER COLORADO RIVER AUTHORITY	TEXAS	FINAL	11/10/2011	NO	COMBINED CYCLE COMBUSTION TURBINES	HIGH EFFICIENCY CTGS	7,720	BTU/KWH	BACT
							0	TONS/MWH	
PALMDALE HYBRID POWER PROJECT	CALIFORNIA	FINAL	10/18/2011	NO	NGCC POWER PLANT AND SOLAR PLANT	THERMALLY EFFICIENT CTGS & SOLAR COMPONENT	774	LB/MWH (SOURCE-WIDE)	BACT
							117	LB/MMBTU	
							7,319	BTU/KWH	
							1,913,000	TONS/YR	
ROBINSON POWER COMPANY	PENNSYLVANIA	FINAL	6/30/2011	NO	GE 7EA COMBUSTION TURBINES	HIGH EFFICIENCY TURBINES	620,000	TONS/YR	VOLUNTARY
PACIFICORP	UTAH	FINAL	5/4/2011	NO	COMBINED CYCLE COMBUSTION TURBINES	HIGH EFFICIENCY CTGS AND HRSG	950	LB/MWH	BACT
RUSSELL CITY ENERGY CENTER	CALIFORNIA	FINAL	2/3/2010	NO		EFFICIENT GENERATING TECHNOLOGY AND NATURAL GAS AS FUEL	7,730	BTU/KWH	VOLUNTARY
WOLVERINE POWER SUPPLY COOPERATIVE	MICHIGAN	NOTE (1)	NOTE (1)	NO	NATURAL GAS FIRED TURBINE		954	LB/MWH	BACT
CPV VALLEY	NEW YORK	DRAFT	7/11/2012	NO	SIEMENS F-CLASS COMBUSTION TURBINES	THERMALLY EFFICIENT TURBINES	925	LB/MWH	BACT
BLACK HILLS POWER - CHEYENNE	WYOMING	FINAL	9/27/2012	NO	GE LM6000 COMBINED CYCLE TURBINES	THERMALLY EFFICIENT TURBINES	1,100	LB/MWH	BACT
							187,318	TONS/YR	
WOODBRIDGE ENERGY CENTER	NEW JERSEY	FINAL	8/24/2012	NO	GE 7FA COMBINED CYCLE COMBUSTION TURBINES	THERMALLY EFFICIENT CTGS	925	LB/MWH	BACT
							7,605	BTU/KWH	
HESS NEWARK ENERGY CENTER	NEW JERSEY	FINAL	10/13/2012	NO	GE 7FA CTGS	THERMALLY EFFICIENT TURBINES	887	LB/MWH	BACT
							7,522	BTU/KWH	
CALPINE DEER PARK	TEXAS	DRAFT	8/2/2012	NO	SIEMENS 501FD2 COMBUSTION TURBINE	THERMALLY EFFICIENT TURBINES	7,730	BTU/KWH	BACT
							0.460	TONS/MWH	
CALPINE CHANNEL ENERGY CENTER	TEXAS	DRAFT	8/30/2012	NO	SIEMENS 501FD2 COMBUSTION TURBINE	THERMALLY EFFICIENT TURBINES	7,730	BTU/KWH	BACT
							0.460	TONS/MWH	

NOTES:
(1) APPROVAL LETTERS FOR THIS FACILITY HAS BEEN ISSUED, BUT COPIES OF THE FINAL PERMIT ARE NOT AVAILABLE

Table C-8
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Nitrogen Oxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNITS	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS
BREITBURN ENERGY- NEWLOVE LEASE	7/17/2009	Horizontal Enclosed Flare	50	MMBTU/H	Forced draft enclosed flare.	0.0146	LB/MMBTU
PETROROCK- TUNNELL LEASE	1/24/2012	Enclosed Ground Flare	17	MMBTU/H	Burner design, premix, and combustion temperature control	15	PPMVD@3% O2
ORION REFINING CORP (NOW VALERO)	1/10/2002	FLARE NO.1 (EMISSION PT. 15-77)	60.7	MMBTU/H		33.6	LB/H
		FLARE NO. 2 (EMISSION PT. 12-81)					LB/H
SABINE PASS LNG TERMINAL	12/6/2011	Marine Flare	1590	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	185.16	LB/H
		Wet/Dry Gas Flares (4)	0.26	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	0.03	LB/H
SALT CREEK GAS PLANT	1/31/2003	FLARES (2)				4.37	LB/H
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	ACID GAS FLARE				0.6	LB/H
		SOUR WATER STRIPPER FLARE				0.36	LB/H
AIR PRODUCTS BAYTOWN I I	11/2/2004	FLARE (NORMAL OPERATION)				11.4	LB/H
VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	5/5/2005	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		0.19	LB/H
FLINT HILLS RESOURCES INSTALLATION OF BOILERS	1/24/2005	FLARES 5,6				1150.93	LB/H
BASF ETHYLENE/PROPYLENE CRACKER	2/3/2006	GROUND FLARE				2219.7	LB/H
ENTERPRISE MONT BELVIEU COMPLEX	1/24/2006	FLARE-NORMAL OPERATION				376.6	LB/H
		FLARE-START-UP, MAINTENANCE, AND SHUTDOWN				154.1	LB/H
AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	8/18/2006	FLARE PILOTS ONLY				0.022	LB/H
		FLARE-MSS				160	LB/H
SABINA PETROCHEMICALS LLC	8/20/2010	HIGH AND LOW PRESSURE FLARES	1600	T/YR		9.07	T/YR

Table C-9
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Carbon Monoxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
BREITBURN ENERGY- NEWLOVE LEASE	7/17/2009	Horizontal Enclosed Flare	50	MMBTU/H	Forced draft enclosed flare	0.0371	LB/MMBTU
DUKE ENERGY FIELD SERVICES - MINDEN	1/24/2002	FLARE				0.26	LB/H
ORION REFINING CORP (NOW VALERO)	1/10/2002	FLARE NO.1 (EMISSION PT. 15-77)	60.7	MMBTU/H		149	LB/H
		FLARE NO. 2 (EMISSION PT. 12-81)	60.7	MMBTU/H		149	LB/H
SABINE PASS LNG TERMINAL	12/6/2011	Marine Flare	1590	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	705.49	LB/H
		Wet/Dry Gas Flares (4)	0.26	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	0.11	LB/H
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	SOUR WATER STRIPPER FLARE				1.9	LB/H
SALT CREEK GAS PLANT	1/31/2003	FLARES (2)				37.2	LB/H
SHELL OIL DEER PARK	7/30/2004	WEST PROPERTY FLARE				500	PPMV
		CCU FLARE				500	PPMV
		EAST PROPERTY FLARE				500	PPMV
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	ACID GAS FLARE				3.1	LB/H
AIR PRODUCTS BAYTOWN I I	11/2/2004	FLARE (NORMAL OPERATION)				797.7	LB/H
VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	5/5/2005	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		1.66	LB/H
FLINT HILLS RESOURCES INSTALLATION OF BOILERS	1/24/2005	FLARES 5,6				884.57	LB/H
VALERO THREE RIVERS REFINERY	8/19/2010	FLARE MSS	0		BEST PRACTICES	0	
BASF ETHYLENE/PROPYLENE CRACKER	2/3/2006	GROUND FLARE				15794.4	LB/H
ENTERPRISE MONT BELVIEU COMPLEX	1/24/2006	FLARE-NORMAL OPERATION				372.7	LB/H
		FLARE-START-UP, MAINTENANCE, AND SHUTDOWN				354.3	LB/H
AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	8/18/2006	FLARE PILOTS ONLY				0.043	LB/H
		FLARE-MSS				1654	LB/H

Table C-10
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
BREITBURN ENERGY- NEWLOVE LEASE	7/17/2009	Horizontal Enclosed Flare	50	MMBTU/H	Forced draft enclosed flare	0.0013	LB/MMBTU
PETROROCK- TUNNELL LEASE	1/24/2012	Enclosed Ground Flare	17	MMBTU/H	Burner design, premix, and combustion temperature control	10	PPMVD@3% O2
DUKE ENERGY FIELD SERVICES - MINDEN	1/24/2002	FLARE				2.82	LB/H
ORION REFINING CORP (NOW VALERO)	1/10/2002	FLARE NO.1 (EMISSION PT. 15-77)	60.7	MMBTU/H	98% OF VOC IN FLARE, FLARE IS CONTROL DEVICE.	25.4	LB/H
		FLARE NO. 2 (EMISSION PT. 12-81)	60.7	MMBTU/H	FLARE IS CONTROL DEVICE FOR VOC EMISSIONS. 98% DESTRUCTION OF VOC IN FLARE.	25.4	LB/H
SABINE PASS LNG TERMINAL	12/6/2011	Marine Flare	1590	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	10.83	LB/H
		Wet/Dry Gas Flares (4)	0.26	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	0.01	LB/H
AIR PRODUCTS BAYTOWN I I	11/2/2004	FLARE (NORMAL OPERATION)				0.01	LB/H
SALT CREEK GAS PLANT	1/31/2003	FLARES (2)				42.82	LB/H
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	ACID GAS FLARE				3.6	LB/H
INDIAN ROCK GATHERING COMPANY LP	11/22/2002	FLARE, LOW PRESSURE			98% VOC DESTRUCTION OF FLARE MEETS 40 CFR 60.18. FLARE IS THE CONTROL.	3.82	LB/H
		FLARE, HIGH PRESSURE			98% VOC DESTRUCTION OF FLARE MEETS 40 CFR 60.18. FLARE IS THE CONTROL.	1.08	LB/H
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	SOUR WATER STRIPPER FLARE				1.1	LB/H
VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	5/5/2005	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		0.72	LB/H
BASF ETHYLENE/PROPYLENE CRACKER	2/3/2006	GROUND FLARE				24418.1	LB/H
ENTERPRISE MONT BELVIEU COMPLEX	1/24/2006	FLARE-NORMAL OPERATION				468.1	LB/H
		FLARE-START-UP, MAINTENANCE, AND SHUTDOWN				63.7	LB/H
AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	8/18/2006	FLARE PILOTS ONLY				0.031	LB/H
		FLARE-MSS				0.2	LB/H
VALERO THREE RIVERS REFINERY	8/19/2010	FLARE MSS	0		BEST PRACTICES	0	
SABINA PETROCHEMICALS LLC	8/20/2010	HIGH AND LOW PRESSURE FLARES	1600	T/YR	FLARE	0.32	T/YR

Table C-11
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Sulfur Dioxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
ORION REFINING CORP (NOW VALERO)	1/10/2002	FLARE NO.1 (EMISSION PT. 15-77)	60.7	MMBTU/H		133	LB/H
		FLARE NO. 2 (EMISSION PT. 12-81)	60.7	MMBTU/H		133	LB/H
SHELL OIL DEER PARK	7/30/2004	EAST PROPERTY FLARE				300	PPM
		CCU FLARE				300	PPM
		WEST PROPERTY FLARE				300	PPM
		THREE FLARES				300	PPM
SALT CREEK GAS PLANT	1/31/2003	FLARES (2)				50.48	LB/H
CITGO CORPUS CHRISTI REFINERY - WEST PLANT	4/20/2005	ACID GAS FLARE				0.2	LB/H
		SOUR WATER STRIPPER FLARE				0.19	LB/H
AIR PRODUCTS BAYTOWN I I	11/2/2004	FLARE (NORMAL OPERATION)				0.04	LB/H
VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	5/5/2005	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		140.5	LB/H
FLINT HILLS RESOURCES INSTALLATION OF BOILERS	1/24/2005	FLARES 5,6				942.51	LB/H
BASF ETHYLENE/PROPYLENE CRACKER	2/3/2006	GROUND FLARE				165.8	LB/H
ENTERPRISE MONT BELVIEU COMPLEX	1/24/2006	FLARE-NORMAL OPERATION				1.1	LB/H
AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	8/18/2006	FLARE PILOTS ONLY				0.002	LB/H
		FLARE-MSS				0.01	LB/H

Table C-12
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Particulate Matter Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
ORION REFINING CORP (NOW VALERO)	1/10/2002	FLARE NO.1 (EMISSION PT. 15-77)	60.7	MMBTU/H		1	LB/H
		FLARE NO. 2 (EMISSION PT. 12-81)	60.7	MMBTU/H		1	LB/H
SABINE PASS LNG TERMINAL	12/6/2011	Marine Flare	1590	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	14.97	LB/H
		Wet/Dry Gas Flares (4)	0.26	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	0.01	LB/H
FLINT HILLS RESOURCES INSTALLATION OF BOILERS	1/24/2005	FLARES 5,6				130.28	LB/H

Table C-13
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Flares
Greenhouse Gas Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT	THROUGHPUT UNIT	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
SABINE PASS LNG TERMINAL	12/6/2011	Marine Flare	1590	MMBTU/H	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR
		Wet/Dry Gas Flares (4)	0.26	MMBTU/H		133	TONS/YR

Table C-14
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Nitrogen Oxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)
FLOPAM INC.	6/14/2010	THERMAL OXIDIZERS		GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES.	0.13
SHINTECH - PLAQUEMINE PVC PLANT	2/27/2009	GAS THERMAL OXIDIZERS	72	GOOD COMBUSTION PRACTICES AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.03
SHINTECH PLAQUEMINE PLANT 2	7/10/2008	TWO THERMAL OXIDIZERS (2M-5, 2M-6)	72	GOOD COMBUSTION PRACTICES	0.02
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	7/9/2003	NCG THERMAL OXIDIZER (BACK-UP)	7.5		0.13

Table C-15
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Carbon Monoxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR	CONTROL DESCRIPTION	EMISSION LIMIT LB/MMBTU
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	7/9/2003	NCG THERMAL OXIDIZER (BACK-UP)	7.5		0.053
SHINTECH - PLAQUEMINE PLANT 2	7/10/2008	TWO THERMAL OXIDIZERS (2M-5, 2M-6)	72	GOOD COMBUSTION PRACTICES	0.08
FLOPAM INC.	6/14/2010	THERMAL OXIDIZERS	0	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES.	0.08
SHINTECH - PLAQUEMINE PVC PLANT	2/27/2009	GAS THERMAL OXIDIZERS	72	GOOD COMBUSTION PRACTICES AND USE OF GASEOUS FUEL	0.11

Table C-16
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Volatile Organic Compound Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	CONTROL DESCRIPTION	EMISSION LIMIT
FLOPAM INC.	6/14/2010	THERMAL OXIDIZERS	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES.	99%

Table C-17
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Particulate Matter Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	PRIMARY FUEL	THROUGHPUT (MMBTU/HR)	CONTROL DESCRIPTION	EMISSION LIMIT (LB/MMBTU)
SHINTECH - PLAQUEMINE PVC PLANT	2/27/2009	GAS THERMAL OXIDIZERS		72	GOOD COMBUSTION PRACTICES AND USE OF GASEOUS FUEL	0.0075
SHINTECH PLAQUEMINE PLANT 2	7/10/2008	TWO THERMAL OXIDIZERS (2M-5, 2M-6)	NATURAL GAS	72	GOOD COMBUSTION PRACTICE AND CLEAN BURNING FUELS	0.0077
FLOPAM INC.	6/14/2010	THERMAL OXIDIZERS	NATURAL GAS		GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES. FUELED BY NATURAL GAS OR PROPANE.	0.008
CONOCO PHILLIPS - BILLINGS REFINERY	11/19/2008	WWTF THERMAL OXIDIZER	REFINERY FUEL GAS / NATURAL GAS	0.0065	PROPER EQUIPMENT DESIGN, GOOD COMBUSTION PRACTICES, OPTIMIZED FUEL-TO-AIR RATIO	1.8923

Table C-18
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Sulfur Dioxide Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	7/9/2003	NCG THERMAL OXIDIZER (BACK-UP)	7.5	SCRUBBER	0.045	LB/H
OWENS CORNING MEDINA	6/14/2004	THERMAL INCINERATOR, JZ			3.13	LB/H
OWENS CORNING MEDINA	6/14/2004	THERMAL INCINERATOR, PCC			3.68	LB/H
LOUISIANA PIGMENT COMPANY TITANIUM DIOXIDE PLANT	12/21/2010	PROCESS OFF GAS INCINERATOR		DESULFURIZATION UNIT UPSTREAM OF THE INCINERATOR STACK	556.51	LB/H
CONOCO PHILLIPS - BILLINGS REFINERY	11/19/2008	WWTF THERMAL OXIDIZER	0.0065	MINIMIZATION OF SULFUR CONTENT IN WASTE STREAM	34	PPMV H2S
SHELL OIL DEER PARK	7/30/2004	SR- 3/4 INCINERATOR			300	PPMV

Table C-19
JCEP LNG Terminal Project
Recent RACT/BACT/LAER Determinations for Thermal Oxidizers
Greenhouse Gas Emissions

FACILITY	PERMIT DATE	EMISSION UNIT DESCRIPTION	CONTROL DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LONE STAR NGL, MONT BELVIEU GAS PLANT	10/12/2012	THERMAL OXIDIZER	GOOD COMBUSTION PRACTICES, PERIODIC TUNEUPS	42,703	TONS/YR
ENERGY TRANSFER CO - JACKSON COUNTY GAS PLANT	5/24/2012	4 THERMAL OXIDIZERS	PERIODIC MAINTENANCE TO MAINTAIN EFFICIENCY	48,377	TONS/YR EACH

Table C-20
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Emergency Diesel Generators
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	NOx EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	EMERGENCY GENERATOR	11.4	NONE INDICATED	0.288	BACT-PSD
USAF EARECKSON AIR STATION	ANCHORAGE, AK	9/29/2003	DIESEL FUEL IC ENGINE GENERATORS (2)	32.2	SCR	0.301	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	(2) BLACK START GENERATORS	58.5	OPERATION < 200 HR/YR	0.455	BACT-PSD
UNION OIL CO. OF CALIFORNIA	KENAI, AK	8/4/1989	GENERATOR, EMERGENCY DIESEL FIRED	449	NONE INDICATED	0.909	BACT-PSD
OHIO RIVER CLEAN FUELS, LLC	COLUMBIAN, OH	11/20/2008	EMERGENCY GENERATOR	23.38	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION	1.132	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	EMERGENCY GENERATOR	16.1	NONE INDICATED	1.240	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	EMERGENCY GENERATOR	7.51	NONE INDICATED	1.274	BACT-PSD
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	EMERGENCY GENERATOR	10.9	NONE INDICATED	1.315	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY DIESEL GENERATOR (2200 HP)	17.60	NONE INDICATED	1.315	BACT-PSD
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	EMERGENCY GENERATOR ENGINE	8.05	TIER 2 ENGINE-BASED,GOOD COMBUSTION PRACTICES (GCP)	1.315	BACT-PSD
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	EMERGENCY GENERATOR	14.4	GOOD COMBUSTION PRACTICES	1.450	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	EMERGENCY GENERATOR	13.7	GCP	1.710	BACT-PSD
DUTCH HARBOR SEAFOOD PROCESSING FAC	ALEUTIANS WEST, AK	10/10/2003	FUEL OIL IC ENGINE GENERATORS (3)	23.8	WATER INJECTION AND LOW NOX DESIGN	1.780	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	1.812	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	NONE	1.858	OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	EMERGENCY GENERATOR	8	NONE INDICATED	1.900	LAER
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	BACKUP GENERATORS (2)	5.4	NONE INDICATED	1.900	BACT-PSD
HARTFORD INSURANCE CO.	SIMSBURY, CT	8/30/1989	GENERATOR, EMERGENCY STANDBY DIESEL FIRED	10.2	LIMIT HRS OF OPERATION	1.961	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	ENGINE DESIGN & LIMIT OPER (<500 H/YR)	2.035	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	2.052	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	2.052	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	SCR	2.189	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	1500 KW EMERGENCY GENERATOR	17.3	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	2.189	BACT-PSD
NOME JOINT UTILITIES - SNAKE RIVER	NOME, AK	11/5/2004	WARTSILA DIESEL ELECTRIC GENERATORS (3)	55.9	FUEL INJECTION RETARD/LOW TEMP COOLING WATER SYS	2.400	BACT-PSD
BROOKLYN NAVY YARD COGENERATION	NEW YORK CITY, NY	6/6/1995	GENERATOR, 3000 KW EMERGENCY	34.2	NONE INDICATED	2.600	LAER
SCE&G - JASPER COUNTY GENERATING	COLUMBIA, SC	5/23/2002	GENERATOR, EMERGENCY DIESEL FUEL	22.8	NONE INDICATED	2.609	BACT-PSD
SOUTH CAROLINA ELECTRIC AND GAS	COPE, SC	7/15/1992	GENERATOR, NO 2 OIL - EMERGENCY	4.6	NONE INDICATED	2.872	BACT-PSD
REDBUD POWER PLT PEREZ	OKLAHOMA	5/6/2002	DIESEL ENGINE, EMERGENCY GENERATOR	14.0	NONE INDICATED	3.113	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	3.200	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL GENERATORS (2)	17.2	NONE INDICATED	3.200	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	EMERGENCY GENERATOR	49	LIMITED USE	3.258	LAER
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	FUEL OIL IC ENGINE GENERATOR	4.9	GOOD COMBUSTION PRACTICES	3.280	BACT-PSD
BRISTOL HOSPITAL, INC.	BRISTOL, CT	10/24/1989	GENERATOR, EMERGENCY DIESEL FIRED	7.14	NONE INDICATED	3.350	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	EMERGENCY GENERATOR	14.8	GOOD COMBUSTION PRACTICES	3.500	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	3.517	OTHER
KC PUBLIC UTILITIES - NEARMAN CREEK	WYANDOTTE, KS	10/18/2005	EMERGENCY BLACK START GENERATOR	24.1	NONE INDICATED	3.519	BACT-PSD
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	DIESEL GENERATOR SET	14.8	NONE INDICATED	3.583	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	DIESEL ENGINE GENERATOR	7.6	ENGINE DESIGN	3.600	BACT-PSD
ROCKINGHAM POWER, LLC POWER GEN	NORTH CAROLINA	6/30/1999	IC ENGINE, EMERGENCY GENERATOR	2.9	LIMITED TO 500 H/YR	3.648	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	4.021	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	EMERGENCY GENERATOR	10.1	GCP, 250 HR/YR	4.113	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	(6) BLACK START DIESEL GENERATORS	19.1	GCP, 500 HR/YR	4.350	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	4.849	OTHER
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	1 EMERGENCY GENERATOR	17.1	RETARD TIMING 6 DEGREES	10.641	NSPS

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED FROM KW, GAL/HR, G/KWH & LB/HP-HR BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES, SCR = SELECTIVE CATALYTIC REDUCTION

Table C-21
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Emergency Diesel Generators
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	CO EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	EMERGENCY GENERATOR	49.0	GCP	0.023	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	EMERGENCY GENERATOR	5.2	GCP, TIMING RETARD	0.042	BACT-PSD
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	EMERGENCY GENERATOR	11.4	NONE INDICATED	0.077	BACT-PSD
USAF EARECKSON AIR STATION	ANCHORAGE, AK	9/29/2003	FUEL OIL IC ENGINE GENERATORS (2)	32.2	OXIDATION CATALYST	0.137	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	OXIDATION CATALYST	0.178	BACT-PSD
NOME JOINT UTILITIES - SNAKE RIVER	NOME, AK	11/5/2004	WARTSILA DIESEL ELECTRIC GENERATORS (3)	55.9	GOOD COMBUSTION PRACTICES	0.188	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	ENGINE DESIGN, LIMIT HOURS (<500 H/YR)	0.202	BACT-PSD
SOUTH CAROLINA ELECTRIC AND GAS	COPE, SC	7/15/1992	GENERATOR, NO 2 OIL - EMERGENCY	4.6	NONE INDICATED	0.219	BACT-PSD
BRISTOL HOSPITAL, INC.	BRISTOL, CT	10/24/1989	GENERATOR, EMERGENCY DIESEL FIRED	7.1	NONE INDICATED	0.230	BACT-PSD
BROOKLYN NAVY YARD COGEN	NEW YORK CITY, NY	6/6/1995	GENERATOR, 3000 KW EMERGENCY	34.2	NONE INDICATED	0.250	LAER
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	DIESEL GENERATOR SET	14.8	NONE INDICATED	0.276	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	EMERGENCY GENERATOR	14.8	GOOD COMBUSTION PRACTICES	0.276	BACT-PSD
KC PUBLIC UTILITIES - NEARMAN CREEK	WYANDOTTE, KS	10/18/2005	EMERGENCY BLACK START GENERATOR	24.1	GOOD COMBUSTION PRACTICES	0.291	BACT-PSD
UNION OIL CO. OF CALIFORNIA	KENAI, AK	8/4/1989	GENERATOR, EMERGENCY DIESEL FIRED	449.0	NONE INDICATED	0.294	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	0.317	OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	EMERGENCY GENERATOR	8.0	GOOD COMBUSTION PRACTICES	0.369	BACT-PSD
KENAI REFINERY	KENAI, AK	3/21/2000	EMERGENCY GENERATOR CF-G-70003	22.8	GOOD OPERATIONAL PRACTICES & MAINT	0.377	BACT-PSD
KENAI REFINERY	KENAI, AK	3/21/2000	EMERGENCY GENERATOR CF-G-70004	22.8	GOOD OPERATIONAL PRACTICES & MAINT	0.377	BACT-PSD
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	EMERGENCY GENERATOR	14.4	GOOD COMBUSTION PRACTICES	0.614	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	0.691	OTHER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	EMERGENCY GENERATOR	23.38	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.649	BACT-PSD
CONSUMERS ENERGY	BAY, MI	12/29/2009	EMERGENCY GENERATOR	22.8	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.677	BACT-PSD
SCE&G - JASPER COUNTY GENERATING	COLUMBIA, SC	5/23/2002	GENERATOR, EMERGENCY DIESEL FUEL	22.8	NONE INDICATED	0.693	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	(2) BLACK START GENERATORS	58.5	OPERATION < 200 HR/YR	0.697	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	1500 KW EMERGENCY GENERATOR	17.3	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICE	0.705	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	EMERGENCY GENERATOR	16.1	NONE INDICATED	0.716	BACT-PSD
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	EMERGENCY GENERATOR ENGINE	8.05	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0.719	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY DIESEL GENERATOR (2200 HP)	17.60	NONE INDICATED	0.719	BACT-PSD
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	EMERGENCY GENERATOR	10.9	NONE INDICATED	0.719	BACT-PSD
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	FUEL OIL IC ENGINE GENERATOR	4.9	GOOD COMBUSTION PRACTICES	0.760	BACT-PSD
ROCKINGHAM POWER, LLC POWER GEN	NORTH CAROLINA	6/30/1999	IC ENGINE, EMERGENCY GENERATOR	2.9	LIMITED TO 500 H/YR OF OPERATION	0.786	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	NONE	0.787	OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	EMERGENCY GENERATOR	13.7	GCP	0.850	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	0.850	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL GENERATORS (2)	17.2	NONE INDICATED	0.850	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	0.876	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	EMERGENCY GENERATOR	10.1	GCP, 250 HR/YR	0.886	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	(6) BLACK START DIESEL GENERATORS	19.1	GCP, 500 HR/YR	0.937	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	1.530	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	1.530	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	2.222	BACT-PSD
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	BACKUP GENERATORS (2)	5.4	NONE INDICATED	2.349	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	DIESEL ENGINE GENERATOR	7.6	ENGINE DESIGN	2.480	BACT-PSD
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	1 EMERGENCY GENERATOR	17.1	RETARD TIMING 6 DEGREES	3.368	NSPS
REDBUD POWER PLT PEREZ"	OKLAHOMA	5/6/2002	DIESEL ENGINE, EMERGENCY GENERATOR	14.0	ENGINE DESIGN	7.134	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED FROM KW, GAL/HR, G/KWH & LB/HP-HR BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-22
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Emergency Diesel Generators
Volatile Organic Compound Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	VOC EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	EMERGENCY GENERATOR	11.4	NONE INDICATED	0.007	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	EMERGENCY GENERATOR	5.2	GCP, TIMING RETARD	0.014	BACT-PSD
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	DIESEL GENERATOR SET	14.8	NONE INDICATED	0.033	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	EMERGENCY GENERATOR	14.8	GOOD COMBUSTION PRACTICES	0.033	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	EMERGENCY GENERATOR	7.51	NONE INDICATED	0.041	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	0.057	OTHER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	EMERGENCY GENERATOR	23.38	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.059	BACT
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	GOOD COMBUSTION CONTROL	0.068	LAER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	EMERGENCY GENERATOR	8.0	GOOD COMBUSTION PRACTICES	0.069	LAER
SCE&G - JASPER COUNTY GENERATING FACILITY	COLUMBIA, SC	5/23/2002	GENERATOR, EMERGENCY DIESEL FUEL	22.8	NONE INDICATED	0.075	LAER
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	EMERGENCY GENERATOR	16.1	NONE INDICATED	0.083	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	0.084	OTHER
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	EMERGENCY GENERATOR	14.4	GOOD COMBUSTION PRACTICES	0.084	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY DIESEL GENERATOR (2200 HP)	17.60	GOOD COMBUSTION	0.088	OTHER
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL GENERATORS (2)	17.2	NONE INDICATED	0.090	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	EMERGENCY GENERATOR	13.7	GCP	0.090	BACT-PSD
REDBUD POWER PLT PEREZ"	OKLAHOMA	5/6/2002	DIESEL ENGINE, EMERGENCY GENERATOR	14.0	ENGINE DESIGN	0.091	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	0.091	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	ENGINE DESIGN, LIMIT OPERATION (<500 H/YR)	0.095	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	1500 KW EMERGENCY GENERATOR	17.3	GOOD COMBUSTION PRACTICES	0.096	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	NONE	0.099	OTHER
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	FUEL OIL IC ENGINE GENERATOR	4.9	GOOD COMBUSTION PRACTICES	0.100	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.127	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.127	BACT-PSD
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	BACKUP GENERATORS (2)	5.4	NONE INDICATED	0.205	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	EMERGENCY GENERATOR	49.0	GOOD COMBUSTION	0.246	LAER
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	0.257	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	DIESEL ENGINE GENERATOR	7.6	ENGINE DESIGN	0.283	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	NORTH CAROLINA	6/30/1999	IC ENGINE, EMERGENCY GENERATOR	2.9	LIMITED TO 500 H/YR OF OPERATION	0.295	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	0.324	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	EMERGENCY GENERATOR	10.1	GCP, 250 HR/YR	0.334	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	(6) BLACK START DIESEL GENERATORS	19.1	GCP, 500 HR/YR	0.353	BACT-PSD
UNION OIL CO. OF CALIFORNIA"	KENAI, AK	8/4/1989	GENERATOR, EMERGENCY DIESEL FIRED	449.0	NONE INDICATED	0.641	BACT-PSD
BRISTOL HOSPITAL, INC."	BRISTOL	10/24/1989	GENERATOR, EMERGENCY DIESEL FIRED	7.1	NONE INDICATED	0.730	BACT-PSD
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	1 EMERGENCY GENERATOR	17.1	RETARD TIMING 6 DEGREES	0.959	NSPS
CONSUMERS ENERGY	BAY, MI	12/29/2009	EMERGENCY GENERATOR	22.8	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL	1.237	OTHER
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	EMERGENCY GENERATOR ENGINE	8.05	TIER 2 ENGINE-BASED,GOOD COMBUSTION PRACTICES (GCP)	1.315	OTHER

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED FROM KW, GAL/HR, G/KWH & LB/HP-HR BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-23
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Emergency Diesel Generators
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	PM/PM-10 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	EMERGENCY GENERATOR	11.4	NONE INDICATED	0.004	BACT-PSD
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	EMERGENCY GENERATOR	10.9	NONE INDICATED	0.004	BACT-PSD
ACE ETHANOL - STANLEY	CHIPPEWA, WI	1/21/2004	DIESEL GENERATOR SET	14.8	LOW SULFUR FUEL	0.019	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	EMERGENCY GENERATOR	14.8	GOOD COMBUSTION PRACTICES	0.019	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	0.032	OTHER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	EMERGENCY GENERATOR	23.38	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.037	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, IJ	1/23/2009	EMERGENCY DIESEL GENERATOR (2200 HP)	17.60	NONE INDICATED	0.041	BACT-PSD
CONSUMERS ENERGY	BAY, MI	12/29/2009	EMERGENCY GENERATOR	21.46	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.041	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	EMERGENCY GENERATOR	7.51	NONE INDICATED	0.041	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	EMERGENCY GENERATOR	7.51	NONE INDICATED	0.041	BACT-PSD
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	EMERGENCY GENERATOR ENGINE	8.05	TIER 2 ENGINE-BASED,GOOD COMBUSTION PRACTICES (GCP)	0.041	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	EMERGENCY GENERATOR	16.1	NONE INDICATED	0.041	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	ENGINE DESIGN	0.044	BACT-PSD
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	0.045	OTHER
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	GOOD COMBUSTION CONTROL	0.051	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	1500 KW EMERGENCY GENERATOR	17.3	GOOD COMBUSTION PRACTICES	0.053	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	EMERGENCY GENERATOR	49	LIMITED USE	0.054	BACT-PSD
CONSUMERS ENERGY	BAY, MI	12/29/2009	EMERGENCY GENERATOR	21.46	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.057	BACT-PSD
KENAI REFINERY	KENAI, AK	3/21/2000	EMERGENCY GENERATOR CF-G-70003	22.8	GOOD OPERATIONAL PRACTICES & MAINT	0.057	BACT-PSD
KENAI REFINERY	KENAI, AK	3/21/2000	EMERGENCY GENERATOR CF-G-70004	22.8	GOOD OPERATIONAL PRACTICES & MAINT	0.057	BACT-PSD
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	EMERGENCY GENERATOR	8.0	CLEAN FUELS	0.059	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL GENERATORS (2)	17.2	NONE INDICATED	0.063	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	EMERGENCY GENERATOR	5.2	GCP, TIMING RETARD	0.066	BACT-PSD
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	EMERGENCY GENERATOR	14.4	GOOD COMBUSTION PRACTICES	0.078	BACT-PSD
SCE&G - JASPER COUNTY GENERATING FACILITY	COLUMBIA, SC	5/23/2002	GENERATOR, EMERGENCY DIESEL FUEL	22.8	CLEAN FUEL(LOW SULFUR DIESEL) GCP	0.083	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.091	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.091	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	NONE	0.099	OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	NONE	0.099	OTHER
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	0.100	BACT-PSD
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	FUEL OIL IC ENGINE GENERATOR	4.9	CLEAN FUELS AND GOOD COMBUSTION PRACTICES	0.100	BACT-PSD
BRISTOL HOSPITAL, INC.	BRISTOL, CT	10/24/1989	GENERATOR, EMERGENCY DIESEL FIRED	7.14	NONE INDICATED	0.100	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	0.105	BACT-PSD
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	BACKUP GENERATORS (2)	5.4	NONE INDICATED	0.110	BACT-PSD
HARTFORD INSURANCE CO.	SIMSBURY, CT	8/30/1989	GENERATOR, EMERGENCY STANDBY DIESEL FIRED	10.2	NONE INDICATED	0.110	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	DIESEL ENGINE GENERATOR	7.6	CLEAN FUELS	0.117	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	EMERGENCY GENERATOR	13.7	GCP	0.140	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	NORTH CAROLINA	6/30/1999	IC ENGINE, EMERGENCY GENERATOR	2.9	LIMITED TO 500 H/YR OF OPERATION	0.260	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	0.292	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	EMERGENCY GENERATOR	10.1	SULFUR LIMITED TO 0.05% BY WEIGHT, 250 HR/YR	0.292	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	(6) BLACK START DIESEL GENERATORS	19.1	SULFUR LIMITED TO 0.05% BY WEIGHT, 500 HR/YR	0.309	BACT-PSD
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	1 EMERGENCY GENERATOR	17.1	NO CONTROLS FEASIBLE	0.491	NSPS

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED FROM KW, GAL/HR, G/KWH & LB/HP-HR BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-24
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Emergency Diesel Generators
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	SO_2 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
AES WOLF HOLLOW LP	AUSTIN, TX	7/20/2000	EMERGENCY GENERATOR E-GEN	3.5	NONE INDICATED	0.001	OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	EMERGENCY GENERATOR	11.4	LOW SULFUR FUEL	0.004	BACT-PSD
CR WING COGENERATION PLANT	BIG SPRING, TX	10/12/1999	STARTUP & EMERGENCY ELEC GENERATOR	15.5	NONE INDICATED	0.032	OTHER
SCE&G - JASPER COUNTY GENERATING FACILITY	COLUMBIA, SC	5/23/2002	GENERATOR, EMERGENCY DIESEL FUEL	22.8	LOW SULFUR (0.05%) DIESEL	0.039	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	EMERGENCY GENERATOR	7.51	NONE INDICATED	0.047	BACT-PSD
ADM CORN PROCESSING - CEDAR RAPIDS	LINN, IA	6/29/2007	EMERGENCY GENERATOR	16.1	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.050	BACT-PSD
KC PUBLIC UTILITIES - NEARMAN CREEK	WYANDOTTE, KS	10/18/2005	EMERGENCY BLACK START GENERATOR	24.1	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.050	BACT-PSD
DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	12/28/2004	BACKUP GENERATORS (2)	5.4	LOW SULFUR FUEL	0.050	BACT-PSD
WEPCO - PORT WASHINGTON STATION	WASHINGTON, WI	10/13/2004	DIESEL ENGINE GENERATOR	7.6	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.050	BACT-PSD
AES RED OAK LLC	SAYREVILLE, NJ	10/24/2001	EMERGENCY GENERATOR	49	LOW SULFUR FUEL	0.050	BACT-PSD
CARDINAL FG CO./ CARDINAL GLASS PLANT	OKLAHOMA	3/18/2003	IC ENGINES, EMERGENCY GENERATORS (2)	22.8	LOW SULFUR FUEL, < 0.05% S	0.050	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY DIESEL GENERATOR (2200 HP)	17.60	NONE INDICATED	0.051	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	9/29/2005	EMERGENCY GENERATOR	11.4	PROPER OPERATION AND MAINTENANCE OF EQUIPMENT	0.051	BACT-PSD
MN MUNICIPAL POWER AGENCY - FAIRBAULT	RICE, MN	7/15/2004	FUEL OIL IC ENGINE GENERATOR	4.9	FUEL SULFUR LIMIT (0.05% BY WEIGHT)	0.051	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	EMERGENCY GENERATOR	13.7	GCP AND LOW SULFUR FUEL	0.052	BACT-PSD
SITHE MYSTIC DEVELOPMENT LLC	CHARLESTOWN, MA	9/29/1999	IC ENGINE EMERGENCY DIESEL GENERATOR	17.1	FUEL SULFUR AND HOURS PER YEAR LIMITS	0.056	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	EMERGENCY GENERATOR	14.1	SULFUR IN OIL LIMITED TO 0.05% BY WEIGHT.	0.057	OTHER
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL-FIRED GENERATOR	6.8	LOW SULFUR FUEL COMBUSTION CONTROL	0.058	BACT-PSD
ODESSA-ECTOR GENERATING STATION	DALLAS, TX	11/18/1999	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.083	BACT-PSD
ARCHER GENERATING STATION	FARMERS BRANCH, TX	1/3/2000	EMERGENCY ELECTRICAL GENERATOR	22.8	NONE INDICATED	0.083	BACT-PSD
BP EXPLORATION ALASKA - BADAMI CENTER	N SLOPE BRGH, AK	8/19/2005	CUMMINS IC ENGINE GENERATOR	14.8	NONE INDICATED	0.150	BACT-PSD
MANKATO ENERGY CENTER	BLUE EARTH, MN	12/4/2003	EMERGENCY GENERATOR	14.8	LOW SULFUR FUEL	0.163	BACT-PSD
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	EMERGENCY GENERATOR	8.0	LOW SULFUR FUEL	0.203	BACT-PSD
BRISTOL HOSPITAL, INC.	BRISTOL, CT	10/24/1989	GENERATOR, EMERGENCY DIESEL FIRED	7.14	NONE INDICATED	0.220	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	(8) EMERGENCY GENERATOR ENGINES EMGEN1-8	3.1	NONE INDICATED	0.259	BACT-PSD
SOUTH CAROLINA ELECTRIC AND GAS COMPANY	COPE, SC	7/15/1992	GENERATOR, NO 2 OIL - EMERGENCY	4.6	FUEL SPEC: 0.3% S FUEL; LIMIT OPER <500 HOURS/YEAR	0.263	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	EMERGENCY GENERATOR	10.1	SULFUR LIMITED TO 0.05% BY WEIGHT, 250 HR/YR	0.272	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	(6) BLACK START DIESEL GENERATORS	19.1	SULFUR LIMITED TO 0.05% BY WEIGHT, 500 HR/YR	0.288	BACT-PSD
REDBUD POWER PLT PEREZ	OKLAHOMA	5/6/2002	DIESEL ENGINE, EMERGENCY GENERATOR	14.0	NONE INDICATED	0.400	BACT-PSD
LONGVIEW POWER, LLC	MAIDSVILLE, WV	3/2/2004	EMERGENCY GENERATOR	14.4	SULFUR IN FUEL	0.451	BACT-PSD
NOME JOINT UTILITIES - SNAKE RIVER	NOME, AK	11/5/2004	WARTSILA DIESEL ELECTRIC GENERATORS (3)	55.9	FUEL SULFUR LIMIT (0.5% BY WEIGHT)	0.500	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL GENERATORS (2)	17.2	FUEL SULFUR LIMIT	0.500	BACT-PSD
NAVY PUBLIC WORKS CENTER	NORFOLK, VA	5/16/1994	1 EMERGENCY GENERATOR	17.1	NO CONTROLS FEASIBLE	0.982	NSPS

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED FROM KW, GAL/HR, G/KWH & LB/HP-HR BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-25
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Diesel Fire Pumps
Nitrogen Oxides Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	NOx EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	EMERGENCY FIRE PUMP ENGINE	2.42	OPERATION < 200 HR/YR	0.414	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	FIRE PUMP ENGINE	4.60	NONE INDICATED	0.802	BACT
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	FIRE PUMP ENGINE	2.52	TIER 3 ENGINE-BASEDGOOD COMBUSTION PRACTICES (GCP)	0.822	BACT
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	FIRE WATER PUMPS (2)	5.46	NONE INDICATED	0.822	BACT-PSD
LA COUNTY PROBATION/FAC PLANNING/ISD	LOS ANGELES, CA	8/14/2003	IC ENGINE FIRE PUMP	1.92	FUEL INJECTION RETARD-AFTER COOLER BY RAW WATER	1.160	BACT-PSD
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	1.200	Other Case-by-Case
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	DIESEL FIRE PUMP	1.30	LEAN BURN ENGINE	1.300	BACT-OTHER
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	BACKUP DIESEL FIRE PUMP	1.40	NONE INDICATED	1.429	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	1.480	BACT-OTHER
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	1.571	LAER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	DIESEL ENGINE FIRE PUMP	1.70	NONE INDICATED	1.620	LAER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	DIESEL FIRE PUMP	1.10	NONE INDICATED	1.850	LAER
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	1.850	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	RETARD ENGINE TIMING; TURBOCHARGER AFTERCOOLING	1.852	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	1.984	LAER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	FIRE PUMP ENGINES (2)	2.40	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER	2.038	BACT
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	FIRE PUMP	1.82	GCP, TIMING RETARD	2.088	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY FIRE PUMP (267-HP DIESEL)	2.14	NONE INDICATED	2.149	BACT
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	DIESEL FIRE PUMP	1.50	< 100 HR/YR OPERATION	2.200	N/A
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	FIRE WATER PUMP	5.28	GOOD ENGINE DESIGN AND OPERATING PRACTICES	2.309	BACT-PSD
VAUGHAN FURNITURE COMPANY	STUART, VA	8/28/1996	DIESEL FIRE PUMP (IC ENGINE)	1.85	300 HOURS/YEAR LIMIT	2.381	BACT
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	2.514	BACT
DUKE ENERGY - AUDRAIN GENERATING STATION	VANDALIA, MO	5/9/2000	EMERGENCY DIESEL FIRE PUMP	1.50	WATER SPRAY INJECTION SYSTEM	2.563	BACT-PSD
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	DIESEL FIRED WATER PUMP	3.40	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	2.618	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	FIRE WATER PUMP	2.40	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	2.700	LAER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	(2) FIRE PUMP DIESEL ENGINE	3.20	LIMIT OPERATING HOURS	2.750	OTHER
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	FIRE WATER PUMP	2.03	NONE INDICATED	2.819	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	FIRE WATER PUMP	3.11	GOOD WORKING ORDER & OPER PER MFGR SPECS.	2.966	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	3.200	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL FIRE PUMP	1.60	NONE INDICATED	3.210	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	3.440	BACT-OTHER
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY, KS	10/18/2005	EMERGENCY BLACK START GENERATOR	24.10	NONE	3.519	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	3.800	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	3.868	BACT-PSD
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	3.873	BACT
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	3.875	BACT
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	DFP DIESEL FIRE PUMP	2.48	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	3.875	BACT
FIRST QUALITY TISSUE, LLC	CLINTON, PA	10/20/2004	FIRE PUMP	4.60	NONE INDICATED	3.875	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL	3.875	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	3.875	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	3.875	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	3.876	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	3.881	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	FIRE WATER PUMP DIESEL ENGINE	2.40	NONE INDICATED	3.886	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	3.894	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	3.894	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL FIRE PUMP ENGINE	3.20	LOW SULFUR FUEL COMBUSTION CONTROL	4.000	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	4.000	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	FIRE PUMP	1.50	NONE INDICATED	4.250	BACT-OTHER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	4.339	LAER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	IGNITION TIMING RETARD	4.410	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.89	GCP	4.410	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	4.410	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	FIRE WATER PUMP DIESEL ENGINE	2.00	ENGINE DESIGN AND LIMITATION OF HOURS	4.410	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	FIRE WATER PUMP DIESEL ENGINE	1.60	ENGINE DESIGN AND LIMITATION OF HOURS	4.410	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	FIRE WATER PUMP (IC ENGINE)	2.12	ENGINE DESIGN AND HOURS LIMIT (<100 H/YR)	4.410	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP EQUIPMENT USAGE LIMITS	4.411	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	DF FIRE PUMP	2.6	NONE INDICATED	4.423	BACT-OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.50	NONE INDICATED	4.429	OTHER
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	DIESEL FIRE PUMP	2.17	NONE	4.429	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	DIESEL EMERGENCY FIRE WATER PUMP	2.30	OPERATION LIMITED TO < 500 HR/YR	4.435	BACT-OTHER
BLYTHE ENERGY PROJECT II	RIVERSIDE CO, CA	4/25/2007	DIESEL FIRE PUMP	2.12	NONE	4.531	BACT-PSD
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	(2) FIRE PUMP DIESEL ENGINE	2.20	LIMIT OPERATING HOURS	4.727	OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	5.000	BACT
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	FIRE PUMP ENGINE	2.07	NONE INDICATED	5.081	BACT-PSD
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	EMERGENCY FIRE PUMP	0.92	LIMITED TO 1,128 GAL/YR DIESEL FUEL	7.750	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	DIESEL FIRE PUMP	0.95	GCP, 500 HR/YR	12.008	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	29.800	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED

Table C-26
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Diesel Fire Pumps
Carbon Monoxide Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	CO EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	DIESEL-FIRED FIRE PUMP	2.3	GCP, INLET AIR FILTER	0.069	BACT
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	FIRE WATER PUMP	5.3	GOOD ENGINE DESIGN AND OPERATING PRACTICES	0.104	BACT-PSD
LA COUNTY PROBATION/FAC PLANNING/ISD	LOS ANGELES, CA	8/14/2003	IC ENGINE FIRE PUMP	1.9	NONE INDICATED	0.121	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	DIESEL FIREWATER PUMP	2.4	OPERATION LIMITED TO < 500 HR/YR	0.180	BACT-OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	DIESEL ENGINE FIRE PUMP	1.7	GOOD COMBUSTION PRACTICES	0.228	BACT-PSD
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	BACKUP DIESEL FIRE PUMP	1.4	NONE INDICATED	0.286	BACT-PSD
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	FIRE WATER PUMP	2.0	NONE INDICATED	0.312	BACT-OTHER
BLYTHE ENERGY PROJECT II	RIVERSIDE CO, CA	4/25/2007	DIESEL FIRE PUMP	2.12	NONE	0.330	BACT-PSD
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	DIESEL FIRED EMERGENCY PUMP	2.2	LIMITED OPERATION < 500 HR/YR	0.331	BACT-PSD
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.360	BACT-OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	DIESEL FIRE PUMP	1.1	NONE INDICATED	0.400	BACT
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	EMERGENCY FIREWATER PUMP	2.0	NONE INDICATED	0.527	Other Case-by-Case
CONSUMERS ENERGY	BAY, MI	12/29/2009	FIRE PUMP	4.2	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL	0.535	BACT
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY FIRE PUMP (267-HP DIESEL)	2.1	NONE INDICATED	0.535	BACT
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	DIESEL FIRED WATER PUMP	3.4	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.553	BACT-PSD
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	DIESEL ENGINE FIRE PUMP	12.0	GOOD COMBUSTION PRACTICES	0.610	BACT-PSD
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	FIRE PUMP ENGINE	2.9	OPERATION LIMITATION	0.611	BACT
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	FIRE WATER PUMP	3.1	GOOD WORKING ORDER / OPER PER MFGR SPECS.	0.618	BACT-PSD
DOME VALLEY ENERGY PARTNERS, LLC	WELTON, AZ	8/10/2003	EMERGENCY FIRE PUMP ENGINE	2.4	OPERATION < 200 HR/YR	0.634	BACT-PSD
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	FIRE WATER PUMP	2.4	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	0.635	BACT
DUKE ENERGY - AUDRAIN GENERATING STATION	VANDALIA, MO	5/9/2000	EMERGENCY DIESEL FIRE PUMP	1.5	GOOD COMBUSTION	0.689	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE, NY	9/1/1992	DIESEL FIRE PUMP	1.3	COMBUSTION CONTROL	0.710	BACT-OTHER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	FIRE PUMP ENGINES (2)	2.4	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.717	BACT
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	FIRE WATER PUMPS (2)	5.5	NONE INDICATED	0.719	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	FIRE PUMP ENGINE	4.6	NONE INDICATED	0.720	BACT
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	DIESEL FIREWATER PUMP ENGINE	1.6	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	0.750	BACT-OTHER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	(2) FIRE PUMP DIESEL ENGINE	2.2	NONE INDICATED	0.773	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	FIRE WATER PUMP (IC ENGINE)	2.5	LIMITED TO 500 H/YR OF OPERATION	0.800	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	DIESEL FIRE PUMP	1.5	< 100 HR/YR OPERATION	0.800	N/A
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.817	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.817	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	FIRE WATER PUMP ENGINE	2.7	NONE INDICATED	0.821	BACT-PSD
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	EMERGENCY DIESEL FIRE PUMP	2.1	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.833	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	FIREWATER PUMP ENGINE	2.4	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.833	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	(2) FIRE WATER PUMPS	2.4	NONE INDICATED	0.833	Other Case-by-Case
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	MAIN DIESEL FIRE PUMP	3.7	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.834	BACT
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	DFP DIESEL FIRE PUMP	2.5	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PR	0.835	BACT
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	DIESEL BOOSTER PUMP	2.1	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.835	BACT
FIRST QUALITY TISSUE, LLC	CLINTON, PA	10/20/2004	FIRE PUMP	4.6	NONE INDICATED	0.838	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	FIREWATER PUMP ENGINE	3.2	GOOD COMBUSTION CONTROL	0.844	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	FIRE WATER PUMP	2.1	LIMITED TO 500 H/YR OPERATION	0.849	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	FIRE WATER PUMP DIESEL ENGINE	2.4	ENGINE DESIGN	0.854	BACT-PSD
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL FIRE PUMP	1.6	NONE INDICATED	0.856	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL FIRE PUMP ENGINE	3.2	LOW SULFUR FUEL COMBUSTION CONTROL	0.863	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	DIESEL FIRE PUMP	1.8	LOWE SULFUR FUEL AND LIMITED OPERATION	0.933	BACT
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.5	NONE INDICATED	0.943	OTHER
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	DF FIRE PUMP	2.6	NONE INDICATED	0.946	BACT-OTHER
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.6	GCP	0.950	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.9	GCP	0.950	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	DIESEL FIRE PUMP ENGINE	1.5	NONE INDICATED	0.950	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	FIRE WATER PUMP DIESEL ENGINE	2.0	GCP AND DESIGN	0.950	BACT-PSD
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	FIRE WATER PUMP DIESEL ENGINE	1.6	GOOD ENGINE DESIGN	0.950	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	FIRE WATER PUMP DIESEL ENGINE	2.2	GCP AND DESIGN	0.950	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	FIRE WATER PUMP (IC ENGINE)	2.1	ENGINE DESIGN AND GCP	0.950	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	EMERGENCY DIESEL FIRE PUMP ENGINE	3.8	GCP EQUIPMENT USAGE LIMITS	0.950	BACT-PSD
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	DIESEL FIRE PUMP	2.17	NONE	0.954	BACT-PSD
CPV WARREN, LLC	FRONT ROYAL, VA	7/30/2004	DIESEL EMERGENCY FIRE WATER PUMP	2.3	OPERATION LIMITED TO < 500 HR/YR	0.957	BACT-OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	FIRE PUMP	3.4	LOW SULFUR FUEL AND LIMITED OPERATION	1.059	BACT
NORTHSTAR DEVELOPMENT PROJECT	ALASKA	2/5/1999	FIRE WATER PUMP	6.0	NONE INDICATED	1.060	BACT-PSD
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	EMERGENCY FIRE PUMP	0.9	LIMITED TO 1,128 GAL/YR DIESEL FUEL	1.674	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	FIRE PUMP ENGINE	2.1	NONE INDICATED	2.144	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	FIRE PUMP	1.8	GCP, TIMING RETARD	2.582	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	DIESEL FIRE PUMP	1.0	GCP, 500 HR/YR	2.588	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	FIRE PUMP	1.5	NONE INDICATED	2.880	BACT-OTHER
OXY NGL, INC.	JOHNSON BAYOU, LA	11/14/1989	(2) FIRE PUMP DIESEL ENGINE	3.2	NONE INDICATED	3.719	BACT-PSD

Table C-27
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Diesel Fire Pumps
Volatile Organic Compounds Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	VOC EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	FIRE WATER PUMP	5.28	GOOD COMBUSTION PRACTICES	0.0133	BACT-PSD
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	DIESEL FIRED WATER PUMP	3.40	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.0147	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	FIRE PUMP ENGINE	4.60	NONE INDICATED	0.021	BACT
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	0.0220	LAER
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	0.0333	BACT
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	FIRE WATER PUMP	2.03	NONE INDICATED	0.0477	BACT-OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	DIESEL ENGINE FIRE PUMP	1.70	GOOD COMBUSTION PRACTICES	0.0480	LAER
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	FIRE PUMP	1.50	NONE INDICATED	0.0550	BACT-OTHER
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	0.0611	BACT
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	DIESEL FIRE PUMP	1.50	<= 100 HR/YR OPERATION	0.0700	N/A
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL FIRE PUMP	1.60	NONE INDICATED	0.0875	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.0912	BACT-PSD
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	DIESEL FIRE PUMP	1.10	NONE INDICATED	0.1000	LAER
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	FIRE PUMP ENGINES (2)	2.40	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.1083	BACT
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	0.1100	BACT-OTHER
FAIRLESS WORKS ENERGY CTR (FMR. SWEC-FALLS TWP)	GLEN ALLEN, PA	8/7/2001	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	0.1295	LAER
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	0.1400	Other Case-by-Case
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.1600	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	FIRE WATER PUMP	3.11	GOOD WORKING ORDER / OPERATION PER MFGR SPECS.	0.2472	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES (< 500 HR/YR)	0.2500	BACT-OTHER
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	BACKUP DIESEL FIRE PUMP	1.40	NONE INDICATED	0.2857	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	FIRE PUMP	1.82	GCP, TIMING RETARD	0.2967	BACT-OTHER
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	0.2985	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.3000	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY FIRE PUMP (267-HP DIESEL)	2.14	GOOD COMBUSTION	0.3090	BACT
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.3090	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	FIRE PUMP ENGINE	2.07	NONE INDICATED	0.3097	BACT-PSD
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.3098	BACT
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	DFP DIESEL FIRE PUMP	2.48	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	0.3105	BACT
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	0.3113	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	FIRE WATER PUMP DIESEL ENGINE	2.40	ENGINE DESIGN	0.3125	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL	0.3125	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.3125	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.3125	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.3125	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	0.3125	Other Case-by-Case
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.3302	BACT
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	FIRE WATER PUMP (IC ENGINE)	2.12	ENGINE DESIGN	0.3302	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.50	NONE INDICATED	0.3429	OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.89	GCP	0.3500	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	0.3500	BACT-PSD
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	DIESEL FIRE PUMP	2.17	NONE	0.355	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	GCP	0.3600	BACT-OTHER
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	0.3600	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	FIRE WATER PUMP DIESEL ENGINE	2.00	COMBUSTION PRACTICES AND DESIGN	0.3600	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP, EQUIPMENT USAGE LIMITS	0.3605	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	DF FIRE PUMP	2.60	NONE INDICATED	0.3615	BACT-OTHER
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	0.3824	BACT
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	FIRE PUMP ENGINE	2.52	TIER 3 ENGINE-BASED, GCP	0.613	BACT
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	FUEL SELECTION; GOOD COMBUSTION	0.7037	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.7100	BACT-PSD
CONSUMERS ENERGY	BAY, MI	12/29/2009	FIRE PUMP	4.20	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.827	BACT
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	DIESEL FIRE PUMP	0.95	GCP, 500 HR/YR	0.9739	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-28
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Diesel Fire Pumps
Particulate Matter Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	PM/PM-10 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	DIESEL ENGINE FIRE PUMP	12.0	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.016	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	DIESEL-FIRED FIRE PUMP	2.32	GCP, INLET AIR FILTER	0.019	BACT
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	DIESEL FIRE PUMP	2.00	OPERATION LIMITED TO < 500 HR/YR	0.026	BACT-OTHER
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	DIESEL ENGINE FIRE PUMP	1.70	CLEAN FUELS	0.030	BACT-PSD
IDAHO POWER COMPANY	PAYETTE, ID	6/25/2010	FIRE PUMP ENGINE	2.52	TIER 3 ENGINE-BASED,GOOD COMBUSTION PRACTICES (GCP)	0.031	BACT
GENOVA OK I POWER PROJECT	GRADY CO., OK	6/13/2002	FIRE WATER PUMP DIESEL ENGINE	1.60	ENGINE DESIGN AND GOOD COMBUSTION	0.031	BACT-PSD
LA COUNTY PROBATION/PAC PLANNING/ISD	LOS ANGELES, CA	8/14/2003	IC ENGINE FIRE PUMP	1.92	NONE INDICATED	0.039	BACT-PSD
ARIZONA CLEAN FUELS YUMA LLC	YUMA, AZ	4/14/2005	FIRE WATER PUMPS (2)	5.46	NONE INDICATED	0.041	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	FIRE PUMP ENGINE	4.60	NONE INDICATED	0.041	BACT
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	09/19/2008 &	FIRE PUMP ENGINE	4.60	NONE INDICATED	0.041	BACT
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	DIESEL FIRED WATER PUMP	3.40	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.041	BACT-PSD
CONSUMERS ENERGY	BAY, MI	12/29/2009	FIRE PUMP	4.20	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.041	BACT
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	FIRE PUMP ENGINE	2.94	OPERATION LIMITATION	0.044	BACT
CALPINE WAWAYANDA	WAWAYANDA, NY	7/22/2002	FIRE WATER PUMP	2.40	OPERATIONAL RESTRICTIONS (< 52 HR/YR)	0.047	BACT
BLYTHE ENERGY PROJECT II	RIVERSIDE CO, CA	4/25/2007	DIESEL FIRE PUMP	2.12	NONE	0.047	BACT-PSD
ASTORIA ENERGY, LLC	ASTORIA, NY	12/5/2001	DIESEL FIREWATER PUMP	2.40	OPERATION LIMITED TO < 500 HR/YR	0.060	BACT-OTHER
FAIRLESS WORKS ENERGY CENTER (FMR. SWEC-FA	GLEN ALLEN, PA	8/7/2001	DIESEL FIRED EMERGENCY PUMP	2.24	LIMITED OPERATION < 500 HR/YR	0.061	BACT-PSD
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	FIRE WATER PUMP	2.03	NONE INDICATED	0.062	BACT-OTHER
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	EMERGENCY FIREWATER PUMP	2.00	NONE INDICATED	0.070	Other Case-by-Case
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	BACKUP DIESEL FIRE PUMP	1.40	NONE INDICATED	0.086	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.40	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.100	BACT-PSD
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	EMERGENCY DIESEL FIRE PUMP ENGINE	3.80	GCP USE OF FUEL < 0.05% S BY WT. EQUIPMENT USAGE LIMIT	0.100	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY FIRE PUMP (267-HP DIESEL)	2.14	NONE INDICATED	0.112	BACT
OHIO RIVER CLEAN FUELS, LLC	COLUMBIANA, OH	11/20/2008	FIRE PUMP ENGINES (2)	2.40	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.113	BACT
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	DIESEL FIRE PUMP	1.80	LOWE SULFUR FUEL AND LIMITED OPERATION	0.120	BACT
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	FIRE PUMP	3.40	LOW SULFUR FUEL AND LIMITED OPERATION	0.120	BACT
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	FIRE PUMP	1.82	GCP, TIMING RETARD	0.121	BACT-PSD
HAWKEYE GENERATING, LLC	ORIENT, IA	7/23/2002	FIRE PUMP	1.82	GCP, TIMING RETARD	0.121	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	DIESEL FIRE PUMP	1.50	SULFUR <= 0.2% BY WEIGHT; <= 100 HR/YR OPERATION	0.170	N/A
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL FIRE PUMP	1.60	NONE INDICATED	0.194	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	FIRE PUMP	1.50	FUEL SPECIFICATION: SULFUR CONTENT </= 0.15% BY WT	0.200	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY, NY	12/10/1994	FIRE PUMP	1.50	FUEL SPECIFICATION: SULFUR CONTENT </= 0.15% BY WT	0.200	BACT-OTHER
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	FIRE WATER PUMP	3.11	GOOD WORKING ORDER AND OPERATION PER MFGR SPECS.	0.210	BACT-PSD
SABINE PASS LNG - IMPORT TERMINAL	CAMERON, LA	11/24/2004	FIRE WATER PUMP	5.28	GOOD COMBUSTION PRACTICE	0.235	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	DIESEL FIREWATER PUMP ENGINE	1.60	GOOD COMB CONTROL / MODERN ENGINES, S < 0.05% (< 500 HR/YR)	0.250	BACT-OTHER
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	3/1/1995	DIESEL ENGINE-DRIVEN FIRE PUMP	2.70	FUEL SELECTION; GOOD COMBUSTION	0.259	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.260	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE, MN	11/10/1998	DIESEL EMERGENCY FIRE PUMP ENGINE	2.70	LIMITED TO BURN DIESEL 150 H/YR	0.260	BACT-PSD
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	FIRE WATER PUMP ENGINE	2.68	NONE INDICATED	0.261	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	FIRE PUMP ENGINE	2.07	NONE INDICATED	0.271	BACT-PSD
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	DIESEL BOOSTER PUMP	2.12	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.274	BACT
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.274	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	EMERGENCY FIREWATER PUMP	2.08	NONE INDICATED	0.274	BACT-PSD
SOUTHWEST ELECTRIC POWER COMPANY (SWEPC	CADDO, LA	3/20/2008	DFP DIESEL FIRE PUMP	2.48	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER	0.274	BACT
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	MAIN DIESEL FIRE PUMP	3.68	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.274	BACT
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL FIRE PUMP ENGINE	3.20	LOW SULFUR FUEL COMBUSTION CONTROL	0.275	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	FIRE WATER PUMP DIESEL ENGINE	2.4	NONE INDICATED	0.275	BACT-PSD
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	FIREWATER PUMP ENGINE	2.40	ANNUAL OPERATION < 250 NON-EMERGENCY HOURS	0.275	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	(2) FIRE WATER PUMPS	2.40	NONE INDICATED	0.275	Other Case-by-Case
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	EMERGENCY DIESEL FIRE PUMP	2.14	GOOD ENGINE DESIGN, < 200 H/YR OPERATION	0.276	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	FIREWATER PUMP ENGINE	3.20	GOOD COMBUSTION CONTROL AND USE OF LOW-SULFUR DIESEL	0.281	BACT-PSD
LAIDLAW BERLIN BIOPOWER, LLC	COOS, NH	7/26/2010	EU03 FIRE PUMP ENGINE	2.3	NONE INDICATED	0.300	BACT
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	FIRE WATER PUMP (IC ENGINE)	2.48	LIMITED TO 500 H/YR OF OPERATION	0.300	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	DF FIRE PUMP	2.60	NONE INDICATED	0.308	BACT-OTHER
CONSUMERS ENERGY	BAY, MI	12/29/2009	FIRE PUMP	4.20	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.310	BACT
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	DIESEL FIRE PUMP	1.10	NONE INDICATED	0.310	BACT
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	LOW ASH FUEL AND GOOD OPERATING PRACTICES	0.310	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.89	GCP	0.310	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	FIRE WATER PUMP (IC ENGINE)	2.12	COMBUSTION CONTROL AND GOOD ENGINE DESIGN	0.310	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.59	LOW ASH FUEL AND GCP	0.310	BACT-OTHER
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.89	GCP	0.310	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	DIESEL FIRE PUMP ENGINE	1.50	NONE INDICATED	0.310	BACT-PSD
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	FIRE WATER PUMP DIESEL ENGINE	2.00	LOW ASH FUEL	0.310	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	FIRE WATER PUMP	2.12	LIMITED TO 500 H/YR OPERATION	0.311	BACT-PSD
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	DIESEL FIRE PUMP	2.17	NONE	0.313	BACT-PSD
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.50	NONE	0.314	OTHER
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.50	NONE	0.314	OTHER
GRAIN PROCESSING CORP.	WASHINGTON, IN	6/10/1997	EMERGENCY FIRE PUMP	0.92	NONE INDICATED	0.543	BACT-PSD
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	DIESEL FIRE PUMP	0.95	SULFUR LIMITED TO 0.05% BY WEIGHT, 500 HR/YR	0.852	BACT-PSD
KIAMICHI ENERGY FACILITY	PITTSBURG CO., OK	5/1/2001	FIRE WATER PUMP DIESEL ENGINE	2.16	GCP AND DESIGN	2.110	BACT-PSD

ASSUMPTION: HEAT INPUT RATE AND EMISSION LIMITS CALCULATED BASED ON A FUEL USAGE RATE OF 8,000 BTU/HP-HR AND FUEL HHV OF 140,000 BTU/GAL, AS NEEDED
GCP = GOOD COMBUSTION PRACTICES

Table C-29
JCEP LNG Terminal Project
Recent BACT/LAER Determinations for Diesel Fire Pumps
Sulfur Dioxide Emissions

FACILITY	LOCATION	PERMIT DATE	EMISSION UNIT DESCRIPTION	THROUGHPUT MMBTU/HR (EACH UNIT)	CONTROL DESCRIPTION	SO_2 EMISSION LIMIT (LB/MMBTU)	PERMIT LIMIT BASIS
EL PASO MANATEE ENERGY CENTER	MANATTE CO., FL	12/1/2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
EL PASO BELLE GLADE ENERGY CENTER	PALM BEACH CO., FL	12/1/2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
EL PASO BROWARD ENERGY CENTER	BROWARD CO., FL	2001	DIESEL FIRE PUMP	2.0	OPERATION LIMITED TO < 500 HR/YR	0.003	BACT-OTHER
TRANSGAS ENERGY SYSTEMS	BROOKLYN, NY	6/4/2003	DIESEL FIRE PUMP	1.1	NONE INDICATED	0.020	BACT
FAIRLESS WORKS ENERGY CENTER (FMR. SWEC-FALLS TO	GLEN ALLEN, PA	8/7/2001	DIESEL FIRED EMERGENCY PUMP	2.2	LIMITED OPERATION < 500 HR/YR	0.047	BACT-PSD
DUKE ENERGY HANGING ROCK ENERGY FACILITY	CHARLOTTE	12/13/2001	FIRE WATER PUMP	2.1	LOW SULFUR FUEL	0.047	BACT-PSD
TATE & LYLE INDGREDIENTS AMERICAS, INC.	WEBSTER, IA	9/19/2008	FIRE PUMP ENGINE	4.6	LIMIT ON SULFUR IN FUEL	0.047	BACT
LONGVIEW ENERGY DEVELOPMENT	LONGVIEW, WA	9/4/2001	FIRE PUMP ENGINE	2.9	LOW SULFUR FUEL OIL (< 0.05% S)	0.048	BACT
LA COUNTY PROBATION/FAC PLANNING/ISD	LOS ANGELES, CA	8/14/2003	IC ENGINE FIRE PUMP	1.9	LOW SULFUR FUEL OIL (TO BE CONVERTED TO ULTRA LOW SULFUR FUEL)	0.050	BACT-PSD
ROCKINGHAM POWER, LLC POWER GENERATING	ROCKINGHAM CO., NC	6/30/1999	FIRE WATER PUMP (IC ENGINE)	2.5	LIMITED TO 500 H/YR OF OPERATION	0.050	BACT-PSD
MANTUA CREEK GENERATING FACILITY	NEW JERSEY	6/26/2001	DIESEL FIRE PUMP	1.5	SULFUR MUST BE <= 0.2% BY WEIGHT; <= 100 HR/YR OPERATION	0.050	N/A
HORSESHOE ENERGY PROJECT	LINCOLN CO., OK	2/12/2002	FIRE WATER PUMP DIESEL ENGINE	2.0	LOW SULFUR DIESEL FUEL	0.050	BACT-PSD
FORSYTH ENERGY PLANT	FORSYTH CO., NC	1/23/2004	EMERGENCY FIREWATER PUMP (IC ENGINE)	11.4	EMERGENCY ONLY, USAGE LIMITED TO < 200 H/YR	0.051	BACT-PSD
ASSOCIATED ELECTRIC COOPERATIVE INC	MAYES, OK	1/23/2009	EMERGENCY FIRE PUMP (267-HP DIESEL)	2.1	LOW SULFUR DIESEL	0.051	BACT
CHOUTEAU POWER PLANT	PRYOR, OK	3/24/1999	EMERGENCY DIESEL FIRE PUMP	2.1	LIMITED TO 200 H/YR OPERATION	0.051	BACT-PSD
MIDAMERICAN ENERGY COMPANY	COUNCIL BLUFFS, IA	6/17/2003	DIESEL FIRE PUMP	3.9	GCP AND LOW SULFUR FUEL	0.052	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON, MA	10/6/1997	DIESEL FIRE PUMP ENGINE	1.5	NONE INDICATED	0.053	BACT-PSD
CASCO BAY ENERGY COMPANY, LLC	VEAZIE, ME	2000	FIRE PUMP	3.4	LOW SULFUR FUEL AND LIMITED OPERATION	0.059	BACT
LAMAR LIGHT & POWER POWER PLANT	POWERS, CO	2/3/2006	DIESEL ENGINE FIRE PUMP	12.0	LOW SULFUR FUEL (0.05% BY WEIGHT)	0.060	BACT-PSD
ARCHER POWER PARTNERS, L.P.	ECTOR CO., TX	1/3/2000	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.101	BACT-PSD
ODESSA-ECTOR GENERATING STATION	ECTOR CO., TX	11/18/1999	EMERGENCY FIREWATER PUMP	2.1	NONE INDICATED	0.101	BACT-PSD
CRESCENT CITY POWER	ORLEANS, LA	6/6/2005	DIESEL FIRED WATER PUMP	3.4	NONE INDICATED	0.180	BACT-PSD
RIVER HILL POWER COMPANY	KARTHAUS TWP, PA	7/21/2005	DIESEL ENGINE FIRE PUMP	1.7	LOW SULFUR FUEL	0.203	BACT-PSD
DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	STEPHENS CO., OK	3/21/2003	FIRE WATER PUMP (IC ENGINE)	2.1	USE OF VERY LOW SULFUR DIESEL FUEL (<0.05% S BY WT)	0.236	BACT-PSD
BELL ENERGY FACILITY	TEMPLE	6/26/2001	FIREWATER PUMP ENGINE	3.2	GOOD COMBUSTION CONTROLS, USE OF LOW SULFUR (0.05%) FUELS	0.250	BACT-PSD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	ARLINGTON, AZ	11/12/2003	DIESEL FIREWATER PUMP ENGINE	1.6	GOOD COMB CONTROL / MODERN ENGINES, S < 0.05% (< 500 HR/YR)	0.250	BACT-OTHER
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	DIESEL BOOSTER PUMP	2.1	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.255	BACT
WPS WESTON 4 - NORTH SITE	WAUSAU, WI	10/18/2004	MAIN DIESEL FIRE PUMP	3.7	FIRING ULTRA LOW SULFUR FUEL OIL (< 0.003%S)	0.255	BACT
SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO, LA	3/20/2008	DFP DIESEL FIRE PUMP	2.5	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	0.258	BACT
BASTROP CLEAN ENERGY CENTER	BASTROP CO., TX	3/21/2000	FIREWATER PUMP ENGINE	2.4	DISTILLATE FUEL OIL < 0.3 WEIGHT PERCENT SULFUR	0.258	BACT-PSD
BRAZOS VALLEY ELECTRIC GENERATING FACILITY	FORT BEND CO., TX	12/31/2002	(2) FIRE WATER PUMPS	2.4	DIESEL </+ 0.3% S, MAX OPER 100 H/YR, NON-EMERGENCY USE	0.258	Other Case-by-Case
HARRIS ENERGY FACILITY	HOUSTON, TX	8/31/2000	FIRE WATER PUMP ENGINE	2.7	NONE INDICATED	0.261	BACT-PSD
DUKE ENERGY WASHINGTON COUNTY LLC	OHIO	1/18/2001	EMERGENCY DIESEL FIRE PUMP ENGINE	3.2	LOW SULFUR FUEL COMBUSTION CONTROL	0.263	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK, ME	12/4/1998	DIESEL FIRE PUMP	1.8	LOWE SULFUR FUEL AND LIMITED OPERATION	0.283	BACT
LIBERTY GENERATING STATION	LINDEN CITY, NJ	3/28/2002	DIESEL FIRE PUMP	3.5	NONE INDICATED	0.286	BACT-OTHER
HOLLAND ENERGY, LLC	HOLLAND, IL	12/3/2001	BACKUP DIESEL FIRE PUMP	1.4	NONE INDICATED	0.286	BACT-PSD
LAKEWOOD COGENERATION, LP	LAKEWOOD, NJ	1993	DF FIRE PUMP	2.6	NONE INDICATED	0.288	BACT-OTHER
BADGER GENERATING CO LLC	PLEASANT PRAIRIE, WI	9/20/2000	EMERGENCY DIESEL FIRE PUMP ENGINE	3.8	DIESEL FUEL SULFUR CONTENT OF 0.05% & EQUIPMENT USAGE LIMITS	0.289	BACT-PSD
EMERY GENERATING STATION	MASON CITY, IA	12/20/2002	EMERGENCY FIRE PUMP (IC ENGINE)	2.6	LOW SULFUR FUEL	0.290	BACT-OTHER
NEARMAN CREEK POWER STATION	WYANDOTTE COUNTY, KS	10/18/2005	EMERGENCY BLACK START GENERATOR	24.10	NONE	0.291	BACT-PSD
ARSENAL HILL POWER PLANT	CADDO CO, LA	3/20/2008	DIESEL FIRE PUMP	2.17	NONE	0.295	BACT-PSD
SUMMIT VINEYARD, LLC	VINEYARD, UT	10/25/2004	DIESEL-FIRED FIRE PUMP	2.3	GCP, INLET AIR FILTER	0.322	BACT
PSEG WATERFORD ENERGY LLC	COLUMBUS, OH	3/29/2001	FIRE WATER PUMP	3.1	GOOD WORKING ORDER AND OPERATION PER MANUFACTURER SPECS.	0.371	BACT-PSD
REDBUD POWER PLT	OKLAHOMA	5/6/2002	FIRE WATER PUMP DIESEL ENGINE	2.4	NONE INDICATED	0.400	BACT-PSD
AES WOLF HOLLOW LP	HOOD CO., TX	7/20/2000	EMERGENCY FIREWATER PUMP	2.0	NONE INDICATED	0.420	Other Case-by-Case
PSI ENERGY - MADISON STATION	MADISON, OH	8/24/2004	EMERGENCY DIESEL FIRE PUMP	1.6	LOW SULFUR FUEL	0.500	BACT-PSD
WEST CASCADE ENERGY FACILITY	COBURG, OR	11/1/2003	FIRE WATER PUMP	2.0	NONE INDICATED	0.507	BACT-OTHER
TENASKA INDIANA PARTNERS, L.P.	OTWELL, IN	11/12/2002	DIESEL FIRE PUMP	1.0	SULFUR LIMITED TO 0.05% BY WEIGHT, 500 HR/YR	0.794	BACT-PSD
LONGVIEW POWER	MAIDSVILLE, WV	12/4/2003	FIRE PUMP ENGINE	2.1	NONE INDICATED	1.597	BACT-PSD

Appendix D
Agency Correspondence

From: ALLEN Philip [mailto:ALLEN.Philip@deq.state.or.us]
Sent: Wednesday, March 13, 2013 7:55 PM
To: Ometz, Darin; Main, Ted
Cc: ABTS Martin; PETERSON Tom
Subject: Jordan Cove Exemption Request and Competing Source Inventory

Ted, Darin,

Your request (1/28/2013) for exemption from conducting pre-construction ambient air quality monitoring for the proposed LNG export facility in Coos Bay is approved. This approval is based on provisions in 40 CFR 52.21, and guidance from the EPA NSR Workshop Manual (1990).

On a separate note, the competing source inventory is still being refined, and is expected to be ready tomorrow. Thanks for your patience.

Phil

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From: Cummings, Tonnie [mailto:tonnie_cummings@nps.gov]
Sent: Tuesday, January 29, 2013 4:41 PM
To: Ometz, Darin
Cc: John_Notar@nps.gov; Graw, Rick -FS; ALLEN Philip; PETERSON Tom; Main, Ted; Floyd, Brad; Coos Bay (bobbraddock@attglobal.net)
Subject: Re: Jordan Cove Protocol for FLM review and Class I Exemption Request

Hi Darin--

Thanks for the opportunity to comment on the AQRV modeling for the proposed Jordan Cove LNG facility. Given that the Q/D is less than 10 for the 2 NPS Class I areas--Crater Lake and Redwood National Parks--we agree refined AQRV modeling and analyses are not required. We are interested in reviewing the BACT analysis for the project when it is available.

--Tonnie

From: ALLEN Philip [mailto:ALLEN.Philip@deq.state.or.us]
Sent: Wednesday, January 23, 2013 1:21 PM
To: Main, Ted; Ometz, Darin; PETERSON Tom
Cc: ABTS Martin; 'Kubo.Teresa@epamail.epa.gov'; Herman Wong; STOCUM Jeffrey; LAZAREV Svetlana
Subject: Jordan Cove Protocol Approval

Ted,

DEQ has reviewed the PSD Dispersion Modeling Protocol for Jordan Cove Energy Project, L.P. (November 2012) as prepared by TRC Environmental. We find the Protocol complete. However, we have the following comments, some of which have been mentioned on previous conference calls.

1) The current version of AERMOD and AERMET is version 12345, as announced by EPA on 12/18/2012. The current version should be used in the analysis.

2) For estimating secondary $PM_{2.5}$, please use the default offset ratios for NOx of 100:1,and for SO_2 of 40:1, as specified in Oregon Rules (OARs).

3) DEQ will update the competing source inventory prepared for the earlier analysis. In order to facilitate the update it would be helpful if you could provide us with that earlier inventory.

4) The monitoring exemption request for pollutants exceeding the SMCs that was described in the protocol should be submitted to DEQ. In addition, the protocol states that air quality monitoring could be required for some of the pollutants. If preliminary modeling of emissions has been completed, the results of that modeling and the list of the pollutants that may require monitoring should be provided if possible.

5) Emergency Generator and pump emissions are exempt from inclusion in the modeling analysis under EPA guidance regarding intermittent sources. Although the emissions from the continuous flare pilot flame are described as negligible, please provide an estimate of these emissions.

6) Although not specifically mentioned in the description of surface characteristics of the North Bend Airport meteorological site, it is assumed that AERSURFACE, or a similar approach following AERMET guidance to address surface characteristics, will be used in the preparation of the SFC and PFL input files to AERMET.

7) In regard to the necessity of an AQRV analysis for Class I areas, DEQ will concur with the decisions of Federal Land Managers.

8) It is our understanding that EPA is a Cooperating Agency for the NEPA analysis, and EPA Region 10 will be reviewing the modeling protocol. Comments from EPA for the NSR/PSD portion of the air quality analysis will be considered as part of our review of the protocol, and will be provided when available from EPA.

The Protocol is approved.

If you have any questions, please contact us. Thanks.

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January 11, 2013

Subject: JCEP LNG Terminal Project
Coos Bay, Coos County, Oregon
Need for Class I Area Air Quality and Air Quality Related Values Analyses

To whom it may Concern:

TRC has been retained by Jordan Cove Energy Project, L.P. (JCEP) to prepare an air permit application for a proposed Liquefied Natural Gas (LNG) Terminal to be constructed in Coos Bay, Coos County, Oregon. The Project will consist of facilities to receive and liquefy natural gas, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The emissions from the project will be approximately centered at the following location: 399,383 meters Easting, 4,809,765 meters Northing, in Zone 10, NAD83.

The following liquefaction facilities are proposed for the Project:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/day;
- Refrigerant storage and resupply system; and
- Aerial Cooling System (Fin-Fan) to reject heat removed during the natural gas liquefaction process.

Associated with the LNG Terminal Project is a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant, the South Dunes Power Plant, which will be used to power the natural gas liquefaction process systems.

The South Dunes Power Plant will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is less than 1.00 grains/100 SCF). Each will be equipped with a natural gas-fired duct burner for supplementary firing and two steam turbine generators (STGs). Emissions from the six combined cycle units will be controlled by the use of dry low-NO_x burner technology and SCR for NO_x control, an oxidation catalyst for CO and VOC control, and the use of clean low-sulfur fuels only (i.e., natural gas) to minimize emissions of SO_2, PM/PM-10/PM-2.5, and H_2SO_4. Exhaust gases from the combined cycle units after emission controls will be dispersed to the atmosphere via individual stacks.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Trace amounts of hydrogen sulfide are removed as well in the CO_2 removal system, due to the characteristics of the absorbent. The gas conditioning trains consist of two parallel trains, each containing two systems in series: a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas (hydrogen sulfide) from the Amine Stripper will be sent to a waste gas incinerator (i.e., thermal oxidizer) in order to oxidize sulfur components.

Estimated potential short-term (24-hour) maximum emissions and annual emissions from the combined cycle units and waste gas incinerator are presented in Table 1. The PM-10 emission rates presented in Table 1 include filterable and condensable particulates.

Table 1: Estimated Potential Emissions

Pollutant	Combustion Turbine/Duct Burner Maximum Short-Term Emissions[1] (lb/hr)	Waste Gas Incinerator Maximum Short-Term Emissions (lb/hr)	Annual Emissions[2] (tpy)
Nitrogen Oxides (NO_x)	4.2	13.3	164.8
Sulfur Dioxide (SO_2)	1.8	79.2	393.2
Particulate Matter with an aerodynamic diameter less than 10 microns (PM-10)	8.8	0.55	184.6
Sulfuric Acid Mist (H_2SO_4)	2.5	NA	56.5

[1] Maximum short-term emission rates based on single combustion turbine operating at the maximum combined emission rate conditions across (12) different load combinations. Emission rates for natural gas firing include maximum proposed level of duct firing.
[2] Annual emissions based on six combustion turbines each operating up to 8,760 hours per year (hr/yr) on natural gas firing at average temperature conditions (55°F) with duct firing occurring for 4,000 of those hours.

Class I areas within 200 kilometers of the proposed Project include:

Crater Lake National Park (Oregon) .... 165 kilometers
Redwood National Park (California) .... 177 kilometers

Kalmiopsis Wilderness Area (Oregon) .... 110 kilometers
Diamond Peak Wilderness Area (Oregon) .... 164 kilometers
Three Sisters Wilderness Area (Oregon) .... 184 kilometers

Following the Draft Revised Federal Land Managers' Air Quality Related Values (AQRVs) Workgroup (FLAG) guidance (October 2010), we believe that this Project is eligible for an exemption from the requirement to perform a Class I area modeling analysis for AQRVs and visibility because of its inherent low emissions and distance to Class I areas.

We understand that the maximum short-term emission rates are used in the exemption analysis even if annual emissions are limited. Assuming full year operation (8,760 hours) of the six turbines at the maximum emitting load, the resulting annual emissions of NOx, SO2, PM-10, and H_2SO_4 would be equal to (4.2 + 1.8 + 8.8+ 2.5) lb/hr x 8760 hr/yr x ton/2000 lb x 6 units= 454.6 tons. Also assuming full year operation of the waste gas incinerator at maximum flow the resulting annual emissions of NO_x, SO_2, PM-10, and H_2SO_4 would be equal to (13.3 + 79.2 + 0.55+ 0.0) lb/hr x 8760 hr/yr x ton/2000 lb x 1 unit= 407.7 tons. The resulting ratio of emissions in tpy to distance in km ("Q/D") for each of the Class I areas is shown below based upon a Q of 862.3 tons.

Class I Area	Q/D Ratio
Crater Lake National Park (Oregon)	5.2
Redwood National Park (California)	4.9
Kalmiopsis Wilderness Area (Oregon)	7.8
Diamond Peak Wilderness Area (Oregon)	5.3
Three Sisters Wilderness Area (Oregon)	4.7

Our understanding of the draft revised FLAG guidance is that a Project with a Q/D ratio of ≤ 10 is considered to have negligible impacts on AQRVs and is exempt from any additional Class I impact or AQRV analysis. The Q/D ratios calculated for the Project at each of the five Class I areas are all less than 10. Therefore, we believe that this project qualifies for an exemption from Class I modeling impact requirements.

With this letter, JCEP is formally requesting an exemption on the need for refined Class I area air quality and AQRV analyses for the five nearby Class I areas based on the potential emissions presented herein. If you should require additional information on the proposed project or have any questions, please do not hesitate to contact me at (201) 508-6964.

Sincerely,

TRC

Darin Ometz

Darin Ometz
Senior Consulting Meteorologist

TRC

cc: Phil Allen, ODEQ
Tom Peterson, ODEQ
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January 28, 2013

Mr. Phil Allen
Oregon Department of Environmental Quality
Air Quality Division
811 SW Sixth Avenue
Portland, OR 97204

**Subject: Jordan Cove Energy Project, L.P.
Coos Bay, Coos County, Oregon
Request for Waiver from Pre-Construction Ambient Air Quality Monitoring**

Dear Mr. Allen:

This letter serves as a formal request on behalf of Jordan Cove Energy Project, L.P. (JCEP) for an exemption from the requirement to perform one year of pre-construction ambient air quality monitoring for the proposed LNG export facility to be constructed in Coos Bay, Coos County, Oregon. This exemption is requested in accordance with Prevention of Significant Deterioration (PSD) of Air Quality regulations promulgated under 40 CFR 52 by the United States Environmental Protection Agency (U.S. EPA). Those regulations state that major new or modified facilities having annual emissions of regulated air pollutants in excess of the significant emission rates (SERs) defined in the PSD regulations must perform an air quality analysis for these pollutants which can include collection of one year of on-site ambient air quality data. Pursuant to 40 CFR 52.21, a waiver from pre-construction ambient air quality monitoring may be granted if one of the following can be demonstrated:

- The proposed facility ambient air quality impacts are less than the significant monitoring concentrations specified in 40 CFR 52.21, or
- Existing quality assured ambient air quality data are available from alternate locations that are representative of, or conservative, as compared to conditions at the proposed facility location.

This requirement does not apply to emitted pollutants for which the area in which the source is locating is designated as non-attainment and for which it is subject to Non-Attainment New Source Review (NNSR). Supporting documentation for this waiver request is presented herein.

Project Description

The Project will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The LNG terminal will be capable of loading LNG ships ranging in capacity from 89,000 cubic meters (m^3) to 160,000 m^3. Approximately 90 ships per year are anticipated to call on the LNG terminal. The LNG loaded onto the ships will be transferred by cryogenic service piping from two 160,000 m^3 (1,006,000 barrels) full-containment LNG storage tanks where it will be stored in a liquefied state until it is pumped out to the LNG vessels. The following liquefaction facilities are proposed for the Project:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 billion standard cubic feet per day (Bscf/d);
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

Because the proposed facility is located in an attainment area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and particulate matter with an aerodynamic diameter less than 10 micrometers (μm) (PM-10) and 2.5 micrometers (μm) (PM-2.5) and will potentially emit more than 100 tons per year of several air pollutants, it will be subject to Prevention of Significant Deterioration (PSD) permitting.

The project will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF), which will be equipped with a natural gas-fired duct burner for supplementary firing and two steam turbine generators (STGs). By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Power Plant) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Power Plant).

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Trace amounts of hydrogen sulfide are removed as well in the CO_2 removal system, due to the characteristics of the absorbent. The gas conditioning trains consist of two parallel trains, each containing two systems in series: a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 million standard cubic feet per day (MMscf/day) of natural gas. Acid gas from the Amine Stripper will be sent to a waste gas incinerator in order to oxidize sulfur components.

Facility Emissions

Under PSD regulations, an air quality dispersion modeling analysis will be required to ensure that CO, PM-10, PM-2.5, SO_2, and NO_2 emissions from the proposed facility will be compliant with National Ambient Air Quality Standards (NAAQS) and applicable PSD increments.

Table 1 presents projected potential facility emission rates and the pollutant specific significant emission rates (SERs) defined in the PSD regulations. A review of the table indicates that the proposed facility is projected to have annual emissions in excess of PSD SERs for CO, NO_x, SO_2, particulates (PM/PM-10/PM-2.5), the ozone precursor VOC, and sulfuric acid mist (H_2SO_4). Thus, the potential for ambient preconstruction monitoring must be addressed for these pollutants. Emissions of lead are below the respective SERs. Further, since there are no approved ambient monitoring techniques for H_2SO_4, an exemption from monitoring is requested for that pollutant.

Background Ambient Air Quality Data

Pursuant to PSD regulations, the Oregon Department of Environmental Quality (ODEQ) may exempt a proposed PSD source from the one-year preconstruction ambient monitoring program requirement if the source can demonstrate through dispersion modeling that air quality impacts from the proposed facility will be below the significant monitoring (or *de minimis*) concentrations (SMCs) established by U.S. EPA and included in the regulations under 40 CFR 52.21 (i)(5)(i). In addition, a monitoring exemption can be requested based upon existing quality assured ambient air quality data that are available from alternate locations and are representative of, or conservative, as compared to conditions at the proposed facility location.

Based on review of the locations of Oregon Department of Environmental Quality (ODEQ) ambient air quality monitoring sites, the closest monitoring sites were used to represent the current background air quality in the site area.

Representative background data for CO was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0013), approximately 117 km northeast of the proposed facility. The monitor is located at Lane Community College at 1059 Willamette, approximately at 44.047896 North Latitude, 123.092049 West Longitude, in a commercial/suburban area.

Representative background data for PM-10 was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0058), approximately 113 km northeast of the proposed facility. The monitor is located at 450 Pacific Highway North, approximately at 44.066304 North Latitude, 123.139831 West Longitude, in a residential/suburban area. Background data for PM-2.5 was obtained from the Cottage Grove station located in Lane County, Oregon (EPA AIRData # 41-039-9004), and approximately 103 km east-northeast of the proposed facility. The monitor is located at 425 N. 14th Cottage Grove City Shops, approximately at 43.799570 North Latitude, 123.053490 West Longitude, in a residential/suburban area.

Representative background data for NO_2 and SO_2 was obtained from the Portland monitoring station located in Multnomah County, Oregon (EPA AIRData # 41-051-0080), and approximately 265 km north-northeast of the proposed facility. The monitor is located at 5824

SE Lafayette, approximately at 45.966667 North Latitude, 122.602222 West Longitude, in a residential/suburban area.

The monitoring data for the most recent three years (2009-2011) are presented in Table 2. Annual potential emissions of the ozone precursor VOC exceed the SER. However, no *de minimis* air quality level is provided for ozone. There is also not an established ambient air quality standard or PSD increment for direct emissions of this pollutant. For these reasons, preconstruction ambient air quality monitoring for direct emissions of VOC does not apply.

Modeled Ambient Air Quality Impacts

As discussed earlier, an applicant may also request an exemption from the requirement to perform preconstruction ambient air quality monitoring if it can be demonstrated that its air quality impacts will be less than the significant monitoring concentrations (SMCs) per 40 CFR 52.21(i)(5)(i) and identified in Table 3. The maximum modeled impacts from the proposed JCEP have been determined and Table 3 provides a summary of those impacts along with comparisons to the SMCs. The maximum modeled impacts were determined based upon the procedures described in the modeling protocol submitted to you on November 28 ,2012 and approved on January 23, 2013.

As shown on the table the maximum modeled impacts for CO, PM-10, SO_2 and NO_x are all below the corresponding SMCs. Note that the SMC for PM-2.5 has been vacated in a January 22, 2013 ruling from the DC Circuit Court of Appeals on *Sierra Club vs. United States Environmental Protection Agency.*

Monitoring Waiver Request

In summary, JCEP is requesting an exemption from the need to perform preconstruction ambient monitoring for lead, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds because they will be emitted in amounts less than their SERs; for fluorides because they are not anticipated as a product of natural gas combustion or processing and for H_2SO_4 because there is no approved monitoring technique available.

Further, JCEP is requesting an exemption from the need to perform preconstruction ambient air quality monitoring for CO, NO_2, SO_2 and PM-10/PM-2.5 on the basis that existing quality assured ambient air quality data is available from alternate locations that are representative or conservative, as compared to conditions at the proposed facility location. In addition, JCEP is also requesting an exemption from the need to perform preconstruction ambient air quality monitoring for CO, SO_2, PM-10, and NO_x based upon the demonstration that maximum modeled ambient air quality impacts are less than the SMCs for these pollutants.

Please feel free to contact me at (201) 508-6964 or Ted Main at (201) 508-6960 should you have any questions regarding this monitoring exemption request.

Sincerely,

TRC

Darin Ometz

Darin Ometz
Senior Consulting Meteorologist

Attachments: Tables 1, 2, and 3

cc: M. Abts, ODEQ
S. Lazarev, ODEQ
J. Stocum, ODEQ
T. Peterson, ODEQ
T. Kubo, U.S. EPA
H. Wong, U.S. EPA
T. Main, TRC
B. Floyd, TRC
B. Braddock, JCEP

TABLE 1: JORDAN COVE ENERGY PROJECT, L.P. COMPARISON OF PROJECTED FACILITY EMISSIONS TO PSD SIGNIFICANT EMISSION RATES

Pollutant	Preliminary Emission Rate (tons per year)	PSD Significant Emission Rate (tons per year)
Carbon Monoxide	156.2	100
Sulfur Dioxide	380.1	40
Particulate Matter (PM)	185.0	25
Particulate Matter less than 10 microns (PM-10)	185.0	15
Particulate Matter less than 2.5 microns (PM-2.5)	185.0	10
Nitrogen Oxides	221.2	40
Ozone (VOC)	207.5	40
Lead	0.008	0.6
Fluorides[a]	N/A	3
Sulfuric Acid Mist[b]	56.5	7
Hydrogen Sulfide	<1	10
Total Reduced Sulfur (including H_2S)	<1	10
Reduced Sulfur Compounds (including H_2S)	<1	10

[a] Not anticipated as a product of natural gas combustion or processing or fuel oil combustion (i.e., emergency diesel generators and diesel fire pumps).

[b] No acceptable monitoring techniques exist for this pollutant.

TABLE 2: JCEP FACILITY AMBIENT CONCENTRATIONS OF CRITERIA POLLUTANTS PROPOSED TO BE USED TO REPRESENT SITE CONDITIONS

Pollutant	Averaging Period	Maximum Ambient Concentrations ($\mu g/m^3$)			NAAQS ($\mu g/m^3$)
		2009	2010	2011	
SO_2	1-Hour[a]	23.6	21.0	23.6	197
	3-Hour	**21.0**	21.0	15.7	1,300
	24-Hour	**10.5**	8.7	7.9	365
	Annual	**4.2**	3.7	NA	80
NO_2	1-Hour[b]	75.2	62.0	62.0	188
	Annual	**19**	17	17	100
CO	1-Hour	**2,415**	2,185	NA	40,000
	8-Hour	**1,840**	1,495	NA	10,000
PM-10	24-Hour	**55**	41	38	150
PM-2.5[c]	24-Hour	30	18	21	35
	Annual	8.5	6.9	7.1	12

[a]1-hour 3-year average 99th percentile value for SO_2 is **22.7** ug/m3.

[b]1-hour 3-year average 98th percentile value for NO_2 is **66.4** ug/m3.

[c]24-hour 3-year average 98th percentile value for PM-2.5 is **23.0** ug/m3; Annual 3-year average value for PM-2.5 is **7.5** ug/m3.

High second-high short term (1-, 3-, 8-, and 24-hour) and maximum annual average concentrations presented for all pollutants other than PM-2.5 and 1-hour SO_2 and NO_2.

Bold values represent the proposed background values for use in any necessary NAAQS analyses.

Monitored background concentrations obtained from the U.S. EPA AIRData and Oregon DEQ Air Quality Reports for 2009-2011.

TABLE 3: JCEP FACILITY MAXIMUM MODELED AMBIENT AIR QUALITY IMPACTS WITH COMPARISON TO SMCS

Pollutant	Averaging Period	Significant Monitoring Concentration ($\mu g/m^3$)	Maximum Modeled Concentration ($\mu g/m^3$)
CO	8-Hour	575	73.1
SO_2	24-Hour	13	12.5
PM-10	24-Hour	10	9.3
NO_x	Annual	14	0.7

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November 28, 2012

Mr. Phil Allen
Oregon Department of Environmental Quality
Air Quality Division
811 SW Sixth Avenue
Portland, OR 97204

Subject: Jordan Cove Energy Project, L.P.
Coos Bay, Coos County, Oregon
Atmospheric Dispersion Modeling Protocol

Dear Mr. Allen:

Enclosed please find two (2) copies of the atmospheric dispersion modeling protocol for the proposed Jordan Cove Energy Project, L.P. (i.e., the Project) LNG export facility to be constructed in Coos Bay, Coos County, Oregon. The Project will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum of LNG. The enclosed protocol contains a project and site description and a preliminary site plan. The protocol also contains a detailed description of the modeling methodology proposed for the air quality impact analysis to be included in the PSD permit application to be submitted for the proposed facility.

The following liquefaction facilities are proposed for the Project:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/d;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

Certain information included in this document warrants special treatment under 18 C.F.R. §388.112. Figures 3-1 and 3-2 are Facility Site Plans that contain Critical Energy Infrastructure Information (CEII) as defined in 18 C.F.R. §388.113(c). More specifically, this schematic relates details about the storage of energy that could be useful to a person in planning an attack on critical infrastructure and does not simply give the general location of that critical infrastructure; it would be exempt from mandatory disclosure (5 U.S. C. §552(b)(1)). JCEP requests treatment as CEII of this material, which has been marked "Critical Energy Infrastructure Information."

Please feel free to contact me at 201 508-6964 should you have any questions regarding the enclosed protocol. We look forward to working with you on this project.

Sincerely,

TRC

Darin Ometz

Darin Ometz
Senior Air Quality Consultant

Attachment

cc: Tom Peterson, ODEQ - Medford
Bob Braddock, JCEP
T. Main, TRC
B. Floyd, TRC

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Oregon Fish and Wildlife Office
2600 SE 98th Avenue, Suite 100
Portland, Oregon 97266
Phone: (503) 231-6179 FAX: (503) 231-6195

January 26, 2013

Subject: Lists of threatened and endangered species that may occur in selected Oregon counties

To Whom It May Concern:

This letter accompanies a species list(s) downloaded from our website (http://www.fws.gov/oregonfwo/Species/Lists/RequestList.asp), which shows threatened and endangered species that may occur within the area of your proposed project. The species list(s) fulfills the requirement of the U.S. Fish and Wildlife Service (Service) under section 7(c) of the Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 *et seq.*).

The purpose of the Act is to provide a means whereby threatened and endangered species and the ecosystems on which they depend may be conserved. Under section 7(a)(1) and 7(a)(2) of the Act and pursuant to 50 CFR 402 *et seq*., Federal agencies are required to utilize their authorities to carry out programs which further species conservation and to determine whether projects may affect threatened and endangered species, and/or designated critical habitat. A Biological Assessment is required for construction projects (or other undertakings having similar physical impacts) that are major Federal actions significantly affecting the quality of the human environment as defined in the National Environmental Policy Act (NEPA) (42 U.S.C. 4332 (2)(c)). For projects other than major construction activities, the Service suggests that a biological evaluation similar to the Biological Assessment be prepared to determine whether they may affect listed and proposed species or critical habitats. Recommended contents of a Biological Assessment are described in Enclosure A, as well as 50 CFR 402.12.

If a Federal agency determines, based on the Biological Assessment or biological evaluation, that threatened and endangered species and/or designated critical habitat may be affected by the project, the agency is required to consult with the Service following the requirements of the regulations that implement the Act (50 CFR 402).

The county species list(s) includes a list of candidate species under review for listing and those species that the Service considers "species of concern." Candidate species have no protection under the Act but are included for consideration as it is possible candidates could be listed prior to the completion of your project. Species of concern are those taxa whose conservation status is of concern to the Service (many previously known as Category 2 candidates), but for which further information is still needed.

If a proposed project may affect only candidate species or species of concern, you are not required to perform a Biological Assessment or evaluation or consult with the Service. However, the Service recommends minimizing impacts to these species to the extent possible in order to prevent potential future conflicts. Therefore, if early evaluation of the project indicates that it is likely to adversely impact a candidate species or species of concern, your agency may wish to request technical assistance from this office.

If your project includes communications or cell towers, you should be aware that migratory birds, another of our Trust Resources, can suffer significant mortality from collisions with towers. Further information on this issue can be obtained from the following web sites: http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/towers.htm and http://www.towerkill.com. Please refer to the recently approved Service Guidance on the Siting, Construction, Operation and Decommissioning of Communications Towers (http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/comtow.html). We recommend its application to relevant projects. We also recommend the tower site evaluation form (found on the guidance webpage), which you may find useful in helping to determine the effects of your proposed project to endangered species and migratory birds.

The bald eagle (*Haliaeetus leucocephalus*) has recovered and was removed from the Federal List of Endangered and Threatened Wildlife and Plants in 2007. The bald eagle occurs in all Oregon counties, and the species continues to be protected under the Bald and Golden Eagle Protection Act. For more information on bald eagles, and for the Service's "National Bald Eagle Management Guidelines," please visit the Service's regional webpage devoted to the bald eagle (http://www.fws.gov/pacific/eagle/).

We appreciate your concern for threatened and endangered species. The Service encourages Federal agencies to investigate opportunities for incorporating conservation of threatened and endangered species into project planning processes as a means of complying with the Act. Please include a copy of this letter and any species lists downloaded from our website with any request for consultation or correspondence about your project that you submit to our office. If you have questions regarding your responsibilities under the Act, please contact Cat Brown at (503) 231-6179. For questions regarding listed salmon and steelhead trout, please contact NOAA Fisheries Service, 525 NE Oregon Street, Suite 500, Portland, Oregon 97232, (503) 230-5400.

Enclosure A

ENCLOSURE A

RESPONSIBILITIES OF FEDERAL AGENCIES UNDER SECTION 7(a) and (c) OF THE ENDANGERED SPECIES ACT

SECTION 7(a) Consultation/Conference

Section 7(a) of the Act requires:

1. Federal agencies to utilize their authorities to carry out programs to conserve endangered and threatened species;
2. Consultation with the U.S. Fish and Wildlife Service (Service) when a Federal action may affect a listed endangered or threatened species or designated critical habitat to insure that any action authorized, funded or carried out by a Federal agency is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. The process is initiated by the Federal agency after it has determined if its action may affect a listed species; and
3. Conference with the Service when a Federal action is likely to jeopardize the continued existence of a proposed species or result in destruction or adverse modification of proposed critical habitat.

SECTION 7(c) Preparation of a Biological Assessment

Section 7(c) of the Act requires Federal agencies or their designees to prepare a Biological Assessment (BA) for construction projects.[1] For actions that are not construction projects, we recommend that a biological evaluation similar to a BA be prepared to evaluate the effects of the proposed project on listed and proposed species and critical habitats. The purpose of the BA or biological evaluation is to identify listed and proposed species which are likely to be affected by a proposed project. The process is initiated by a Federal agency by requesting a list of threatened and endangered species and critical habitats. The BA or biological evaluation should be completed within 180 days after its initiation (or within such a time period as is mutually agreeable). If the BA is not initiated within 90 days of receipt of the species list, the accuracy of the species list should be informally verified with the Service. No irreversible commitment of resources is to be made during the preparation of the BA which would foreclose reasonable and prudent alternatives to jeopardy to listed species. Planning, design, and administrative actions may be taken; however, no construction may begin.

A biological assessment or biological evaluation should include the following information:

1. Description of proposed action (project).
Describe the following and attach any relevant maps, diagrams, or designs;

- **Who** is proposing the action?
- **Where** is the action? Be as specific as possible. Include maps, county, township, range, stream, and any other pertinent information.
- **What** is the proposed action? Describe what is planned, the objectives of the action, include designs, diagrams, and best management practices applied, etc.
- **How** is the action going to be implemented? Give specific details, such as what type

[1] A construction project (or other undertaking having similar physical impacts) is a major Federal action significantly affecting the quality of the human environment as referred to in NEPA (42 U.S.C. 4332. (2)c.

of equipment is used, how the action area will be accessed, etc.
- **When** will the action be implemented?

2. Description of listed and proposed species and critical habitat, status, distribution and habitat use by the species in the project area.

Identify which listed, proposed and candidate species and critical habitats may potentially be affected (beneficially or adversely) by the action. Describe how the species use the project area. Assistance with this information can be obtained from local offices of the Service.

3. Description of the action area.

Describe all areas affected by the proposed project. The action area refers to the area directly or indirectly affected by the proposed action; this area will usually be larger than the project footprint. Include on-site inspection or survey data, views of recognized experts (e.g., ODFW), and literature reviews.

4. Effects of the proposed action on listed and proposed species and designated or proposed critical habitat.

Describe in detail the effects of the action on the species and their habitats including direct and indirect effects, as well as effects that are interrelated and interdependent effects. Summarize your analysis of all project effects.

5. Description of measures to minimize effects to listed species, and proposed project monitoring.

Describe methods to be used to avoid, minimize and correct adverse short and long-term effects. Describe what will be monitored, who will monitor and the frequency of monitoring.

6. Determination of effect.

Clearly state your final effects determination for each listed and proposed species and designated and proposed critical habitat. Effects determinations may be:
- no effect
- may affect, not likely to adversely affect (appropriate for actions that have only beneficial, insignificant, or discountable effects)
- may affect, likely to adversely affect (appropriate for actions with effects to listed species or designated critical habitat that are not entirely insignificant, discountable or wholly beneficial)

7. Attachments.

Attachments should include all relevant information supporting the above categories such as maps, project design, drawings, specifications, pollution control plan, photos of project site and adjacent area, site survey data, and literature cited.

For more information on consultation under section 7 of the Endangered Species Act, visit the Service's national consultation website at http://www.fws.gov/endangered/what-we-do/consultations-overview.html.

FEDERALLY LISTED, PROPOSED, CANDIDATE SPECIES AND SPECIES OF CONCERN UNDER THE JURISDICTION OF THE FISH AND WILDLIFE SERVICE WHICH MAY OCCUR WITHIN COOS COUNTY, OREGON

LISTED SPECIES

Birds

Marbled murrelet	*Brachyramphus marmoratus*	CH T
Western snowy (coastal) plover	*Charadrius alexandrinus nivosus*	CH T
Short-tailed albatross	*Phoebastria albatrus*	E
Northern spotted owl	*Strix occidentalis caurina*	CH T

Reptiles and Amphibians

Marine:

Loggerhead sea turtle	*Caretta caretta*	E
Green sea turtle	*Chelonia mydas*	T
Leatherback sea turtle	*Dermochelys coriacea*	E
Olive (=Pacific) ridley sea turtle	*Lepidochelys olivacea*	T

Plants

Western lily	*Lilium occidentale*	E

PROPOSED SPECIES

None

No Proposed Endangered Species	PE
No Proposed Threatened Species	PT

SPECIES OF CONCERN

Mammals

White-footed vole	*Arborimus albipes*
Townsend's western big-eared bat	*Corynorhinus townsendii townsendii*
Silver-haired bat	*Lasionycteris noctivagans*
Long-eared myotis bat	*Myotis evotis*
Fringed myotis bat	*Myotis thysanodes*
Long-legged myotis bat	*Myotis volans*
Yuma myotis bat	*Myotis yumanensis*

Birds

Northern goshawk	*Accipiter gentilis*
Upland sandpiper	*Bartramia longicauda*
Olive-sided flycatcher	*Contopus cooperi*
Black oystercatcher	*Haematopus bachmani*
Harlequin duck	*Histrionicus histrionicus*
Yellow-breasted chat	*Icteria virens*
Acorn woodpecker	*Melanerpes formicivorus*
Lewis' woodpecker	*Melanerpes lewis*
Mountain quail	*Oreortyx pictus*
Band-tailed pigeon	*Patagioenas fasciata*
Oregon vesper sparrow	*Pooecetes gramineus affinis*

Purple martin	*Progne subis*

Reptiles and Amphibians

Northern Pacific pond turtle	*Actinemys marmorata marmorata*
Coastal tailed frog	*Ascaphus truei*
Del Norte salamander	*Plethodon elongatus*
Northern red-legged frog	*Rana aurora aurora*
Foothill yellow-legged frog	*Rana boylii*
Southern torrent (seep) salamander	*Rhyacotriton variegatus*

Fish

River lamprey	*Lampetra ayresi*
Pacific lamprey	*Lampetra tridentata*
Coastal cutthroat trout	*Oncorhynchus clarki ssp*
Millicoma dace	*Rhinichthys cataractae ssp.*

Invertebrates

Snails:

Newcomb's littorine snail	*Algamorda newcombiana*

Clams:

California floater mussel	*Anodonta californiensis*

Plants

Pink sand-verbena	*Abronia umbellata ssp. breviflora*
Bensoniella	*Bensoniella oregona*
Pt. Reyes bird's-beak	*Cordylanthus maritimus ssp. palustris*
Frye's Limbella	*Limbella fryei*
Silvery phacelia	*Phacelia argentea*
Coast checkermallow	*Sidalcea malviflora ssp. patula*
Leach's brodiaea	*Triteleia hendersonii var. leachiae*

DELISTED SPECIES

Birds

Aleutian Canada goose	*Branta canadensis leucopareia*
American Peregrine falcon	*Falco peregrinus anatum*
Bald eagle	*Haliaeetus leucocephalus*
Brown pelican	*Pelecanus occidentalis*

Definitions:

Listed Species: 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 become endangered in the foreseeable future.

Proposed Species: Taxa for which the Fish and Wildlife Service or National Marine Fisheries Service has published a proposal to list as endangered or threatened in the Federal Register.

Candidate Species: Taxa for which the Fish and Wildlife Service has sufficient biological information to support a proposal to list as endangered or threatened.

FEDERALLY LISTED, PROPOSED, CANDIDATE SPECIES AND SPECIES OF CONCERN UNDER THE JURISDICTION OF THE FISH AND WILDLIFE SERVICE WHICH MAY OCCUR WITHIN COOS COUNTY, OREGON

Species of Concern: Taxa whose conservation status is of concern to the U.S. Fish and Wildlife Service (many previously known as Category 2 candidates), but for which further information is still needed. Such species receive no legal protection and use of the term does not necessarily imply that a species will eventually be proposed for listing.

Delisted Species: A species that has been removed from the Federal list of endangered and threatened wildlife and plants.

Key:

E	Endangered
T	Threatened
CH	Critical Habitat has been designated for this species
PE	Proposed Endangered
PT	Proposed Threatened
PCH	Critical Habitat has been proposed for this species

Notes:

Marine & Anadromous Species: Please consult the National Marine Fisheries Service (NMFS) (http://www.nmfs.noaa.gov/pr/species/) for marine and anadromous species. The National Marine Fisheries Service (NMFS) manages mostly marine and anadromous species, while the U.S. Fish and Wildlife Service manages the remainder of the listed species, mostly terrestrial and freshwater species.

Marine Turtle Conservation and Management: All six species of sea turtles occurring in the U.S. are protected under the Endangered Species Act of 1973. In 1977, NOAA Fisheries and the U.S. Fish and Wildlife Service signed a Memorandum of Understanding to jointly administer the Endangered Species Act with respect to marine turtles. NOAA Fisheries has the lead responsibility for the conservation and recovery of sea turtles in the marine environment and the U.S. Fish and Wildlife Service has the lead for the conservation and recovery of sea turtles on nesting beaches. For more information, see the NOAA Fisheries webpage on sea turtles http://www.nmfs.noaa.gov/pr/species/turtles/.

Gray Wolf: In 2008, the Service published a final rule that established a distinct population segment of the gray wolf (*Canis lupis*) in the northern Rocky Mountains (which includes a portion of Eastern Oregon, east of the centerline of Highway 395 and Highway 78 north of Burns Junction and that portion of Oregon east of the centerline of Highway 95 south of Burns Junction). Any wolves found west of this line in Oregon belong to the conterminous USA population [see 73 FR 10514]. On May 5, 2011, the Fish and Wildlife Service published a final rule – as directed by legislative language in the Fiscal Year 2011 appropriations bill – reinstating the Service's 2009 decision to delist biologically recovered gray wolf populations in the Northern Rocky Mountains. Gray wolves in Oregon are State-listed as endangered, regardless of location.

Appendix E
Air Quality Modeling Protocol

Jordan Cove Energy Project, L.P.

Air Quality Modeling Protocol

Prepared for

Oregon Department of Environmental Quality

Prepared by

TRC Environmental
Lyndhurst, NJ

November 2012

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1.0 INTRODUCTION

Jordan Cove Energy Project L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal on an approximate 168-acre site located on the bay side of the North Spit of Coos Bay, Oregon between Coos Bay Navigation Channel Miles (CM) 7.0 and 8.0. The project, known as the Jordan Cove Energy Project (JCEP), or Project (or Facility) will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum of LNG. The LNG terminal will be capable of loading LNG ships ranging in capacity from 89,000 cubic meters (m^3) to 160,000 m^3. Approximately 90 ships per year are anticipated to call on the LNG terminal. The LNG loaded onto the ships will be transferred by cryogenic service piping from two 160,000 m^3 (1,006,000 barrels) full-containment LNG storage tanks where it will be stored in a liquefied state until it is pumped out to the LNG vessels. The following liquefaction facilities are proposed for the Project:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bscf/d;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

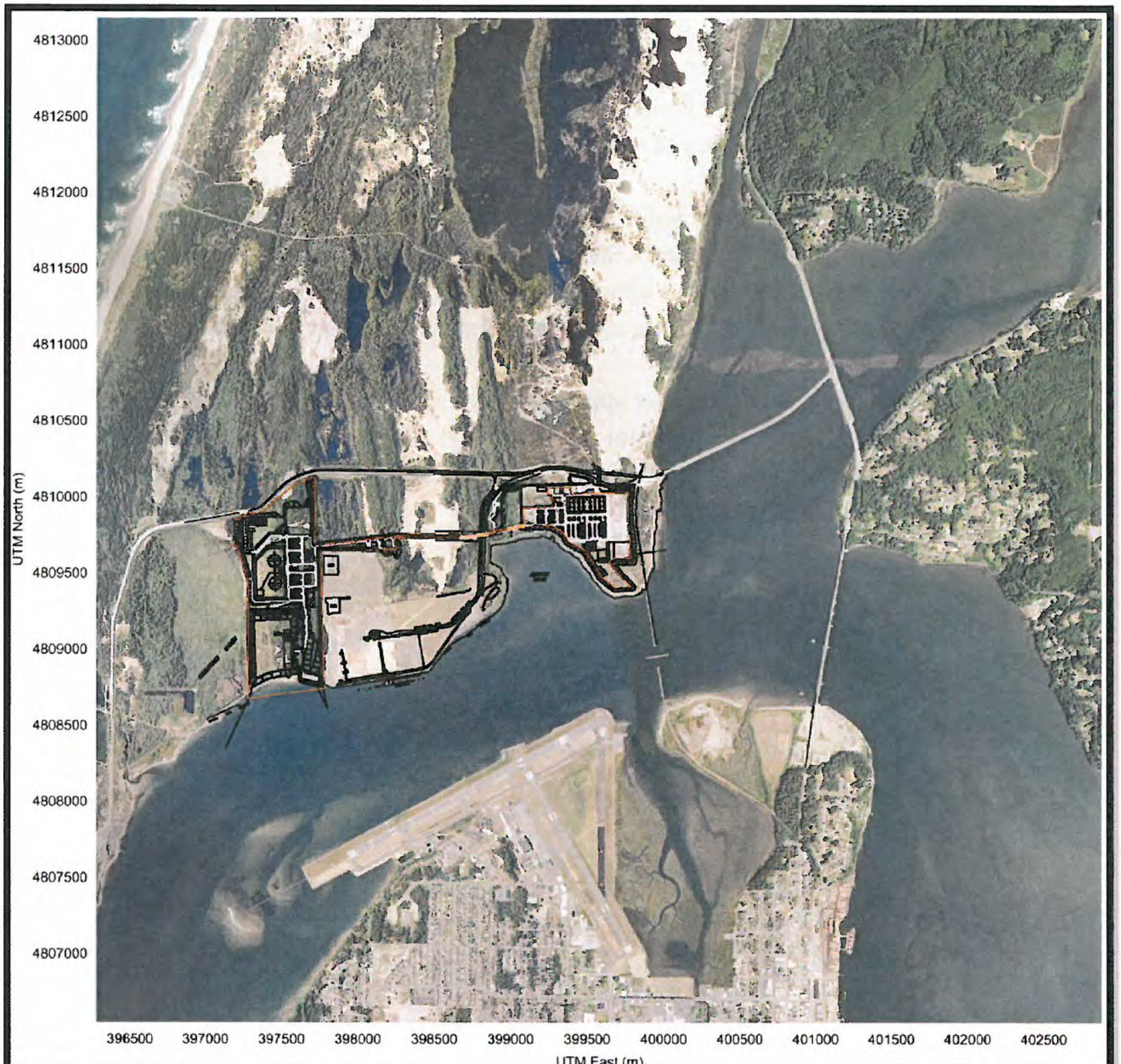
There are two sites to be referenced within this one facility. The first is the Liquefaction site, which contains the four (4) Liquefaction trains, two (2) LNG full containment tanks, and the marine berthing and load-out facilities. The second area is referred to as the South Dunes Power Station site which contains two gas pre-treatment trains, the South Dunes Power Plant, and the common infrastructure for the plant entrance and administration buildings. Figure 1-1 shows the location of the proposed facility equipment and the surrounding area.

Because the proposed facility is located in an attainment area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and particulate matter with an aerodynamic diameter less than 10 micrometers (μm) (PM-10) and 2.5 micrometers (PM-2.5) and will potentially emit more than 100 tons per year of several air pollutants, it will be subject to federal Prevention of Significant Deterioration (PSD) permitting. It is expected that emissions of nitrogen oxides (NO_x), ozone (as volatile organic compound (VOC)), PM-10, PM-2.5, and CO will exceed the pollutant specific PSD significant emission rates (SER) and, consequently, an air dispersion modeling analysis will be required for these pollutants.

Based upon preliminary emission calculations for the project sources, facility emissions will be greater than 100 tons per year for criteria air pollutants and thus, the project will require an Oregon DEQ Air Contaminant Discharge Permit (ACDP). The project will be designed with criteria pollutant emissions above federal Prevention of Significant Deterioration applicability thresholds and thus, federal major source PSD rules will also apply. The Plant Site Emission Limits (PSELs) shown in Table 1 will exceed the Significant Emission Rates established in Oregon Administrative Rules OAR 340-200-0020 for NOx, CO, SO_2, and PM/PM-10/PM-2.5 and therefore an air quality modeling analysis is required to show that no National Ambient Air Quality Standards (NAAQS) or PSD Increments will be violated in accordance with OAR 340-222-0041(3)(b)(c). As part of the modeling assessment, this modeling protocol has been prepared to detail the techniques that are proposed in completing the NAAQS and PSD Increments air quality evaluation.

The air quality analysis will be required to demonstrate that the proposed facility will be compliant with all applicable PSD increment levels and National Ambient Air Quality Standards (NAAQS). Initially, the air quality impact of the proposed facility will be modeled using potential emission rates to determine if the facility will yield significant air quality impacts (i.e., maximum modeled concentrations are greater than the PSD significant impact concentrations). The significance modeling will be performed for multiple combustion turbine operating loads. The pollutant-specific "worst-case" operating scenario determined from the significance modeling analysis will be used in all subsequent modeling, including any PSD increment and multiple offsite source NAAQS analyses, if necessary.

Figure 1-1: Site Location Map



2.0 AREA DESCRIPTION

The area surrounding the facility (within 3 kilometers) consists mainly of forested areas, sand dunes, and water bodies to the east, north, and west of the site with some industrial use along the bay to the south. The residential area of North Bend as well as North Bend Municipal Airport (currently known as the Southwest Oregon Regional Airport) is located to the south of the facility. Approximately 90% of the land uses within 3 kilometers of the facility consist of water, forest/undeveloped areas and sand dunes.

The graded elevation of the proposed facility site will vary from 30 to 60 feet above mean sea level (MSL). Topography proximate of the facility is relatively flat with elevations ranging from MSL to 160 feet above MSL within 1 kilometer of the site. To the east of the site lies some rolling terrain with hill top elevations ranging up to approximately 600 feet above MSL.

The proposed facility will be located at approximately 43.434024 North Latitude, 124.243219 West Longitude, North American Datum 1983 (NAD83). The approximate Universal Transverse Mercator (UTM) coordinates of the proposed facility are 399,383 meters Easting, 4,809,765 meters Northing, in Zone 10, NAD83.

3.0 FACILITY DESCRIPTION

The information contained in this section provides an overview of the equipment, operations, stack parameters, and emission rates for the proposed Project. Equipment specific parameters are presented based upon preliminary design since final equipment design has not been completed for the Project. Information presented in this section will be included and revised if appropriate in the PSD/ACDP permit application, and any changes that have been made will be reflected in the application. In addition, greater detail specific to equipment descriptions and manufacturer specifications will be provided in the PSD/ACDP permit application. Therefore, the PSD/ACDP permit application will be the means by which the following parameters and facility design are verified and presented as final.

3.1 Equipment/Fuels

The project will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF), which will be equipped with a natural gas-fired duct burner for supplementary firing and two steam turbine generators (STGs). By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Station) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Station). Figure 3-1 presents a general arrangement drawing of the proposed South Dunes Power Plant facility while Figure 3-2 presents a general arrangement of the liquefaction area.

Emissions from the six combined cycle units will be controlled by the use of dry low-NO_x burner technology and SCR for NO_x control, an oxidation catalyst for CO and VOC control, and the use of clean low-sulfur fuels only (i.e., natural gas) to minimize emissions of SO_2, PM/PM-10/PM-2.5, and H_2SO_4. Exhaust gases from the combined cycle units after emission controls will be dispersed to the atmosphere via individual stacks. Steam from the steam turbine will be sent to a condenser where it will be cooled to a liquid state and returned to the HRSG. Waste heat from the condenser will be dissipated through the air cooled condensers.

In addition to the South Dunes Power Station, the LNG Liquefaction Project will have a number of fugitive VOC emission sources from piping/flanges/valves from both land-based and vessel based sources. The four LNG liquefaction trains will be electric and thus, only fugitive VOC emissions are expected from that equipment.

While combustion emissions from the LNG vessels during hoteling, berthing, deberthing, and transit are expected, these activities are exempt from ODEQ and PSD permitting requirements as they are not considered direct emissions from the Facility. The power to provide for the pumps to onload the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the onloading process that would be subject to ACDP and PSD review as well as the requirement to model those emissions. If a cumulative ambient air quality modeling analysis is necessary, then these vessel based emission sources would be included as offsite sources for the purposes of an air quality standards compliance demonstration.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Trace amounts of hydrogen sulfide are removed as well in the CO_2 removal system, due to the characteristics of the absorbent. The gas conditioning trains consist of two parallel trains, each containing two systems in series: a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas from the Amine Stripper will be sent to a waste gas incinerator in order to oxidize sulfur components. Air emissions from the amine and dehydration systems are not expected and thus, will not be included in the modeling analysis.

Design details of the incinerator are currently being developed and that emission source will be modeled to demonstrate compliance with all applicable regulations in accordance with this air modeling protocol.

A Ground Flare is included in the project design to handle gas relieved during emergency upset conditions including but not limited to: extended power outages, extended emergency shut down events, and unexpected loss of vapor handling equipment during LNG Ship loading with the LNG Storage Tank operating near maximum normal operating pressure. The low pressure flare header is continuously purged with fuel gas. A small pilot (42,500 btu/hr) with electronic ignition will be continuously operated. The flare will not be included in the modeling analysis as it will only operate during emergency events with the exception of the small continuous flare pilot flame, which will have negligible air emissions.

3.2 Operation

The combined cycle units will be operated to follow electrical demand (i.e., dispatch mode) of the liquefaction facility, but will be designed and permitted to operate on a continuous basis.

The combined cycle units typically will not operate at steady-state below 50% load and the duct burner will only operate at full load conditions for the combustion turbines. Therefore, the HRSG steam production will follow the combustion turbine loads and higher HRSG steam output will only occur when duct firing is employed during combustion turbine full load operation.

The incinerator is expected to operate continuously while the gas conditioning system is in operation.

3.3 Selection of Sources for Modeling

The emission sources responsible for most of the potential air emissions from the Project are the six GE LM6000 combustion turbines. These units will be included in and are the main focus of the modeling analyses. As discussed in Section 3.4, the modeling will include consideration of operation over a range of turbine loads and operating scenarios. Initial modeling of the turbines by themselves will be conducted to identify those operating conditions for each pollutant and averaging period that yield the maximum modeled impacts. Any subsequent modeling incorporating other emissions units at the plant or other offsite facilities or indirect facility emissions will include the turbines operating conditions that yield the maximum modeled impacts. Modeling conducted for PM-10 and PM-2.5 will include filterable and condensable PM.

Ancillary sources (the emergency generator, fire pump, and incinerator) will also be included in the modeling for appropriate pollutants and averaging periods. The emergency equipment may operate for up to one-half hour in any day for readiness testing and maintenance purposes. Operation of the emergency equipment for longer periods of time in an emergency mode would not be expected to occur when the turbines are operating.

Although only limited operation is expected from the emergency equipment, initial modeling to assess short-term Project impacts will assume concurrent operation of the emergency equipment for readiness testing (i.e., less than 1-hour per day) with the combustion turbines.

3.4 Exhaust Stack Configuration and Emission Parameters

The preliminary general arrangement for the proposed South Dunes Station is presented in Figure 3-1. Preliminary exhaust characteristics of the turbine/HRSG stack during different operating scenarios are provided in Table 3-1. Exhaust parameters are presented for gas firing at three ambient temperatures (20 degrees Fahrenheit, 59 degrees Fahrenheit, and 90 degrees Fahrenheit) and three loads (50%, 75%, and 100%). Table 3-2 presents the preliminary potential emission rates for each of the operating scenarios. In addition, emission rates and stack parameters are presented for duct firing during natural gas operation at 100% load. Thus, emission rates and stack parameters for twelve (12) ambient temperatures and load combinations will be used to determine the "worst-case" operating scenario for the turbines.

Emissions and exhaust parameters from the facility ancillary equipment are currently being developed and will be presented in the ACDP permit application. As discussed in Section 3.3, the emergency diesel firepump and emergency diesel generator will only be included in the modeling analysis for appropriate pollutants and averaging periods when used for readiness testing (i.e., less than 1-hour per day). The emergency equipment emission rates will be scaled by the amount of expected hours of operation (i.e., up to one hour per day and 200 hours per year) over the averaging period for the air quality standard being modeled. For example, the hourly emission rate will be scaled by 1 hour operation/8 hour averaging period to model 8-hour CO impacts.

3.5 Good Engineering Practice Stack Height

Section 123 of the Clean Air Act (CAA) Amendments required the United States Environmental Protection Agency (U.S. EPA) to promulgate regulations to assure that the degree of emission limitation for the control of any air pollutant under an applicable State Implementation Plan (SIP) was not affected by (1) stack heights that exceed GEP or (2) any other dispersion technique. The U.S. EPA provides specific guidance for determining GEP stack height and for determining whether building downwash will occur in the Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations), (EPA-450/4-80-023R, June, 1985). GEP is defined as "...the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain "obstacles"."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) are avoided. The U.S. EPA GEP stack height regulations specify that the GEP stack height be calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

Where: H_B = the height of adjacent or nearby structures, and
L = the lesser dimension (height or projected width of the adjacent or nearby structures).

A preliminary site plan for the proposed Facility is shown in Figures 3-1 and 3-2. A final site plan will be included in the PSD/ACDP air permit application that will be submitted to the

ODEQ. A preliminary GEP stack height analysis has been conducted using the U.S. EPA approved Building Profile Input Program with PRIME (BPIPPRM, version 04274). The results of the preliminary analysis are presented in Table 3-3. The largest controlling structure at the South Dunes Station will be the air cooled condensers, at a height of 75 feet above grade, resulting in a formula GEP height of 187.5 feet above grade. The largest controlling structure at the liquefaction area will be the LNG storage tanks, at a height of 200 feet above grade, resulting in a formula GEP height of 500 feet above grade. Since non-GEP stacks will be proposed, direction-specific downwash parameters for the combustion turbine exhaust stacks would be determined using BPIPPRM, version 04274. Direction-specific downwash parameters for the additional auxiliary equipment exhaust stacks to be modeled (i.e., incinerator and emergency equipment) will also be determined using BPIPPRM, version 04274. Any direction-specific building downwash parameters will be input to the PSD modeling analysis.

Figure 3-3 provides an isometric view of the Facility structures proposed to be included in the BPIP analysis.

Figure 3-1: Preliminary Site Plan (South Dunes Area)

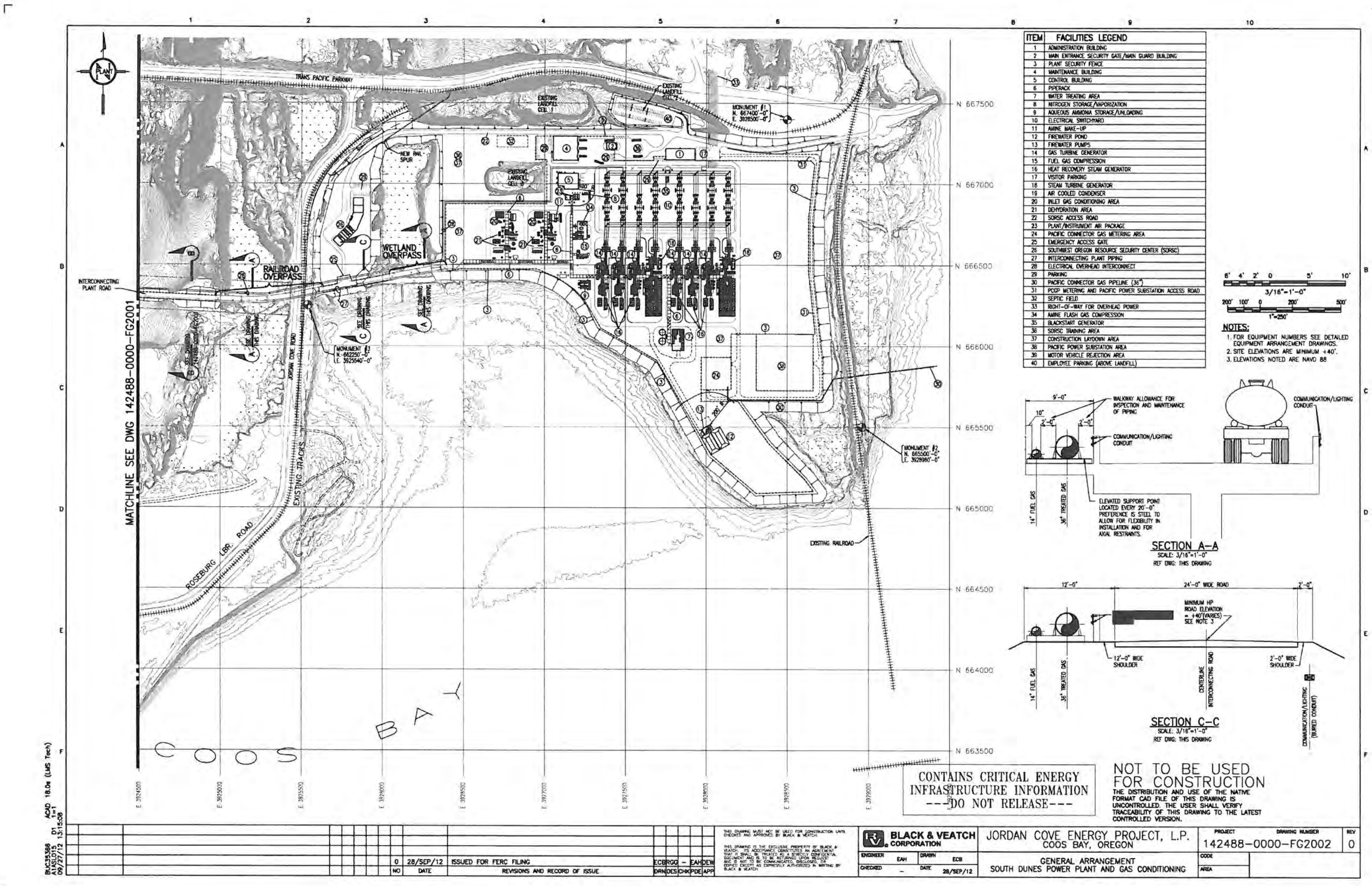


Figure 3-2: Preliminary Site Plan (Liquefaction Area)

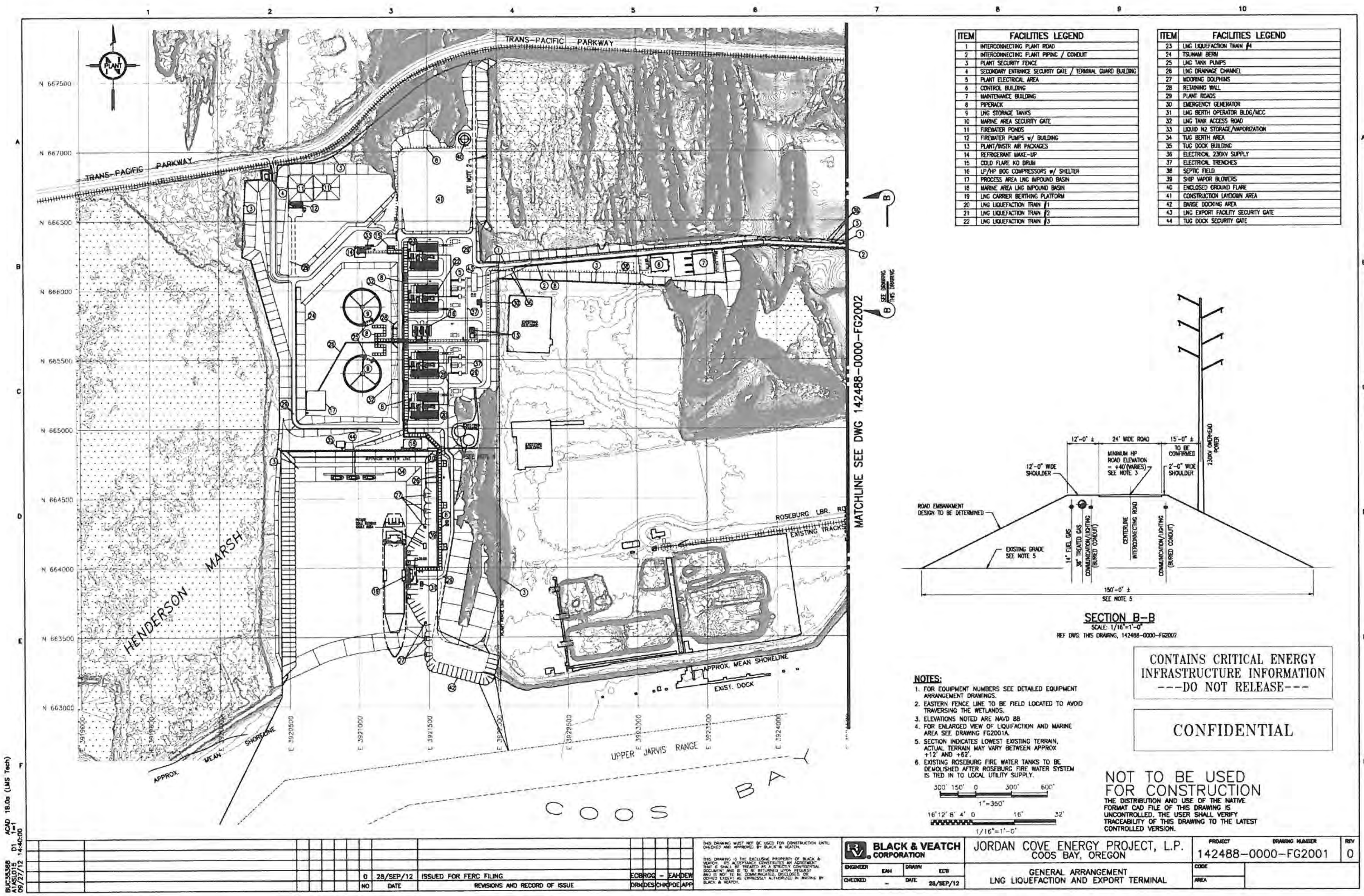


Figure 3-3: Buildings included in BPIP Analysis

Table 3-1: Combustion Turbine Preliminary Source Parameters

Operating Case	Fuel	Ambient Temperature (°F)	Operating Load (%)	Duct Burner Operation (On/Off)	Modeling Stack Parameters	
					Exhaust Temperature (K)	Exhaust Velocity (m/s)[a]
Case1	Gas	20F	100	Off	399.6	24.54
Case2	Gas	20F	100	On	394.8	24.29
Case3	Gas	20F	75	Off	399.8	19.84
Case4	Gas	20F	50	Off	399.8	16.20
Case5	Gas	59F	100	Off	395.3	22.97
Case6	Gas	59F	100	On	392.9	22.86
Case7	Gas	55F	75	Off	399.8	20.51
Case8	Gas	59F	50	Off	399.8	15.75
Case9	Gas	90F	100	Off	395.8	21.09
Case10	Gas	90F	100	On	391.9	20.98
Case11	Gas	90F	75	Off	399.8	17.94
Case12	Gas	90F	50	Off	399.8	14.55

[a]Based on a stack diameter of 10.0 feet.

Table 3-2: Combustion Turbine Preliminary Emission Rates

Operating Case	Modeled Emission Rate (g/s)[a]			
	NO_x	CO	PM-10/PM-2.5[b]	SO2
Case1	0.491	0.605	1.298	0.215
Case2	0.542	0.655	1.499	0.233
Case3	0.378	0.466	1.222	0.164
Case4	0.290	0.353	1.172	0.123
Case5	0.491	0.605	1.336	0.214
Case6	0.517	0.630	1.449	0.224
Case7	0.391	0.479	1.235	0.168
Case8	0.290	0.353	1.197	0.125
Case9	0.428	0.529	1.298	0.186
Case10	0.529	0.643	1.638	0.229
Case11	0.340	0.416	1.235	0.145
Case12	0.252	0.315	1.184	0.110
Case13	0.491	0.605	1.298	0.215
Case14	0.542	0.655	1.499	0.233

[a]Emissions are for one (1) combustion turbine.
[b]Filterable plus condensable.

Table 3-3: GEP Stack Height Analysis

Structure	Height (ft)	Maximum Projected Width (ft)	5L Region of Influence (ft)	H_{GEP}=H+1.5L (ft)
HRSGs	70	58	290	157
ACCs	75	252	375	187.5
Steam Turbine Generator	50	65	250	125
Administration Building	36	192	180	90
Maintenance Building	36	212	180	90
Control Building	15	160	75	37.5
Liquefaction Train	70	127	350	175
LNG Tank	200	266	1000	500
Fire Pump Building	15	110	75	37.5

4.0 REGULATORY REQUIREMENTS

Air quality modeling requirements are specified under Federal U.S. EPA and ODEQ regulatory programs including PSD and the Oregon Administrative Rules (OAR) Chapter 340, Division 200-268. All applicable requirements that include air quality impact assessments are outlined in this section.

4.1 New Source Review

The Federal NSR program consists of the non-attainment NSR and PSD programs. Applicability of these programs to the proposed facility is determined based upon the attainment status and the potential emissions of the proposed facility.

4.1.1 Attainment Status

The U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for each of the following criteria air pollutants: particulate matter (PM) with an aerodynamic diameter of 10 microns or less (PM_{10}), PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead (Pb).

Areas in which the NAAQS are being met are referred to as attainment areas. Areas in which the NAAQS are not being met are referred to as nonattainment areas. Areas that were formerly nonattainment areas but are now in attainment and covered by a maintenance plan are referred to as maintenance areas. Areas for which sufficient data are not available to determine a classification are referred to as unclassifiable. The federal attainment status designations of areas in Oregon with respect to NAAQS are listed at 40 CFR 81.338. The Project is located in Coos County in the Southwest Oregon Intrastrate Air Quality Control Region (AQCR). The proposed location of the JCEP facility is in an area currently designated as in attainment/unclassifiable for all criteria pollutants. Based on review of the locations of Oregon Department of Environmental Quality ambient air quality monitoring sites, the closest monitoring sites were initially used to represent the current background air quality in the site area. JCEP understands that the ODEQ will provide ambient background PM_{10}, $PM_{2.5}$, NO_2, SO_2, and CO values once they are deemed necessary for the analysis.

Possible background data for CO was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0013), approximately 117 km northeast of the proposed facility. The monitor is located at Lane Community College at 1059 Willamette, approximately at 44.047896 North Latitude, 123.092049 West Longitude, in a commercial/suburban area.

Possible background data for PM_{10} was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0058), approximately 113 km northeast of the proposed facility. The monitor is located at 450 Pacific Highway North, approximately at 44.066304 North Latitude, 123.139831 West Longitude, in a residential/suburban area.

Possible background data for $PM_{2.5}$ was obtained from the Cottage Grove station located in Lane County, Oregon (EPA AIRData # 41-039-9004), and approximately 103 km east-northeast of the proposed facility. The monitor is located at 425 N. 14th Cottage Grove City Shops, approximately at 43.799570 North Latitude, 123.053490 West Longitude, in a residential/suburban area.

Possible background data for NO_2 and SO_2 was obtained from the Portland monitoring station located in Multnomah County, Oregon (EPA AIRData # 41-051-0080), and approximately 265 km north-northeast of the proposed facility. The monitor is located at 5824 SE Lafayette, approximately at 45.966667 North Latitude, 122.602222 West Longitude, in a residential/suburban area.

4.1.2 Prevention of Significant Deterioration

The Oregon Administrative Rules adopt the Prevention of Significant Deterioration program pursuant to 40 CFR 51.166, which is administered through the ODEQ air permitting process, and applies to a new or modified major facility located in an attainment area. The Department accepted administration of the PSD program from the U.S. EPA in January of 1986 through approved State Implementation Plans (SIPs). As such, any fossil fuel fired steam electric plant with a heat input capacity greater than 250 mmBTU/hr and potential emissions greater than 100 tons per year of any regulated pollutant is considered a "major" source and is subject to the PSD regulations. Based on potential emissions from the fossil fuel fired combustion turbines, the proposed facility will have potential emissions greater than 100 tons per year of multiple regulated pollutants. Thus, the proposed facility will be subject to the PSD permitting requirements.

Facilities subject to PSD must perform an air quality analysis (which includes atmospheric dispersion modeling) and a best available control technology (BACT) demonstration for those pollutants that exceed the pollutant specific Significant Emission Rates (SERs) identified in the regulations. These emission rates are provided in Table 4-1 with preliminary estimates of annual facility wide potential to emit. The final annual facility emissions have not been determined and will be presented in the final ACDP application.

Dispersion modeling for the PSD requirements consists of three analyses: a significance analysis, a NAAQS/OAAQS analysis, and a PSD increment analysis. The significance analysis compares the maximum-modeled ambient concentrations from the proposed facility to the significant impact levels (SILs) listed in Table 4-2 for each pollutant. If the modeled concentrations for the proposed facility are less than the SILs, then more detailed NAAQS and PSD increment analyses are not required under PSD regulations. However, if the modeled concentrations are greater than the SILs, then NAAQS and PSD increment analyses are required for that pollutant. The NAAQS and PSD increments are listed in Table 4-2.

4.1.3 Preconstruction Ambient Air Quality Monitoring Exemption

As discussed previously, PSD regulations require an applicant to perform an air quality analysis for those pollutants emitted in quantities exceeding the SERs shown in Table 4-1. This analysis can include the collection of up to one year of ambient air quality monitoring data. Preliminary facility emissions indicate that air quality monitoring could be required for some of the pollutants listed in Table 4-1.

Pursuant to the PSD regulations codified in 40 CFR 51.166 and 40 CFR 52.21, U.S. EPA may exempt a proposed PSD source, otherwise subject to the one-year pre-construction ambient monitoring requirement, if either 1) the predicted ambient impact, i.e., the highest modeled concentration for the applicable averaging time, caused by the proposed significant emissions increase (or significant net emissions increase) are less than the prescribed significant monitoring values, or 2) existing quality assured ambient air quality data are available from alternate locations that are representative of, or conservative, as compared to conditions at the proposed facility location. TRC, on behalf of JCEP, is submitting a preconstruction monitoring exemption request to the ODEQ under separate cover, a copy of which will be included in the ACDP permit application.

4.2 Oregon DEQ Regulations

4.2.1 Division 202 (Ambient Air Quality Standards)

Division 202 of OAR 340 contains ambient air quality standards that apply throughout the state of Oregon. The Oregon Ambient Air Quality Standards (OAAQS) are included in Table 4-3. The OAAQS are comparable to or more stringent than National Ambient Air Quality Standards (NAAQS) that EPA has established for designated criteria pollutants.

4.2.2 Division 216 (Air Contaminant Discharge Permits)

Division 216 is the preconstruction and operating permit program for major sources in Oregon. The rule states that "no person may construct, install, establish, develop or operate any air contaminant source which is referred to in Table 1 without first obtaining an ACDP from the Department. Table 1 of OAR 340-216 lists natural gas processing and associated fuel burning equipment as an affected source with the requirement that sources with emissions above 100 tons per year of any criteria air pollutant must obtain a Standard ACDP. The JCEP will have emissions of NO_x, CO, SO_2, and PM-10/PM-2.5 above 100 tons per year and thus, a Standard ACDP will be applied for and obtained from the ODEQ.

A Standard ACDP contains the following:

1. All applicable requirements, including general ACDP conditions for incorporating generally applicable requirements.

2. Source Specific Plant Site Emission Limits PSELs or Generic PSELs as specified in OAR 340 Division 222

3. Testing, Monitoring, Recordkeeping, and Reporting Requirements sufficient to determine compliance with the PSEL and other emission limits and standards

4. A permit duration not to exceed 5 years.

Table 4-1: Preliminary Emission Rates, PSD Significant Emission Rates, and Non-attainment NSR Thresholds

Pollutant	Preliminary Emission Rate (tons per year)	PSD Significant Emission Rate (tons per year)	NNSR Major Source/Modification Threshold (tons per year)
Carbon Monoxide	144	100	100/100
Sulfur Dioxide	542	40	100/40
Particulate Matter (PM)	293	25	100/25
Particulate Matter less than 10 microns (PM-10)	293	15	100/15
Particulate Matter less than 2.5 microns (PM-2.5)	293	10	100/10[a]
Nitrogen Oxides	163	40	25/25
Ozone (VOC)	107	40	25/25
Greenhouse Gases (GHGs)	3,992,000	100,000	NA
Lead	0.01	0.6	10/0.6
Fluorides	NA	3	NA
Sulfuric Acid Mist	57	7	NA
Hydrogen Sulfide	<1	10	NA
Total Reduced Sulfur (including H_2S)	<1	10	NA
Reduced Sulfur Compounds (including H_2S)	<1	10	NA

Note: Pursuant to 40 CFR 52.21 (b) (23) (i).
[a]Under 40 CFR 51, Appendix S, new sources with potential emissions greater than or equal to 100 tons per year and modifications to existing major sources with emissions greater than or equal to 40 tons per year of SO_2 or 10 tons per year of PM-2.5 are subject to non-attainment NSR for PM-2.5.

Table 4-2: National Ambient Air Quality Standards, PSD Increments, Significant Monitoring Concentrations, and Significant Impact Levels

Pollutant	Averaging Period	NAAQS[a] (μg/m³)	Class II PSD Increment (μg/m³)	Significant Monitoring Concentrations (μg/m³)	Significant Impact Level (μg/m³)
Carbon Monoxide	1-Hour 8-Hour	40,000 10,000	-- --	-- 575	2,000 500
Nitrogen Dioxide	1-Hour Annual	188 100	-- 25	-- 14	7.5[b] 1
Ozone (VOC)	8-Hour	160	--	--	--
Coarse Particulate Matter (PM-10)	24-Hour Annual	150 --	30 17	10 --	5 1
Fine Particulate Matter (PM-2.5)	24-Hour Annual	35 15	9 4	4 --	1.2 0.3
Sulfur Dioxide	1-Hour 24-Hour Annual 3-Hour	197 365 80 1,300	-- 91 20 512	-- 13 -- --	7.9[c] 5 1 25
Lead	3-Month	0.15	--	0.1	--

Note: (--) indicates there are no standards for this pollutant.

[a]All short-term (1-hr, 3-hr, 8-hr, and 24-hr) standards except ozone, PM-2.5,PM-10, and 1-hour SO_2 and NO_2 are not to be exceeded more than once per year. For 8-hr ozone, EPA uses the average of the annual 4th highest 8-hour daily maximum concentrations from each of the last three years of air quality monitoring data to determine a violation of the standard. For 24-hour PM-10, EPA uses the 6th highest 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standards. For 24-hour PM-2.5, EPA uses the 98% percentile 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standard. For the 1-hour NO2 NAAQS, compliance would be determined by the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area and for the 1-hour SO2 NAAQS, compliance would be determined with the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area.

[b]Interim SIL per Guidance from EPA.

[c]Interim SIL per August 12, 2010 memorandum "Guidance Concerning the Implementation of the 1-hour SO2 NAAQS for the Prevention of Significant Deterioration Program" from Steven Page (Director of U.S. EPA OAQPS).

Table 4-3: Oregon Ambient Air Quality Standards

Pollutant	Averaging Period	OAAQS[a] (ug/m³)
Sulfur Dioxide	annual 24-hour average 3-hour average	52.4 262 1,300
PM-10	annual 24-hour average	50 150
Carbon Monoxide	8-hour average 1-hour average	10,000 40,000
Ozone	8-hour average	160
Nitrogen Dioxide	annual	100
Lead	Rolling 3-month average	1.5

[a]Oregon short-term standards are not to be exceeded more than once in any 12 month period. Long-term standards are never to be exceeded.

5.0 MODELING METHODOLOGY

Air quality dispersion modeling will be performed consistent with the procedures found in the following documents: Guideline on Air Quality Models (Revised) (U.S. EPA, 2005), New Source Review Workshop Manual (U.S. EPA, 1990), and Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (U.S. EPA, 1992).

5.1 Model Selection

The U.S. EPA has compiled a set of preferred and alternative computer models for the calculation of pollutant impacts. The selection of a model depends on the characteristics of the source, as well as the nature of the surrounding study area. Of the four classes of models available, the Gaussian type model is the most widely used technique for estimating the impacts of nonreactive pollutants.

The U.S. EPA AERMOD model is proposed to be used. The AERMOD model was designed for assessing pollutant concentrations from a wide variety of sources (point, area, and volume). AERMOD is currently recommended for modeling studies in rural or urban areas, flat or complex terrain, and transport distances less than 50 kilometers, with one hour to annual averaging times. In November 2005, AERMOD became a U.S. EPA guideline model replacing the Industrial Source Complex (ISCST3) model which had been the preferred model for many years for most modeling applications.

AERMOD (version 12060 with PRIME) will be used for the modeling of the proposed facility's potential emissions to determine the maximum ambient air concentrations. The regulatory default option will be used in the dispersion modeling analysis.

5.2 Surrounding Area and Land Use

A land cover classification analysis was performed to determine whether the urban source modeling option in AERMOD should be used in quantifying ground-level concentrations. The urban option in AERMOD accounts for the effects of increased surface heating on pollutant dispersion under stable atmospheric conditions. Essentially, the urban convective boundary layer forms in the night when stable rural air flows onto a warmer urban surface. The urban surface is warmer than the rural surface because the urban surface cools at a slower rate than the rural surface when the sun sets. The methodology utilized to determine whether the project is located in an urban or rural area is described below.

An aerial map covering the area within a 3-kilometer radius of the site was reviewed (see Figure 5-1) along with a USGS topographical map and indicated that approximately 90% of the surrounding area is water, wooded areas, and sand dunes. Note that the "AERMOD Implementation Guide" published on October 19, 2007 cautions users against applying the 3-kilometer Land Use Procedure on a source-by-source basis and instead consider the potential for urban heat island influences across the full modeling domain (i.e., 20 kilometers x 20 kilometers). This approach is consistent with the fact that the urban heat island is not a localized effect, but is more regional in character.

The population density within 3 kilometers of the proposed site was assessed utilizing the data from the U.S. Census Bureau. The population density within 3 kilometers of the site is approximately 580 persons per square kilometer.

In summary, the area within 3 kilometers of the proposed site is characterized primarily by rural land uses and the population density is below the 750 persons per square kilometer threshold for utilizing the Urban Source option in AERMOD. Because the urban heat island is more of a regional effect, the Urban Source option in AERMOD will not be utilized since the area is more rural in nature over the modeling domain.

5.3 Meteorological Data

For any PSD modeling analysis conducted using the AERMOD model, two meteorological datasets are required: 1) hourly surface data and 2) upper air sounding data. According to the Guideline on Air Quality Models (Revised) (2005), the meteorological data used in a PSD modeling analysis should be selected based on its spatial and climatological representativeness of a proposed facility site and its ability to accurately characterize the transport and dispersion conditions in the area of concern. The spatial and climatological representativeness of the meteorological data are dependent on four factors:

1. The proximity of the meteorological monitoring site to the area under consideration;
2. The complexity of the terrain;
3. The exposure of the meteorological monitoring site; and,
4. The period of time during which data were collected.

This protocol presents one hourly surface dataset and one upper air sounding dataset for use in modeling the proposed facility to be located in the Coos County. Each of these meteorological datasets was reviewed using the U.S. EPA criteria.

The nearest National Weather Service (NWS) operated meteorological monitoring station to the proposed facility site is at the North Bend Municipal Airport (WBAN 24284) (also known as the Southwest Oregon Regional Airport) in Coos County. The airport is located approximately 1.7 km south of the proposed facility site at an elevation of approximately 12 feet above MSL. Figure

5-2 shows the location of the North Bend Municipal Airport in relation to the proposed facility site. The meteorological monitoring station at the Airport continues to operate.

Both the proposed facility site and North Bend Municipal Airport are located in the coastal plain area of Coos Bay, just to the east of the Pacific Ocean. Both locations are in open areas at approximately the same elevation.

A wind rose (graphical display of wind speed and direction) displaying the composite wind rose for all five years (2006-2011) of wind speed and direction for the North Bend Municipal Airport is shown in Figure 5-3. Over the five (5) year period, predominant winds varied between southeast, south-southeast, and north-northwest. The average wind speed over the five years is 7.74 knots. Calm winds during the five years had an average frequency of 10.83 percent. Additionally, the wind data recorded at the airport is reasonably consistent from year to year.

In order to determine geographical representativeness, an examination of the surface characteristics around the proposed JCEP facility site and around the North Bend Municipal Airport was performed. Land cover data was obtained from the Earth Resources Observation and Science (EROS) web site at: http://edc.usgs.gov/. Land cover data was obtained for Oregon, more specifically for an area encompassing a 20 kilometer radius around the JCEP proposed facility and the North Bend Municipal Airport. The surface characteristics for each land cover classification were mapped to AERMET land use categories. A comparison of the monthly surface characteristics for the JCEP site and airport are provided in the following table.

Comparison of Surface Characteristics around North Bend Airport and JCEP Facility

Month	Albedo		Bowen Ratio		Roughness Length	
	North Bend	JCEP	North Bend	JCEP	North Bend	JCEP
January	0.14	0.14	0.40	0.42	0.011	0.017
February	0.14	0.14	0.40	0.42	0.011	0.017
March	0.13	0.13	0.34	0.35	0.014	0.025
April	0.13	0.13	0.34	0.35	0.014	0.025
May	0.13	0.13	0.34	0.35	0.014	0.025
June	0.13	0.14	0.29	0.29	0.016	0.03
July	0.13	0.14	0.29	0.29	0.016	0.03
August	0.13	0.14	0.29	0.29	0.016	0.03
September	0.13	0.14	0.40	0.41	0.015	0.03
October	0.13	0.14	0.40	0.41	0.015	0.03
November	0.13	0.14	0.40	0.41	0.015	0.03
December	0.14	0.14	0.40	0.42	0.011	0.017

As illustrated by the previous table, there is essentially no difference between the surface characteristics around the JCEP facility and the land use characteristics around the North Bend

Municipal Airport, thus the North Bend Municipal Airport meteorological data is considered reasonably representative for the JCEP project site.

Thus, based on the information provided above, the applicant believes that the meteorological data recorded at the North Bend Municipal Airport are representative of the air regime at the proposed facility site and suitable to be used in an atmospheric dispersion modeling study because:

- Due to the proximity of the airport to the proposed facility site and the lack of significant intervening terrain features, overall climatological conditions would be expected to be quite similar at both the airport and the proposed facility site;
- The elevation of the airport (approximately 12 feet above MSL) and the proposed facility site elevation (approximately 30-60 feet above MSL) are comparable;
- The meteorological tower is well sited and in an area free of obstructions to wind flow; and,
- The quality of the available data is good, exceeding U.S. EPA data recovery guidelines and displaying consistency from year to year of the available data record.

Concurrent upper air sounding data from Salem McNary Field Airport (WBAN 24232), in Marion County was also obtained. These data will be used with the concurrent hourly surface data to create the meteorological dataset required for the modeling analysis. Salem is approximately 195 km to the north-northeast of the proposed facility site. Based on Holzworth's *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States*, it is believed that upper air meteorological conditions in the Salem area are more representative along the coast than those from the further inland, albeit, closer upper air station at Medford Rogue Valley International Airport in Jackson County. Both the surface and upper air sounding data will be processed using AERMOD's meteorological processor, AERMET (version 11059). The surface data from North Bend Municipal Airport, the upper air sounding data from Salem McNary Field as well as the input and output files for AERMET, will be included electronically on CD-ROM in the ACDP Application. The output from AERMET will be used as the meteorological database for the air quality modeling analysis and will consist of a surface data file and a vertical profile data file.

Additionally, the height of the meteorological station adequately typifies the emission release heights. The JCEP facility will be constructed on a graded elevation of approximately 30-60 feet above sea level. The exhaust heights for the emission units will be between 20 and 150 feet above grade, or between 50 and 210 feet above sea level. The meteorological tower height for modeling will be 33 feet above a grade of 12 feet above sea level. This relatively modest height difference might be of concern if extreme stratification of the boundary layer would frequently occur. Fortunately, the winds are quite seasonal, with a strong southeast component during the winter months, and a strong northerly component during the summer months. This minimizes the stratification that might be caused by marine layer advection and Thermal Internal Boundary Layer (TIBL) effects when the wind blows from the ocean towards the east. Since the wind flow nearly always passes over the land, either from the southeast or the north and northwest, the boundary layer should be well mixed and TIBL effects are minimal. Therefore, the height of the tower at 45 feet above sea level is sufficient to reasonably represent the wind regime at the height of the emission points. Furthermore, the wind speeds will be scaled to the emission point heights using typical power law scaling formula for a non-stratified boundary layer. The power law scaling will be performed internally by AERMOD in accordance with Section 6.2.5 of the *Meteorological Monitoring Guidance for Regulatory Modeling Applications* – February, 2000.

5.4 Sources

The proposed facility will consist of various types of emission sources. The AERMOD technical manual will be used to set up the various sources to develop a logical and comprehensive modeling assessment. The following identifies the types of sources and how they will be assessed.

- Combustion Turbine Exhaust Stacks – Single point sources
- Ancillary Equipment Exhaust Stacks – Single point sources

5.5 Load Analysis

The proposed facility's combustion turbines will be operated over a range of loads. The air permit application will provide a detailed discussion of all the sources at the proposed facility and how they are assessed in the air quality analysis. All twelve (12) combustion turbine operating cases as listed in Table 3-1 will be modeled to determine which case is the "worst-case" operating scenario for each pollutant and averaging period. These "worst-case" loads will then be used for any subsequent NAAQS or PSD Increment modeling, including additional facility sources and potentially offsite sources.

5.6 Startups/Shutdowns

Startup is a short-term, transitional mode of operation for the combined cycle units. In combined cycle operation, where the exhaust gases are directed through a HRSG to produce steam for a steam turbine generator, additional startup time is necessary in order to reduce thermal shock and excessive wear in both the HRSG and the steam turbine. Emission rates of some pollutants may be higher during startup operations because emissions controls may not become fully effective until a minimum threshold operating load and or control device temperature is attained. The need for additional modeling to account for predicted short-term

Project impacts during startup of the combined cycle units will be assessed for those criteria pollutants whose short-term emission rates during startup may exceed those during normal operation and for which a short-term NAAQS or PSD increment has been defined (i.e., for CO and NO_2). In addition, the need for startup modeling will be assessed for SO_2 and PM-10/PM-2.5.

Startup and shutdown conditions refer to all times when the CTG operates below the minimum operating load (~50% load). Startups are defined as cold, warm, and hot. The cold startup refers to startups after 72 hours of shutdown time and requires approximately 3.83 hours. The warm startup refers to startups after typically 8.1 – 72 hours of shutdown time and requires approximately 2.23 hours. The hot startup refers to a typical shutdown time of about 8 hours or less and can be achieved in 1.65 hours. Shutdowns can occur at any time and take approximately 0.63 hours.

The short-term duration of startup and the relatively limited cumulative time of startup relative to normal operation mean that startup impacts will not have an appreciable effect on annual impacts when taking into account the downtime necessary for each start-up type. For these reasons, no start-up/shutdown modeling for the annual impacts is proposed unless for an annual averaging period pollutant (i.e., NOx, PM-2.5, and SO2) the calculated potential to emit significantly increases when considering the start-up/shutdown events.

Because the startup/shutdown durations from some types will be shorter than some of the averaging periods modeled, the modeled concentrations for these averaging periods that extend beyond the start-up duration will be determined based on the combination of the startup conditions for the appropriate amount of time and the worst-case full-load pollutant- and averaging period-specific operating scenario determined in the combustion turbine load analysis.

In summary, the worst-case startup/shutdown emissions for CO, SO_2, NO_x, and PM-10/PM-2.5 will be modeled if the pollutant(s) have higher emissions during startup and shutdown conditions when compared to normal operation for short-term averaging periods. For annual averaging periods, start-ups will only be included in the modeling analysis if the potential to emit for the Facility increases due to the inclusion of start-ups into the annual potential to emit calculation.

5.7 1-Hour NO_2 Modeling

The air quality modeling analysis for the 1-hour NO_2 NAAQS will be performed consistent with the guidance and procedures established in the March 1, 2011 guidance memorandum from Tyler Fox (EPA OAQPS) titled "Additional Clarification Regarding Application of Appendix W

Modeling Guidance for the 1-Hour NO_2 NAAQS" (Memorandum). Based upon the discussion in the memorandum regarding the treatment of intermittent sources it is proposed that only equipment or operating scenarios that "are continuous or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations" will be included in the 1-Hour NO_2 modeling analysis.

This methodology per the examples provided in the Memorandum would exempt any Facility equipment or operating scenarios from 1-hour NO_2 compliance modeling that does not operate on a normal daily or routine schedule. For example, the emergency generators and firewater pumps are not expected to be tested more than once per week for more than 1-hour and thus, would not be expected to contribute significantly to the annual distribution of maximum 1-hour concentrations. For these reasons consistent with the Memorandum it is proposed that the 1-hour NO_2 modeling will not include the emergency equipment at the site.

5.8 Receptor Grid

5.8.1 Basic Grid

The AERMOD model requires receptor data consisting of location coordinates and ground-level elevations. The receptor generating program, AERMAP (Version 11103), will be used to develop a complete receptor grid to a distance of 10 kilometers from the proposed facility. AERMAP uses digital elevation model (DEM) or the National Elevation Dataset (NED) data obtained from the USGS. The preferred elevation dataset based on NED data will be used in AERMAP to process the receptor grid. This is currently the preferred data to be used with AERMAP as indicated in the U.S. EPA AERMOD Implementation Guide (U.S. EPA, 2009). AERMAP will be run to determine the representative elevation for each receptor using 1/3 arc second NED files that will be obtained for an area covering at least 20 kilometers in all directions from the Facility. The NED data will be obtained through the USGS Seamless Data Server (http://seamless.usgs.gov/index.php).

The following rectangular (i.e. Cartesian) receptors will be used to assess the air quality impact of the proposed facility:

- Fine grid receptors ≤ 60 meters for a 10 km (east-west) x 10 km (north-south) grid centered on the proposed facility site.
- Coarse grid receptors ≤ 600 meters for a 20 km x 20 km grid centered on the proposed facility site.

Receptors will be placed along the facility fence line or property boundary every 25 meters. Grid receptors within the fenced plant property will be excluded from the grid as public access will be precluded in this area. Receptors will not be included in the ship berthing area since this area will be restricted to public access and is not considered ambient air. Plots of the facility receptor grid are presented in Figures 5-4 and 5-5.

5.8.2 Special Receptors

An additional analysis will be performed using selected sensitive receptors, if necessary, for the health risk assessment modeling. These locations will include schools, hospitals, day care, and senior care facilities within one (1) kilometer of the proposed facility. A summary table of air quality concentrations at sensitive receptors will be provided in the air permit application, if necessary.

5.9 Background Ambient Air Quality

The Project is located in Coos County in the Southwest Oregon Intrastrate Air Quality Control Region (AQCR). The proposed location of the JCEP facility is in an area currently designated as in attainment/unclassifiable for all criteria pollutants. Based on review of the locations of Oregon Department of Environmental Quality (ODEQ) ambient air quality monitoring sites, the closest monitoring sites were initially used to represent the current background air quality in the site area. JCEP understands that the ODEQ will provide ambient background PM_{10}, $PM_{2.5}$, NO_2, SO_2, and CO values once they are deemed necessary for the analysis.

Possible background data for CO was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0013), approximately 117 km northeast of the proposed facility. The monitor is located at Lane Community College at 1059 Willamette, approximately at 44.047896 North Latitude, 123.092049 West Longitude, in a commercial/suburban area.

Possible background data for PM10 was obtained from the Eugene monitoring station located in Lane County, Oregon (EPA AIRData # 41-039-0058), approximately 113 km northeast of the proposed facility. The monitor is located at 450 Pacific Highway North, approximately at 44.066304 North Latitude, 123.139831 West Longitude, in a residential/suburban area.

Possible background data for PM2.5 was obtained from the Cottage Grove station located in Lane County, Oregon (EPA AIRData # 41-039-9004), and approximately 103 km east-northeast of the proposed facility. The monitor is located at 425 N. 14th Cottage Grove City Shops, approximately at 43.799570 North Latitude, 123.053490 West Longitude, in a residential/suburban area.

Possible background data for NO_2 and SO_2 was obtained from the Portland monitoring station located in Multnomah County, Oregon (EPA AIRData # 41-051-0080), and approximately 265 km north-northeast of the proposed facility. The monitor is located at 5824 SE Lafayette, approximately at 45.966667 North Latitude, 122.602222 West Longitude, in a residential/suburban area.

The monitoring data for three recent years (2009-2011) are presented and compared to the NAAQS in Table 5-1. The maximum measured concentrations for each of these pollutants during the last three years are all below applicable standards and are proposed to be used in a NAAQS analysis should one be required.

5.10 NAAQS/OAAQS Analysis

Should modeled concentrations be greater than the SILs for one or more pollutants, NAAQS/OAAQS analyses for those pollutants will be performed. The first step of conducting the NAAQS/OAAQS analysis will be to determine the pollutant specific area(s) of impact of the proposed facility. The area of impact corresponds to the distance at which the model calculated pollutant concentrations fall below the SILs. The second step is obtaining off-site major source inventories within the area of impact plus a distance to be determined based upon discussions with ODEQ. Discussions with ODEQ will be centered on the development of an off-site source inventory and the procedures recommended for preparing a multiple source inventory. These off-site major sources would be included in the NAAQS/OAAQS modeling analysis along with all sources at the proposed facility. The resultant concentrations will then be added to the representative background concentration for comparison to the NAAQS/OAAQS. If the modeled concentration plus the background concentration is less than the NAAQS/OAAQS, the proposed facility is considered acceptable relative to the NAAQS/OAAQS. JCEP will demonstrate that its modeled impact plus representative background concentrations will be in compliance with the NAAQS/OAAQS presented in Table 4-2 and 4-3, respectively.

5.11 PSD Increment Analysis

Should modeled concentrations be greater than the SILs, the source must also demonstrate compliance with the PSD increments established for SO_2, NO_2, and PM-10/PM-2.5. The proposed facility is located in a PSD Class II area. JCEP will demonstrate that its modeled impact will be in compliance with the Class II PSD increments presented in Table 4-2.

5.11.1 Additional Impact Analyses

In addition to assessing impacts on the NAAQS and PSD increments, facilities subject to PSD review must assess the potential impact for the area as a result of growth, and the potential impacts to soils, vegetation, and visibility in the area surrounding the proposed facility.

5.11.2 Assessment of Impacts due to Growth

The proposed facility will be reviewed to assess the potential for affecting local and regional industrial, commercial, and residential growth. Factors that will be examined include the effects the transient working force will have during construction, which is anticipated to occur for up to 36 months, with a currently planned 2017 commercial operation date. If an increase in the permanent working force is required, the effects on the local growth will also be examined. Other effects to growth that will be examined include the air quality constraints the emissions from the proposed facility will have on precluding new growth, and the potential for drawing new industrial growth due to the electricity generated.

5.11.3 Assessment of Impacts on Soils and Vegetation

Pursuant to PSD regulations, an assessment of the potential impacts of the proposed facility on soils and vegetation will be prepared. The methodology outlined in A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, EPA 450/2-81-078 will be used. This assessment will compare the maximum-modeled facility impacts plus background to pollutant-specific concentration levels. These pollutant-specific concentration levels are minimum pollutant concentration levels at which damage to the natural vegetation and predominant crops could occur. Therefore, if the maximum-modeled concentrations are less than the pollutant-specific concentration levels, then no damage to vegetation will be anticipated. The specific impact criteria levels to be used for the comparison will be identified for predominant soil and vegetation types based upon a review of the current literature.

5.11.4 Impact on Visibility

An assessment of the proposed facility's potential impact on visibility within the surrounding area will be performed using the U.S. EPA VISCREEN model (version 88341).

5.11.5 Impacts on Class I Areas

Per guidance from ODEQ, air quality concentrations of NO_x, SO_2, PM-2.5 and PM-10 in Class I areas within 200 km of the proposed facility will be determined. Class I areas within 200 kilometers include:

Crater Lake National Park (Oregon) .... 165 kilometers
Redwood National Park (California) .... 177 kilometers

Kalmiopsis Wilderness Area (Oregon) .... 110 kilometers
Diamond Peak Wilderness Area (Oregon) .... 164 kilometers
Three Sisters Wilderness Area (Oregon) .... 184 kilometers

One ring of receptors spaced at one degree intervals and at a distance of 50-kilometers from the proposed facility will be modeled at three different elevations: the lowest elevation and the highest elevation in the five (5) previously mentioned Class I areas, as well as the final plume rise, as determined by running SCREEN3 at F-stability and a 2.5 meter per second wind speed. Maximum concentrations should be less than both the Class I SILs and ODEQ SILs.

If requested by ODEQ, the Federal Land Manager (FLM) for these Class I areas will be notified by correspondence and requested to determine if assessments of air quality related values (AQRVs) in the Class I areas would be required. Copies of both the request letter and the FLM's response will be included in the PSD permit application.

5.12 Modeling Submittal

The permit application for the proposed facility will include a section detailing the modeling methodology and results from the modeling analysis. All final stack parameters and emission rates will be presented in the report. All modeling input and output files used in the analysis will be submitted in electronic format (DVD-ROM) with the permit application.

Table 5-1: Maximum Measured Ambient Air Quality Concentrations

Pollutant	Averaging Period	Maximum Ambient Concentrations ($\mu g/m^3$)			NAAQS ($\mu g/m^3$)
		2009	2010	2011	
SO_2	1-Hour[a]	23.6	21.0	23.6	197
	3-Hour	**21.0**	21.0	15.7	1,300
	24-Hour	**10.5**	8.7	7.9	365
	Annual	**4.2**	3.7	NA	80
NO_2	1-Hour[b]	75.2	62.0	62.0	188
	Annual	**19**	17	17	100
CO	1-Hour	**2,415**	2,185	NA	40,000
	8-Hour	**1,840**	1,495	NA	10,000
PM-10	24-Hour	**55**	41	38	150
PM-2.5[c]	24-Hour	30	18	21	35
	Annual	8.5	6.9	7.1	15

[a]1-hour 3-year average 99th percentile value for SO_2 is **22.7** ug/m3.
[b]1-hour 3-year average 98th percentile value for NO_2 is **66.4** ug/m3.
[c]24-hour 3-year average 98th percentile value for PM-2.5 is **23.0** ug/m3; Annual 3-year average value for PM-2.5 is **7.5** ug/m3.
High second-high short term (1-, 3-, 8-, and 24-hour) and maximum annual average concentrations presented for all pollutants other than PM-2.5 and 1-hour SO_2 and NO_2.
Bold values represent the proposed background values for use in any necessary NAAQS analyses.
Monitored background concentrations obtained from the U.S. EPA AIRData and Oregon DEQ Air Quality Reports for 2009-2011.

Figure 5-1: 3-km Radius around the Jordan Cove Energy Project

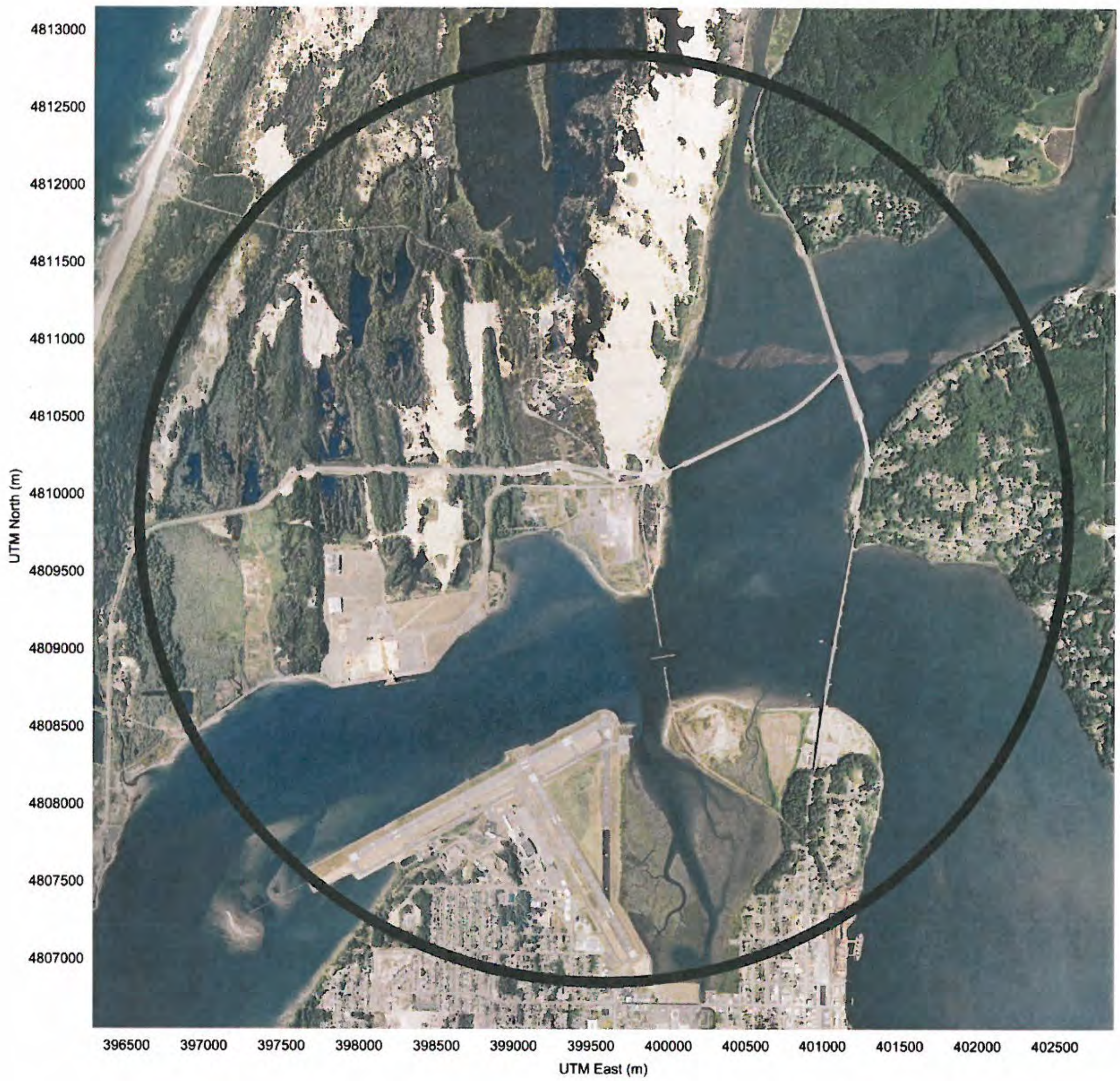


Figure 5-2: Location of the Proposed JCEP Facility and North Bend Municipal Airport

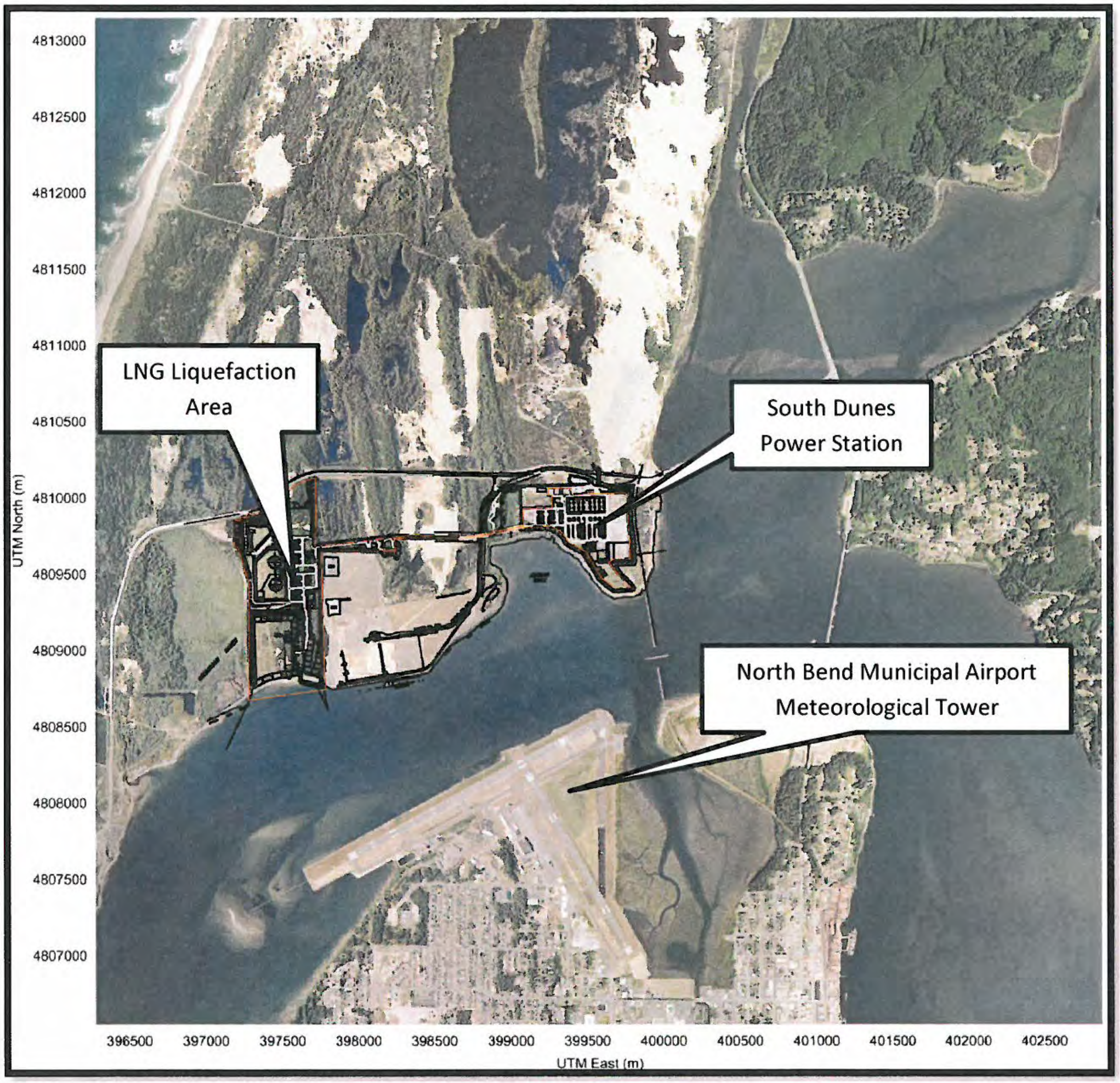


Figure 5-3: Wind Rose for North Bend Municipal Airport (2007-2011)

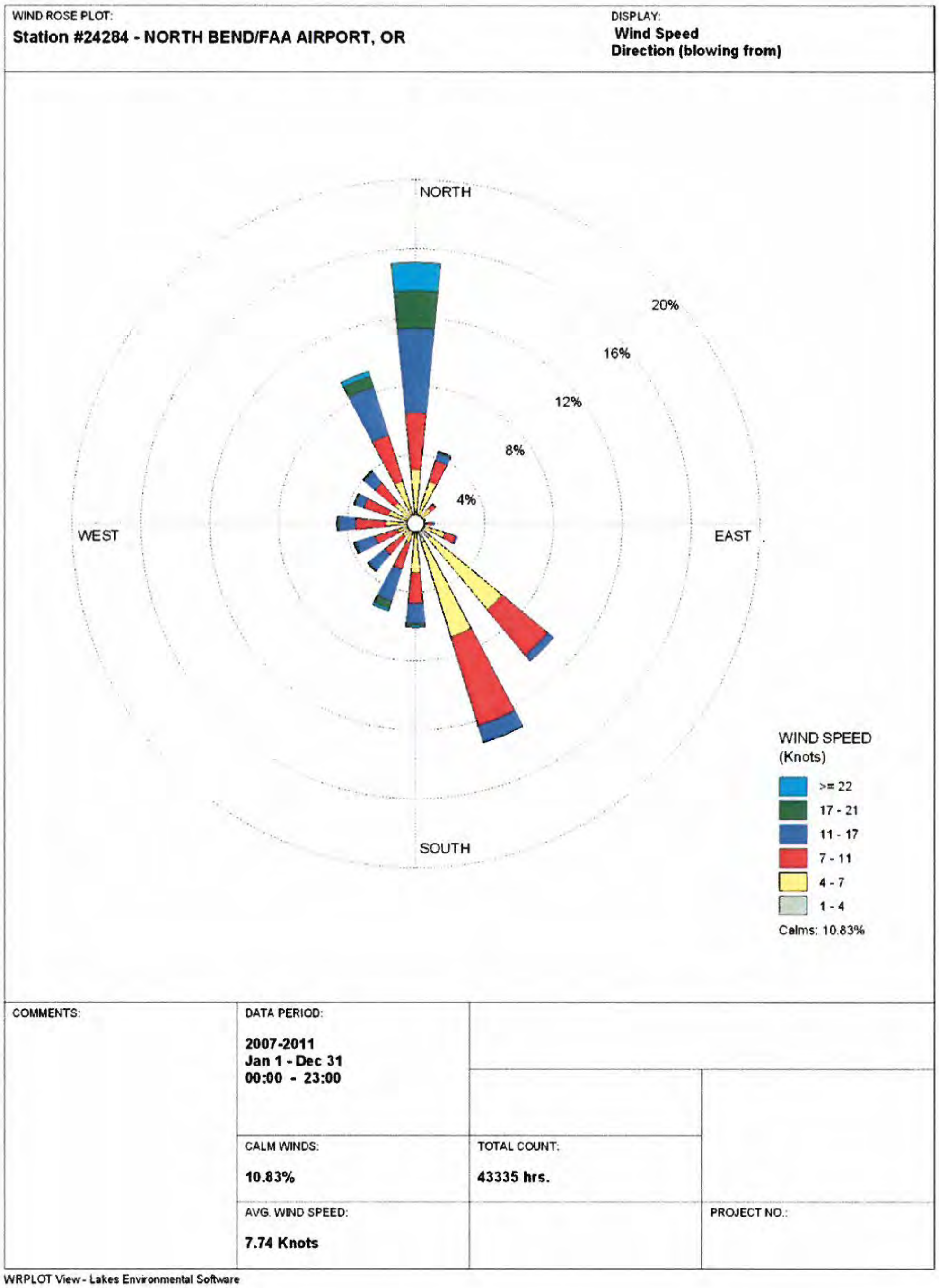


Figure 5-4: Modeling Receptor Grid (Full Grid)

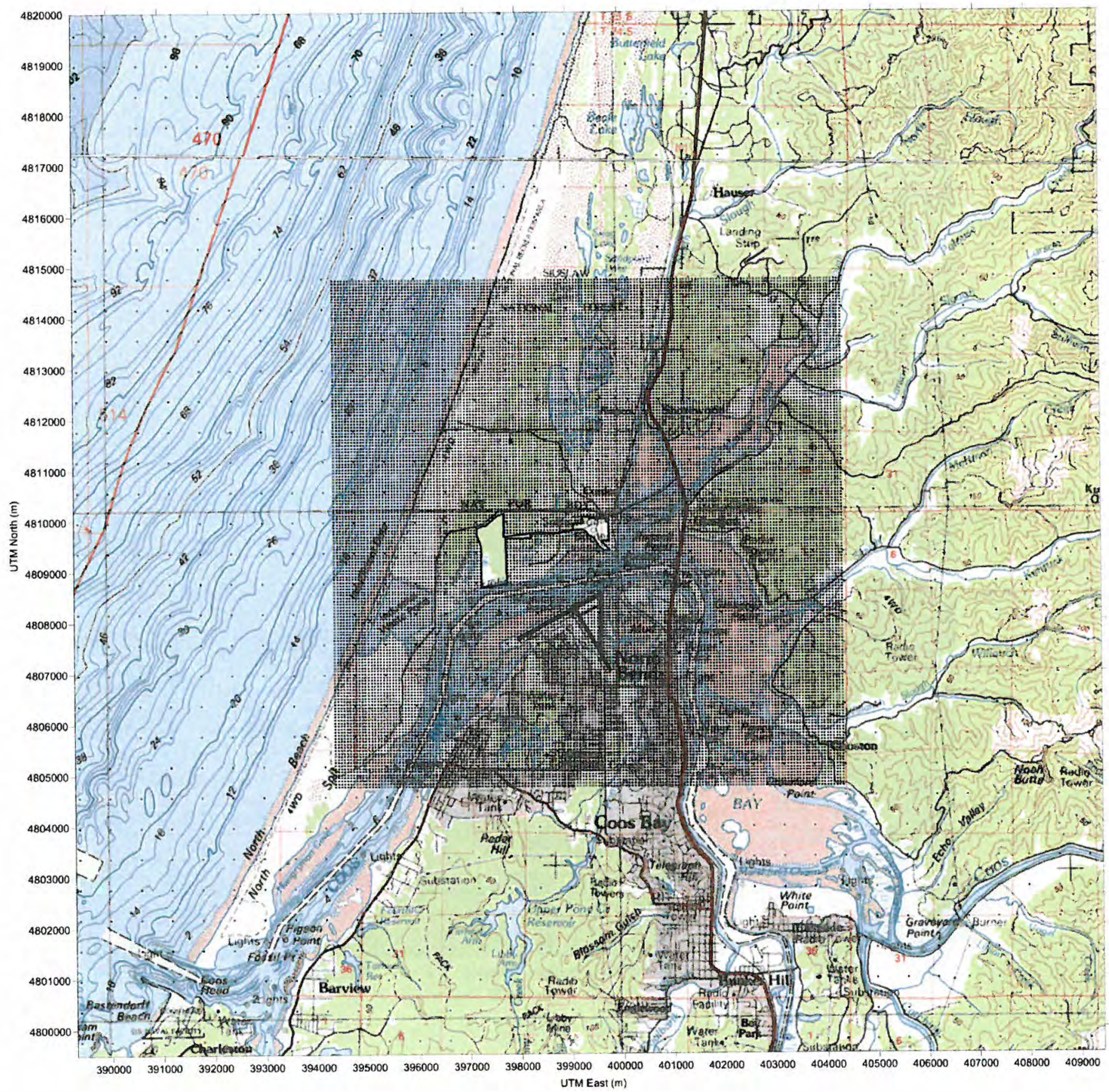
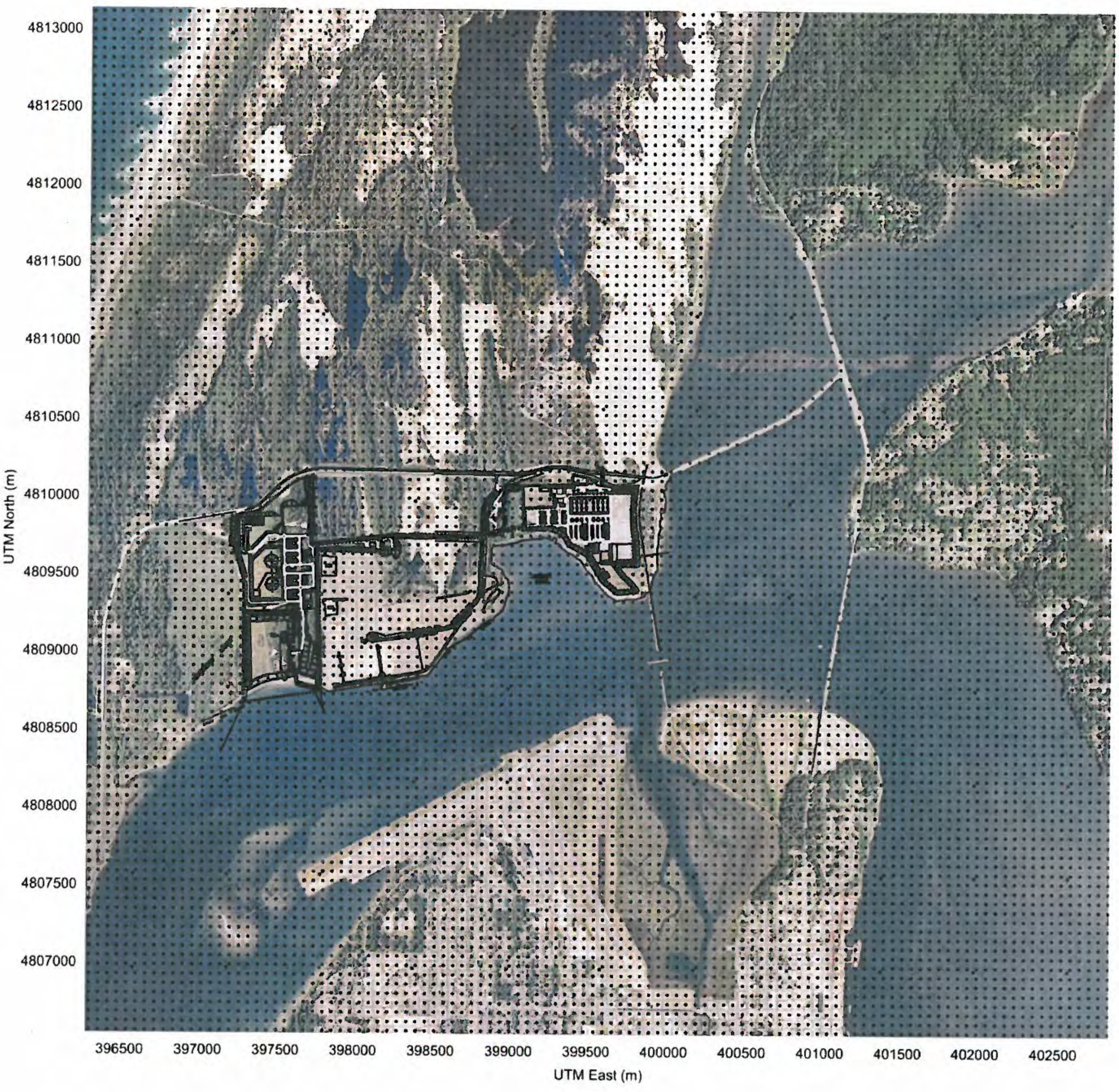


Figure 5-5: Modeling Receptor Grid (Near Grid)



REFERENCES

U.S. EPA, 2005. Guideline on Air Quality Models (Revised). Appendix W to Title 40 U.S. Code of Federal Regulations (CFR) Parts 51 and 52, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. November 6, 2005.

U.S. EPA, 1992. "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised". EPA Document 454/R-92-019, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

U.S. EPA, 1990. "New Source Review Workshop Manual, Draft". Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

U.S. EPA, 1985. Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised). EPA-450/4-80-023R. U.S. Environmental Protection Agency.

U.S. EPA, 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals. EPA 450/2-81-078. Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. December 1980.

U.S. EPA, 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO2 NAAQS. U.S. EPA. March 1, 2011.

Appendix F
Summary of Combustion Turbine Load Analysis

Jordan Cove Energy Project - Six GE LM6000 PG Combustion Turbines - Single Flue Stacks (119 feet above grade)

1-Hour	MAX XOQ	AVERAGE 5-YR XOQ	yymmddhh	UTMX	UTMY	ELEV (m)	NO2	CO	PM10	PM2.5	SO2	Distance	Direction
CASE01	78.02718	72.191742	9082805	403803	4809685	111.06	28.38	47.19	NA	NA	15.55	4421	91
CASE02	79.56716	73.500906	9082805	403803	4809685	111.06	31.86	52.13	NA	NA	17.13	4421	91
CASE03	83.96838	78.296076	9082805	403803	4809685	111.06	23.68	39.15	NA	NA	12.82	4421	91
CASE04	87.3916	83.79538	9090321	403803	4809625	108.81	19.43	30.83	NA	NA	10.35	4422	92
CASE05	81.25937	74.924694	9082805	403803	4809685	111.06	29.45	49.15	NA	NA	16.05	4421	91
CASE06	81.93628	75.4765	9082805	403803	4809685	111.06	31.19	51.62	NA	NA	16.93	4421	91
CASE07	83.31019	77.270048	9082805	403803	4809685	111.06	24.15	39.89	NA	NA	12.95	4421	91
CASE08	87.8033	84.52305	10070622	403563	4809385	102.97	19.60	30.98	NA	NA	10.54	4197	95
CASE09	83.31409	77.245904	9082805	403803	4809685	111.06	26.47	44.09	NA	NA	14.40	4421	91
CASE10	83.98469	78.248826	9082805	403803	4809685	111.06	33.13	53.97	NA	NA	17.94	4421	91
CASE11	85.42525	81.053484	9082805	403803	4809685	111.06	22.06	35.52	NA	NA	11.74	4421	91
CASE12	90.48718	86.672814	10070622	403563	4809385	102.97	17.47	28.50	NA	NA	9.50	4197	95
3-Hour	**MAX XOQ**	**AVERAGE 5-YR XOQ**	**yymmddhh**	**UTMX**	**UTMY**	**ELEV (m)**	**NO2**	**CO**	**PM10**	**PM2.5**	**SO2**	**Distance**	**Direction**
CASE01	36.92085	33.283948	10082224	405583	4805165	125.4	NA	NA	NA	NA	7.95	7720	127
CASE02	37.25467	33.975486	10082224	406183	4805165	112.36	NA	NA	NA	NA	8.68	8210	124
CASE03	39.85181	36.70285	10082224	406183	4805165	112.36	NA	NA	NA	NA	6.53	8210	124
CASE04	43.1908	39.637152	11072803	404283	4806985	97.28	NA	NA	NA	NA	5.33	5634	120
CASE05	38.18389	34.865454	10082224	406183	4805165	112.36	NA	NA	NA	NA	8.18	8210	124
CASE06	38.54702	35.205536	10082224	406183	4805165	112.36	NA	NA	NA	NA	8.65	8210	124
CASE07	39.42972	36.180048	10082224	406183	4805165	112.36	NA	NA	NA	NA	6.61	8210	124
CASE08	43.58009	40.066162	11072803	404283	4806985	97.28	NA	NA	NA	NA	5.44	5634	120
CASE09	39.42675	36.17234	10082224	406183	4805165	112.36	NA	NA	NA	NA	7.35	8210	124
CASE10	39.85289	36.696384	10082224	406183	4805165	112.36	NA	NA	NA	NA	9.14	8210	124
CASE11	41.54325	38.079628	11072803	404283	4806985	97.28	NA	NA	NA	NA	6.02	5634	120
CASE12	44.50473	41.132964	11072803	404283	4806985	97.28	NA	NA	NA	NA	4.88	5634	120
8-Hour	**MAX XOQ**	**AVERAGE 5-YR XOQ**	**yymmddhh**	**UTMX**	**UTMY**	**ELEV (m)**	**NO2**	**CO**	**PM10**	**PM2.5**	**SO2**	**Distance**	**Direction**
CASE01	22.32274	17.037362	7050724	404283	4807105	103.12	NA	13.50	NA	NA	NA	5575	118
CASE02	22.73746	17.432494	7050724	404283	4807105	103.12	NA	14.90	NA	NA	NA	5575	118
CASE03	24.11885	18.985182	7050724	404223	4807165	99.69	NA	11.24	NA	NA	NA	5494	118
CASE04	25.77333	20.88047	7050724	404103	4807225	98.05	NA	9.09	NA	NA	NA	5360	118
CASE05	23.18731	17.91806	7050724	404283	4807105	103.12	NA	14.02	NA	NA	NA	5575	118
CASE06	23.3637	18.069424	7050724	404283	4807105	103.12	NA	14.72	NA	NA	NA	5575	118
CASE07	23.76984	18.648236	7050724	404223	4807165	99.69	NA	11.38	NA	NA	NA	5494	118
CASE08	25.99514	21.161312	7050724	404103	4807225	98.05	NA	9.17	NA	NA	NA	5360	118
CASE09	23.76934	18.6414	7050724	404283	4807105	103.12	NA	12.58	NA	NA	NA	5575	118
CASE10	24.12184	18.965894	7050724	404223	4807165	99.69	NA	15.50	NA	NA	NA	5494	118
CASE11	25.03066	19.913496	7050724	404223	4807165	99.69	NA	10.41	NA	NA	NA	5494	118
CASE12	26.62133	21.877782	7050724	404163	4807225	95.8	NA	8.39	NA	NA	NA	5413	118
24-Hour	**MAX XOQ**	**AVERAGE 5-YR XOQ**	**yymmddhh**	**UTMX**	**UTMY**	**ELEV (m)**	**NO2**	**CO**	**PM10**	**PM2.5**	**SO2**	**Distance**	**Direction**
CASE01	7.44197	7.133756	7050724	404283	4807105	103.12	NA	NA	5.72	5.48	1.60	5575	118
CASE02	7.58025	7.236274	7050724	404283	4807105	103.12	NA	NA	7.35	7.02	1.77	5575	118
CASE03	8.8131	7.89243	8011024	399723	4810045	6.31	NA	NA	6.11	5.47	1.44	441	51
CASE04	10.86415	8.94868	8011024	399723	4810045	6.31	NA	NA	6.98	5.75	1.34	441	51
CASE05	7.73369	7.416206	8072324	399583	4800365	100.17	NA	NA	6.24	5.98	1.66	9402	179
CASE06	7.83931	7.49144	8072324	399583	4800365	100.17	NA	NA	7.21	6.89	1.76	9402	179
CASE07	8.44844	7.745386	8011024	399723	4810045	6.31	NA	NA	5.96	5.47	1.42	441	51
CASE08	11.11482	9.131172	8011024	399723	4810045	6.31	NA	NA	7.42	6.10	1.39	441	51
CASE09	8.23848	7.702314	8011024	399723	4810045	6.31	NA	NA	6.33	5.92	1.54	441	51
CASE10	8.39317	7.807438	8011024	399723	4810045	6.31	NA	NA	9.31	8.66	1.92	441	51
CASE11	9.88603	8.37951	8011024	399723	4810045	6.31	NA	NA	6.98	5.91	1.43	441	51
CASE12	11.85704	9.614676	8011024	399723	4810045	6.31	NA	NA	7.77	6.30	1.30	441	51
Annual	**MAX XOQ**	**AVERAGE 5-YR XOQ**	**Year**	**UTMX**	**UTMY**	**ELEV (m)**	**NO2**	**CO**	**PM10**	**PM2.5**	**SO2**	**Distance**	**Direction**
CASE01	0.55423	0.491368	2008	399543	4809205	0	0.20	NA	0.43	0.38	0.12	582	164
CASE02	0.57247	0.508052	2008	399543	4809205	0	0.23	NA	0.56	0.49	0.13	582	164
CASE03	0.74178	0.657264	2008	399543	4809265	0	0.21	NA	0.51	0.46	0.12	525	162
CASE04	0.94245	0.842866	2008	399543	4809265	0	0.20	NA	0.61	0.54	0.12	525	162
CASE05	0.61683	0.547272	2008	399543	4809265	0	0.23	NA	0.50	0.44	0.13	525	162
CASE06	0.62671	0.55624	2008	399543	4809265	0	0.24	NA	0.58	0.51	0.14	525	162
CASE07	0.70682	0.62743	2008	399543	4809265	0	0.21	NA	0.50	0.44	0.12	525	162
CASE08	0.97169	0.870074	2008	399543	4809265	0	0.21	NA	0.65	0.58	0.12	525	162
CASE09	0.69095	0.613164	2008	399543	4809265	0	0.22	NA	0.53	0.47	0.13	525	162
CASE10	0.7064	0.627534	2008	399543	4809265	0	0.28	NA	0.78	0.70	0.16	525	162
CASE11	0.83965	0.747488	2008	399543	4809265	0	0.21	NA	0.59	0.53	0.12	525	162
CASE12	1.05452	0.947066	2008	399543	4809265	0	0.20	NA	0.69	0.62	0.12	525	162

Notes: 24-hour and annual PM-2.5, 1-Hour SO2, and 1-Hour NO2 impacts based upon average 5-yr XOQ.
XOQ represents six combustion turbines.

Appendix G
Electronic Air Quality Modeling Files

This DVD contains the modeling input and output files for the proposed JCEP LNG Terminal Project
located in Coos County, Oregon. The following are brief descriptions
for each of the modeling files used in the air quality modeling analysis. (March 2013)

** Note that all files with the .inp extension are input files.
** All files with the .out extension are output files.

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMAP

** This Directory contains the AERMAP input and output files used to process the standard modeling receptor grid.

```
06/21/2012  02:13 PM       166,154,079 74762863.tif
06/21/2012  02:11 PM       166,185,655 79795317.tif
10/24/2012  01:25 PM           887,089 aermap.exe
10/24/2012  01:34 PM           995,125 aermap.inp
10/27/2012  08:53 PM             4,105 aermap.out
10/27/2012  08:53 PM         1,809,538 JCEPREC.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMAP\SIAGrid

** This Directory contains the AERMAP input and output files used to process the extended modeling receptor grid
** used in determining some pollutant specific SIAs.

```
11/30/2012  04:05 PM        94,228,591 02742229.tif
11/30/2012  05:10 PM        94,228,591 19939544.tif
11/30/2012  05:10 PM        94,255,935 20338806.tif
11/30/2012  04:05 PM        94,228,591 30287896.tif
11/30/2012  05:09 PM        94,255,935 38675475.tif
11/30/2012  04:06 PM        94,228,591 41141311.tif
11/30/2012  04:06 PM        94,228,591 55618685.tif
11/30/2012  04:05 PM        94,228,591 57854013.tif
11/30/2012  04:06 PM        94,228,591 60445903.tif
11/30/2012  05:14 PM        94,228,591 61713044.tif
11/30/2012  04:05 PM        94,243,343 63455854.tif
11/30/2012  05:10 PM        94,228,591 64287507.tif
11/30/2012  04:06 PM        94,269,723 67857865.tif
11/30/2012  04:06 PM        94,242,375 85153958.tif
11/30/2012  05:10 PM        94,255,935 91248159.tif
11/30/2012  05:11 PM        94,243,343 99327441.tif
10/24/2012  01:25 PM           887,089 aermap.exe
11/30/2012  05:19 PM           814,354 aermap.inp
12/01/2012  06:38 PM             9,089 aermap.out
12/01/2012  06:38 PM         1,363,448 JCEPREC.out
```

```
**************************************************************************************
*********************************
```

** This Directory contains the processing of meteorological datasets with AERMET to create AERMOD ready .sfc and .pfl files.

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET

```
03/18/2013  04:22 PM    <DIR>          AERSURF
03/18/2013  03:29 PM    <DIR>          Merge
03/18/2013  02:00 PM    <DIR>          Stage 3
03/18/2013  03:32 PM    <DIR>          Surface
03/18/2013  03:35 PM    <DIR>          Upper Air
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET\AERSURF

```
04/04/2012  03:35 PM               988 AERSURFACE.DAT
04/04/2012  03:35 PM           333,270 albedo_bowen_domain.txt
10/11/2000  02:47 PM           133,712 conus.las
10/11/2000  02:47 PM           133,712 conus.los
04/04/2012  03:35 PM           357,476 coos.log
04/04/2012  03:35 PM             8,929 coos.out
04/10/2008  10:54 AM        38,779,233 oregon.nlcd.tif.gz
01/07/2002  03:42 PM       483,850,538 oregon_NLCD_erd_032400.tif
04/04/2012  03:35 PM            13,804 roughness_domain.txt
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET\Merge

```
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:28 PM               195 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:36 AM               922 COOS.MSG
12/20/2012  11:36 AM            86,061 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.dat
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.dat
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET\Stage 3

```
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:46 PM             8,599 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:37 AM         1,060,385 COOS.MSG
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM            23,232 COOS.RPT
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET\Surface

```
04/04/2012  03:05 PM        32,544,214 726917-24284-0711.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:06 PM               372 aermet.INP
12/20/2012  11:33 AM        26,215,855 COOS.MSG
12/20/2012  11:33 AM           239,433 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.DAT
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMET\Upper Air

```
04/04/2012  02:12 PM        23,927,474 72694.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  02:05 PM               373 aermet.INP
12/20/2012  11:33 AM        24,526,315 COOS.MSG
12/20/2012  11:33 AM            14,241 COOS.RPT
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.DAT
```

****

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD

```
03/18/2013  10:17 AM    &lt;DIR&gt;          Class I Screening
03/19/2013  11:24 AM    &lt;DIR&gt;          Load Analysis_Combustion Turbines
03/18/2013  10:17 AM    &lt;DIR&gt;          SIA Modeling
03/18/2013  10:18 AM    &lt;DIR&gt;          Single Source Modeling
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening

** This Directory contains the AERMOD input and output files used for Class I screening modeling

```
03/19/2013  11:22 AM    &lt;DIR&gt;          NO2Annual
03/19/2013  11:21 AM    &lt;DIR&gt;          PM1024HR
03/19/2013  11:21 AM    &lt;DIR&gt;          PM10Annual
03/19/2013  11:22 AM    &lt;DIR&gt;          PM2.524HR
03/19/2013  11:22 AM    &lt;DIR&gt;          PM2.5Annual
03/19/2013  11:20 AM    &lt;DIR&gt;          SO224HR
03/19/2013  11:20 AM    &lt;DIR&gt;          SO23HR
03/19/2013  11:21 AM    &lt;DIR&gt;          SO2Annual
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual

```
03/19/2013  11:22 AM    &lt;DIR&gt;          2007
03/19/2013  11:22 AM    &lt;DIR&gt;          2008
03/19/2013  11:22 AM    &lt;DIR&gt;          2009
03/19/2013  11:22 AM    &lt;DIR&gt;          2010
03/19/2013  11:22 AM    &lt;DIR&gt;          2011
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,465 aermod.inp
03/07/2013  06:14 PM           225,793 annno207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:16 PM           106,467 aermod.inp
03/07/2013  06:15 PM           225,793 annno208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
```

```
                                            dir.dat
03/07/2013  05:16 PM               106,467 aermod.inp
03/07/2013  06:14 PM               225,793 annno209class1.out
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual\2010

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  05:17 PM               106,469 aermod.inp
03/07/2013  06:14 PM               225,793 annno210class1.out
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\NO2Annual\2011

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  05:17 PM               106,467 aermod.inp
03/07/2013  06:15 PM               227,662 annno211class1.out
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\PM1024HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\PM1024HR\2007

03/07/2013  06:00 PM               276,095 24hrpm07class1.out
12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:54 PM                78,630 aermod.inp
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\PM1024HR\2008

03/07/2013  06:08 PM               276,095 24hrpm08class1.out
12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:54 PM                78,630 aermod.inp
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\PM1024HR\2009

03/07/2013  06:10 PM               276,095 24hrpm09class1.out
12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:55 PM                78,630 aermod.inp
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I Screening\PM1024HR\2010
```

```
03/07/2013  06:14 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM1024HR\2011

03/07/2013  06:15 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:50 PM            78,630 aermod.inp
03/07/2013  05:59 PM           197,121 annpm07class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:05 PM           197,121 annpm08class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:07 PM           197,121 annpm09class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:10 PM           197,121 annpm10class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM10Annual\2011
```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:14 PM           198,990 annpm11class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:22 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR\2007

03/07/2013  05:57 PM           276,095 24hrpm07class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:47 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR\2008

03/07/2013  06:01 PM           276,095 24hrpm08class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR\2009

03/07/2013  06:04 PM           276,095 24hrpm09class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR\2010

03/07/2013  06:07 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.524HR\2011

03/07/2013  06:12 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:49 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual
```

```
03/19/2013  11:22 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:44 PM            78,635 aermod.inp
03/07/2013  05:54 PM           197,121 annpm2507class1.out
03/07/2013  05:58 PM           197,121 annpm2508class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  05:57 PM           197,121 annpm2509class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  06:04 PM           197,121 annpm2510class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:46 PM            78,635 aermod.inp
03/07/2013  06:06 PM           198,990 annpm2511class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO224HR

03/07/2013  06:55 PM           109,668 24hrso2.out
03/07/2013  06:55 PM           277,964 24hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:05 PM            78,140 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
```

```
Screening\SO23HR

03/07/2013  06:55 PM           109,668 3hourso2.out
03/07/2013  06:55 PM           277,964 3hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:04 PM            78,138 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual

03/19/2013  11:20 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:59 PM            78,133 aermod.inp
03/07/2013  06:02 PM           100,499 annso207.out
03/07/2013  06:09 PM           197,121 annso207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:09 PM           100,499 annso208.out
03/07/2013  06:02 PM           197,121 annso208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:11 PM           100,499 annso209.out
03/07/2013  06:12 PM           197,121 annso209class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:14 PM           100,499 annso210.out
03/07/2013  06:14 PM           197,121 annso210class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Class I
Screening\SO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
```

```
03/07/2013  06:15 PM           100,499 annso211.out
03/07/2013  06:15 PM           198,990 annso211class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines

03/19/2013  11:24 AM    <DIR>          2007
03/19/2013  11:24 AM    <DIR>          2008
03/19/2013  11:24 AM    <DIR>          2009
03/19/2013  11:24 AM    <DIR>          2010
03/19/2013  11:24 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  05:28 AM       268,260,264 load07.out

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:38 AM       268,260,264 load08.out

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:05 AM       268,260,264 load09.out

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:14 AM       268,260,264 load10.out

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Load Analysis_Combustion Turbines\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:22 AM       268,262,133 load11.out

**********************************************************************************************************************
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling

** This Directory contains the AERMOD input and output files used for modeling pollutant specific significant impact areas

```
03/19/2013  11:27 AM    <DIR>          NO21HR
03/19/2013  11:29 AM    <DIR>          PM1024HR
03/19/2013  11:29 AM    <DIR>          PM2.524HR
03/19/2013  11:27 AM    <DIR>          PM2.5Annual
03/19/2013  11:29 AM    <DIR>          SO21HR
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling\NO21HR

```
03/08/2013  12:25 AM         5,145,536 1hrno2.8th
03/08/2013  12:25 AM         5,145,536 1hrno2.txt
03/08/2013  12:25 AM        12,777,361 1hrso2sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  03:53 PM         1,379,664 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling\PM1024HR

```
03/19/2013  11:29 AM    <DIR>          2007
03/19/2013  11:29 AM    <DIR>          2008
03/19/2013  11:29 AM    <DIR>          2009
03/19/2013  11:29 AM    <DIR>          2010
03/19/2013  11:29 AM    <DIR>          2011
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling\PM1024HR\2007

```
03/08/2013  12:34 AM         2,617,117 24HRPM07.txt
03/08/2013  12:34 AM        20,191,763 24hrpm07sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:13 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling\PM1024HR\2008

```
03/08/2013  12:36 AM         2,617,117 24HRPM08.txt
03/08/2013  12:36 AM        20,191,763 24hrpm08sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA Modeling\PM1024HR\2009

```
03/08/2013  12:24 AM         2,617,117 24HRPM09.txt
03/08/2013  12:24 AM        20,191,763 24hrpm09sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA

```
Modeling\PM1024HR\2010

03/08/2013  12:25 AM         2,617,117 24HRPM10.txt
03/08/2013  12:27 AM        20,191,763 24hrpm10sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM1024HR\2011

03/08/2013  12:49 AM         2,617,117 24HRPM11.txt
03/08/2013  12:49 AM        20,193,632 24hrpm11sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:15 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR

03/19/2013  11:28 AM    <DIR>          2007
03/19/2013  11:28 AM    <DIR>          2008
03/19/2013  11:28 AM    <DIR>          2009
03/19/2013  11:28 AM    <DIR>          2010
03/19/2013  11:29 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR\2007

03/08/2013  12:20 AM         2,617,117 24HRPM07.txt
03/08/2013  12:24 AM        20,191,763 24hrpm2507sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:10 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR\2008

03/08/2013  12:42 AM         2,617,117 24HRPM08.txt
03/08/2013  12:42 AM        20,191,763 24hrpm2508sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:10 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR\2009

03/08/2013  12:27 AM         2,617,117 24HRPM09.txt
03/08/2013  12:27 AM        20,191,763 24hrpm2509sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR\2010

03/08/2013  12:12 AM         2,617,117 24HRPM10.txt
03/08/2013  12:16 AM        20,191,763 24hrpm2510sia.out
```

```
                                          dir.dat
12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:11 PM             1,395,644 aermod.inp
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.524HR\2011

03/08/2013  12:29 AM             2,617,117 24HRPM11.txt
03/08/2013  12:29 AM            20,193,632 24hrpm2511sia.out
12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:11 PM             1,395,644 aermod.inp
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual

03/19/2013  11:27 AM    <DIR>          2007
03/19/2013  11:27 AM    <DIR>          2008
03/19/2013  11:27 AM    <DIR>          2009
03/19/2013  11:27 AM    <DIR>          2010
03/19/2013  11:27 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:06 PM             1,395,648 aermod.inp
03/08/2013  12:11 AM            10,940,646 annpm2507sia.out
03/08/2013  12:09 AM             2,397,238 AnnuPM07.txt
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:07 PM             1,395,648 aermod.inp
03/08/2013  12:29 AM            10,940,646 annpm2508sia.out
03/08/2013  12:29 AM             2,397,238 AnnuPM08.txt
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:07 PM             1,395,648 aermod.inp
03/08/2013  12:37 AM            10,940,646 annpm2509sia.out
03/08/2013  12:37 AM             2,397,238 AnnuPM09.txt
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM             2,545,152 aermod.exe
03/07/2013  04:08 PM             1,395,648 aermod.inp
03/08/2013  12:26 AM            10,940,646 annpm2510sia.out
03/08/2013  12:23 AM             2,397,238 AnnuPM10.txt
12/20/2012  11:37 AM             2,936,208 COOS.PFL
12/20/2012  11:37 AM             7,231,060 COOS.SFC
```

```
 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:08 PM         1,395,648 aermod.inp
03/08/2013  12:19 AM        10,942,515 annpm2511sia.out
03/08/2013  12:17 AM         2,397,238 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\SIA
Modeling\SO21HR

03/08/2013  08:34 AM         5,145,536 1hrso2.txt
03/08/2013  08:34 AM        20,172,305 1hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:17 PM         1,395,151 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC


*************************************************************************************
*********************************

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling

** This Directory contains the AERMOD input and output files used for modeling the
Facility for the purposes of obtaining maximum modeled impacts

03/19/2013  11:33 AM    <DIR>          CO1HR
03/19/2013  11:33 AM    <DIR>          CO8HR
03/19/2013  11:33 AM    <DIR>          NO21HR
03/19/2013  11:34 AM    <DIR>          NO2Annual
03/19/2013  11:36 AM    <DIR>          PM1024HR
03/19/2013  11:36 AM    <DIR>          PM10Annual
03/19/2013  11:35 AM    <DIR>          PM2.524HR
03/19/2013  11:35 AM    <DIR>          PM2.5Annual
03/19/2013  11:37 AM    <DIR>          SO21HR
03/19/2013  11:33 AM    <DIR>          SO224HR
03/19/2013  11:33 AM    <DIR>          SO23HR
03/19/2013  11:37 AM    <DIR>          SO2Annual

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\CO1HR

03/08/2013  10:24 AM        26,861,331 1hrCO.out
03/08/2013  10:24 AM         3,473,322 1HRCO.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:49 PM         1,855,704 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\CO8HR

03/08/2013  10:24 AM        26,861,331 8hrCO.out
03/08/2013  10:24 AM         3,473,322 8HRCO.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:51 PM         1,855,704 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO21HR

```
03/06/2013  08:30 PM         6,829,166 1hrno2.8th
03/06/2013  08:30 PM        21,808,564 1hrno2.out
03/06/2013  08:30 PM         6,829,166 1hrno2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:48 PM         1,825,861 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual

```
03/19/2013  11:34 AM    <DIR>          2007
03/19/2013  11:34 AM    <DIR>          2008
03/19/2013  11:34 AM    <DIR>          2009
03/19/2013  11:34 AM    <DIR>          2010
03/19/2013  11:34 AM    <DIR>          2011
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM         3,181,493 AnnNO207.txt
03/07/2013  08:58 PM        21,965,930 anno207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  09:09 PM        21,965,930 annno208.out
03/07/2013  09:09 PM         3,181,493 AnnNO208.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM        21,965,930 annno209.out
03/07/2013  08:58 PM         3,181,493 AnnNO209.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  09:06 PM        21,965,930 annno210.out
03/07/2013  09:06 PM         3,181,493 AnnNO210.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\NO2Annual\2011

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  09:07 PM        21,967,799 annno211.out
03/07/2013  09:07 PM         3,181,493 AnnNO211.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR

03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR\2007

03/07/2013  06:45 PM        26,785,295 24hrpm07.out
03/07/2013  06:45 PM         3,473,322 24HRPM07.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR\2008

03/07/2013  06:53 PM        26,785,295 24hrpm08.out
03/07/2013  06:53 PM         3,473,322 24HRPM08.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR\2009

03/07/2013  06:46 PM        26,785,295 24hrpm09.out
03/07/2013  06:46 PM         3,473,322 24HRPM09.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR\2010

03/07/2013  06:46 PM        26,785,295 24hrpm10.out
03/07/2013  06:46 PM         3,473,322 24HRPM10.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:36 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM1024HR\2011

03/07/2013  06:48 PM        26,787,164 24hrpm11.out
03/07/2013  06:48 PM         3,473,322 24HRPM11.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
```

```
                                         dir.dat
03/07/2013  02:36 PM            1,841,805 aermod.inp
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual

```
03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual\2007

```
12/20/2012  03:20 PM            2,545,152 aermod.exe
03/08/2013  01:04 PM            1,841,801 aermod.inp
03/08/2013  03:38 PM           14,504,228 Annpm07.out
03/08/2013  03:38 PM            3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual\2008

```
12/20/2012  03:20 PM            2,545,152 aermod.exe
03/08/2013  01:05 PM            1,841,801 aermod.inp
03/08/2013  03:44 PM           14,504,228 Annpm08.out
03/08/2013  03:44 PM            3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual\2009

```
12/20/2012  03:20 PM            2,545,152 aermod.exe
03/08/2013  01:05 PM            1,841,801 aermod.inp
03/08/2013  03:39 PM           14,504,228 Annpm09.out
03/08/2013  03:39 PM            3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual\2010

```
12/20/2012  03:20 PM            2,545,152 aermod.exe
03/08/2013  01:05 PM            1,841,801 aermod.inp
03/08/2013  03:40 PM           14,504,228 Annpm10.out
03/08/2013  03:40 PM            3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM10Annual\2011

```
12/20/2012  03:20 PM            2,545,152 aermod.exe
03/08/2013  01:06 PM            1,841,801 aermod.inp
03/08/2013  03:42 PM           14,506,097 Annpm11.out
03/08/2013  03:42 PM            3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM            2,936,208 COOS.PFL
12/20/2012  11:37 AM            7,231,060 COOS.SFC
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR

```
03/19/2013  11:35 AM    <DIR>          2007
03/19/2013  11:35 AM    <DIR>          2008
03/19/2013  11:35 AM    <DIR>          2009
03/19/2013  11:35 AM    <DIR>          2010
03/19/2013  11:35 AM    <DIR>          2011
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR\2007

```
03/06/2013  06:04 PM         3,473,322 24HRPM07.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:10 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:04 PM        31,654,956 load07.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR\2008

```
03/06/2013  06:09 PM         3,473,322 24HRPM08.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:17 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:09 PM        31,654,956 load08.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR\2009

```
03/06/2013  06:04 PM         3,473,322 24HRPM09.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:18 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:04 PM        31,654,956 load09.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR\2010

```
03/06/2013  06:05 PM         3,473,322 24HRPM10.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:18 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:05 PM        31,654,956 load10.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.524HR\2011

```
03/06/2013  06:07 PM         3,473,322 24HRPM11.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:19 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:07 PM        31,656,825 load11.out
```

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\PM2.5Annual

```
03/19/2013  11:34 AM    <DIR>          2007
```

```
                                              dir.dat
03/19/2013  11:35 AM    <DIR>          2008
03/19/2013  11:35 AM    <DIR>          2009
03/19/2013  11:35 AM    <DIR>          2010
03/19/2013  11:35 AM    <DIR>          2011

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:31 PM         1,841,802 aermod.inp
03/07/2013  07:03 PM        14,504,228 annpm2507.out
03/07/2013  07:03 PM         3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:31 PM         1,841,802 aermod.inp
03/07/2013  06:59 PM        14,504,228 annpm2508.out
03/07/2013  06:59 PM         3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:55 PM        14,504,228 annpm2509.out
03/07/2013  06:55 PM         3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:52 PM        14,504,228 annpm2510.out
03/07/2013  06:52 PM         3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:55 PM        14,506,097 annpm2511.out
03/07/2013  06:55 PM         3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source
Modeling\SO21HR

03/07/2013  03:43 AM        36,533,537 1hrso2.out
03/07/2013  03:43 AM        24,982,168 1hrso2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:56 PM         1,841,415 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

12/20/2012 11:37 AM 7,231,060 COOS.SFC

Directory of PSD_ACDP application\Appendix G_Modeling Files\AERMOD\Single Source Modeling\SO224HR

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03/07/2013 06:45 PM 14,504,228 annso207out.out
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12/20/2012 11:37 AM 7,231,060 COOS.SFC

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12/20/2012 11:37 AM 7,231,060 COOS.SFC

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Directory of PSD_ACDP application\Appendix G_Modeling Files\BPIP

** This Directory contains the BPIP input and output used for the building downwash analysis

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** This Directory contains the VISCREEN input and output files used for screening visibility modeling

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Appendix H
Toxic Air Pollutant Impacts Summary

Jordan Cove Energy Project, L.P.
Air Toxics Impacts Assessment

Maximum Modeled Annual XOQ	ug/m^3 per g/s emitted
Six Combustion turbines with DB	0.7064
Six Combustion turbines without DB	0.6910
Thermal Oxidizers	0.54008

Note: XOQs represent all combustion turbines or TOs

Hazardous Air Pollutants (HAPs)	New Combustion Turbines Natural Gas Firing Max Hourly Per CT	Duct Burners Natural Gas Firing Max Hourly Per DB	Thermal Oxidizers Gas Firing Max Hourly per TO	Maximum Modeled Concentrations (ug/m^3)					Oregon DEQ Ambient Benchmark (ug/m^3)	Hazard Quotient (Unitless)
				CTs			Thermal Oxidizers	Facility Total		
	lb/hr	lb/hr	lb/hr	with DB	without DB	Maximum Annual				
VOC-HAP										
Acetaldehyde	2.22E-02			1.97E-03	1.93E-03	1.95E-03	0.00E+00	1.95E-03	0.45	4.33E-03
Acrolein	3.55E-03			3.16E-04	3.09E-04	3.12E-04	0.00E+00	3.12E-04	0.02	1.56E-02
Benzene	6.65E-03	2.16E-04	3.58E-05	6.11E-04	5.79E-04	5.93E-04	2.44E-06	5.96E-04	0.13	4.58E-03
1,3-Butadiene	2.38E-04			2.12E-05	2.07E-05	2.10E-05	0.00E+00	2.10E-05	0.03	6.98E-04
Dichlorobenzene		1.24E-04	2.05E-05	1.10E-05	0.00E+00	5.02E-06	1.39E-06	6.41E-06	0.09	7.13E-05
Ethylbenzene	1.77E-02			1.58E-03	1.54E-03	1.56E-03	0.00E+00	1.56E-03	0.4	3.90E-03
Formaldehyde	6.09E-02	7.72E-03	1.28E-03	6.11E-03	5.31E-03	5.67E-03	8.71E-05	5.76E-03	3	1.92E-03
Hexane		1.85E-01	3.07E-02	1.65E-02	0.00E+00	7.53E-03	2.09E-03	9.62E-03	7000	1.37E-06
Naphthalene	7.20E-04	6.28E-05	1.04E-05	6.97E-05	6.27E-05	6.59E-05	7.08E-07	6.66E-05	0.03	2.22E-03
Propylene Oxide	1.61E-02			1.43E-03	1.40E-03	1.41E-03	0.00E+00	1.41E-03	-	-
Toluene	7.20E-02	3.50E-04	5.80E-05	6.44E-03	6.27E-03	6.35E-03	3.95E-06	6.35E-03	400	1.59E-05
Xylenes	3.55E-02			3.16E-03	3.09E-03	3.12E-03	0.00E+00	3.12E-03	700	4.45E-06
Polycyclic Organic Compounds (POM)										
Total POM	1.2E-03	9.08E-06	1.50E-06	1.09E-04	1.06E-04	1.08E-04	1.02E-07	1.08E-04	0.009	1.20E-02
Metal-HAPs										
Arsenic	1.09E-04	2.06E-05	3.41E-06	1.15E-05	9.46E-06	1.04E-05	2.32E-07	1.06E-05	0.0002	5.31E-02
Beryllium	6.52E-06	1.24E-06	2.05E-07	6.90E-07	5.67E-07	6.23E-07	1.39E-08	6.37E-07	0.0004	1.59E-03
Cadmium	5.97E-04	1.13E-04	1.88E-05	6.33E-05	5.20E-05	5.71E-05	1.28E-06	5.84E-05	0.0006	9.74E-02
Chromium	7.60E-04	1.44E-04	2.39E-05	8.05E-05	6.62E-05	7.27E-05	1.62E-06	7.44E-05	-	-
Lead	2.72E-04	5.15E-05	8.53E-06	2.88E-05	2.36E-05	2.60E-05	5.80E-07	2.66E-05	0.15	1.77E-04
Manganese	2.06E-04	3.91E-05	6.48E-06	2.19E-05	1.80E-05	1.97E-05	4.41E-07	2.02E-05	0.09	2.24E-04
Mercury	1.41E-04	2.68E-05	4.43E-06	1.50E-05	1.23E-05	1.35E-05	3.02E-07	1.38E-05	0.3	4.60E-05
Nickel	1.14E-03	2.16E-04	3.58E-05	1.21E-04	9.93E-05	1.09E-04	2.44E-06	1.12E-04	0.002	5.58E-02
Selenium	1.30E-05	2.47E-06	4.09E-07	1.38E-06	1.13E-06	1.25E-06	2.79E-08	1.27E-06	-	-

Appendix I
Multisource Air Quality Modeling Protocol

Jordan Cove Energy Project, L.P.

Multisource Air Quality Modeling Protocol

Prepared for

Oregon Department of Environmental Quality

Prepared by

TRC Environmental
Lyndhurst, NJ

April 2013

1.0 INTRODUCTION

TRC, on behalf of Jordan Cove Energy Project, L.P. (JCEP), compiled a multisource modeling emissions inventory to support a multisource National Ambient Air Quality Standards (NAAQS) analysis for the proposed liquefied natural gas (LNG) export terminal (to be known as the JCEP LNG Terminal (i.e., the Project or Facility). As presented in the single source modeling analysis provided in the JCEP PSD Air Permit Application and submitted to the Department on March 26, 2013, some modeled pollutant impacts were determined to be above the significant impact concentrations (SIC) specified in OAR 340-200-0020, Table 1. As such, an offsite source impact analysis is necessary to comply with the provisions presented in OAR 340-225-0050 for NAAQS and PSD Class II increment assessments. The inventory was compiled for the criteria pollutants nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and particulate matter with an aerodynamic diameter less than 10 and 2.5 micrometers (PM-10 and PM-2.5).

The inventory for existing offsite sources is based on information provided from the Oregon Department of Environmental Quality (ODEQ). A separate PSD increment inventory was provided by the ODEQ for modeling and comparing to the PSD Class II increment thresholds. A list of sources to be included in the modeling analysis was obtained with the approval of Mr. Phil Allen. This list included twelve sources located in Oregon that would need to be included in a multisource modeling analysis for NAAQS and PSD Class II increment compliance.

TRC obtained from ODEQ, air emissions data relative to the following twelve air emission facilities:

Source	Distance
Roseburg Forest Products	28.3 km
Bay Area Hospital	5.7 km
Southport Forest Products	15.2 km
Southport Forest Products	4.2 km
Coastal Cremation and Funeral Services	5.3 km
Georgia Pacific West	9.2 km
LTM	11.6 km
Lower Umpqua Crematory	30.5 km
LTM	14.8 km
Laskey Clifton	16.0 km
LTM – Knife River	14.9 km
Oregon Resources Corp.	8.9 km

Figure 1-1 presents the locations of the 12 facilities on a topographic map of the area surrounding the proposed facility.

While not explicitly required by any Federal or Oregon air regulations, ODEQ has requested that JCEP provide an estimate of LNG carrier emissions and subsequent impact modeling of these emissions. This document provides an estimate of the LNG carrier emissions while the LNG carriers are hotelling and loading (i.e., stationary). A full analysis including the transit and berthing/deberthing processes (i.e., time periods when the vessels are mobile and are excluded from ODEQ air permitting) will be provided as part of the FERC NEPA licensing process and will be provided to ODEQ via a copy of JCEP's Final Resource Report 9 (FERC ID PF12-7). This protocol contains the emission calculations and subsequent air emissions dispersion modeling methodology for those activities that occur while the LNG carrier is berthed, including the indirect (i.e., secondary) source emissions from the LNG vessels "hotelling" process (while the carrier is berthed and the propulsion engines are idling). These emissions will be modeled as competing sources in the NAAQS analyses.

The following sections outline the inventory development and proposed modeling methodologies that will be followed along with summary spreadsheets presenting source locations and base elevations, stack parameters, and emissions for each source.

2.0 INVENTORY METHODOLOGY

2.1.1 Off-site Stationary Sources

The multisource modeling inventory consists of three main parts – (1) source locations and base elevations, (2) source stack parameters (height, diameter, exhaust velocity, and exhaust temperature), and (3) source pollutant emission rates. A list of off-site stationary sources was obtained from ODEQ and modified as necessary to be as accurate as possible. A description of these modifications is provided below.

The source locations, in Universal Transverse Mercator (UTM) coordinates, North American Datum 1983 (NAD83), Zone 10, provided by ODEQ were confirmed by conducting an address and aerial map match to confirm the coordinates were as accurate as possible. The offsite stationary source stack parameters and emissions were obtained from ODEQ.

Additionally, ODEQ requested for the off-site source cumulative modeling analysis that building downwash be included in the analysis for those stacks that may be affected by downwash in the wake of buildings nearby. The ODEQ specified that downwash should be included for three of the off-site sources, including the Bay Area Hospital, Georgia Pacific, and Southport Forest Products. A survey of these facilities was performed by licensed surveyors (SHN Consulting Engineers and Geologists, Inc). The results of this survey are provided in Appendix A, and the resultant building downwash analysis is included in a single off-site building downwash BPIP file also provided as a hardcopy in Appendix A. The off-site survey provided precise stack locations and heights at each location, which were then used to confirm the details in the off-site source inventory provided by ODEQ. The stationary source off-site inventory proposed to be used in the multisource NAAQS and PSD increment analysis is shown in Table 2-1.

As provided in the JCEP PSD Air Permit Application, the single source modeling indicated potential exceedances of the SICs for 1-hour NO_2, 24-hour and annual PM-2.5, 24-hour PM-10, and 1-hour SO_2. As such, in accordance with OAR 340-225-0050(2)(b), the multisource NAAQS analysis will include the JCEP stationary sources, the offsite sources included in Table 2-1, and the representative background concentrations presented in the JCEP Monitoring exemption request, which was approved by the department on March 13, 2013.

Additionally, in order to comply with the PSD Class II increment provisions in accordance with OAR 340-225-0050(b)(1), a PSD Class II increment analysis will be necessary for 24-hour and annual PM-2.5, and 24-hour PM-10. A PSD Class II increment analysis is not necessary for 1-hour NO_2 and 1-hour SO_2 since there are no established increments for these specific averaging periods as shown in OAR 340-202-0210, Table 1. As shown in OAR 340-225-0020, the baseline concentration dates for PM-10 and PM-2.5 are 1978 and 2007, respectively. Thus, the PSD increment analysis for PM-2.5 will include only those offsite sources that began operation after January 1, 2007. Based upon a review of the Oregon DEQ TRAACS database activity start dates the only offsite facility that began operation in 2007 or later is the Oregon Resources Corp. facility. The PSD Class II increment analysis will include the JCEP stationary sources and the competing PSD increment consuming source impacts above the baseline concentrations as identified in Table 2-1.

2.1.2 LNG Vessel Source

The Project will have associated mobile sources (i.e., LNG vessels) that will be moored at the ship berthing area during loading of LNG from the LNG storage tanks or directly after undergoing the gas conditioning and liquefaction processes. The Project is designed to accept any LNG vessel capable of onloading LNG at the facility and thus, it is not possible to prepare emission estimates for a single LNG vessel design. However, emissions have been determined for the 148,000 m^3 LNG carrier ships, which are typical of the LNG ships anticipated to transit the waterway to the Project. Power demands while the LNG vessels are being loaded are expected to be 1.9 MW for ship hotelling and 1.675 MW to maintain the propulsion system on hot standby. As indicated in the introduction, this protocol contains the emission calculations and subsequent dispersion modeling methodology for those activities that occur while the LNG carrier is stationary (i.e., berthed). The power to provide for the pumps to onload the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the onloading process that would be subject to ACDP and PSD review as well as the requirement to formally model those emissions.

The current fleet of LNG vessels consists primarily of vessels that have boiler/steam turbine driven (ST) propulsion systems. It is expected that by the operational date of the JCEP terminal, currently expected in 2018, that the fleet of LNG vessels that will call on the terminal will consist of a mix of vessels powered by ST propulsion and dual-fuel diesel–electric (DFDE) propulsion. Furthermore, it is expected that most, if not all of the ST and DFDE vessels combust either LNG boil off gas (BOG) or oil (marine distillate) in their propulsion and auxiliary power systems. Thus, an envelope of four (4) LNG vessel operating cases was developed in order to provide worst-case air emission calculations and associated air quality modeling impacts for these emissions. Specifically, these cases consist of LNG vessels firing either marine oil or BOG for LNG carriers utilizing ST propulsion or DFDE propulsion.

Appendix B contains the detailed emission calculations for the LNG vessels while stationary. Each table provides all of the pertinent assumptions/basis for the emission calculations during each phase of the loading and hotelling delivery cycle process. It is expected that each vessel would take approximately 24 hours to transit from mouth of the Coos Bay Estuarine System, undergo onloading of LNG, and transit back to the mouth of the Coos Bay Estuarine System. Of those 24 hours, 17.5 would be expected to take place while the vessels are berthed. Annual emissions were based upon a maximum of 90 ship calls per year.

The LNG vessel emission rates will be scaled by the amount of expected hours of operation (i.e., up to thirteen hours per day for LNG loading) over the averaging period for the air quality standard being modeled. For example, the hourly emission rate will be scaled by 13 hours of operation/24 hour averaging period to model 24-hour PM-2.5 impacts. Appendix B contains tables detailing all of the averaging specific emission rates proposed to be used in the modeling analysis along with corresponding AERMOD IDs for those activities. Additionally, for the averaging times less than 24-hours, not all of the discreet loading cycle vessel activities could occur simultaneously, and thus, multiple source groups in AERMOD will be necessary to accurately model the sub-daily averaging periods. Note that additional source groups will not be developed for those situations that would yield identical dispersion modeling results (i.e., for 1-hour averaging period modeling, the emissions during connecting and disconnecting of the arms with propulsion on hot standby are identical, and thus, only 1-source group will be used for two (2) discreet delivery cycle activities). All of the discreet source groups will be identified in the AERMOD input files.

2.1.2.1 Vessel Downwash

A typical LNG vessel is designed such that the exhaust stacks are constantly subject to building downwash resulting from the vessel superstructure, most notably the ship bridge. Because a single LNG Carrier design will not be the basis for the Project design, a GEP analysis has been determined for the 148,000 m^3 vessels, which are typical of the LNG ships anticipated to transit the waterway to the Project. A ship of this capacity has a typical height of approximately 109 feet, which results in a GEP formula height of 272 feet. The typical stack height for a 148,000 m^3 LNG vessel is on the order of 131 feet above sea level and therefore is less than the GEP formula stack height of 272 ft. Thus, direction-specific building downwash parameters will be included in the modeling analysis for the LNG vessel stack. The direction-specific downwash parameters will be determined using the U.S. EPA Building Profile Input Program (BPIP-PRIME, Version 04274). Appendix C contains the printouts of the BPIP-PRIME input files containing the building dimensions and heights for all structures to be utilized in the building downwash analysis along with a figure identifying the vessel design used in the analysis.

2.1.2.2 Vessel Fuel Oil Sulfur Limit

The facility currently expects to begin commercial operation in 2018 or later and as such, the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI world-wide fuel sulfur limit cap will be 3.5%. It should be noted that the Annex VI worldwide cap will be reduced to a value of 0.5% by 2020. The U.S. EPA recently submitted and was granted on March 26, 2010 a request to the International Maritime Organization (IMO) that the entire coastline of the United States and Canada be designated as emission control areas (ECA) under MARPOL Annex VI. Under this regulation by 2015, all vessels entering within 200 nautical miles (230 miles) of the U.S. coast would be required to operate on a fuel with a sulfur content less than 0.1%. Thus, a maximum sulfur content of 0.1% for LNG vessel emission calculations purposes is regulated by IMO MARPOL Annex VI regulations and will be enforced by the U.S. Coast Guard.

Jordan Cove intends to restrict a vessel's maximum fuel oil sulfur content to a value of 0.1% while the vessels are moored at the terminal. It is likely that most vessels from 2018 and beyond will utilize fuels during the LNG loading process that have a maximum sulfur content of 0.1% to comply with the Annex VI ECA requirements. The sulfur in the fuel limit for indirect source emission activities can be established and monitored through the Jordan Cove Terminal Regulations, which form part of the port Operations Manual. The following language (or functionally similar) could appear in this Manual.

- Fuel with a sulfur content in excess of 0.1% shall be considered noncompliant and fuel with a sulfur content equal to or below 0.1% shall be considered compliant. Sulfur contents will be established through standard analytical test methods. Fuel can be defined singly as either oil or BOG or can be defined as a mixture of oil/BOG.
- Any LNG vessel that is not capable of operating on a compliant fuel while berthed at the terminal will not be accepted by the Terminal.
- As part of the Terminal clearance process, Jordan Cove will require each arriving vessel to perform the following:
  1. Confirm and acknowledge the fuel sulfur restriction and submit a plan to Jordan Cove demonstrating the manner of compliance with the restriction while berthed.
  2. Submit the latest bunker analysis report providing the sulfur content of the on-board fuel oil.
- Following the review of the bunker analysis report and confirmation of an acceptable implementation plan, the vessel would be cleared to call at the Terminal.
- Jordan Cove would maintain all records of arriving vessel's compliance, including the bunker analysis reports, and make them available for review for a period of three years after a delivery.

3.0 PROPOSED MODELING METHODOLOGY

The multisource modeling will be conducted in accordance with the single source modeling protocol approved by the Department on January 23, 2013. Some additional methodology beyond that required for single source modeling is required to perform a multisource NAAQS analysis. The following methodologies are proposed for the multisource air quality modeling analysis.

3.1.1 1-Hour NO_2 Modeling Methodology

The air quality modeling analysis for the 1-hour NO_2 NAAQS will be performed consistent with the guidance and procedures established in the March 1, 2011 guidance memorandum from Tyler Fox (EPA OAQPS) titled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 NAAQS" (Memorandum). As the memo states, a modified and acceptable "first tier" approach for NAAQS demonstrations is to utilize a uniform monitored background contribution based on the monitored 98th-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data (i.e., the 1-hour NO_2 NAAQS design value). This value for the area surrounding the Project (i.e., 66.4 ug/m^3) is then added to the five-year average of the maximum 98th percentile modeled 1-hour NO_2 concentrations for comparison to the NAAQS. This approach will be utilized as a "first tier" demonstration for the 1-hour NO_2 NAAQS.

The proposed "second tier" approach is to combine monitored background and modeled concentrations on an hour-of-day pairing and, if necessary, by season and hour-of-day pairing. As stated in the Memorandum:

> *"We believe that an appropriate methodology for incorporating background concentrations in the cumulative impact assessment for the 1-hour NO_2 standard would be to use multiyear averages of the 98th-percentile of the available background concentrations by season and hour-of-day..."*
>
> *"...we recommend that background values by season and hour-of-day used in this context should be based on the 3rd highest values for each season and hour of day combination , whereas the 8th-highest value should be used if values vary by hour-of-day only...."*

To calculate the necessary hour-of-day background concentrations, the 98% background concentration (i.e., 8th-highest value) will be calculated for each hour of the day and for each of three years of background data. Each of these values will then be averaged to obtain a set of 24 three year average 98% background values by hour-of-day that can be added to the modeled concentrations for comparison with the 1-hour NO_2 NAAQS. An AERMOD model option (keyword BACKGROUND) will be used to sum each modeled concentration with the background concentration that was calculated for that hour-of-day. The 1-hour NO_2 design value can then be calculated using the 5-year-average highest of the 98th percentile concentrations across all receptors. This design value would then be used for comparison with the NAAQS.

As a 2nd level "second-tier" demonstration of the 1-hour NO_2 NAAQS, combining monitored and modeled concentrations will be accomplished on a hour-of-day by season approach. The hour-of-day monitored concentrations will be divided by season for each year. Then those seasonal groups will be further binned into 24 hour-of-day groups for a total of 96 bins of values (product of 4 seasons and 24 hours) for each year. The 3rd highest value from each bin will then be found per year. Finally, to obtain the values to be summed with the modeled concentrations, the average of those 3rd highest values will be taken over the three year period. This methodology results in a set of 96 three year average 98% background values by hour-of-day and season that can be added to the modeled concentrations for comparison with the 1-hour NO_2 NAAQS using the BACKGROUND keyword in AERMOD.

3.1.2 24-Hour PM-2.5 Modeling Methodology

Compliance with the PM-2.5 NAAQS may be demonstrated by calculating the five-year average of the maximum 24-hour average PM-2.5 prediction at any receptor and then this value is added to the 3-year average 98th percentile 24-hour background value from a representative PM-2.5 monitor and compared to the 24-hour NAAQS. The five-year average maximum modeled 24-hour PM-2.5 value will be added to the 3-year average 98th percentile 24-hour background value from a representative PM-2.5 monitor (i.e., the Lane County monitor in Cottage Grove, with a 3-year average 98th percentile value of 23.0 ug/m^3) and compared to the 24-hour PM-2.5 NAAQS.

A "second tier" demonstration of the 24-hour PM-2.5 NAAQS is proposed by adding the 3-year average 98th percentile 24-hour background concentration with the maximum five-year average of the 98th percentile 24-hour PM-2.5 modeled concentrations.

3.1.3 Modeling Receptor Grid

In general the modeling receptor grid used to determine the maximum modeled concentrations and extent of the modeled SIA will also be used for the NAAQS and PSD increment modeling demonstrations. However, there may be instances of receptors being located on offsite source property that is precluded from public access, and thus would not be considered ambient air for the source that owns the property. For these cases, modeling will be conducted using a tiered approach. The first tier approach will be to demonstrate compliance with the NAAQS and increments by including receptors at all offsite locations, regardless of if they are located at locations not considered ambient air to the source that owns the property. If compliance with the NAAQS and increments is demonstrated using this conservative receptor grid assumption, then no further refinements to the receptor grid will be necessary.

As a second tier receptor grid approach, any receptors that have excessively high or modeled NAAQS or PSD increment violations located on an offsite source property will be removed from the analysis when including all offsite sources. An additional set of offsite source modeling will then be conducted for those receptors located on offsite source property and modeled without the emissions from the owners of that property.

Figure 1-1: Offsite Source Locations

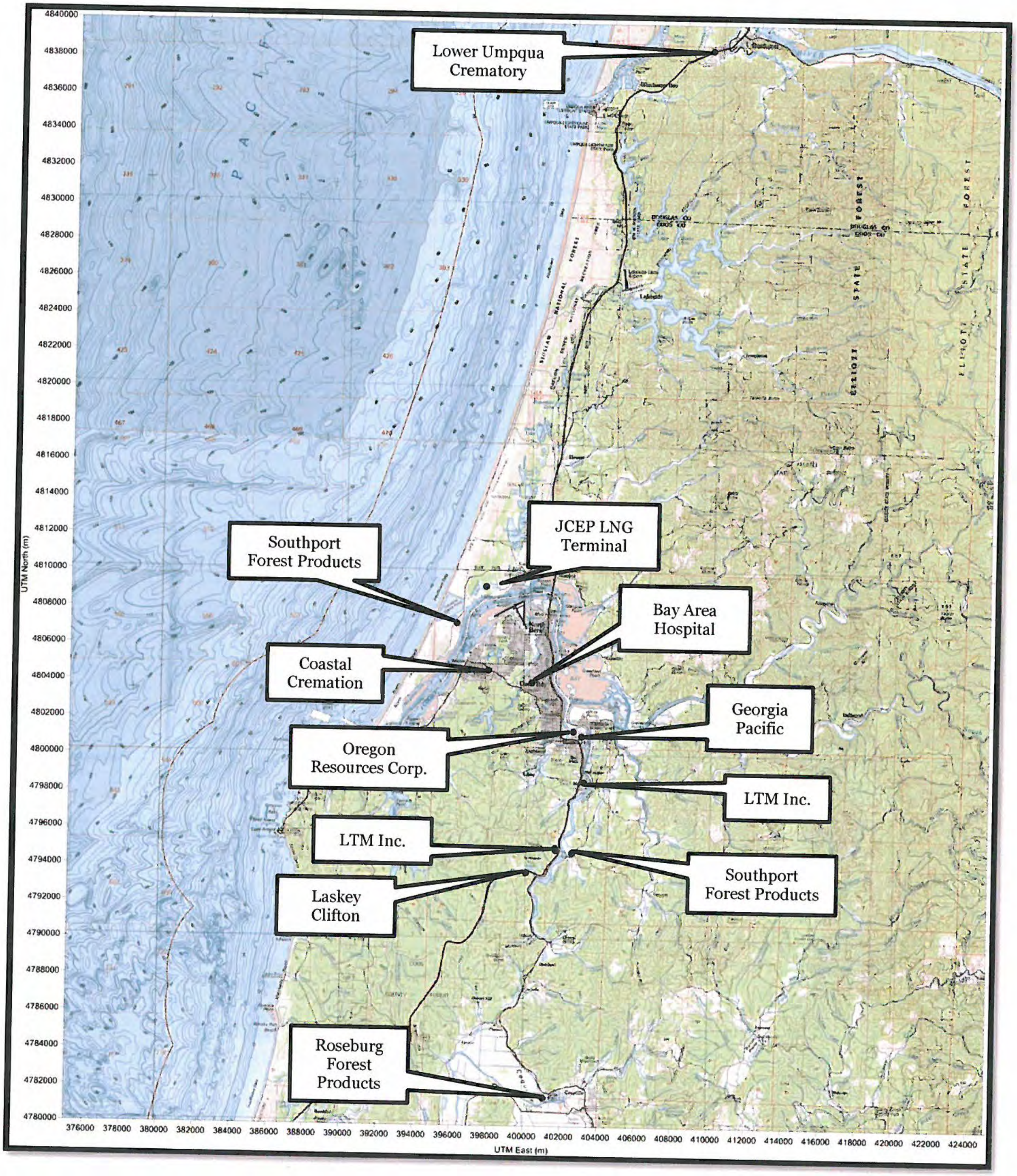
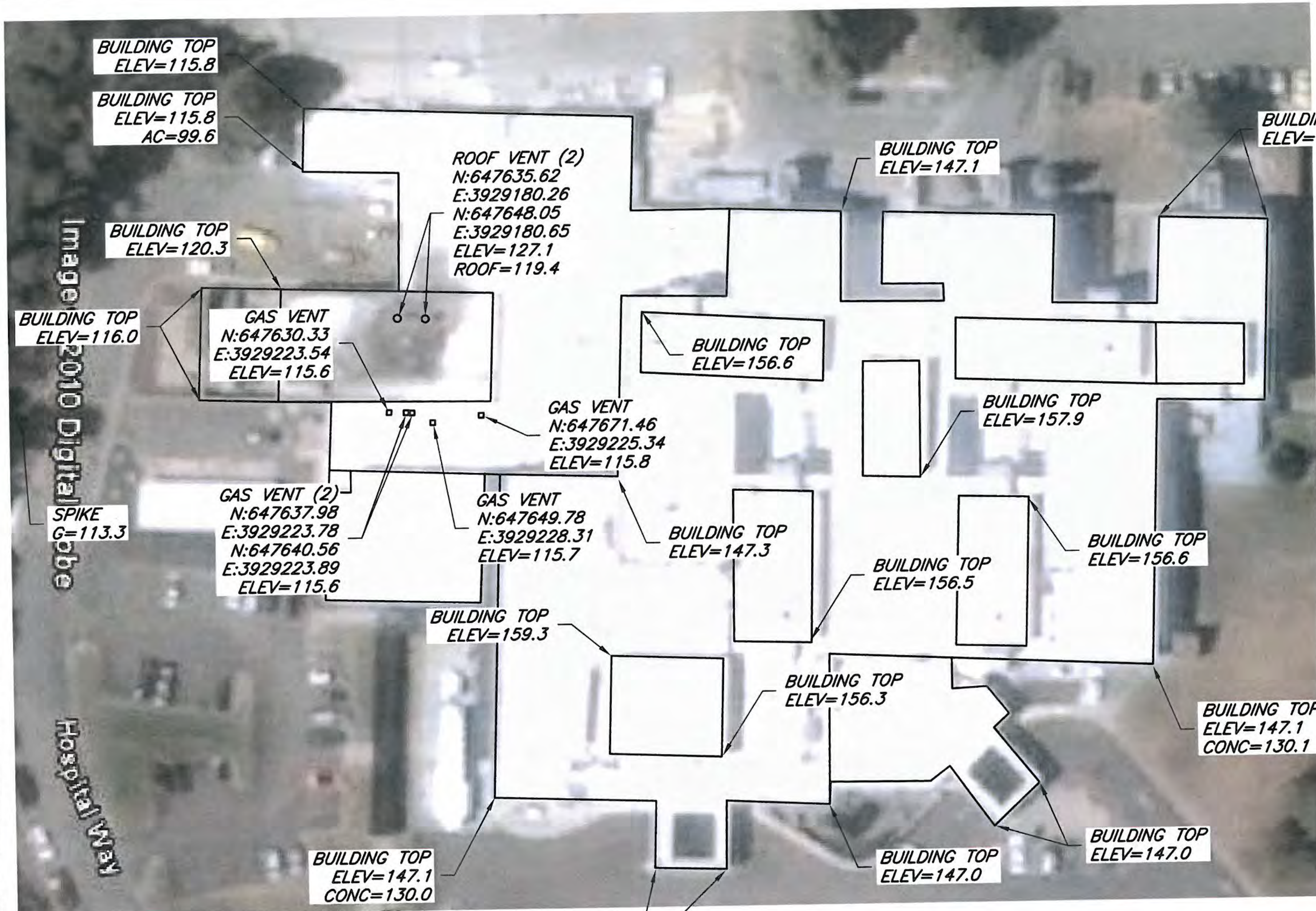
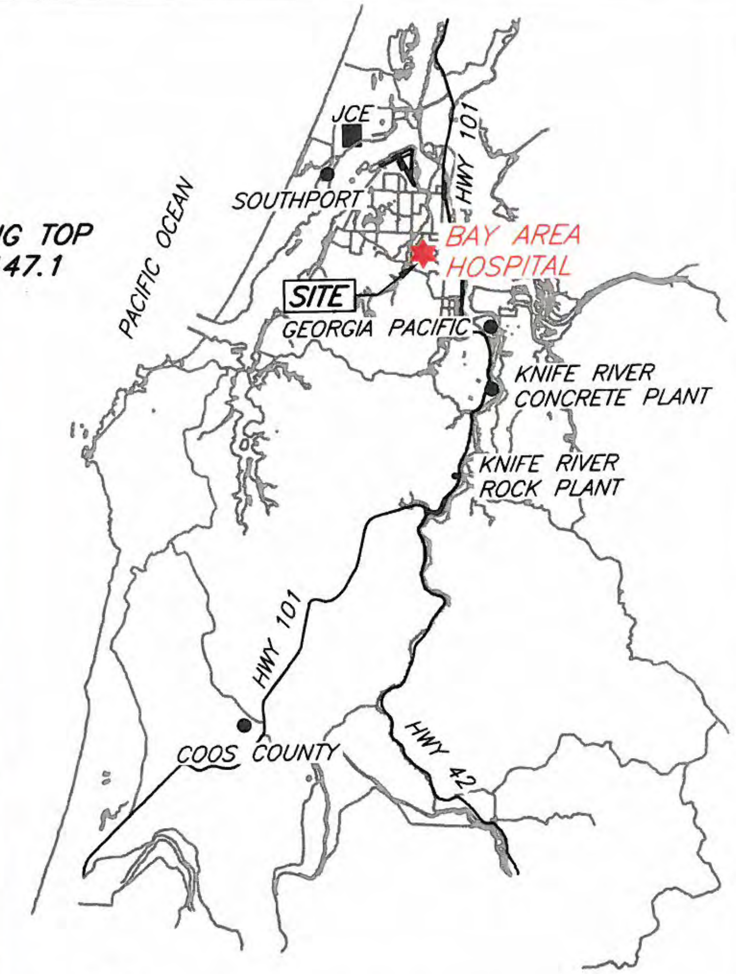


Table 2-1: Proposed Multisource Modeling Inventory

Facility	AERMOD ID	UTM-East m	UTM-North m	Stack Base (m)	Stack Height (m)	Stack Temp. (K)	Stack Exit Velocity (m/s)	Stack Exit Diameter (m)	PM-10 NAAQS (g/s)	PM-10 Increment (g/s)	PM-2.5 NAAQS (g/s)	PM-2.5 Increment (g/s)	NO_x NAAQS (g/s)	SO_2 NAAQS (g/s)
Roseburg Forest Products	RFPB	401,078	4,781,545	19.0	23.0	479.0	15.90	1.44	0.371	0.371	0.337	-	2.106	0.498
Roseburg Forest Products	RFPD	401,078	4,781,545	19.0	17.0	437.0	12.30	1.56	0.285	0.285	0.285	-	0.043	0.014
Roseburg Forest Products	RFPP	401,078	4,781,545	19.0	15.0	322.0	3.00	4.35	0.475	0.475	0.237	-	0.000	0.000
Roseburg Forest Products	RFPC	401,078	4,781,545	19.0	15.0	297.0	10.00	2.00	0.173	0.173	0.086	-	0.000	0.000
Bay Area Hospital	BAH	400,107	4,804,089	56.0	8.4	453.0	0.10	0.50	0.010	0.010	0.100	-	0.100	0.190
Southport Forest Products 1	SFP1	402,429	4,794,866	32.0	12.0	293.0	0.10	1.00	0.060	0.030	0.060	-	0.000	0.000
Southport Forest Products 2	SFP2	396,000	4,807,280	5.0	12.0	293.0	0.10	1.00	0.040	0.030	0.040	-	0.000	0.000
Coastal Cremation & Funeral Services	CCFS	397,745	4,804,741	37.0	10.9	735.0	2.00	0.88	0.020	0.020	0.020	-	0.020	0.000
Georgia Pacific West Inc.	GPW	402,859	4,801,197	4.0	18.3	293.0	0.10	1.00	0.240	0.200	0.240	-	0.000	0.000
LTM, Inc. 1	LTMA	403,015	4,798,708	18.0	17.0	311.0	1.00	2.00	0.070	0.060	0.070	-	0.000	0.000
Lower Umpqua Crematory	LUC	409,409	4,838,625	18.0	11.0	740.0	2.00	1.00	0.000	0.000	0.000	-	0.000	0.019
LTM, Inc. 2	LTMC	401,518	4,795,125	6.0	15.9	293.0	0.10	1.50	0.160	0.120	0.160	-	0.000	0.000
Laskey Clifton	LC	399,955	4,793,778	28.0	6.7	404.0	20.70	1.00	1.000	0.000	0.030	-	0.030	0.000
LTM-Knife River	LTMAP	401,542	4,795,012	6.0	6.1	383.0	18.90	1.30	0.090	0.070	0.290	-	0.290	0.200
Oregon Resources Corp	ORC	402,398	4,801,447	4.0	10.0	324.8	16.20	0.76	0.415	0.104	0.415	0.104	0.244	0.001

Appendix A
Offsite Building Survey and BPIP Downwash File





NOTES:

1. BASIIS OF BEARING IS OREGON STATE PLANE COORDINATE SYSTEM NAD83.
2. CONTROL POINTS USED FOR ROTATION ARE CP#1 AND CP#173 FROM JCE PROJECT ON THE NORTH SPIT OF COOS BAY.
3. VERTICAL DATUM IS NAVD88 USING SAME CONTROL POINTS AS DESCRIBED IN NOTE #2.
4. SURVEYS WERE PERFORMED FROM FEBRUARY 22 – MARCH 15, 2010.
5. INSTRUMENTS USED FOR THIS PROJECT WERE TRIMBLE R8 GPS RECIEVERS WITH TSC2 DATA COLLECTOR. TRIMBLE ROBOTIC TOTAL STATION WITH ACV WAS USED TO TIE BUILDING AND STACK HEIGHTS.
6. ASSISTING WITH THIS SURVEY WAS SHAWN FRAZZINI.

STACK NOTES:

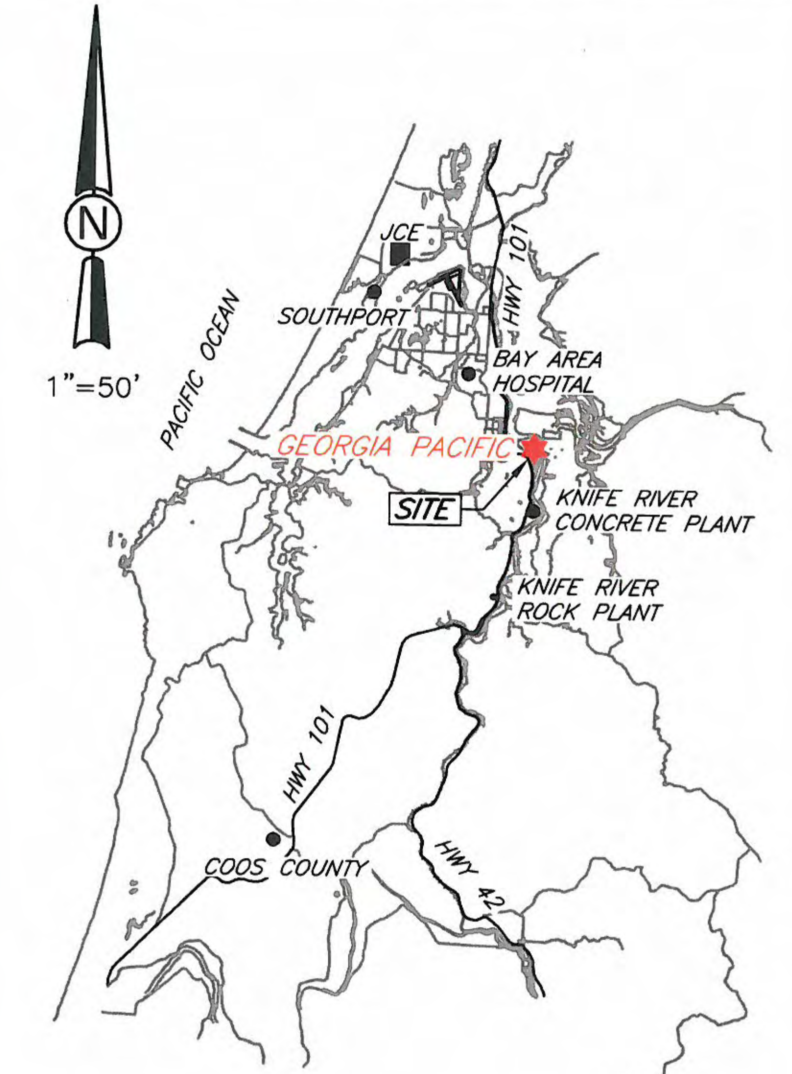
1. 20 INCH DIAMETER STACK OPENING ON BOTH STACKS WITH 40 INCH COVERS.
2. 2'-2" X 2'-2" SQUARE DRYER EXHAUST OPENINGS ON 2 NORTHERLY EXHAUSTS.
3. 1'-6" X 1'-6" SQUARE DRYER EXHAUST OPENINGS ON 3 SOUTHERLY EXHAUSTS.

REGISTERED PROFESSIONAL LAND SURVEYOR
OREGON
JULY 09, 2002
Walter E. White
55547
EXPIRES 6/30/10

N
1"=50'

SHN Consulting Engineers & Geologists, Inc.	Jorden Cove Point Source Survey Coos County, Oregon	Bay Area Hospital SHN 006625.200
	March 2010 / 006625_220 PointSource	Figure 3

\\Coosbay\projects\2006\006625-JCESampling\Dwgs\006625_220v , SAVED: 3/24/2010 10:06 AM WWHITE, PLOTTED: 3/24/2010 10:11 AM, WALTER WHITE



NOTES:

1. BASIIS OF BEARING IS OREGON STATE PLANE COORDINATE SYSTEM NAD83.
2. CONTROL POINTS USED FOR ROTATION ARE CP#1 AND CP#173 FROM JCE PROJECT ON THE NORTH SPIT OF COOS BAY.
3. VERTICAL DATUM IS NAVD88 USING SAME CONTROL POINTS AS DESCRIBED IN NOTE #2.
4. SURVEYS WERE PERFORMED FROM FEBRUARY 22 – MARCH 15, 2010.
5. INSTRUMENTS USED FOR THIS PROJECT WERE TRIMBLE R8 GPS RECIEVERS WITH TSC2 DATA COLLECTOR. TRIMBLE ROBOTIC TOTAL STATION WITH ACV WAS USED TO TIE BUILDING AND STACK HEIGHTS.
6. ASSISTING WITH THIS SURVEY WAS SHAWN FRAZZINI.

STACK NOTES:

1. 4' DIAMETER CYCLONE EXHAUST.
2. 4'X4' SQUARE BLOWER EXHAUST.

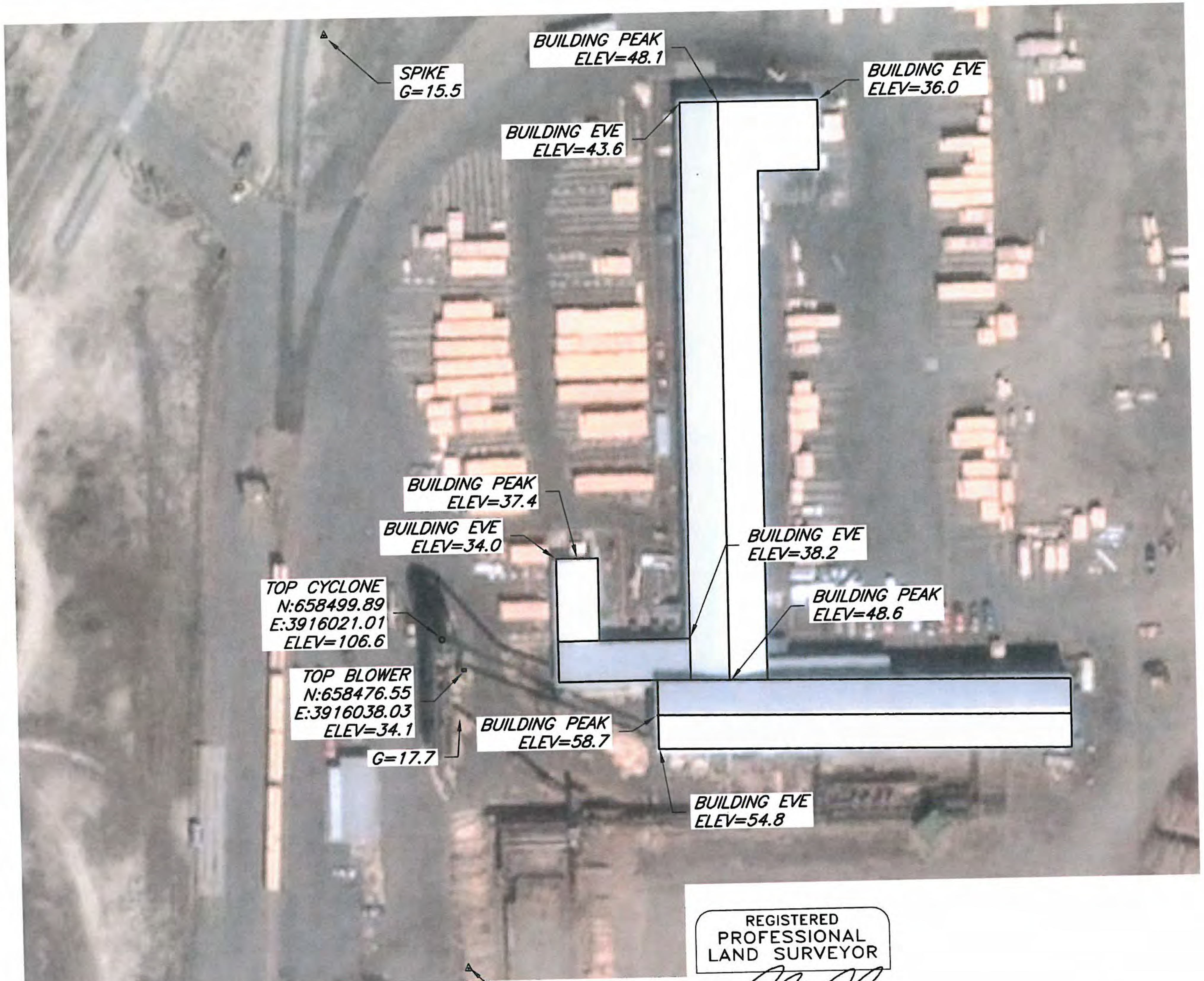
REGISTERED
PROFESSIONAL
LAND SURVEYOR

OREGON
JULY 09, 2002
Walter E. White
55547

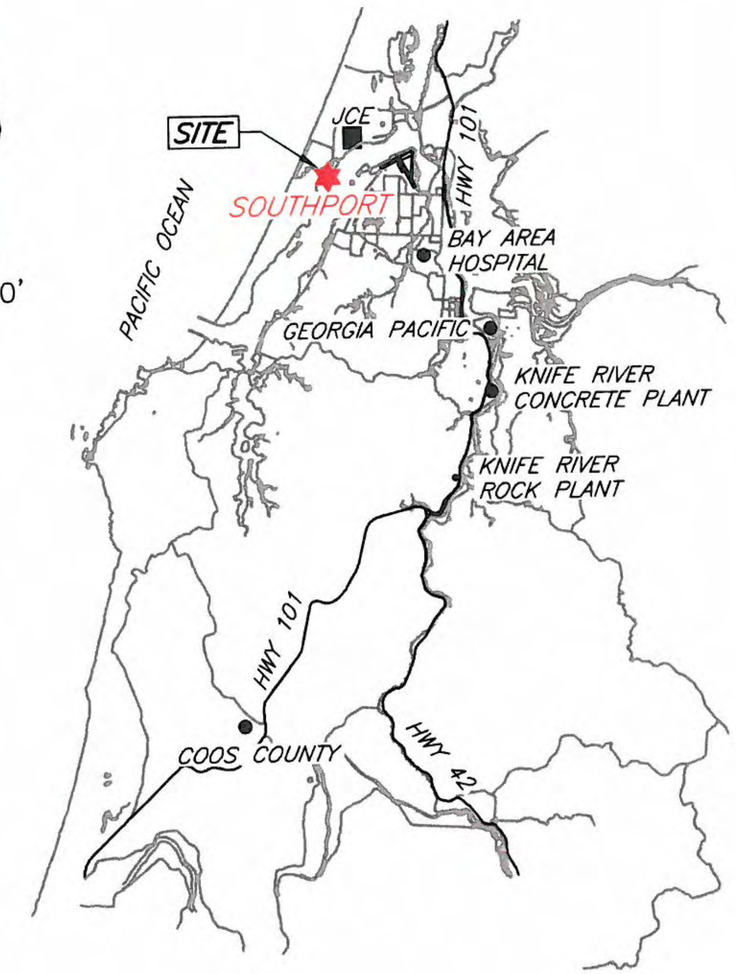
EXPIRES 6/30/10

SHN Consulting Engineers & Geologists, Inc.	Jorden Cove Point Source Survey Coos County, Oregon	Georgia Pacific SHN 006625.200
	March 2010 / 006625_220 PointSource	Figure 2

\\Coosbay\projects\2006\006625-JCESampling\Dwgs\006625_220v , SAVED: 3/24/2010 10:06 AM WWHITE, PLOTTED: 3/24/2010 10:12 AM , WALTER WHITE



1"=80'



NOTES:

1. BASIIS OF BEARING IS OREGON STATE PLANE COORDINATE SYSTEM NAD83.
2. CONTROL POINTS USED FOR ROTATION ARE CP#1 AND CP#173 FROM JCE PROJECT ON THE NORTH SPIT OF COOS BAY.
3. VERTICAL DATUM IS NAVD88 USING SAME CONTROL POINTS AS DESCRIBED IN NOTE #2.
4. SURVEYS WERE PERFORMED FROM FEBRUARY 22 – MARCH 15, 2010.
5. INSTRUMENTS USED FOR THIS PROJECT WERE TRIMBLE R8 GPS RECIEVERS WITH TSC2 DATA COLLECTOR. TRIMBLE ROBOTIC TOTAL STATION WITH ACV WAS USED TO TIE BUILDING AND STACK HEIGHTS.
6. ASSISTING WITH THIS SURVEY WAS SHAWN FRAZZINI.

STACK NOTES:

1. 4'X4' SQUARE BLOWER EXHAUST OPENING.
2. 4' DIAMETER CYCLONE EXHAUST OPENING.

REGISTERED
PROFESSIONAL
LAND SURVEYOR

OREGON
JULY 09, 2002
Walter E. White
55547

EXPIRES 6/30/10

SHN Consulting Engineers & Geologists, Inc.	Jorden Cove Point Source Survey Coos County, Oregon	Southport SHN 006625.200
March 2010	006625_220 PointSource	Figure 6

OFFSITE

```
'Jordan Cove Energy Center Offsite Source BPIP - NAD27 Coords'
'p'
'METERS    ' 1.00000000
'UTMY'      .0000
  8
'SFPA    '          1       5.39
          4      12.50
396145.4   4807057.
396236.8   4807058.
396236.3   4807074.
396144.9   4807072.
'SFPB    '          1       5.39
          6       9.27
396169.3   4807073.
396166.0   4807186.
396179.4   4807186.
396179.0   4807202.
396148.6   4807201.
396152.3   4807073.
'SFPC    '          1       5.39
          6       6.00
396123.2   4807072.
396152.3   4807073.
396152.1   4807082.
396132.0   4807081.
396131.4   4807099.
396122.2   4807099.
'BAHA    '          1      56.00
          4       6.31
400216.0   4803864.
400215.6   4803904.
400200.6   4803904.
400200.6   4803864.
'BAHB    '          1      56.00
         14       4.94
400175.7   4803878.
400184.4   4803878.
400184.4   4803891.
400200.6   4803891.
400200.6   4803904.
400215.6   4803904.
400216.0   4803882.
400225.3   4803882.
400225.6   4803921.
400200.8   4803922.
400200.6   4803936.
400188.6   4803936.
400189.1   4803923.
400176.2   4803923.
'BAHC    '          1      56.00
          4      14.48
400225.3   4803882.
400243.2   4803882.
400243.2   4803903.
400225.5   4803903.
'BAHD    '          6      56.00
         21      14.48
400225.5   4803905.
400269.9   4803905.
400270.0   4803927.
400279.2   4803927.
400279.3   4803937.
400269.9   4803937.
```

```
400270.2   4803951.
400267.1   4803951.
400266.8   4803965.
400264.7   4803967.
400272.8   4803974.
400266.7   4803980.
400249.8   4803967.
400250.3   4803995.
400214.0   4803995.
400213.8   4804010.
400188.9   4804010.
400188.6   4803936.
400200.6   4803936.
400200.8   4803922.
400225.6   4803921.
         4      18.20
400250.2   4803921.
400263.6   4803921.
400263.8   4803936.
400250.4   4803936.
         4      17.34
400227.2   4803937.
400248.0   4803938.
400248.0   4803948.
400227.2   4803948.
         4      17.37
400211.2   4803924.
400212.0   4803949.
400203.8   4803949.
400203.0   4803924.
         4      17.77
400209.3   4803955.
400225.0   4803955.
400225.0   4803963.
400209.1   4803962.
         4      17.37
400227.6   4803968.
400248.0   4803968.
400248.0   4803978.
400227.6   4803978.
'GPWA    '          1          4.00
         6       9.36
402925.5   4801004.
403029.4   4801002.
403029.7   4801021.
403000.7   4801022.
403000.8   4801027.
402925.8   4801028.
   3
'SFP2    '       5.39           .00   396097.3   4807081.3
'BAH     '      56.00           .00   400204.4   4803891.4
'GPW     '       4.00           .00   402956.1   4800999.2
```

Appendix B
LNG Vessel Emission Calculations

TABLE B1
Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Diesel-Electric Propulsion (Fuel Oil)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM		HC		SOx		CO_2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	1.41	25.89	1.16	1.75	0.08	2.49	0.11	3.08	0.14	5,025.11	226.13	0.13	0.01	0.04	0.00
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	1.41	25.89	1.16	1.75	0.08	2.49	0.11	3.08	0.14	5,025.11	226.13	0.13	0.01	0.04	0.00
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	31.44	3.54	25.89	2.91	1.75	0.20	2.49	0.28	3.08	0.35	5,025.11	565.32	0.13	0.02	0.04	0.01
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	26.79	15.68	22.06	12.90	1.49	0.87	2.13	1.24	2.62	1.53	4,282.14	2,505.05	0.11	0.07	0.04	0.02

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	8.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

TABLE B2
Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Diesel-Electric Propulsion (BOG)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM		HC		SOx		CO_2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	15.84	0.71	10.05	0.45	0.32	0.01	6.09	0.27	0.52	0.02	3,350.07	150.75	0.40	0.02	0.01	0.00
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	15.84	0.71	10.05	0.45	0.32	0.01	6.09	0.27	0.52	0.02	3,350.07	150.75	0.40	0.02	0.01	0.00
Contingency (propulsinn on hot standby)	2.50	5%	80%	2	1	1,675	2,520	15.84	1.78	10.05	1.13	0.32	0.04	6.09	0.69	0.52	0.06	3,350.07	376.68	0.40	0.04	0.01	0.00
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	13.50	7.89	8.56	5.01	0.27	0.16	5.19	3.04	0.44	0.26	2,854.76	1,670.03	0.34	0.20	0.006	0.003

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

TABLE B3
Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Steam Turbine Propulsion (Fuel Oil)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM/PM10		HC		SOx		CO_2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.82	1.95	0.09	2.15	0.10	0.11	0.00	6.18	0.28	9,542.82	429.43	0.38	0.02	0.04	0.00
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.82	1.95	0.09	2.15	0.10	0.11	0.00	6.18	0.28	9,542.82	429.43	0.38	0.02	0.04	0.00
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	18.32	2.06	1.95	0.22	2.15	0.24	0.11	0.01	6.18	0.70	9,542.82	1,073.57	0.38	0.04	0.04	0.00
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	15.61	9.13	1.66	0.97	1.83	1.07	0.09	0.05	5.27	3.08	8,131.90	4,757.16	0.33	0.19	0.04	0.02

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

TABLE B4
Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Steam Turbine Propulsion (BOG)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM		HC		SOx		CO2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.44	4.35	0.20	0.39	0.02	0.29	0.01	0.03	0.001	6,733.28	303.00	0.13	0.01	0.12	0.01
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.44	4.35	0.20	0.39	0.02	0.29	0.01	0.03	0.001	6,733.28	303.00	0.13	0.01	0.12	0.01
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	9.73	1.10	4.35	0.49	0.39	0.04	0.29	0.03	0.03	0.003	6,733.28	757.49	0.13	0.01	0.12	0.01
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	8.29	4.85	3.71	2.17	0.33	0.19	0.24	0.14	0.02	0.01	5,737.75	3,356.59	0.11	0.06	0.11	0.06

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	8.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

TABLE B5
Jordan Cove Energy Project, L.P.
LNG Vessel Emission Factors

Assumptions

LNG Capacity, m^3	148,000
DFDE ships Efficiency, loading	47%
ST ships Efficiency, loading	25%
FO Sulfur Content, loading	0.10%

EMISSION FACTORS (lb/mmBtu)[1]				
Pollutant	Dual Fuel Diesel Engine Ships		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	5.20E-01	1.03E+00	1.70E-01	3.20E-01
CO	3.30E-01	8.50E-01	7.60E-02	3.40E-02
PM[3]	1.05E-02	5.73E-02	6.80E-03	3.76E-02
VOC	2.00E-01	8.19E-02	5.00E-03	1.90E-03
SO2	1.70E-02	1.01E-01	5.00E-04	1.08E-01
CO2[2]	1.10E+02	1.65E+02	1.18E+02	1.67E+02
CH_4[4]	1.30E-02	4.41E-03	2.25E-03	6.67E-03
N_2O[4]	2.21E-04	1.47E-03	2.16E-03	7.33E-04

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ships		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM[3]	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2[2]	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4[4]	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O[4]	7.26E-04	4.84E-03	1.34E-02	4.54E-03

References

1. An Assessment of Air Emissions from Liquefied Natural Gas Ships Using Different Power Systems and Different Fuels. Afton, Yinka; Ervin, David. Journal of the Air & Waste Management Association, Volume 58, March 2008.
FO PM emission factors for ST vessels were adjusted for the FO Sulfur (0.1%) content based upon U.S. EPA AP-42 Emission Factors, Table 1.3-1 and 1.3-2.
2. Based upon U.S. EPA AP-42 compilation of Emission Factors, Table 3.4-1 for Diesel Engines, and Tables 1.3-12 and 1.4-2 for ST ships.
3. PM emission factors include both filterable and condensable emissions.
4. For Steam Turbine Ships: Based upon U.S. EPA AP-42 Compilation of Emission Factors, Tables 1.3-3, 1.3-8, and 1.4-2.
For DFDE Ships: California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, Table C.7 - Residual Fuel, Industrial and a Heating Value of 150,000 Btu/Gal.

** Efficiencies where based upon the paper "Dual Fuel Electric LNG Carrier" (September 2006) prepared by Barend Thijssen of Wartsila Ship Power Solutions

TABLE B6
Jordan Cove Energy Project, L.P.
Stack Parameters Summary for LNG Vessels

Assumptions

Stack Height, ft	131.23
Stack Height, m	40.00
Stack Diameter, ft	5.00
Stack Diameter, m	1.52
F-Factors (wscf/mmBtu) from U.S. EPA	
Oil Combustion	10320
NG Combustion	10610
DFDE Efficiency, loading	47%
ST ships Efficiency, loading	25%

Note: Efficiencies were based upon the paper "Dual Fuel Electric LNG Carrier" (September 2006) prepared by Barend Thijssen of Wartsila Ship Power Solutions.

Steam Turbine Ships (Oil Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	49	16091	22745	275	408.15	19.31	5.88

Steam Turbine Ships (Natural Gas Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	49	16544	23384	275	408.15	19.85	6.05

TABLE B6
Jordan Cove Energy Project, L.P.
Stack Parameters Summary for LNG Vessels

DFDE Ships (Oil Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	26	8559	18468	662	623.15	15.68	4.78

DFDE Ships (Natural Gas Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	26	8800	18987	662	623.15	16.12	4.91

TABLE B7
Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(English Units)

DFDE Ships (Oil Operation)

Period	Transit Time	NOx		CO		PM		SOx		Modeled Emission Rates (Scaled accordingly for averaging period)										
										1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
	hr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Hotelling																			
Connect Arms and Cool Down (propulsion on hot standby)	1.00	31.44	1.41	25.89	1.16	1.75	0.08	3.08	0.14	31.44	0.32	25.89	3.24	0.07	0.02	3.08	1.03	0.13	0.03
Purge and Disconnect Arms (propulsion on hot standby)	1.00	31.44	1.41	25.89	1.16	1.75	0.08	3.08	0.14	31.44	0.32	25.89	3.24	0.07	0.02	3.08	1.03	0.13	0.03
Contingency (propulsion on hot standby)	2.50	31.44	3.54	25.89	2.91	1.75	0.20	3.08	0.35	31.44	0.81	25.89	8.09	0.18	0.04	3.08	2.56	0.32	0.08
LNG Loading																			
Cargo transfer (propulsion on hot standby)	13.00	26.79	15.68	22.06	12.90	1.49	0.87	2.62	1.53	26.79	3.58	22.06	22.06	0.81	0.20	2.62	2.62	1.42	0.35

DFDE Ships (Natural Gas Operation)

Period	Transit Time	NOx		CO		PM		SOx		Modeled Emission Rates (Scaled accordingly for averaging period)									
										1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
	hr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Hotelling																			
Connect Arms and Cool Down (propulsion on hot standby)	1.00	15.84	0.71	10.05	0.45	0.32	0.01	0.52	0.02	15.84	0.16	10.05	1.26	0.01	0.003	0.52	0.17	0.02	0.01
Purge and Disconnect Arms (propulsion on hot standby)	1.00	15.84	0.71	10.05	0.45	0.32	0.01	0.52	0.02	15.84	0.16	10.05	1.26	0.01	0.003	0.52	0.17	0.02	0.01
Contingency (propulsion on hot standby)	2.50	15.84	1.78	10.05	1.13	0.32	0.04	0.52	0.06	15.84	0.41	10.05	3.14	0.03	0.01	0.52	0.43	0.05	0.01
LNG Loading																			
Cargo transfer (propulsion on hot standby)	13.00	13.50	7.89	8.56	5.01	0.27	0.16	0.44	0.26	13.50	1.80	8.56	8.56	0.15	0.04	0.44	0.44	0.24	0.06

TABLE B7
Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(English Units)

Steam Turbine Ships (Oil Operation)

Period	Transit Time hr	NOx lb/hr	NOx tpy	CO lb/hr	CO tpy	PM lb/hr	PM tpy	SOx lb/hr	SOx tpy	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Hotelling																			
Connect Arms and Cool Down (propulsion on hot standby)	1.00	18.32	0.82	1.95	0.09	2.15	0.10	6.18	0.28	18.32	0.19	1.95	0.24	0.09	0.02	6.18	2.06	0.26	0.06
Purge and Disconnect Arms (propulsion on hot standby)	1.00	18.32	0.82	1.95	0.09	2.15	0.10	6.18	0.28	18.32	0.19	1.95	0.24	0.09	0.02	6.18	2.06	0.26	0.06
Contingency (propulsion on hot standby)	2.50	18.32	2.06	1.95	0.22	2.15	0.24	6.18	0.70	18.32	0.47	1.95	0.61	0.22	0.06	6.18	5.15	0.64	0.16
LNG Loading																			
Cargo transfer (propulsion on hot standby)	13.00	15.61	9.13	1.66	0.97	1.83	1.07	5.27	3.08	15.61	2.09	1.66	1.66	0.99	0.24	5.27	5.27	2.85	0.70

Steam Turbine Ships (Natural Gas Operation)

Period	Transit Time hr	NOx lb/hr	NOx tpy	CO lb/hr	CO tpy	PM lb/hr	PM tpy	SOx lb/hr	SOx tpy	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Hotelling																			
Connect Arms and Cool Down (propulsion on hot standby)	1.00	9.73	0.44	4.35	0.20	0.39	0.02	0.03	0.001	9.73	0.10	4.35	0.54	0.02	0.004	0.03	0.01	0.001	0.0003
Purge and Disconnect Arms (propulsion on hot standby)	1.00	9.73	0.44	4.35	0.20	0.39	0.02	0.03	0.001	9.73	0.10	4.35	0.54	0.02	0.004	0.03	0.01	0.001	0.0003
Contingency (propulsion on hot standby)	2.50	9.73	1.10	4.35	0.49	0.39	0.04	0.03	0.003	9.73	0.25	4.35	1.36	0.04	0.01	0.03	0.02	0.003	0.001
LNG Loading																			
Cargo transfer (propulsion on hot standby)	13.00	8.29	4.85	3.71	2.17	0.33	0.19	0.02	0.01	8.29	1.11	3.71	3.71	0.18	0.04	0.02	0.02	0.01	0.003

TABLE B8
Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(Metric Units)

DFDE Ships (Oil Operation)

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period									
									1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
									g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	DFDEHTL1	1.00	5%	80%	2	1	1,675	2,520	3.96	0.04	3.26	0.41	0.009	0.002	0.388	0.388	0.016	0.004
Purge and Disconnect Arms (propulsion on hot standby)	DFDEHTL2	1.00	5%	80%	2	1	1,675	2,520	3.96	0.04	3.26	0.41	0.009	0.002	0.388	0.388	0.016	0.004
Contingency (propulsion on hot standby)	DFDEHTL3	2.50	5%	80%	2	1	1,675	2,520	3.96	0.10	3.26	1.02	0.023	0.006	0.388	0.388	0.040	0.010
LNG Loading																		
Cargo transfer (propulsion on hot standby)	DFDEHTL4	13.00	5%	60%	2	1	1,675	1,900	3.38	0.45	2.78	2.78	0.10	0.03	0.330	0.330	0.179	0.044

DFDE (Natural Gas Operation)

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period)									
									1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
									g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	GDFDEHTL1	1.00	5%	80%	2	1	1,675	2,520	2.00	0.02	1.27	0.16	0.002	0.0004	0.065	0.0652	0.0027	0.0007
Purge and Disconnect Arms (propulsion on hot standby)	GDFDEHTL2	1.00	5%	80%	2	1	1,675	2,520	2.00	0.02	1.27	0.16	0.002	0.0004	0.065	0.0652	0.0027	0.0007
Contingency (propulsion on hot standby)	GDFDEHTL3	2.50	5%	80%	2	1	1,675	2,520	2.00	0.05	1.27	0.40	0.004	0.001	0.065	0.0652	0.0068	0.0017
LNG Loading																		
Cargo transfer (propulsion on hot standby)	GDFDEHTL4	13.00	5%	60%	2	1	1,675	1,900	1.70	0.23	1.08	1.08	0.019	0.005	0.056	0.0556	0.0301	0.0074

TABLE B8
Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(Metric Units)

Steam Turbine Ships (Oil Operation

Period	AERMOD ID	Transit Time	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power	Electric Power	Modeled Emission Rates (Scaled accordingly for averaging period)									
									1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
		hr					kW	kW	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	STHTL1	1.00	5%	80%	2	1	1,675	2,520	2.31	0.02	0.25	0.03	0.011	0.003	0.779	0.779	0.032	0.008
Purge and Disconnect Arms (propulsion on hot standby)	STHTL2	1.00	5%	80%	2	1	1,675	2,520	2.31	0.02	0.25	0.03	0.011	0.003	0.779	0.779	0.032	0.008
Contingency (propulsion on hot standby)	STHTL3	2.50	5%	80%	2	1	1,675	2,520	2.31	0.06	0.25	0.08	0.03	0.01	0.779	0.779	0.081	0.020
LNG Loading																		
Cargo transfer (propulsion on hot standby)	STHTL4	13.00	5%	60%	2	1	1,675	1,900	1.97	0.26	0.21	0.21	0.13	0.03	0.664	0.664	0.360	0.089

Steam Turbine Ships (Natural Gas Operation)

Period	AERMOD ID	Transit Time	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power	Electric Power	Modeled Emission Rates (Scaled accordingly for averaging period)									
									1-Hour NO_x	Annual NO_x	1- Hour CO	8-Hour CO	24-Hour PM	Annual PM	1-Hour SO_2	3-Hour SO_2	24-Hour SO_2	Annual SO_2
		hr					kW	kW	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	GSTHTL1	1.00	5%	80%	2	1	1,675	2,520	1.23	0.01	0.55	0.07	0.002	0.001	0.004	0.004	0.0002	0.00004
Purge and Disconnect Arms (propulsion on hot standby)	GSTHTL2	1.00	5%	80%	2	1	1,675	2,520	1.23	0.01	0.55	0.07	0.002	0.001	0.004	0.004	0.0002	0.00004
Contingency (propulsion on hot standby)	GSTHTL3	2.50	5%	80%	2	1	1,675	2,520	1.23	0.03	0.55	0.17	0.005	0.001	0.004	0.004	0.0004	0.0001
LNG Loading																		
Cargo transfer (propulsion on hot standby)	GSTHTL4	13.00	5%	60%	2	1	1,675	1,900	1.05	0.14	0.47	0.47	0.023	0.006	0.003	0.003	0.0017	0.0004

Appendix C
LNG Vessel BPIP Downwash File

Figure C-1: LNG Vessel Structure for BPIP

```
'Jordan Cove Energy Center - Coos Bay - Oregon - GEP analysis using BPIP'
'p'
'METERS     ' 1.00000000
'UTMY'       .0000
   3
'SHIP1    '          2          .00
         13       14.60
397540.8    4808805.71
397552.8    4808820.71
397562.4    4808850.71
397565.7    4808897.71
397565.7    4809078.71
397561.9    4809101.71
397553.4    4809120.71
397527.7    4809120.71
397519.6    4809101.71
397515.8    4809078.71
397515.7    4808897.71
397519.1    4808850.71
397528.7    4808819.71
          6        21.40
397531.1     4808850.71
397550.3     4808850.71
397562.1     4808891.71
397562.1     4809047.71
397519.3     4809047.71
397519.3     4808891.71
'SHIP2    '          2          .00
         14        30.30
397515.5     4809051.71
397534.7     4809051.71
397537.2     4809048.71
397544.3     4809048.71
397546.8     4809051.71
397566.0     4809051.71
397566.0     4809053.71
397559.6     4809053.71
397558.2     4809055.71
397558.2     4809073.71
397523.2     4809073.71
397523.2     4809055.71
397521.9     4809053.71
397515.5     4809053.71
         12        33.20
397526.8     4809051.71
397534.7     4809051.71
397537.1     4809048.71
397544.3     4809048.71
397546.8     4809051.71
397554.6     4809051.71
397554.6     4809058.71
397549.1     4809058.71
397549.1     4809064.71
397532.4     4809064.71
397532.4     4809058.71
397526.8     4809058.71
'SHIP3    '          3          .00
          6        21.40
397521.5     4809082.71
397559.9     4809082.71
397559.9     4809094.71
397558.8     4809101.71
397522.7     4809101.71
```

```
397521.5    4809094.71
         4      27.50
397529.4    4809088.71
397552.0    4809088.71
397552.0    4809101.71
397529.4    4809101.71
         4      35.90
397537.1    4809092.71
397544.3    4809092.71
397544.3    4809101.71
397537.1    4809101.71
   1
'SHIPSTK '        .00          .00  397540.7 4809097.7
```

Appendix J
Multisource Electronic Modeling Files

This DVD contains the modeling input and output files for the proposed JCEP LNG Terminal Project
located in Coos County, Oregon. The following are brief descriptions
for each of the modeling files used in the air quality modeling analysis. (May 2013)
(Appendix J)

** Note that all files with the .inp extension are input files.
** All files with the .out extension are output files.

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMAP

** This Directory contains the AERMAP input and output files used to process the standard modeling receptor grid.

```
06/21/2012  02:13 PM       166,154,079 74762863.tif
06/21/2012  02:11 PM       166,185,655 79795317.tif
10/24/2012  01:25 PM           887,089 aermap.exe
10/24/2012  01:34 PM           995,125 aermap.inp
10/27/2012  08:53 PM             4,105 aermap.out
10/27/2012  08:53 PM         1,809,538 JCEPREC.out
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMAP\SIAGrid

** This Directory contains the AERMAP input and output files used to process the extended modeling receptor grid
** used in determining some pollutant specific SIAs.

```
11/30/2012  04:05 PM        94,228,591 02742229.tif
11/30/2012  05:10 PM        94,228,591 19939544.tif
11/30/2012  05:10 PM        94,255,935 20338806.tif
11/30/2012  04:05 PM        94,228,591 30287896.tif
11/30/2012  05:09 PM        94,255,935 38675475.tif
11/30/2012  04:06 PM        94,228,591 41141311.tif
11/30/2012  04:06 PM        94,228,591 55618685.tif
11/30/2012  04:05 PM        94,228,591 57854013.tif
11/30/2012  04:06 PM        94,228,591 60445903.tif
11/30/2012  05:14 PM        94,228,591 61713044.tif
11/30/2012  04:05 PM        94,243,343 63455854.tif
11/30/2012  05:10 PM        94,228,591 64287507.tif
11/30/2012  04:06 PM        94,269,723 67857865.tif
11/30/2012  04:06 PM        94,242,375 85153958.tif
11/30/2012  05:10 PM        94,255,935 91248159.tif
11/30/2012  05:11 PM        94,243,343 99327441.tif
10/24/2012  01:25 PM           887,089 aermap.exe
11/30/2012  05:19 PM           814,354 aermap.inp
12/01/2012  06:38 PM             9,089 aermap.out
12/01/2012  06:38 PM         1,363,448 JCEPREC.out
```

****
****

** This Directory contains the processing of meteorological datasets with AERMET to create AERMOD ready .sfc and .pfl files.

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMET

```
03/18/2013  04:22 PM    <DIR>          AERSURF
03/18/2013  03:29 PM    <DIR>          Merge
03/18/2013  02:00 PM    <DIR>          Stage 3
03/18/2013  03:32 PM    <DIR>          Surface
03/18/2013  03:35 PM    <DIR>          Upper Air
```

```
 Directory of \JCEP PSD Air Permit Application\Modeling Files
Appendix\AERMET\AERSURF

04/04/2012  03:35 PM               988 AERSURFACE.DAT
04/04/2012  03:35 PM           333,270 albedo_bowen_domain.txt
10/11/2000  02:47 PM           133,712 conus.las
10/11/2000  02:47 PM           133,712 conus.los
04/04/2012  03:35 PM           357,476 coos.log
04/04/2012  03:35 PM             8,929 coos.out
04/10/2008  10:54 AM        38,779,233 oregon.nlcd.tif.gz
01/07/2002  03:42 PM       483,850,538 oregon_NLCD_erd_032400.tif
04/04/2012  03:35 PM            13,804 roughness_domain.txt

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMET\Merge

12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:28 PM               195 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:36 AM               922 COOS.MSG
12/20/2012  11:36 AM            86,061 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.dat
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.dat

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMET\Stage
3

12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:46 PM             8,599 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:37 AM         1,060,385 COOS.MSG
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM            23,232 COOS.RPT
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files
Appendix\AERMET\Surface

04/04/2012  03:05 PM        32,544,214 726917-24284-0711.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:06 PM               372 aermet.INP
12/20/2012  11:33 AM        26,215,855 COOS.MSG
12/20/2012  11:33 AM           239,433 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.DAT

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMET\Upper
Air

04/04/2012  02:12 PM        23,927,474 72694.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  02:05 PM               373 aermet.INP
12/20/2012  11:33 AM        24,526,315 COOS.MSG
12/20/2012  11:33 AM            14,241 COOS.RPT
```

```
                                          dir.dat
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.DAT

*************************************************************************************
*********************************

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD

03/18/2013  10:17 AM    <DIR>          Class I Screening
03/19/2013  11:24 AM    <DIR>          Load Analysis_Combustion Turbines
03/18/2013  10:17 AM    <DIR>          SIA Modeling
03/18/2013  10:18 AM    <DIR>          Single Source Modeling

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening

** This Directory contains the AERMOD input and output files used for Class I
screening modeling


03/19/2013  11:22 AM    <DIR>          NO2Annual
03/19/2013  11:21 AM    <DIR>          PM1024HR
03/19/2013  11:21 AM    <DIR>          PM10Annual
03/19/2013  11:22 AM    <DIR>          PM2.524HR
03/19/2013  11:22 AM    <DIR>          PM2.5Annual
03/19/2013  11:20 AM    <DIR>          SO224HR
03/19/2013  11:20 AM    <DIR>          SO23HR
03/19/2013  11:21 AM    <DIR>          SO2Annual


 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\NO2Annual


03/19/2013  11:22 AM    <DIR>          2007
03/19/2013  11:22 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011


 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\NO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,465 aermod.inp
03/07/2013  06:14 PM           225,793 annno207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\NO2Annual\2008


12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:16 PM           106,467 aermod.inp
03/07/2013  06:15 PM           225,793 annno208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
```

```
I Screening\NO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:16 PM           106,467 aermod.inp
03/07/2013  06:14 PM           225,793 annno209class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\NO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,469 aermod.inp
03/07/2013  06:14 PM           225,793 annno210class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\NO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,467 aermod.inp
03/07/2013  06:15 PM           227,662 annno211class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM1024HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM1024HR\2007

03/07/2013  06:00 PM           276,095 24hrpm07class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:54 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM1024HR\2008

03/07/2013  06:08 PM           276,095 24hrpm08class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:54 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM1024HR\2009

03/07/2013  06:10 PM           276,095 24hrpm09class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
                                            dir.dat
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM1024HR\2010

03/07/2013  06:14 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM1024HR\2011

03/07/2013  06:15 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:50 PM            78,630 aermod.inp
03/07/2013  05:59 PM           197,121 annpm07class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:05 PM           197,121 annpm08class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:07 PM           197,121 annpm09class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:10 PM           197,121 annpm10class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM10Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:14 PM           198,990 annpm11class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:22 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR\2007

03/07/2013  05:57 PM           276,095 24hrpm07class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:47 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR\2008

03/07/2013  06:01 PM           276,095 24hrpm08class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR\2009

03/07/2013  06:04 PM           276,095 24hrpm09class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR\2010

03/07/2013  06:07 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.524HR\2011

03/07/2013  06:12 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:49 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual

03/19/2013  11:22 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:44 PM            78,635 aermod.inp
03/07/2013  05:54 PM           197,121 annpm2507class1.out
03/07/2013  05:58 PM           197,121 annpm2508class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  05:57 PM           197,121 annpm2509class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  06:04 PM           197,121 annpm2510class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:46 PM            78,635 aermod.inp
03/07/2013  06:06 PM           198,990 annpm2511class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class
I Screening\SO224HR

03/07/2013  06:55 PM           109,668 24hrso2.out
03/07/2013  06:55 PM           277,964 24hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:05 PM            78,140 aermod.inp
```

```
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO23HR

```
03/07/2013  06:55 PM           109,668 3hourso2.out
03/07/2013  06:55 PM           277,964 3hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:04 PM            78,138 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual

```
03/19/2013  11:20 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:59 PM            78,133 aermod.inp
03/07/2013  06:02 PM           100,499 annso207.out
03/07/2013  06:09 PM           197,121 annso207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:09 PM           100,499 annso208.out
03/07/2013  06:02 PM           197,121 annso208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:11 PM           100,499 annso209.out
03/07/2013  06:12 PM           197,121 annso209class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:14 PM           100,499 annso210.out
03/07/2013  06:14 PM           197,121 annso210class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Class

```
I Screening\SO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:15 PM           100,499 annso211.out
03/07/2013  06:15 PM           198,990 annso211class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines

03/19/2013  11:24 AM    <DIR>          2007
03/19/2013  11:24 AM    <DIR>          2008
03/19/2013  11:24 AM    <DIR>          2009
03/19/2013  11:24 AM    <DIR>          2010
03/19/2013  11:24 AM    <DIR>          2011


 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  05:28 AM       268,260,264 load07.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:38 AM       268,260,264 load08.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:05 AM       268,260,264 load09.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:14 AM       268,260,264 load10.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Load
Analysis_Combustion Turbines\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:22 AM       268,262,133 load11.out
```

```
*******************************************************************************
*******************************

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling

** This Directory contains the AERMOD input and output files used for modeling
pollutant specific significant impact areas

03/19/2013  11:27 AM    <DIR>          NO21HR
03/19/2013  11:29 AM    <DIR>          PM1024HR
03/19/2013  11:29 AM    <DIR>          PM2.524HR
03/19/2013  11:27 AM    <DIR>          PM2.5Annual
03/19/2013  11:29 AM    <DIR>          SO21HR

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\NO21HR

03/08/2013  12:25 AM         5,145,536 1hrno2.8th
03/08/2013  12:25 AM         5,145,536 1hrno2.txt
03/08/2013  12:25 AM        12,777,361 1hrso2sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  03:53 PM         1,379,664 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR

03/19/2013  11:29 AM    <DIR>          2007
03/19/2013  11:29 AM    <DIR>          2008
03/19/2013  11:29 AM    <DIR>          2009
03/19/2013  11:29 AM    <DIR>          2010
03/19/2013  11:29 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR\2007

03/08/2013  12:34 AM         2,617,117 24HRPM07.txt
03/08/2013  12:34 AM        20,191,763 24hrpm07sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:13 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR\2008

03/08/2013  12:36 AM         2,617,117 24HRPM08.txt
03/08/2013  12:36 AM        20,191,763 24hrpm08sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR\2009

03/08/2013  12:24 AM         2,617,117 24HRPM09.txt
03/08/2013  12:24 AM        20,191,763 24hrpm09sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
```

```
                                     dir.dat
03/07/2013  04:14 PM          1,395,645 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR\2010

03/08/2013  12:25 AM          2,617,117 24HRPM10.txt
03/08/2013  12:27 AM         20,191,763 24hrpm10sia.out
12/20/2012  03:20 PM          2,545,152 aermod.exe
03/07/2013  04:14 PM          1,395,645 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM1024HR\2011

03/08/2013  12:49 AM          2,617,117 24HRPM11.txt
03/08/2013  12:49 AM         20,193,632 24hrpm11sia.out
12/20/2012  03:20 PM          2,545,152 aermod.exe
03/07/2013  04:15 PM          1,395,645 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR

03/19/2013  11:28 AM    &lt;DIR&gt;          2007
03/19/2013  11:28 AM    &lt;DIR&gt;          2008
03/19/2013  11:28 AM    &lt;DIR&gt;          2009
03/19/2013  11:28 AM    &lt;DIR&gt;          2010
03/19/2013  11:29 AM    &lt;DIR&gt;          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR\2007

03/08/2013  12:20 AM          2,617,117 24HRPM07.txt
03/08/2013  12:24 AM         20,191,763 24hrpm2507sia.out
12/20/2012  03:20 PM          2,545,152 aermod.exe
03/07/2013  04:10 PM          1,395,644 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR\2008

03/08/2013  12:42 AM          2,617,117 24HRPM08.txt
03/08/2013  12:42 AM         20,191,763 24hrpm2508sia.out
12/20/2012  03:20 PM          2,545,152 aermod.exe
03/07/2013  04:10 PM          1,395,644 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR\2009

03/08/2013  12:27 AM          2,617,117 24HRPM09.txt
03/08/2013  12:27 AM         20,191,763 24hrpm2509sia.out
12/20/2012  03:20 PM          2,545,152 aermod.exe
03/07/2013  04:11 PM          1,395,644 aermod.inp
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC
```

```
 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR\2010

03/08/2013  12:12 AM         2,617,117 24HRPM10.txt
03/08/2013  12:16 AM        20,191,763 24hrpm2510sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.524HR\2011

03/08/2013  12:29 AM         2,617,117 24HRPM11.txt
03/08/2013  12:29 AM        20,193,632 24hrpm2511sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual

03/19/2013  11:27 AM    <DIR>          2007
03/19/2013  11:27 AM    <DIR>          2008
03/19/2013  11:27 AM    <DIR>          2009
03/19/2013  11:27 AM    <DIR>          2010
03/19/2013  11:27 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:06 PM         1,395,648 aermod.inp
03/08/2013  12:11 AM        10,940,646 annpm2507sia.out
03/08/2013  12:09 AM         2,397,238 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:07 PM         1,395,648 aermod.inp
03/08/2013  12:29 AM        10,940,646 annpm2508sia.out
03/08/2013  12:29 AM         2,397,238 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:07 PM         1,395,648 aermod.inp
03/08/2013  12:37 AM        10,940,646 annpm2509sia.out
03/08/2013  12:37 AM         2,397,238 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
```

```
                                   dir.dat
03/07/2013  04:08 PM           1,395,648 aermod.inp
03/08/2013  12:26 AM          10,940,646 annpm2510sia.out
03/08/2013  12:23 AM           2,397,238 AnnuPM10.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  04:08 PM           1,395,648 aermod.inp
03/08/2013  12:19 AM          10,942,515 annpm2511sia.out
03/08/2013  12:17 AM           2,397,238 AnnuPM11.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\SIA
Modeling\SO21HR

03/08/2013  08:34 AM           5,145,536 1hrso2.txt
03/08/2013  08:34 AM          20,172,305 1hrso2out.out
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  04:17 PM           1,395,151 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC


*******************************************************************************************
**********************************

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling

** This Directory contains the AERMOD input and output files used for modeling the
Facility for the purposes of obtaining maximum modeled impacts

03/19/2013  11:33 AM    <DIR>          CO1HR
03/19/2013  11:33 AM    <DIR>          CO8HR
03/19/2013  11:33 AM    <DIR>          NO21HR
03/19/2013  11:34 AM    <DIR>          NO2Annual
03/19/2013  11:36 AM    <DIR>          PM1024HR
03/19/2013  11:36 AM    <DIR>          PM10Annual
03/19/2013  11:35 AM    <DIR>          PM2.524HR
03/19/2013  11:35 AM    <DIR>          PM2.5Annual
03/19/2013  11:37 AM    <DIR>          SO21HR
03/19/2013  11:33 AM    <DIR>          SO224HR
03/19/2013  11:33 AM    <DIR>          SO23HR
03/19/2013  11:37 AM    <DIR>          SO2Annual

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\CO1HR

03/08/2013  10:24 AM          26,861,331 1hrCO.out
03/08/2013  10:24 AM           3,473,322 1HRCO.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:49 PM           1,855,704 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\CO8HR

03/08/2013  10:24 AM          26,861,331 8hrCO.out
```

```
03/08/2013  10:24 AM         3,473,322 8HRCO.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:51 PM         1,855,704 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO21HR

```
03/06/2013  08:30 PM         6,829,166 1hrno2.8th
03/06/2013  08:30 PM        21,808,564 1hrno2.out
03/06/2013  08:30 PM         6,829,166 1hrno2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:48 PM         1,825,861 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO2Annual

```
03/19/2013  11:34 AM    <DIR>          2007
03/19/2013  11:34 AM    <DIR>          2008
03/19/2013  11:34 AM    <DIR>          2009
03/19/2013  11:34 AM    <DIR>          2010
03/19/2013  11:34 AM    <DIR>          2011
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO2Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM         3,181,493 AnnNO207.txt
03/07/2013  08:58 PM        21,965,930 anno207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO2Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  09:09 PM        21,965,930 annno208.out
03/07/2013  09:09 PM         3,181,493 AnnNO208.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO2Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM        21,965,930 annno209.out
03/07/2013  08:58 PM         3,181,493 AnnNO209.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\NO2Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  09:06 PM        21,965,930 annno210.out
03/07/2013  09:06 PM         3,181,493 AnnNO210.txt
```

```
                                      dir.dat
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\NO2Annual\2011

12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:28 PM           1,869,854 aermod.inp
03/07/2013  09:07 PM          21,967,799 annno211.out
03/07/2013  09:07 PM           3,181,493 AnnNO211.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM1024HR

03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM1024HR\2007

03/07/2013  06:45 PM          26,785,295 24hrpm07.out
03/07/2013  06:45 PM           3,473,322 24HRPM07.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:35 PM           1,841,805 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM1024HR\2008

03/07/2013  06:53 PM          26,785,295 24hrpm08.out
03/07/2013  06:53 PM           3,473,322 24HRPM08.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:35 PM           1,841,805 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM1024HR\2009

03/07/2013  06:46 PM          26,785,295 24hrpm09.out
03/07/2013  06:46 PM           3,473,322 24HRPM09.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:35 PM           1,841,805 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM1024HR\2010

03/07/2013  06:46 PM          26,785,295 24hrpm10.out
03/07/2013  06:46 PM           3,473,322 24HRPM10.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:36 PM           1,841,805 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
```

Source Modeling\PM1024HR\2011

```
03/07/2013  06:48 PM        26,787,164 24hrpm11.out
03/07/2013  06:48 PM         3,473,322 24HRPM11.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:36 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual

```
03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:04 PM         1,841,801 aermod.inp
03/08/2013  03:38 PM        14,504,228 Annpm07.out
03/08/2013  03:38 PM         3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:44 PM        14,504,228 Annpm08.out
03/08/2013  03:44 PM         3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:39 PM        14,504,228 Annpm09.out
03/08/2013  03:39 PM         3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:40 PM        14,504,228 Annpm10.out
03/08/2013  03:40 PM         3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\PM10Annual\2011

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:06 PM         1,841,801 aermod.inp
```

```
                                                dir.dat
03/08/2013  03:42 PM        14,506,097 Annpm11.out
03/08/2013  03:42 PM         3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR

03/19/2013  11:35 AM    <DIR>          2007
03/19/2013  11:35 AM    <DIR>          2008
03/19/2013  11:35 AM    <DIR>          2009
03/19/2013  11:35 AM    <DIR>          2010
03/19/2013  11:35 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR\2007

03/06/2013  06:04 PM         3,473,322 24HRPM07.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:10 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:04 PM        31,654,956 load07.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR\2008

03/06/2013  06:09 PM         3,473,322 24HRPM08.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:17 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:09 PM        31,654,956 load08.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR\2009

03/06/2013  06:04 PM         3,473,322 24HRPM09.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:18 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:04 PM        31,654,956 load09.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR\2010

03/06/2013  06:05 PM         3,473,322 24HRPM10.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:18 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:05 PM        31,654,956 load10.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.524HR\2011

03/06/2013  06:07 PM         3,473,322 24HRPM11.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:19 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:07 PM        31,656,825 load11.out
```

```
 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual

03/19/2013  11:34 AM    <DIR>          2007
03/19/2013  11:35 AM    <DIR>          2008
03/19/2013  11:35 AM    <DIR>          2009
03/19/2013  11:35 AM    <DIR>          2010
03/19/2013  11:35 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:31 PM         1,841,802 aermod.inp
03/07/2013  07:03 PM        14,504,228 annpm2507.out
03/07/2013  07:03 PM         3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:31 PM         1,841,802 aermod.inp
03/07/2013  06:59 PM        14,504,228 annpm2508.out
03/07/2013  06:59 PM         3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:55 PM        14,504,228 annpm2509.out
03/07/2013  06:55 PM         3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:52 PM        14,504,228 annpm2510.out
03/07/2013  06:52 PM         3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:55 PM        14,506,097 annpm2511.out
03/07/2013  06:55 PM         3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO21HR
```

```
                                                  dir.dat
03/07/2013  03:43 AM        36,533,537 1hrso2.out
03/07/2013  03:43 AM        24,982,168 1hrso2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:56 PM         1,841,415 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO224HR

03/08/2013  05:00 AM         3,473,322 24hrso2.out
03/08/2013  05:00 AM        26,787,164 24hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/15/2013  03:47 PM         1,841,307 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO23HR

03/08/2013  05:01 AM         3,473,322 3hourso2.out
03/08/2013  05:01 AM        26,787,164 3hrso2.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/15/2013  03:46 PM         1,841,305 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO2Annual

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03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:37 AM    <DIR>          2009
03/19/2013  11:37 AM    <DIR>          2010
03/19/2013  11:37 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:45 PM         1,841,300 aermod.inp
03/07/2013  06:45 PM         3,181,493 annso207.out
03/07/2013  06:45 PM        14,504,228 annso207out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:45 PM         1,841,300 aermod.inp
03/07/2013  06:51 PM         3,181,493 annso208.out
03/07/2013  06:51 PM        14,504,228 annso208out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single
Source Modeling\SO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:46 PM         3,181,493 annso209.out
03/07/2013  06:46 PM        14,504,228 annso209out.out
```

```
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\SO2Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:48 PM         3,181,493 annso210.out
03/07/2013  06:48 PM        14,504,228 annso210out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\AERMOD\Single Source Modeling\SO2Annual\2011

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:48 PM         3,181,493 annso211.out
03/07/2013  06:48 PM        14,506,097 annso211out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

****

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling

** This Directory contains the AERMOD input and output files used for modeling the Facility for the purposes of obtaining maximum modeled impacts
** including offsite sources and vessel sources

```
05/03/2013  09:16 AM    <DIR>          CO1HR
05/03/2013  09:17 AM    <DIR>          CO8HR
05/03/2013  09:24 AM    <DIR>          NO21HR
05/03/2013  09:23 AM    <DIR>          NO2Annual
05/03/2013  09:29 AM    <DIR>          PM1024HR
05/03/2013  09:26 AM    <DIR>          PM2.524HR
05/03/2013  09:29 AM    <DIR>          PM2.524HR BAH Receptor
05/03/2013  09:25 AM    <DIR>          PM2.5Annual
05/03/2013  09:43 AM    <DIR>          SO21HR
05/03/2013  09:44 AM    <DIR>          SO21HR BAH Receptor
05/03/2013  09:47 AM    <DIR>          SO224HR
05/03/2013  09:44 AM    <DIR>          SO23HR
05/03/2013  09:42 AM    <DIR>          SO2Annual
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\CO1HR

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:43 PM         1,944,970 aermod.inp
04/12/2013  08:24 PM        84,856,869 co1hr.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC

```
Multisource Modeling\CO8HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:50 PM         1,944,244 aermod.inp
04/13/2013  09:24 AM        43,907,767 CO8hr.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO21HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:52 PM         1,917,122 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/12/2013  03:37 PM        83,817,172 No21hr.out

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual

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05/03/2013  09:23 AM    <DIR>          2009
05/03/2013  09:23 AM    <DIR>          2010
05/03/2013  09:23 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:51 PM         1,957,013 aermod.inp
04/07/2013  02:58 PM        13,014,020 AnnNo207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:01 PM         1,957,013 aermod.inp
04/07/2013  03:30 PM        13,014,020 AnnNo208.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:01 PM         1,957,013 aermod.inp
04/07/2013  01:52 PM        13,014,020 AnnNo209.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,957,013 aermod.inp
04/07/2013  03:09 PM        13,014,020 AnnNo210.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

```
 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\NO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,957,013 aermod.inp
04/07/2013  02:55 PM        13,015,889 AnnNo211.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM1024HR

04/13/2013  02:49 AM        23,389,635 24hrPM10.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:56 PM         1,928,742 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM2.524HR

04/13/2013  04:21 PM        48,785,315 24hrPM2.5.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:55 PM         1,937,400 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM2.524HR BAH Receptor

04/05/2013  04:37 PM           465,343 24hrPM2.5.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:56 PM           126,079 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM2.5Annual

05/03/2013  09:25 AM    <DIR>          2007
05/03/2013  09:25 AM    <DIR>          2008
05/03/2013  09:25 AM    <DIR>          2009
05/03/2013  09:25 AM    <DIR>          2010
05/03/2013  09:25 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:53 PM         1,928,811 aermod.inp
04/07/2013  01:40 PM        12,986,998 AnnPM2.507.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,928,811 aermod.inp
04/07/2013  01:39 PM        12,986,998 AnnPM2.508.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\PM2.5Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  11:54 AM        12,986,998 AnnPM2.509.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\PM2.5Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  01:42 PM        12,986,998 AnnPM2.510.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\PM2.5Annual\2011

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  02:22 PM        12,988,867 AnnPM2.511.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\SO21HR

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:57 PM         1,933,038 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/12/2013  11:21 PM        84,732,223 So21Hr.out
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\SO21HR BAH Receptor

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:57 PM           121,679 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/05/2013  04:35 PM           485,080 SO21hr.out
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\SO224HR

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:00 PM         1,928,280 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/13/2013  12:37 AM        23,389,635 SO224Hr.out
```

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC Multisource Modeling\SO23HR

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:59 PM         1,928,820 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/12/2013  03:12 PM        63,776,127 SO23hr.out
```

```
 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual

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05/03/2013  09:42 AM    <DIR>          2008
05/03/2013  09:42 AM    <DIR>          2009
05/03/2013  09:42 AM    <DIR>          2010
05/03/2013  09:42 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:57 PM         1,928,204 aermod.inp
04/07/2013  01:31 PM        12,986,998 AnnSo207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:04 PM         1,928,204 aermod.inp
04/07/2013  01:16 PM        12,986,998 AnnSo208.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:04 PM         1,928,204 aermod.inp
04/07/2013  12:03 PM        12,986,998 AnnSo209.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:04 PM         1,928,204 aermod.inp
04/07/2013  01:16 PM        12,986,998 AnnSo210.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\FERC
Multisource Modeling\SO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:04 PM         1,928,204 aermod.inp
04/07/2013  12:32 PM        12,988,867 AnnSo211.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

*************************************************************************************
*********************************

 Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\BPIP

** This Directory contains the BPIP input and output used for the building downwash
analysis
```

dir.dat

```
11/02/2012  01:21 PM           720,946 Bpipprm.exe
03/05/2013  12:36 PM           410,099 jcepgep.out
03/05/2013  12:36 PM             6,588 JCEPGEP.PIP
03/05/2013  12:36 PM            37,043 jcepgep.sum
```

****

Directory of \JCEP PSD Air Permit Application\Modeling Files Appendix\VISCREEN

** This Directory contains the VISCREEN input and output files used for screening visibility modeling

```
03/08/2013  01:09 PM             7,709 jordan cove LNG viscreen
03/08/2013  01:09 PM             2,209 jordan cove LNG viscreen output
```

****

Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling

** This Directory contains the AERMOD input and output files used for ODEQ multisource modeling analysis including offsite sources
and vessel sources while stationary

```
05/29/2013  10:37 AM    <DIR>          BAH Receptor
05/29/2013  11:32 AM    <DIR>          NO21HR
05/29/2013  11:39 AM    <DIR>          PM1024HR
05/29/2013  11:39 AM    <DIR>          PM1024HR_Increment
05/29/2013  11:37 AM    <DIR>          PM2.524HR
05/29/2013  11:37 AM    <DIR>          PM2.524HR_Direct Emissions
05/29/2013  11:38 AM    <DIR>          PM2.524HR_Increment
05/29/2013  11:35 AM    <DIR>          PM2.5Annual
05/29/2013  11:36 AM    <DIR>          PM2.5Annual_Increment
05/29/2013  11:40 AM    <DIR>          SO21HR
05/29/2013  11:45 AM    <DIR>          With50kmGrid
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Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\BAH Receptor

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05/29/2013  11:52 AM    <DIR>          PM1024HR_Increment
05/29/2013  11:51 AM    <DIR>          PM2.524HR
05/29/2013  11:51 AM    <DIR>          PM2.524HR_Increment
05/29/2013  11:50 AM    <DIR>          PM2.5Annual
05/29/2013  11:51 AM    <DIR>          PM2.5Annual_Increment
05/29/2013  11:52 AM    <DIR>          SO21HR
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Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\BAH Receptor\PM1024HR

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```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:44 PM            51,623 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM1024HR_Increment


05/23/2013  02:32 PM           114,518 24HRPM10.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  02:29 PM            51,627 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.524HR

05/23/2013  02:31 PM           109,878 24HRPM2.5.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:39 PM            51,669 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.524HR_Increment


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12/20/2012  03:20 PM         2,545,152 aermod.exe
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12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual

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05/29/2013  11:50 AM    <DIR>          2008
05/29/2013  11:50 AM    <DIR>          2009
05/29/2013  11:50 AM    <DIR>          2010
05/29/2013  11:50 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:47 PM            51,393 aermod.inp
05/23/2013  02:28 PM           100,615 AnnPM2.507.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  02:27 PM            51,393 aermod.inp
05/23/2013  02:28 PM           100,615 AnnPM2.508.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual\2009
```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  02:27 PM            51,393 aermod.inp
05/23/2013  02:28 PM           100,615 AnnPM2.509.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  02:27 PM            51,393 aermod.inp
05/23/2013  02:28 PM           100,615 AnnPM2.510.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  02:28 PM            51,393 aermod.inp
05/23/2013  02:28 PM           102,484 AnnPM2.511.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment


05/29/2013  11:31 AM    <DIR>          2007
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05/29/2013  11:31 AM    <DIR>          2009
05/29/2013  11:31 AM    <DIR>          2010
05/29/2013  11:31 AM    <DIR>          2011
05/23/2013  02:28 PM            92,892 AnnPM2.507.out
05/23/2013  02:28 PM            92,892 AnnPM2.508.out
05/23/2013  02:28 PM            92,892 AnnPM2.509.out
05/23/2013  02:28 PM            92,892 AnnPM2.510.out
05/23/2013  02:29 PM            94,761 AnnPM2.511.out

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment\2007


12/20/2012  03:20 PM         2,545,152 aermod.exe
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12/20/2012  11:37 AM         7,231,060 COOS.SFC


 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment\2008

05/29/2013  11:31 AM    <DIR>          .
05/29/2013  11:31 AM    <DIR>          ..
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:49 PM            45,447 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment\2009
```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:49 PM            45,447 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:50 PM            45,447 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\PM2.5Annual_Increment\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/23/2013  01:50 PM            45,447 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\BAH Receptor\SO21HR

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12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
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05/14/2013  03:08 PM         1,841,510 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
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12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM1024HR_Increment

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05/14/2013  03:35 PM         1,862,951 aermod.inp
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12/20/2012  11:37 AM         7,231,060 COOS.SFC
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 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
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05/14/2013  03:21 PM         1,862,997 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
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05/23/2013  10:31 AM         1,862,997 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.524HR_Increment

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12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.5Annual

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05/29/2013  11:35 AM    <DIR>          2009
05/29/2013  11:35 AM    <DIR>          2010
05/29/2013  11:35 AM    <DIR>          2011

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
05/22/2013  01:03 PM         1,862,779 aermod.inp
05/22/2013  09:41 PM        12,678,896 AnnPM2.507.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.5Annual\2008

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05/22/2013  01:03 PM         1,862,779 aermod.inp
05/23/2013  12:30 AM        12,678,896 AnnPM2.508.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual\2009

```
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05/22/2013  01:03 PM         1,862,779 aermod.inp
05/22/2013  09:39 PM        12,678,896 AnnPM2.509.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
05/22/2013  01:03 PM         1,862,779 aermod.inp
05/22/2013  09:50 PM        12,678,896 AnnPM2.510.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual\2011

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12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
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Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual_Increment

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05/29/2013  11:36 AM    <DIR>          2009
05/29/2013  11:36 AM    <DIR>          2010
05/29/2013  11:36 AM    <DIR>          2011
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Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual_Increment\2007

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05/22/2013  01:02 PM         1,854,590 aermod.inp
05/23/2013  03:50 PM        12,457,994 AnnPM2.507.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual_Increment\2008

```
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05/23/2013  10:09 AM         1,854,590 aermod.inp
05/23/2013  03:59 PM        12,457,994 AnnPM2.508.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
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Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling Files\ODEQ Multisource Modeling\PM2.5Annual_Increment\2009

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05/23/2013  10:09 AM          1,854,590 aermod.inp
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12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.5Annual_Increment\2010

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05/23/2013  03:54 PM         12,457,994 AnnPM2.510.out
12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\PM2.5Annual_Increment\2011

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12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\SO21HR

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12/20/2012  11:37 AM          2,936,208 COOS.PFL
12/20/2012  11:37 AM          7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\With50kmGrid

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05/29/2013  11:45 AM    <DIR>          PM1024HR
05/29/2013  11:46 AM    <DIR>          PM1024HR_Increment
05/29/2013  11:43 AM    <DIR>          PM2.524HR
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 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\With50kmGrid\NO21HR

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12/20/2012  11:37 AM          7,231,060 COOS.SFC
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 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\With50kmGrid\PM1024HR

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03/28/2013  03:50 PM         1,416,848 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\With50kmGrid\PM1024HR_Increment

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05/14/2013  03:37 PM         1,416,848 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of \JCEP PSD Air Permit Application\Appendix G_Air Quality Modeling
Files\ODEQ Multisource Modeling\With50kmGrid\PM2.524HR


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Appendix K
FERC Evaluation of Emissions and Impacts from Marine Vessels

Jordan Cove Energy Project, L.P.

Evaluation of Emissions and Air Quality Impacts from Marine Vessels

Prepared for

Federal Energy Regulatory Commission
(Docket PF12-7)

Prepared by

TRC Environmental
Lyndhurst, NJ
May 2013

1.0 INTRODUCTION

Jordan Cove Energy Project, L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal on an approximate 168-acre site located on the bay side of the North Spit of Coos Bay, Oregon between Coos Bay Navigation Channel Miles (CM) 7.0 and 8.0. The project, known as the Jordan Cove Energy Project (JCEP) LNG Terminal Project, or Project (or Facility) will consist of facilities to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The LNG terminal will be capable of loading LNG ships ranging in capacity from 89,000 cubic meters (m^3) to 160,000 m^3. Approximately 90 ships per year are anticipated to call on the LNG terminal. The LNG loaded onto the ships will be transferred by cryogenic service piping from two 160,000 m^3 (1,006,000 barrels) full-containment LNG storage tanks where it will be stored in a liquefied state until it is pumped out to the LNG vessels.

While not explicitly required by any Federal or Oregon air regulations, FERC has requested that JCEP provide an estimate of LNG carrier emissions and subsequent impact modeling of these emissions while the LNG carrier is maneuvering, docking, or undocking, and loading. This document provides an analysis of LNG carrier emissions and impact modeling while the LNG carrier is in transit, maneuvering, docking or undocking, and loading from the time the carrier enters the mouth of the Coos Bay Estuarine System to the time the carrier is moored at the LNG terminal, as well as the return trip back to the mouth of the Coos Bay Estuarine System. The LNG vessel modeling was prepared with the modeling methodology used for assessing the proposed facility's air quality impact, which was detailed in the Air Quality Modeling Protocol submitted to the ODEQ on November 28, 2012 and approved on January 23, 2013. A copy of the air quality modeling protocol can be found in Appendix B.9 of Resource Report 9. Also, the modeling was conducted using the additional modeling methodology required for the multisource impact analysis including existing offsite source (provided by ODEQ) using the methodology described in the JCEP LNG Terminal Project "Multisource Modeling Methodology" submitted to ODEQ in April 2013 and included in Appendix B.9 of Resource Report 9.

Based upon potential emission calculations for the Project sources, facility emissions will be greater than 100 tons per year for criteria air pollutants and thus, the Project will require an Oregon DEQ Air Contaminant Discharge Permit (ACDP). Also, because the proposed facility is located in an attainment area for all pollutants and will potentially emit more than 100 tons per year of several air pollutants, it will be subject to federal Prevention of Significant Deterioration (PSD) permitting. The ODEQ has determined with respect to LNG terminals that the emissions from the LNG carriers during LNG loading are included in the terminal's Plant Site Emission Limits (PSELs) and thus the federal PSD applicability determination for the facility. These "direct" emissions include those activities attributable to providing power for the LNG transfer system, including the LNG transfer pumps, as well as fugitive emissions from ship-board LNG piping and pumping systems. The ODEQ has determined that all emissions associated with the "hotelling" process as well as the berthing, deberthing, and transit processes, are not directly associated with the terminal activities and thus, are not considered part of the stationary source's emissions and subject to any ACDP or PSD permit requirements. The power to provide for the pumps to load the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the loading process that would be subject to ACDP and PSD review.

2.0 LNG CARRIER AND SUPPORT TUG EMISSIONS

The Project will have associated mobile sources (i.e., LNG vessels) that will be moored at the ship berthing area during loading of LNG from the LNG storage tanks or directly after undergoing the gas conditioning and liquefaction processes. The Project is designed to accept any LNG vessel capable of onloading LNG at the facility and thus, it is not possible to prepare emission estimates for a single LNG vessel design. However, emissions have been determined for the 148,000 m^3 LNG carrier ships, which are typical of the LNG ships anticipated to transit the waterway to the Project. Power demands while the LNG vessels are being loaded are expected to be 1.9 MW for ship hotelling and 1.675 MW to maintain the propulsion system on hot standby. The power to provide for the pumps to onload the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the onloading process that would be subject to ACDP and PSD review as well as the requirement to formally model those emissions.

The current fleet of LNG vessels consists primarily of vessels that have boiler/steam turbine driven (ST) propulsion systems. It is expected that by the operational date of the JCEP terminal, currently expected in 2018, that the fleet of LNG vessels that will call on the terminal will consist of a mix of vessels powered by ST propulsion and dual-fuel diesel–electric (DFDE) propulsion. Furthermore, it is expected that most, if not all of the ST and DFDE vessels combust either LNG boil off gas (BOG) or oil (marine distillate) in their propulsion and auxiliary power systems. Thus, an envelope of four (4) LNG vessel operating cases was developed in order to provide worst-case air emission calculations and associated air quality modeling impacts for these emissions. Specifically, these cases consist of LNG vessels firing either marine oil or BOG for LNG carriers utilizing ST propulsion or DFDE propulsion.

Appendix A contains the detailed emission calculations for the LNG vessels and support tugs for the secondary emission sources (i.e., those emissions not directly associated with terminal activities). Each table provides all of the pertinent assumptions/basis for the emission calculations during each phase of the transit/berthing/loading/deberthing delivery cycle process. As shown in the tables, it is expected that each vessel would take approximately 24 hours to transit from mouth of the Coos Bay Estuarine System, be loaded with LNG, and transit back to the mouth of the Coos Bay Estuarine System. Of those 24 hours, 17.5 would be expected to take place while the vessels are berthed. Annual emissions were based upon a maximum of 90 ship calls per year.

Fuel Oil Sulfur Limit

The facility currently expects to begin commercial operation in 2018 or later and as such, the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI world-wide fuel sulfur limit cap will be 3.5%. It should be noted that the Annex VI worldwide cap will be reduced to a value of 0.5% by 2020. The U.S. EPA recently submitted and was granted on March 26, 2010 a request to the International Maritime Organization (IMO) that the entire coastline of the United States and Canada be designated as emission control areas (ECA) under MARPOL Annex VI. Under this regulation by 2015, all vessels entering within 200 nautical miles (230 miles) of the U.S. coast would be required to operate on a fuel with a sulfur content less than 0.1%. Thus, a maximum sulfur content of 0.1% for LNG vessel emission calculations purposes is regulated by IMO MARPOL Annex VI regulations and will be enforced by the U.S. Coast Guard.

Jordan Cove intends to restrict a vessel's maximum fuel oil sulfur content to a value of 0.1% while the vessels are moored at the terminal. It is likely that most vessels from 2018 and beyond will utilize fuels during the LNG loading process that have a maximum sulfur content of 0.1% to comply with the Annex VI ECA requirements. The sulfur in the fuel limit for indirect source emission activities can be established and monitored through the Jordan Cove Terminal Regulations, which form part of the port Operations Manual. The following language (or functionally similar) could appear in this Manual.

- Fuel with a sulfur content in excess of 0.1% shall be considered noncompliant and fuel with a sulfur content equal to or below 0.1% shall be considered compliant. Sulfur contents will be established through standard analytical test methods. Fuel can be defined singly as either oil or BOG or can be defined as a mixture of oil/BOG.
- Any LNG vessel that is not capable of operating on a compliant fuel while berthed at the terminal will not be accepted by the Terminal.
- As part of the Terminal clearance process, Jordan Cove will require each arriving vessel to perform the following:
  1. Confirm and acknowledge the fuel sulfur restriction and submit a plan to Jordan Cove demonstrating the manner of compliance with the restriction while berthed.
  2. Submit the latest bunker analysis report providing the sulfur content of the on-board fuel oil.
- Following the review of the bunker analysis report and confirmation of an acceptable implementation plan, the vessel would be cleared to call at the Terminal.
- Jordan Cove would maintain all records of arriving vessel's compliance, including the bunker analysis reports, and make them available for review for a period of three years after a delivery.

3.0 AIR QUALITY IMPACT ANALYSIS

3.1 SOURCE DATA

Terminal Sources

There are two sites to be referenced within this one facility. The first is the Liquefaction site, which contains the four (4) Liquefaction trains, two (2) LNG full containment tanks, and the marine berthing and load-out facilities. The second area is referred to as the South Dunes Power Station site, which contains two gas pre-treatment trains, the South Dunes Power Plant, and the common infrastructure for the plant entrance and administration buildings. The South Dunes Power Station site will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF) and which will be equipped with natural gas-fired duct burners for supplementary firing and two steam turbine generators (STGs). Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Station) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Station).

In addition to the South Dunes Power Station, the LNG Liquefaction Project will have a number of fugitive VOC emission sources from piping/flanges/valves from both land-based and vessel based sources. The four LNG liquefaction trains will be electric and thus, only fugitive VOC emissions are expected from that equipment.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide ($CO2$) and water. Mercury is also removed to prevent corrosion in downstream equipment. Hydrogen sulfide and mercaptans are removed using a scavenging system.

The gas conditioning trains consist of two parallel trains, each containing two systems in series: a scavenger system to reduce hydrogen sulfide and mercaptans, a $CO2$ removal process which utilizes a primary amine to absorb $CO2$, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas from the Amine Stripper will be sent to a thermal oxidizer in order to oxidize sulfur components. Air emissions from the amine and dehydration systems are not expected.

Modeled emission and stack parameters for the JCEP Facility stationary sources are identical to those used in the single source PSD/ACDP modeling analyses provided in Section 5 of the ODEQ PSD/ACDP application included in Appendix B.9 of Resource Report 9.

Marine Based Sources

LNG vessel boilers and/or engines are determined by the demands of the propulsion system and auxiliary power needs while at sea and 148,000 m^3 vessel propulsion power requirements have been conservatively estimated to be 33.5 MW with additional auxiliary power of 9.45 MW. Power requirements while in the Coos Bay Navigation Channel and during hotelling are significantly lower than at-sea propulsion demand and are provided for each step of the delivery cycle process in the attached emission calculations and modeling parameters spreadsheets (see Appendix A). Power demands while the LNG vessels being loaded with LNG are expected to be 1.9 MW for ship hotelling activities.

Appendix A contains emission and stack exhaust parameters (i.e., height, exit velocity, exit temperature, and exit diameter) for a typical LNG Carrier and associated support tug. Spreadsheets are provided for the envelope of vessel propulsion types and fuel types. Each table provides all of the pertinent assumptions/basis for the emission calculations and stack parameters during each phase of the delivery cycle process.

A set of point sources with spacing of every 200 meters was developed to simulate a LNG Carrier's transit to and from the JCEP Facility. It is assumed that a vessel may transit to and from the JCEP Facility in 1.5 hours over the 13.5 kilometer length of the passageway (i.e., a speed of approximately 5 knots). Thus, a set of 68 discrete point sources was developed to simulate the LNG Carrier's transit from the mouth of the Coos Bay Estuarine System to and from the JCEP Facility.

<u>Short-Term and Annual Modeling Methodology for Marine Sources</u>

As indicated in the attached emission calculation and stack parameter spreadsheets, the LNG vessel delivery cycle process takes approximately 24 hours with a maximum of 90 vessels per year on an annual basis. Of the 24 hour delivery cycle, 13 hours are associated with the LNG loading and hotelling process while the remaining 11 hours consist of the transit to and from the mouth of the Coos Bay Estuarine System, the berthing and deberthing processes, and purging and connecting/disconnecting of the arms. Thus, on an annual basis, ship emissions will occur for a maximum of 2,160 hours per year. As such, the annual emissions utilized for the annual averaged concentration modeling were scaled accordingly based upon the maximum amount of hours occurring for the process in a given year (i.e., hotelling emissions were scaled by 1,170/8,760).

Similarly, the short-term modeling (i.e., 1-hour, 3-hour, 8-hour, and 24-hour) accounted for times the vessels and support tugs are in each discreet process of the delivery cycle. For the averaging times less than 24-hours, not all of the discreet delivery cycle vessel activities could occur simultaneously over the same short term time period, and thus, multiple source groups in AERMOD were necessary to accurately model the sub-daily averaging periods (i.e., 1-hour, 3-hour and 24-hour). Note that additional source groups were not developed for those situations that would yield identical dispersion modeling results (i.e., for 1-hour CO modeling, the transit emissions to and from the Terminal are identical and thus, only 1-source group was used for two (2) discreet delivery cycle activities). Also note that both BOG and FO operation while the vessels are moored are included in the same dispersion modeling runs as discreet source groups (with "G" added to the source group ID to identify BOG operation). Please refer to the attached dispersion modeling AERMOD files for descriptions of the numerous source groups included in the dispersion modeling runs. Please refer to Appendix A for a spreadsheet that provides all short-term and annual modeled emission rates.

3.2 MODELING METHODOLOGY

As discussed previously, modeling was performed consistent with the Project "Air Quality Modeling Protocol" submitted to the ODEQ on November 28, 2012 and approved on January 23, 2013. Modeling methodology details specific to the LNG vessels and support tugs are provided in detail in this section.

3.2.1 Good Engineering Practice Stack Height Analysis

Section 123 of the Clean Air Act Amendments of 1977 required U.S. EPA to promulgate regulations to assure that the control of any air pollutant under an applicable State Implementation Plan (SIP) was not affected by (1) stack heights that exceed Good Engineering Practice (GEP) or (2) any other dispersion technique. The U.S. EPA provides specific guidance for determining GEP stack height and for determining whether building downwash will occur in the Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations), (U.S. EPA-450/4-80-023R, June, 1985). GEP, with respect to stack height, is defined in Section 123 of the Clean Air Act Amendments of 1977 as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes which may be created by the source itself, nearby structures, or nearby terrain obstacles."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) are avoided. The U.S. EPA GEP stack height regulations specify that the GEP stack height is calculated in the following manner:

$$H_{GEP} = HB + 1.5L$$

where:

where:	HB	=	the height of adjacent or nearby structures, and
	L	=	the lesser dimension (height or projected width) of the adjacent or nearby structures).

The downwash parameters utilized for the single source and cumulative source analyses for the JCEP Facility stationary sources were used for the combined stationary and mobile source (i.e., LNG Carrier) modeling analysis. For a more complete description of the stationary source GEP analysis please refer to Section 5 of the JCEP PSD Air Permit Application located in Appendix B.9 of Resource Report 9.

The controlling structures (i.e., the structure(s) that yield the maximum associated GEP height) for the LNG Carrier exhaust stacks will be the LNG Carrier itself. Because a single LNG Carrier design will not be the basis for the JCEP design, a GEP analysis has been determined for the 148,000 m^3 LNG ships, which are typical of the LNG ships anticipated to transit the waterway to the Project. A ship of this capacity may have a typical height of approximately 109 feet, which results in a GEP formula height of 272 feet. The typical stack height for a 148,000 m^3 LNG Carrier is on the order of 131 feet above grade level and therefore is less than the GEP formula stack height of 272 ft. Thus, direction-specific building downwash parameters were included in the modeling analysis for the LNG carrier stack. The direction-specific downwash parameters were determined using the U.S. EPA Building Profile Input Program (BPIP-PRIME, Version 04274). Similarly, the support tugs with typical stack heights of 35 feet above grade would be subject to building downwash associated with LNG carriers. The attached electronic BPIP-PRIME input files contain the building dimensions and heights for all structures utilized in the building downwash analysis.

Because the LNG ships will have different orientations with respect to a north-south orientation while navigating the Coos Bay channel, BPIP-PRIME was ran for 10 different orientations accounting for the rotation angles from North. Thus, the downwash parameters accounted for the LNG ship's rotation angle while navigating the Coos Bay channel. Table 3-1 provides the orientation of each approximate straight-line segment of the LNG Carrier's and support tugs transit through the Coos Bay channel along with the AERMOD ID's corresponding to each individual segment.

TABLE 3-1: BPIP Rotation Angles and AERMOD IDs		
Transit Segment	**AERMOD Stack ID**	**Rotation Angle from North**
1	VES1-VES13	-56.1
2	VES14-VES17	-108.6
3	VES18- VES23	-154.6
4	VES24- VES38	-135.2
5	VES39- VES50	-154.8
6	VES51- VES57	-171.0
7	VES58- VES59	-149.0
8	VES60- VES63	-133.4
9	VES64	-101.8
10	VES65- VES68	0.0

3.3 MODELING RESULTS

The results of the modeling analysis utilizing the methodology presented in this document and in the Project single source and multisource modeling protocols are summarized in Table 3-2. The maximum predicted impacts were added to the representative background concentrations for comparison to the OAAQS/NAAQS. As required by ODEQ for the stationary source PSD modeling analysis, offsite source impacts were included for 1-hour SO_2 and NO_2, 24-hour PM-10/PM-2.5, and annual PM-2.5. Results of the air quality assessment indicate that the concentrations of CO, SO_2, NO_x, and PM-10/PM-2.5 are below the NAAQS and OAAQS with the addition of the mobile sources to the single source and cumulative source modeling analyses.

Thus, the Project will not cause or contribute to the violation of any NAAQS/OAAQS with the addition of the mobile sources and therefore, no additional Class II modeling is required.

3.4 MODELING FILES

A DVD containing the modeling input and output files is provided in Appendix B. Note that the DVD also contains the modeling files used in the single source modeling for the JCEP PSD Air Permit Application.

Table 3-2: Maximum Modeled Concentrations for Comparison to NAAQS

Pollutant	Averaging Time	Maximum Modeled Concentration (ug/m3)	Background Air Quality (ug/m3)	Total Impact (ug/m3)	OAQQS/ NAAQS (ug/m3)
SO_2	1-hour	56.8	23	80	197
	3-hour	22.9	21	44	1,300
	24-hour	8.8	11	19	262/365
	Annual	0.3	4	4	52.4/80
NO_2	1-hour	113.9	66	180	188
	Annual	1.2	19	20	100
CO	1-hour	890	2,415	3,305	40,000
	8-hour	107	1,840	1,947	10,000
PM-2.5	24-hour	6.5	23	30	35
	Annual	0.8	8	8	12
PM-10	24-hour	9.3	55	64	150

APPENDIX A

DETAILED EMISSION CALCULATIONS

Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Diesel-Electric Propulsion (Fuel Oil)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM		HC		SOx		CO_2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Inward Bound to Berth (Assuming Oil Operation only)																							
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	13.45	163.97	11.07	11.05	0.75	15.80	1.07	19.48	1.32	31,829.34	2,148.48	0.85	0.06	0.28	0.02
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	48.63	3.28	40.02	2.70	2.70	0.18	3.86	0.26	4.76	0.32	7,768.14	524.35	0.21	0.01	0.07	0.00
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	1.41	25.89	1.16	1.75	0.08	2.49	0.11	3.08	0.14	5,025.11	226.13	0.13	0.01	0.04	0.00
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	1.41	25.89	1.16	1.75	0.08	2.49	0.11	3.08	0.14	5,025.11	226.13	0.13	0.01	0.04	0.00
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	31.44	3.54	25.89	2.91	1.75	0.20	2.49	0.28	3.08	0.35	5,025.11	565.32	0.13	0.02	0.04	0.01
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	26.79	15.68	22.06	12.90	1.49	0.87	2.13	1.24	2.62	1.53	4,282.14	2,505.05	0.11	0.07	0.04	0.02
Outward Bound to K Buoy (Assuming Oil Operation only)																							
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	48.63	4.38	40.02	3.60	2.70	0.24	3.86	0.35	4.76	0.43	7,768.14	699.13	0.21	0.02	0.07	0.01
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	13.45	163.97	11.07	11.05	0.75	15.80	1.07	19.48	1.32	31,829.34	2,148.48	0.85	0.06	0.28	0.02
TOTAL	**24.00**								**56.60**		**46.59**		**3.14**		**4.49**		**5.54**		**9,043.08**		**0.24**		**0.08**

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Diesel-Electric Propulsion (BOG)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx lb/hr	NOx tpy	CO lb/hr	CO tpy
Inward Bound to Berth (Assuming Oil Operation only)											
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	13.45	163.97	11.07
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	48.63	3.28	40.02	2.70
Hotelling											
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,875	2,520	15.84	0.71	10.05	0.45
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	15.84	0.71	10.05	0.45
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	15.84	1.78	10.05	1.13
LNG Loading											
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	13.50	7.89	8.56	5.01
Outward Bound to K Buoy (Assuming Oil Operation only)											
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	48.63	4.38	40.02	3.60
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	13.45	163.97	11.07
TOTAL	**24.00**								**45.68**		**35.48**

Period	PM lb/hr	PM tpy	HC lb/hr	HC tpy	SOx lb/hr	SOx tpy	CO_2 lb/hr	CO_2 tpy	CH_4 lb/hr	CH_4 tpy	N_2O lb/hr	N_2O tpy
Inward Bound to Berth (Assuming Oil Operation only)												
Transit	11.05	0.75	15.80	1.07	19.48	1.32	31,829.34	2,148.48	0.85	0.06	0.28	0.02
Berthing and All Fast	2.70	0.18	3.86	0.26	4.76	0.32	7,768.14	524.35	0.21	0.01	0.07	0.00
Hotelling												
Connect Arms and Cool Down (propulsion on hot standby)	0.32	0.01	6.09	0.27	0.52	0.02	3,350.07	150.75	0.40	0.02	0.01	0.00
Purge and Disconnect Arms (propulsion on hot standby)	0.32	0.01	6.09	0.27	0.52	0.02	3,350.07	150.75	0.40	0.02	0.01	0.00
Contingency (propulsion on hot standby)	0.32	0.04	6.09	0.69	0.52	0.06	3,350.07	376.88	0.40	0.04	0.01	0.00
LNG Loading												
Cargo transfer (propulsion on hot standby)	0.27	0.16	5.10	3.04	0.44	0.26	2,854.76	1,670.03	0.34	0.20	0.006	0.003
Outward Bound to K Buoy (Assuming Oil Operation only)												
Warm Engines & Cast Off	2.70	0.24	3.86	0.35	4.76	0.43	7,768.14	699.13	0.21	0.02	0.07	0.01
Transit	11.05	0.75	15.80	1.07	19.48	1.32	31,829.34	2,148.48	0.85	0.06	0.28	0.02
TOTAL		**2.14**		**7.01**		**3.74**		**7,868.87**		**0.43**		**0.05**

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Steam Turbine Propulsion (Fuel Oil)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM/PM10		HC		SOx		CO_2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Inward Bound to Berth (Assuming Oil Operation only)																							
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	6.18	9.73	0.66	10.75	0.73	0.54	0.04	30.89	2.09	47,672.90	3,217.92	1.91	0.13	0.21	0.01
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	22.34	1.51	2.37	0.16	2.62	0.18	0.13	0.01	7.54	0.51	11,634.85	785.35	0.47	0.03	0.05	0.00
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.82	1.95	0.09	2.15	0.10	0.11	0.00	6.18	0.28	9,542.82	429.43	0.38	0.02	0.04	0.00
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.82	1.95	0.09	2.15	0.10	0.11	0.00	6.18	0.28	9,542.82	429.43	0.38	0.02	0.04	0.00
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	18.32	2.06	1.95	0.22	2.15	0.24	0.11	0.01	6.18	0.70	9,542.82	1,073.57	0.38	0.04	0.04	0.00
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	15.61	9.13	1.66	0.97	1.83	1.07	0.09	0.05	5.27	3.08	8,131.90	4,757.16	0.33	0.19	0.04	0.02
Outward Bound to K Buoy (Assuming Oil Operation only)																							
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	22.34	2.01	2.37	0.21	2.62	0.24	0.13	0.01	7.54	0.68	11,634.85	1,047.14	0.47	0.04	0.05	0.00
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	6.18	9.73	0.66	10.75	0.73	0.54	0.04	30.89	2.09	47,672.90	3,217.92	1.91	0.13	0.21	0.01
TOTAL	**24.00**								**28.72**		**3.05**		**3.37**		**0.17**		**9.89**		**14,957.91**		**0.60**		**0.07**

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

Jordan Cove Energy Project, L.P.
Air Emissions Summary
LNG Ship Emissions
Steam Turbine Propulsion (BOG)

Assumptions

LNG Capacity, m^3	148,000
Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	16,750
Electric Power Engine Rating (kW)	3,150

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	NOx		CO		PM		HC		SOx		CO2		CH_4		N_2O	
								lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Inward Bound to Berth (Assuming Oil Operation only)																							
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	6.18	9.73	0.66	10.75	0.73	0.54	0.04	30.89	2.09	47,672.90	3,217.92	1.91	0.13	0.21	0.01
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	22.34	1.51	2.37	0.16	2.62	0.18	0.13	0.01	7.54	0.51	11,634.85	785.35	0.47	0.03	0.05	0.00
Hotelling																							
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.44	4.35	0.20	0.39	0.02	0.29	0.01	0.03	0.001	6,733.28	303.00	0.13	0.01	0.12	0.01
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.44	4.35	0.20	0.39	0.02	0.29	0.01	0.03	0.001	6,733.28	303.00	0.13	0.01	0.12	0.01
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	9.73	1.10	4.35	0.49	0.39	0.04	0.29	0.03	0.03	0.003	6,733.28	757.49	0.13	0.01	0.12	0.01
LNG Loading																							
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	8.29	4.85	3.71	2.17	0.33	0.19	0.24	0.14	0.02	0.01	5,737.75	3,356.59	0.11	0.06	0.11	0.06
Outward Bound to K Buoy (Assuming Oil Operation only)																							
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	22.34	2.01	2.37	0.21	2.62	0.24	0.13	0.01	7.54	0.68	11,634.85	1,047.14	0.47	0.04	0.05	0.00
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	6.18	9.73	0.66	10.75	0.73	0.54	0.04	30.89	2.09	47,672.90	3,217.92	1.91	0.13	0.21	0.01
TOTAL	**24.00**								**22.70**		**4.74**		**2.14**		**0.29**		**5.38**		**12,938.41**		**0.42**		**0.12**

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ship		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.80E-02	3.33E-01	3.10E-03	6.69E-01
CO2	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O	7.26E-04	4.84E-03	1.34E-02	4.54E-03

Jordan Cove Energy Project, L.P.
LNG Vessel Emission Factors

Assumptions

LNG Capacity, m^3	148,000
DFDE ships Efficiency, loading	47%
ST ships Efficiency, loading	25%
FO Sulfur Content, loading	0.10%

EMISSION FACTORS (lb/mmBtu)[1]				
Pollutant	Dual Fuel Diesel Engine Ships		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	5.20E-01	1.03E+00	1.70E-01	3.20E-01
CO	3.30E-01	8.50E-01	7.60E-02	3.40E-02
PM[3]	1.05E-02	5.73E-02	6.80E-03	3.76E-02
VOC	2.00E-01	8.19E-02	5.00E-03	1.90E-03
SO2	1.70E-02	1.01E-01	5.00E-04	1.08E-01
CO2[2]	1.10E+02	1.65E+02	1.18E+02	1.67E+02
CH_4[4]	1.30E-02	4.41E-03	2.25E-03	6.67E-03
N_2O[4]	2.21E-04	1.47E-03	2.16E-03	7.33E-04

EMISSION FACTORS (g/kWh)				
Pollutant	Dual Fuel Diesel Engine Ships		Steam Turbine Ships	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
NOx	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM[3]	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO2	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO2[2]	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4[4]	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O[4]	7.26E-04	4.84E-03	1.34E-02	4.54E-03

References

1. An Assessment of Air Emissions from Liquefied Natural Gas Ships Using Different Power Systems and Different Fuels. Afton, Yinka; Ervin, David.
Journal of the Air & Waste Management Association, Volume 58, March 2008.
FO PM emission factors for ST vessels were adjusted for the FO Sulfur (0.1%) content based upon U.S. EPA AP-42 Emission Factors, Table 1.3-1 and 1.3-2.
2. Based upon U.S. EPA AP-42 compilation of Emission Factors, Table 3.4-1 for Diesel Engines, and Tables 1.3-12 and 1.4-2 for ST ships.
3. PM emission factors include both filterable and condensable emissions.
4. For Steam Turbine Ships: Based upon U.S. EPA AP-42 Compilation of Emission Factors, Tables 1.3-3, 1.3-8, and 1.4-2.
For DFDE Ships: California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, Table C.7 - Residual Fuel, Industrial and a Heating Value of 150,000 Btu/Gal.
** Efficiencies where based upon the paper "Dual Fuel Electric LNG Carrier" (September 2006) prepared by Barend Thijssen of Wartsila Ship Power Solutions

Jordan Cove Energy Project
Air Emissions Summary
Support Tug Emissions

Support Tug Assumptions

Number of Ship Calls per year	90
Propulsion Engine Rating (kW)	3,080

Period	Transit Time hr	Propulsion Power Load Factor	Number of Support Tugs	Propulsion Power kW	NOx		CO		PM		HC		SOx		CO_2		CH_4		N_2O	
					lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Hotelling																				
Connect Arms and Cool Down (propulsion on hot standby)	1.00	10%	2	616	2.44	0.11	3.40	0.15	0.05	0.002	0.37	0.02	0.07	0.003	937.10	42.17	0.12	0.006	0.03	0.001
Purge and Disconnect Arms (propulsion on hot standby)	1.00	10%	2	616	2.44	0.11	3.40	0.15	0.05	0.002	0.37	0.02	0.07	0.003	937.10	42.17	0.12	0.006	0.03	0.001
Contingency (propulsion on hot standby)	2.50	10%	2	616	2.44	0.28	3.40	0.38	0.05	0.01	0.37	0.04	0.07	0.007	937.10	105.42	0.12	0.014	0.03	0.003
LNG Loading																				
Cargo transfer (propulsion on hot standby)	13.00	10%	2	616	2.44	1.43	3.40	1.99	0.05	0.03	0.37	0.21	0.07	0.04	937.10	548.20	0.12	0.07	0.03	0.016

EMISSION FACTORS (g/kWh)	
Pollutant	HSD Engine (marine diesel fuel)
NOx	1.80E+00
CO	2.50E+00
PM	4.00E-02
VOC	2.70E-01
SO2	4.80E-02
CO2	6.90E+02
CH_4	9.00E-02
N_2O	2.00E-02

References:

1. Based upon "Current methodoligies in preparing mobile source port-related emission inventories", U.S. EPA, April 2009.

DETAILED STACK PARAMETER CALCULATIONS

Jordan Cove Energy Project, L.P.
Stack Parameters Summary for LNG Vessels

Assumptions

Stack Height, ft	131.23
Stack Height, m	40.00
Stack Diameter, ft	5.00
Stack Diameter, m	1.52
F-Factors (wscf/mmBtu) from U.S. EPA	
Oil Combustion	10320
NG Combustion	10610
DFDE Efficiency, loading	47%
ST ships Efficiency, loading	25%

Note: Efficiencies were based upon the paper "Dual Fuel Electric LNG Carrier" (September 2006) prepared by Barend Thijssen of Wartsila Ship Power Solutions.

Steam Turbine Ships (Oil Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Inward Bound to Berth (Assuming Oil Operation only)													
Transit	1.50	50%	80%	16,750	7,560	24,310	286	94329	133330	275	408.15	113.17	34.50
Berthing and All Fast	1.50	10%	82%	3,350	2,583	5,933	70	23021	32540	275	408.15	27.62	8.42
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	57	18882	26689	275	408.15	22.65	6.91
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	49	16091	22745	275	408.15	19.31	5.88
Outward Bound to K Buoy (Assuming Oil Operation only)													
Warm Engines & Cast Off	2.00	10%	82%	3,350	2,583	5,933	70	23021	32540	275	408.15	27.62	8.42
Transit	1.50	50%	80%	16,750	7,560	24,310	286	94329	133330	275	408.15	113.17	34.50

Steam Turbine Ships (Natural Gas Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Inward Bound to Berth (Assuming Oil Operation only)													
Transit	1.50	50%	80%	16,750	7,560	24,310	286	94329	133330	275	408.15	113.17	34.50
Berthing and All Fast	1.50	10%	82%	3,350	2,583	5,933	70	23021	32540	275	408.15	27.62	8.42
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	57	19413	27439	275	408.15	23.29	7.10
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	49	16544	23384	275	408.15	19.85	6.05
Outward Bound to K Buoy (Assuming Oil Operation only)													
Warm Engines & Cast Off	2.00	10%	82%	3,350	2,583	5,933	70	23021	32540	275	408.15	27.62	8.42
Transit	1.50	50%	80%	16,750	7,560	24,310	286	94329	133330	275	408.15	113.17	34.50

Jordan Cove Energy Project, L.P.
Stack Parameters Summary for LNG Vessels

DFDE Ships (Oil Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Inward Bound to Berth (Assuming Oil Operation only)													
Transit	1.50	50%	80%	16,750	7,560	24,310	193	63617	137266	662	623.15	116.52	35.51
Berthing and All Fast	1.50	10%	82%	3,350	2,583	5,933	47	15526	33501	662	623.15	28.44	8.67
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	30	10044	21671	662	623.15	18.39	5.61
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	26	8559	18468	662	623.15	15.68	4.78
Outward Bound to K Buoy (Assuming Oil Operation only)													
Warm Engines & Cast Off	2.00	10%	82%	3,350	2,583	5,933	47	15526	33501	662	623.15	28.44	8.67
Transit	1.50	50%	80%	16,750	7,560	24,310	193	63617	137266	662	623.15	116.52	35.51

DFDE Ships (Natural Gas Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power kW	Electric Power kW	Total Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Inward Bound to Berth (Assuming Oil Operation only)													
Transit	1.50	50%	80%	16,750	7,560	24,310	193	63617	137266	662	623.15	116.52	35.51
Berthing and All Fast	1.50	10%	82%	3,350	2,583	5,933	47	15526	33501	662	623.15	28.44	8.67
Hotelling													
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
Contingency (propulsion on hot standby)	2.50	5%	80%	1,675	2,520	4,195	30	10326	22280	662	623.15	18.91	5.76
LNG Loading													
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	1,675	1,900	3,575	26	8800	18987	662	623.15	16.12	4.91
Outward Bound to K Buoy (Assuming Oil Operation only)													
Warm Engines & Cast Off	2.00	10%	82%	3,350	2,583	5,933	47	15526	33501	662	623.15	28.44	8.67
Transit	1.50	50%	80%	16,750	7,560	24,310	193	63617	137266	662	623.15	116.52	35.51

Jordan Cove Energy Project, L.P.
Stack Parameters Summary for Support Tugs

Assumptions

Stack Height, ft	35.00
Stack Height, m	10.67
Stack Diameter, ft	1.00
Stack Diameter, m	0.30
F-Factors (wscf/mmBtu)	
Oil Combustion	10320
HSD Efficiency	38%

Support Tugs (Stack Parameters are for each individual support tug)

Period	Transit Time hr	Propulsion Power Load Factor	Number of Support Tugs	Propulsion Power kW	Total Heat Input (mmBtu/hr)	Stack Exit Flow (SCFM)	Stack Exit Flow (ACFM)	Stack Exit Temperature (F)	Stack Exit Temperature (K)	Stack Exit Velocity (ft/sec)	Stack Exit Velocity (m/sec)
Hotelling											
Connect Arms and Cool Down (propulsion on hot standby)	1.00	10%	2	308	3	912	1968	662	623.15	41.76	12.73
Purge and Disconnect Arms (propulsion on hot standby)	1.00	10%	2	308	3	912	1968	662	623.15	41.76	12.73
Contingency (propulsion on hot standby)	2.50	10%	2	308	3	912	1968	662	623.15	41.76	12.73
LNG loading											
Cargo transfer (propulsion on hot standby)	13.00	10%	2	308	3	912	1968	662	623.15	41.76	12.73

MODELED EMISSION PARAMETERS SUMMARY (ENGLISH AND METRIC UNITS)

Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(English Units)

DFDE Ships (Oil Operation)

								Modeled Emission Rates (Scaled accordingly for averaging period									
Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Inward Bound to Berth (Assuming Oil Operation only)																	
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	3.07	163.97	30.74	0.69	0.17	19.48	9.74	1.22	0.30
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	48.63	0.75	40.02	7.50	0.17	0.04	4.76	2.38	0.30	0.07
Hotelling																	
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	0.32	25.89	3.24	0.07	0.02	3.08	1.03	0.13	0.03
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	31.44	0.32	25.89	3.24	0.07	0.02	3.08	1.03	0.13	0.03
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	31.44	0.81	25.89	8.09	0.18	0.04	3.08	2.56	0.32	0.08
LNG Loading																	
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	26.79	3.58	22.06	22.06	0.81	0.20	2.62	2.62	1.42	0.35
Outward Bound to K Buoy (Assuming Oil Operation only)																	
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	NA	1.00	NA	NA	0.22	0.06	NA	NA	0.40	0.10
Transit	1.50	50%	80%	2	3	16,750	7,560	NA	3.07	NA	NA	0.69	0.17	NA	NA	1.22	0.30

DFDE Ships (Natural Gas Operation)

								Modeled Emission Rates (Scaled accordingly for averaging period									
Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Inward Bound to Berth (Assuming Oil Operation only)																	
Transit	1.50	50%	80%	2	3	16,750	7,560	199.27	3.07	163.97	30.74	0.69	0.17	19.48	9.74	1.22	0.30
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	48.63	0.75	40.02	7.50	0.17	0.04	4.76	2.38	0.30	0.07
Hotelling																	
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	15.84	0.16	10.05	1.26	0.01	0.003	0.52	0.17	0.02	0.01
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	15.84	0.16	10.05	1.26	0.01	0.003	0.52	0.17	0.02	0.01
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	15.84	0.41	10.05	3.14	0.03	0.01	0.52	0.43	0.05	0.01
LNG Loading																	
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	13.50	1.80	8.56	8.56	0.15	0.04	0.44	0.44	0.24	0.06
Outward Bound to K Buoy (Assuming Oil Operation only)																	
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	NA	1.00	NA	NA	0.22	0.06	NA	NA	0.40	0.10
Transit	1.50	50%	80%	2	3	16,750	7,560	NA	3.07	NA	NA	0.69	0.17	NA	NA	1.22	0.30

Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(English Units)

Steam Turbine Ships (Oil Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Inward Bound to Berth (Assuming Oil Operation only)																	
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	1.41	9.73	1.82	0.67	0.17	30.89	15.45	1.93	0.48
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	22.34	0.34	2.37	0.45	0.16	0.04	7.54	3.77	0.47	0.12
Hotelling																	
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.19	1.95	0.24	0.09	0.02	6.18	2.06	0.26	0.06
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	18.32	0.19	1.95	0.24	0.09	0.02	6.18	2.06	0.26	0.06
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	18.32	0.47	1.95	0.61	0.22	0.06	6.18	5.15	0.64	0.16
LNG Loading																	
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	15.61	2.09	1.66	1.66	0.99	0.24	5.27	5.27	2.85	0.70
Outward Bound to K Buoy (Assuming Oil Operation only)																	
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	NA	0.46	NA	NA	0.22	0.05	NA	NA	0.63	0.15
Transit	1.50	50%	80%	2	3	16,750	7,560	NA	1.41	NA	NA	0.67	0.17	NA	NA	1.93	0.48

Steam Turbine Ships (Natural Gas Operation)

Period	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x lb/hr	Annual NO_x lb/hr	1- Hour CO lb/hr	8-Hour CO lb/hr	24-Hour PM lb/hr	Annual PM lb/hr	1-Hour SO_2 lb/hr	3-Hour SO_2 lb/hr	24-Hour SO_2 lb/hr	Annual SO_2 lb/hr
Inward Bound to Berth (Assuming Oil Operation only)																	
Transit	1.50	50%	80%	2	3	16,750	7,560	91.53	1.41	9.73	1.82	0.67	0.17	30.89	15.45	1.93	0.48
Berthing and All Fast	1.50	10%	82%	2	1	3,350	2,583	22.34	0.34	2.37	0.45	0.16	0.04	7.54	3.77	0.47	0.12
Hotelling																	
Connect Arms and Cool Down (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.10	4.35	0.54	0.02	0.004	0.03	0.01	0.001	0.0003
Purge and Disconnect Arms (propulsion on hot standby)	1.00	5%	80%	2	1	1,675	2,520	9.73	0.10	4.35	0.54	0.02	0.004	0.03	0.01	0.001	0.0003
Contingency (propulsion on hot standby)	2.50	5%	80%	2	1	1,675	2,520	9.73	0.25	4.35	1.36	0.04	0.01	0.03	0.02	0.003	0.001
LNG Loading																	
Cargo transfer (propulsion on hot standby)	13.00	5%	60%	2	1	1,675	1,900	8.29	1.11	3.71	3.71	0.18	0.04	0.02	0.02	0.01	0.003
Outward Bound to K Buoy (Assuming Oil Operation only)																	
Warm Engines & Cast Off	2.00	10%	82%	2	1	3,350	2,583	NA	0.46	NA	NA	0.22	0.05	NA	NA	0.63	0.15
Transit	1.50	50%	80%	2	3	16,750	7,560	NA	1.41	NA	NA	0.67	0.17	NA	NA	1.93	0.48

Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(Metric Units)

DFDE Ships (Oil Operation)

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x g/s	Annual NO_x g/s	1- Hour CO g/s	8-Hour CO g/s	24-Hour PM g/s	Annual PM g/s	1-Hour SO_2 g/s	3-Hour SO_2 g/s	24-Hour SO_2 g/s	Annual SO_2 g/s
Inward Bound to Berth (Assuming Oil Operation only)																		
Transit	LNG01	1.50	50%	80%	2	3	16,750	7,560	25.11	0.39	20.66	3.87	0.087	0.021	2.455	1.23	0.15	0.04
Berthing and All Fast	LNG02	1.50	10%	82%	2	1	3,350	2,583	6.13	0.09	5.04	0.95	0.021	0.005	0.599	0.30	0.04	0.01
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	DFDEHTL1	1.00	5%	80%	2	1	1,675	2,520	3.96	0.04	3.26	0.41	0.009	0.002	0.388	0.388	0.016	0.004
Purge and Disconnect Arms (propulsion on hot standby)	DFDEHTL2	1.00	5%	80%	2	1	1,675	2,520	3.96	0.04	3.26	0.41	0.009	0.002	0.388	0.388	0.016	0.004
Contingency (propulsion on hot standby)	DFDEHTL3	2.50	5%	80%	2	1	1,675	2,520	3.96	0.10	3.26	1.02	0.023	0.006	0.388	0.388	0.040	0.010
LNG Loading																		
Cargo transfer (propulsion on hot standby)	DFDEHTL4	13.00	5%	60%	2	1	1,675	1,900	3.38	0.45	2.78	2.78	0.10	0.03	0.330	0.330	0.179	0.044
Outward Bound to K Buoy (Assuming Oil Operation only)																		
Warm Engines & Cast Off	LNG08	2.00	10%	82%	2	1	3,350	2,583	NA	0.13	NA	NA	0.028	0.007	0.599	NA	0.05	0.01
Transit	LNG09	1.50	50%	80%	2	3	16,750	7,560	NA	0.39	NA	NA	0.087	0.021	2.455	NA	0.15	0.04

DFDE (Natural Gas Operation)

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period) 1-Hour NO_x g/s	Annual NO_x g/s	1- Hour CO g/s	8-Hour CO g/s	24-Hour PM g/s	Annual PM g/s	1-Hour SO_2 g/s	3-Hour SO_2 g/s	24-Hour SO_2 g/s	Annual SO_2 g/s
Inward Bound to Berth (Assuming Oil Operation only)																		
Transit	LNG01	1.50	50%	80%	2	3	16,750	7,560	25.11	0.39	20.66	3.87	0.087	0.021	2.455	1.23	0.15	0.04
Berthing and All Fast	LNG02	1.50	10%	82%	2	1	3,350	2,583	6.13	0.09	5.04	0.95	0.021	0.005	0.599	0.30	0.04	0.01
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	GDFDEHTL1	1.00	5%	80%	2	1	1,675	2,520	2.00	0.02	1.27	0.16	0.002	0.0004	0.065	0.0652	0.0027	0.0007
Purge and Disconnect Arms (propulsion on hot standby)	GDFDEHTL2	1.00	5%	80%	2	1	1,675	2,520	2.00	0.02	1.27	0.16	0.002	0.0004	0.065	0.0652	0.0027	0.0007
Contingency (propulsion on hot standby)	GDFDEHTL3	2.50	5%	80%	2	1	1,675	2,520	2.00	0.05	1.27	0.40	0.004	0.001	0.065	0.0652	0.0068	0.0017
LNG Loading																		
Cargo transfer (propulsion on hot standby)	GDFDEHTL4	13.00	5%	60%	2	1	1,675	1,900	1.70	0.23	1.08	1.08	0.019	0.005	0.056	0.0556	0.0301	0.0074
Outward Bound to K Buoy (Assuming Oil Operation only)																		
Warm Engines & Cast Off	LNG08	2.00	10%	82%	2	1	3,350	2,583	NA	0.13	NA	NA	0.028	0.007	0.599	NA	0.05	0.01
Transit	LNG09	1.50	50%	80%	2	3	16,750	7,560	NA	0.39	NA	NA	0.087	0.021	2.455	NA	0.15	0.04

Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(Metric Units)

Steam Turbine Ships (Oil Operation

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period									
									1-Hour NO_x g/s	Annual NO_x g/s	1- Hour CO g/s	8-Hour CO g/s	24-Hour PM g/s	Annual PM g/s	1-Hour SO_2 g/s	3-Hour SO_2 g/s	24-Hour SO_2 g/s	Annual SO_2 g/s
Inward Bound to Berth (Assuming Oil Operation only)																		
Transit	LNG01	1.50	50%	80%	2	3	16,750	7,560	11.53	0.18	1.23	0.23	0.085	0.021	3.892	1.95	0.24	0.06
Berthing and All Fast	LNG02	1.50	10%	82%	2	1	3,350	2,583	2.81	0.04	0.30	0.06	0.021	0.005	0.950	0.47	0.06	0.01
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	STHTL1	1.00	5%	80%	2	1	1,675	2,520	2.31	0.02	0.25	0.03	0.011	0.003	0.779	0.779	0.032	0.008
Purge and Disconnect Arms (propulsion on hot standby)	STHTL2	1.00	5%	80%	2	1	1,675	2,520	2.31	0.02	0.25	0.03	0.011	0.003	0.779	0.779	0.032	0.008
Contingency (propulsion on hot standby)	STHTL3	2.50	5%	80%	2	1	1,675	2,520	2.31	0.06	0.25	0.08	0.03	0.01	0.779	0.779	0.081	0.020
LNG Loading																		
Cargo transfer (propulsion on hot standby)	STHTL4	13.00	5%	60%	2	1	1,675	1,900	1.97	0.26	0.21	0.21	0.13	0.03	0.664	0.664	0.360	0.089
Outward Bound to K Buoy (Assuming Oil Operation only)																		
Warm Engines & Cast Off	LNG08	2.00	10%	82%	2	1	3,350	2,583	NA	0.06	NA	NA	0.028	0.007	0.950	NA	0.08	0.02
Transit	LNG09	1.50	50%	80%	2	3	16,750	7,560	NA	0.18	NA	NA	0.085	0.021	3.892	NA	0.24	0.06

Steam Turbine Ships (Natural Gas Operation)

Period	AERMOD ID	Transit Time hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period)									
									1-Hour NO_x g/s	Annual NO_x g/s	1- Hour CO g/s	8-Hour CO g/s	24-Hour PM g/s	Annual PM g/s	1-Hour SO_2 g/s	3-Hour SO_2 g/s	24-Hour SO_2 g/s	Annual SO_2 g/s
Inward Bound to Berth (Assuming Oil Operation only)																		
Transit	LNG01	1.50	50%	80%	2	3	16,750	7,560	11.53	0.18	1.23	0.23	0.085	0.021	3.892	1.95	0.24	0.06
Berthing and All Fast	LNG02	1.50	10%	82%	2	1	3,350	2,583	2.81	0.04	0.30	0.06	0.021	0.005	0.950	0.47	0.06	0.01
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	GSTHTL1	1.00	5%	80%	2	1	1,675	2,520	1.23	0.01	0.55	0.07	0.002	0.001	0.004	0.004	0.0002	0.00004
Purge and Disconnect Arms (propulsion on hot standby)	GSTHTL2	1.00	5%	80%	2	1	1,675	2,520	1.23	0.01	0.55	0.07	0.002	0.001	0.004	0.004	0.0002	0.00004
Contingency (propulsion on hot standby)	GSTHTL3	2.50	5%	80%	2	1	1,675	2,520	1.23	0.03	0.55	0.17	0.005	0.001	0.004	0.004	0.0004	0.0001
LNG Loading																		
Cargo transfer (propulsion on hot standby)	GSTHTL4	13.00	5%	60%	2	1	1,675	1,900	1.05	0.14	0.47	0.47	0.023	0.006	0.003	0.003	0.0017	0.0004
Outward Bound to K Buoy (Assuming Oil Operation only)																		
Warm Engines & Cast Off	LNG08	2.00	10%	82%	2	1	3,350	2,583	NA	0.06	NA	NA	0.028	0.007	0.950	NA	0.08	0.02
Transit	LNG09	1.50	50%	80%	2	3	16,750	7,560	NA	0.18	NA	NA	0.085	0.021	3.892	NA	0.24	0.06

Jordan Cove Energy Project, L.P.
Modeled Air Emissions Parameter Summary
LNG Vessels
(Metric Units)

Support Tugs

Period	AERMOD ID	Transit Time Hr	Propulsion Power Load Factor	Electric Power Load Factor	Propulsion Power Engines	Electric Power Engines	Propulsion Power kW	Electric Power kW	Modeled Emission Rates (Scaled accordingly for averaging period 1-Hour NOx g/s	Annual NO_x g/s	1- Hour CO g/s	8-Hour CO g/s	24-Hour PM g/s	Annual PM g/s	1-Hour SO2 g/s	3-Hour SO_2 g/s	24-Hour SO_2 g/s	Annual SO_2 g/s
Hotelling																		
Connect Arms and Cool Down (propulsion on hot standby)	TUGS01	1.00	10%	NA	2	NA	616	NA	0.31	0.003	0.43	0.05	0.0003	0.00007	0.0082	0.0082	0.0003	0.00008
Purge and Disconnect Arms (propulsion on hot standby)	TUGS02	1.00	10%	NA	2	NA	616	NA	0.31	0.003	0.43	0.05	0.0003	0.00007	0.0082	0.0082	0.0003	0.00008
Contingency (propulsion on hot standby)	TUGS03	2.50	10%	NA	2	NA	616	NA	0.31	0.008	0.43	0.13	0.0007	0.00018	0.0082	0.0082	0.0009	0.00021
LNG Loading																		
Cargo transfer (propulsion on hot standby)	TUGS04	13.00	10%	NA	2	NA	616	NA	0.31	0.04	0.43	0.43	0.0037	0.0009	0.0082	0.0082	0.0044	0.0011

APPENDIX B

AIR QUALITY MODLEING FILES DVD

dir.dat

This DVD contains the modeling input and output files for the proposed JCEP LNG Terminal Project
located in Coos County, Oregon. The following are brief descriptions
for each of the modeling files used in the air quality modeling analysis. (May 2013)

```
** Note that all files with the .inp extension are input files.
** All files with the .out extension are output files.

 Directory of FERC RR9\Modeling Files Appendix\AERMAP

** This Directory contains the AERMAP input and output files used to process the
standard modeling receptor grid.

06/21/2012  02:13 PM       166,154,079 74762863.tif
06/21/2012  02:11 PM       166,185,655 79795317.tif
10/24/2012  01:25 PM           887,089 aermap.exe
10/24/2012  01:34 PM           995,125 aermap.inp
10/27/2012  08:53 PM             4,105 aermap.out
10/27/2012  08:53 PM         1,809,538 JCEPREC.out

Directory of FERC RR9\Modeling Files Appendix\AERMAP\SIAGrid

** This Directory contains the AERMAP input and output files used to process the
extended modeling receptor grid
** used in determining some pollutant specific SIAs.

11/30/2012  04:05 PM        94,228,591 02742229.tif
11/30/2012  05:10 PM        94,228,591 19939544.tif
11/30/2012  05:10 PM        94,255,935 20338806.tif
11/30/2012  04:05 PM        94,228,591 30287896.tif
11/30/2012  05:09 PM        94,255,935 38675475.tif
11/30/2012  04:06 PM        94,228,591 41141311.tif
11/30/2012  04:06 PM        94,228,591 55618685.tif
11/30/2012  04:05 PM        94,228,591 57854013.tif
11/30/2012  04:06 PM        94,228,591 60445903.tif
11/30/2012  05:14 PM        94,228,591 61713044.tif
11/30/2012  04:05 PM        94,243,343 63455854.tif
11/30/2012  05:10 PM        94,228,591 64287507.tif
11/30/2012  04:06 PM        94,269,723 67857865.tif
11/30/2012  04:06 PM        94,242,375 85153958.tif
11/30/2012  05:10 PM        94,255,935 91248159.tif
11/30/2012  05:11 PM        94,243,343 99327441.tif
10/24/2012  01:25 PM           887,089 aermap.exe
11/30/2012  05:19 PM           814,354 aermap.inp
12/01/2012  06:38 PM             9,089 aermap.out
12/01/2012  06:38 PM         1,363,448 JCEPREC.out


*************************************************************************************
*********************************

** This Directory contains the processing of meteorological datasets with AERMET to
create AERMOD ready .sfc and .pfl files.

 Directory of FERC RR9\Modeling Files Appendix\AERMET


03/18/2013  04:22 PM    <DIR>          AERSURF
03/18/2013  03:29 PM    <DIR>          Merge
03/18/2013  02:00 PM    <DIR>          Stage 3
03/18/2013  03:32 PM    <DIR>          Surface
03/18/2013  03:35 PM    <DIR>          Upper Air
```

```
 Directory of FERC RR9\Modeling Files Appendix\AERMET\AERSURF

04/04/2012  03:35 PM               988 AERSURFACE.DAT
04/04/2012  03:35 PM           333,270 albedo_bowen_domain.txt
10/11/2000  02:47 PM           133,712 conus.las
10/11/2000  02:47 PM           133,712 conus.los
04/04/2012  03:35 PM           357,476 coos.log
04/04/2012  03:35 PM             8,929 coos.out
04/10/2008  10:54 AM        38,779,233 oregon.nlcd.tif.gz
01/07/2002  03:42 PM       483,850,538 oregon_NLCD_erd_032400.tif
04/04/2012  03:35 PM            13,804 roughness_domain.txt

 Directory of FERC RR9\Modeling Files Appendix\AERMET\Merge

12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:28 PM               195 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:36 AM               922 COOS.MSG
12/20/2012  11:36 AM            86,061 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.dat
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.dat

 Directory of FERC RR9\Modeling Files Appendix\AERMET\Stage 3

12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:46 PM             8,599 aermet.INP
12/20/2012  11:36 AM        21,036,835 COOS.MRG
12/20/2012  11:37 AM         1,060,385 COOS.MSG
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM            23,232 COOS.RPT
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMET\Surface

04/04/2012  03:05 PM        32,544,214 726917-24284-0711.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  03:06 PM               372 aermet.INP
12/20/2012  11:33 AM        26,215,855 COOS.MSG
12/20/2012  11:33 AM           239,433 COOS.RPT
12/20/2012  11:33 AM         6,766,315 SFEXOUT.DAT
12/20/2012  11:33 AM         6,766,318 SFQAOUT.DAT

 Directory of FERC RR9\Modeling Files Appendix\AERMET\Upper Air

04/04/2012  02:12 PM        23,927,474 72694.dat
12/20/2012  11:31 AM         2,136,064 aermet.exe
04/04/2012  02:05 PM               373 aermet.INP
12/20/2012  11:33 AM        24,526,315 COOS.MSG
12/20/2012  11:33 AM            14,241 COOS.RPT
12/20/2012  11:33 AM         4,139,570 UAEXOUT.DAT
12/20/2012  11:33 AM         4,139,489 UAQAOUT.DAT

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 Directory of FERC RR9\Modeling Files Appendix\AERMOD

03/18/2013  10:17 AM    <DIR>          Class I Screening
03/19/2013  11:24 AM    <DIR>          Load Analysis_Combustion Turbines
03/18/2013  10:17 AM    <DIR>          SIA Modeling
03/18/2013  10:18 AM    <DIR>          Single Source Modeling

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening

** This Directory contains the AERMOD input and output files used for Class I
screening modeling


03/19/2013  11:22 AM    <DIR>          NO2Annual
03/19/2013  11:21 AM    <DIR>          PM1024HR
03/19/2013  11:21 AM    <DIR>          PM10Annual
03/19/2013  11:22 AM    <DIR>          PM2.524HR
03/19/2013  11:22 AM    <DIR>          PM2.5Annual
03/19/2013  11:20 AM    <DIR>          SO224HR
03/19/2013  11:20 AM    <DIR>          SO23HR
03/19/2013  11:21 AM    <DIR>          SO2Annual


 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\NO2Annual


03/19/2013  11:22 AM    <DIR>          2007
03/19/2013  11:22 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011


 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\NO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,465 aermod.inp
03/07/2013  06:14 PM           225,793 annno207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\NO2Annual\2008


12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:16 PM           106,467 aermod.inp
03/07/2013  06:15 PM           225,793 annno208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\NO2Annual\2009


12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:16 PM           106,467 aermod.inp
03/07/2013  06:14 PM           225,793 annno209class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\NO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,469 aermod.inp
03/07/2013  06:14 PM           225,793 annno210class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\NO2Annual\2011


12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:17 PM           106,467 aermod.inp
03/07/2013  06:15 PM           227,662 annno211class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC


 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\PM1024HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM1024HR\2007

03/07/2013  06:00 PM           276,095 24hrpm07class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:54 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM1024HR\2008

03/07/2013  06:08 PM           276,095 24hrpm08class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:54 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM1024HR\2009

03/07/2013  06:10 PM           276,095 24hrpm09class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM1024HR\2010

03/07/2013  06:14 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
```

```
                                                dir.dat
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM1024HR\2011

03/07/2013  06:15 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:55 PM            78,630 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\PM10Annual

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:21 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM10Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:50 PM            78,630 aermod.inp
03/07/2013  05:59 PM           197,121 annpm07class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM10Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:05 PM           197,121 annpm08class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM10Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:51 PM            78,630 aermod.inp
03/07/2013  06:07 PM           197,121 annpm09class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM10Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:10 PM           197,121 annpm10class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM10Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:52 PM            78,630 aermod.inp
03/07/2013  06:14 PM           198,990 annpm11class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\PM2.524HR

03/19/2013  11:21 AM    <DIR>          2007
03/19/2013  11:22 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.524HR\2007

03/07/2013  05:57 PM           276,095 24hrpm07class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:47 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.524HR\2008

03/07/2013  06:01 PM           276,095 24hrpm08class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.524HR\2009

03/07/2013  06:04 PM           276,095 24hrpm09class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.524HR\2010

03/07/2013  06:07 PM           276,095 24hrpm10class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:48 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.524HR\2011

03/07/2013  06:12 PM           277,964 24hrpm11class1.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:49 PM            78,631 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\PM2.5Annual

03/19/2013  11:22 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:22 AM    <DIR>          2009
03/19/2013  11:22 AM    <DIR>          2010
03/19/2013  11:22 AM    <DIR>          2011
```

```
 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:44 PM            78,635 aermod.inp
03/07/2013  05:54 PM           197,121 annpm2507class1.out
03/07/2013  05:58 PM           197,121 annpm2508class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  05:57 PM           197,121 annpm2509class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:45 PM            78,635 aermod.inp
03/07/2013  06:04 PM           197,121 annpm2510class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:46 PM            78,635 aermod.inp
03/07/2013  06:06 PM           198,990 annpm2511class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\SO224HR

03/07/2013  06:55 PM           109,668 24hrso2.out
03/07/2013  06:55 PM           277,964 24hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:05 PM            78,140 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\SO23HR

03/07/2013  06:55 PM           109,668 3hourso2.out
03/07/2013  06:55 PM           277,964 3hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:04 PM            78,138 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

```
 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I Screening\SO2Annual

03/19/2013  11:20 AM    <DIR>          2007
03/19/2013  11:20 AM    <DIR>          2008
03/19/2013  11:21 AM    <DIR>          2009
03/19/2013  11:21 AM    <DIR>          2010
03/19/2013  11:21 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\SO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:59 PM            78,133 aermod.inp
03/07/2013  06:02 PM           100,499 annso207.out
03/07/2013  06:09 PM           197,121 annso207class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\SO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:09 PM           100,499 annso208.out
03/07/2013  06:02 PM           197,121 annso208class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\SO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:11 PM           100,499 annso209.out
03/07/2013  06:12 PM           197,121 annso209class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\SO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:14 PM           100,499 annso210.out
03/07/2013  06:14 PM           197,121 annso210class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Class I
Screening\SO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  05:02 PM            78,133 aermod.inp
03/07/2013  06:15 PM           100,499 annso211.out
03/07/2013  06:15 PM           198,990 annso211class1.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines

03/19/2013  11:24 AM    <DIR>          2007
03/19/2013  11:24 AM    <DIR>          2008
```

```
                                               dir.dat
03/19/2013  11:24 AM    <DIR>          2009
03/19/2013  11:24 AM    <DIR>          2010
03/19/2013  11:24 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  05:28 AM       268,260,264 load07.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:41 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:38 AM       268,260,264 load08.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:05 AM       268,260,264 load09.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:14 AM       268,260,264 load10.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Load Analysis_Combustion
Turbines\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
12/12/2012  10:42 AM         1,834,867 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
12/21/2012  06:22 AM       268,262,133 load11.out

********************************************************************************
********************************

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling

** This Directory contains the AERMOD input and output files used for modeling
pollutant specific significant impact areas

03/19/2013  11:27 AM    <DIR>          NO21HR
03/19/2013  11:29 AM    <DIR>          PM1024HR
03/19/2013  11:29 AM    <DIR>          PM2.524HR
03/19/2013  11:27 AM    <DIR>          PM2.5Annual
```

```
03/19/2013  11:29 AM    <DIR>          SO21HR

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\NO21HR

03/08/2013  12:25 AM         5,145,536 1hrno2.8th
03/08/2013  12:25 AM         5,145,536 1hrno2.txt
03/08/2013  12:25 AM        12,777,361 1hrso2sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  03:53 PM         1,379,664 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR

03/19/2013  11:29 AM    <DIR>          2007
03/19/2013  11:29 AM    <DIR>          2008
03/19/2013  11:29 AM    <DIR>          2009
03/19/2013  11:29 AM    <DIR>          2010
03/19/2013  11:29 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR\2007

03/08/2013  12:34 AM         2,617,117 24HRPM07.txt
03/08/2013  12:34 AM        20,191,763 24hrpm07sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:13 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR\2008

03/08/2013  12:36 AM         2,617,117 24HRPM08.txt
03/08/2013  12:36 AM        20,191,763 24hrpm08sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR\2009

03/08/2013  12:24 AM         2,617,117 24HRPM09.txt
03/08/2013  12:24 AM        20,191,763 24hrpm09sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR\2010

03/08/2013  12:25 AM         2,617,117 24HRPM10.txt
03/08/2013  12:27 AM        20,191,763 24hrpm10sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:14 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM1024HR\2011

03/08/2013  12:49 AM         2,617,117 24HRPM11.txt
03/08/2013  12:49 AM        20,193,632 24hrpm11sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:15 PM         1,395,645 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
```

```
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR

03/19/2013  11:28 AM    <DIR>          2007
03/19/2013  11:28 AM    <DIR>          2008
03/19/2013  11:28 AM    <DIR>          2009
03/19/2013  11:28 AM    <DIR>          2010
03/19/2013  11:29 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR\2007

03/08/2013  12:20 AM         2,617,117 24HRPM07.txt
03/08/2013  12:24 AM        20,191,763 24hrpm2507sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:10 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR\2008

03/08/2013  12:42 AM         2,617,117 24HRPM08.txt
03/08/2013  12:42 AM        20,191,763 24hrpm2508sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:10 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR\2009

03/08/2013  12:27 AM         2,617,117 24HRPM09.txt
03/08/2013  12:27 AM        20,191,763 24hrpm2509sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR\2010

03/08/2013  12:12 AM         2,617,117 24HRPM10.txt
03/08/2013  12:16 AM        20,191,763 24hrpm2510sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.524HR\2011

03/08/2013  12:29 AM         2,617,117 24HRPM11.txt
03/08/2013  12:29 AM        20,193,632 24hrpm2511sia.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:11 PM         1,395,644 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual

03/19/2013  11:27 AM    <DIR>          2007
03/19/2013  11:27 AM    <DIR>          2008
03/19/2013  11:27 AM    <DIR>          2009
03/19/2013  11:27 AM    <DIR>          2010
03/19/2013  11:27 AM    <DIR>          2011
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual\2007

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:06 PM         1,395,648 aermod.inp
03/08/2013  12:11 AM        10,940,646 annpm2507sia.out
03/08/2013  12:09 AM         2,397,238 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual\2008

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:07 PM         1,395,648 aermod.inp
03/08/2013  12:29 AM        10,940,646 annpm2508sia.out
03/08/2013  12:29 AM         2,397,238 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual\2009

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:07 PM         1,395,648 aermod.inp
03/08/2013  12:37 AM        10,940,646 annpm2509sia.out
03/08/2013  12:37 AM         2,397,238 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual\2010

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:08 PM         1,395,648 aermod.inp
03/08/2013  12:26 AM        10,940,646 annpm2510sia.out
03/08/2013  12:23 AM         2,397,238 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\PM2.5Annual\2011

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:08 PM         1,395,648 aermod.inp
03/08/2013  12:19 AM        10,942,515 annpm2511sia.out
03/08/2013  12:17 AM         2,397,238 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

Directory of FERC RR9\Modeling Files Appendix\AERMOD\SIA Modeling\SO21HR

```
03/08/2013  08:34 AM         5,145,536 1hrso2.txt
03/08/2013  08:34 AM        20,172,305 1hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  04:17 PM         1,395,151 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

****
****

Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling

** This Directory contains the AERMOD input and output files used for modeling the Facility for the purposes of obtaining maximum modeled impacts

```
                                            dir.dat
03/19/2013  11:33 AM    <DIR>          CO1HR
03/19/2013  11:33 AM    <DIR>          CO8HR
03/19/2013  11:33 AM    <DIR>          NO21HR
03/19/2013  11:34 AM    <DIR>          NO2Annual
03/19/2013  11:36 AM    <DIR>          PM1024HR
03/19/2013  11:36 AM    <DIR>          PM10Annual
03/19/2013  11:35 AM    <DIR>          PM2.524HR
03/19/2013  11:35 AM    <DIR>          PM2.5Annual
03/19/2013  11:37 AM    <DIR>          SO21HR
03/19/2013  11:33 AM    <DIR>          SO224HR
03/19/2013  11:33 AM    <DIR>          SO23HR
03/19/2013  11:37 AM    <DIR>          SO2Annual

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\CO1HR

03/08/2013  10:24 AM        26,861,331 1hrCO.out
03/08/2013  10:24 AM         3,473,322 1HRCO.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:49 PM         1,855,704 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\CO8HR

03/08/2013  10:24 AM        26,861,331 8hrCO.out
03/08/2013  10:24 AM         3,473,322 8HRCO.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:51 PM         1,855,704 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\NO21HR

03/06/2013  08:30 PM         6,829,166 1hrno2.8th
03/06/2013  08:30 PM        21,808,564 1hrno2.out
03/06/2013  08:30 PM         6,829,166 1hrno2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:48 PM         1,825,861 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual

03/19/2013  11:34 AM    <DIR>          2007
03/19/2013  11:34 AM    <DIR>          2008
03/19/2013  11:34 AM    <DIR>          2009
03/19/2013  11:34 AM    <DIR>          2010
03/19/2013  11:34 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM         3,181,493 AnnNO207.txt
03/07/2013  08:58 PM        21,965,930 anno207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual\2008
```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:27 PM         1,869,854 aermod.inp
03/07/2013  09:09 PM        21,965,930 annno208.out
03/07/2013  09:09 PM         3,181,493 AnnNO208.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  08:58 PM        21,965,930 annno209.out
03/07/2013  08:58 PM         3,181,493 AnnNO209.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  09:06 PM        21,965,930 annno210.out
03/07/2013  09:06 PM         3,181,493 AnnNO210.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\NO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:28 PM         1,869,854 aermod.inp
03/07/2013  09:07 PM        21,967,799 annno211.out
03/07/2013  09:07 PM         3,181,493 AnnNO211.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR

03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR\2007

03/07/2013  06:45 PM        26,785,295 24hrpm07.out
03/07/2013  06:45 PM         3,473,322 24HRPM07.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR\2008

03/07/2013  06:53 PM        26,785,295 24hrpm08.out
03/07/2013  06:53 PM         3,473,322 24HRPM08.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
```

```
                                           dir.dat
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR\2009

03/07/2013  06:46 PM        26,785,295 24hrpm09.out
03/07/2013  06:46 PM         3,473,322 24HRPM09.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:35 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR\2010

03/07/2013  06:46 PM        26,785,295 24hrpm10.out
03/07/2013  06:46 PM         3,473,322 24HRPM10.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:36 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM1024HR\2011

03/07/2013  06:48 PM        26,787,164 24hrpm11.out
03/07/2013  06:48 PM         3,473,322 24HRPM11.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:36 PM         1,841,805 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM10Annual

03/19/2013  11:36 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:36 AM    <DIR>          2009
03/19/2013  11:36 AM    <DIR>          2010
03/19/2013  11:36 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM10Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:04 PM         1,841,801 aermod.inp
03/08/2013  03:38 PM        14,504,228 Annpm07.out
03/08/2013  03:38 PM         3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM10Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:44 PM        14,504,228 Annpm08.out
03/08/2013  03:44 PM         3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
```

```
Modeling\PM10Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:39 PM        14,504,228 Annpm09.out
03/08/2013  03:39 PM         3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM10Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:05 PM         1,841,801 aermod.inp
03/08/2013  03:40 PM        14,504,228 Annpm10.out
03/08/2013  03:40 PM         3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM10Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/08/2013  01:06 PM         1,841,801 aermod.inp
03/08/2013  03:42 PM        14,506,097 Annpm11.out
03/08/2013  03:42 PM         3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR

03/19/2013  11:35 AM    <DIR>          2007
03/19/2013  11:35 AM    <DIR>          2008
03/19/2013  11:35 AM    <DIR>          2009
03/19/2013  11:35 AM    <DIR>          2010
03/19/2013  11:35 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR\2007

03/06/2013  06:04 PM         3,473,322 24HRPM07.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:10 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:04 PM        31,654,956 load07.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR\2008

03/06/2013  06:09 PM         3,473,322 24HRPM08.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  03:17 PM         1,841,843 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
03/06/2013  06:09 PM        31,654,956 load08.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR\2009

03/06/2013  06:04 PM         3,473,322 24HRPM09.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
```

```
                                          dir.dat
03/06/2013  03:18 PM           1,841,843 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC
03/06/2013  06:04 PM          31,654,956 load09.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR\2010

03/06/2013  06:05 PM           3,473,322 24HRPM10.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/06/2013  03:18 PM           1,841,843 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC
03/06/2013  06:05 PM          31,654,956 load10.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.524HR\2011

03/06/2013  06:07 PM           3,473,322 24HRPM11.txt
12/20/2012  03:20 PM           2,545,152 aermod.exe
03/06/2013  03:19 PM           1,841,843 aermod.inp
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC
03/06/2013  06:07 PM          31,656,825 load11.out

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual

03/19/2013  11:34 AM    &lt;DIR&gt;          2007
03/19/2013  11:35 AM    &lt;DIR&gt;          2008
03/19/2013  11:35 AM    &lt;DIR&gt;          2009
03/19/2013  11:35 AM    &lt;DIR&gt;          2010
03/19/2013  11:35 AM    &lt;DIR&gt;          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:31 PM           1,841,802 aermod.inp
03/07/2013  07:03 PM          14,504,228 annpm2507.out
03/07/2013  07:03 PM           3,181,493 AnnuPM07.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:31 PM           1,841,802 aermod.inp
03/07/2013  06:59 PM          14,504,228 annpm2508.out
03/07/2013  06:59 PM           3,181,493 AnnuPM08.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM           2,545,152 aermod.exe
03/07/2013  02:32 PM           1,841,802 aermod.inp
03/07/2013  06:55 PM          14,504,228 annpm2509.out
03/07/2013  06:55 PM           3,181,493 AnnuPM09.txt
12/20/2012  11:37 AM           2,936,208 COOS.PFL
12/20/2012  11:37 AM           7,231,060 COOS.SFC
```

```
 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:52 PM        14,504,228 annpm2510.out
03/07/2013  06:52 PM         3,181,493 AnnuPM10.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:32 PM         1,841,802 aermod.inp
03/07/2013  06:55 PM        14,506,097 annpm2511.out
03/07/2013  06:55 PM         3,181,493 AnnuPM11.txt
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\SO21HR

03/07/2013  03:43 AM        36,533,537 1hrso2.out
03/07/2013  03:43 AM        24,982,168 1hrso2.txt
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/06/2013  02:56 PM         1,841,415 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\SO224HR

03/08/2013  05:00 AM         3,473,322 24hrso2.out
03/08/2013  05:00 AM        26,787,164 24hrso2out.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/15/2013  03:47 PM         1,841,307 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source Modeling\SO23HR

03/08/2013  05:01 AM         3,473,322 3hourso2.out
03/08/2013  05:01 AM        26,787,164 3hrso2.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
03/15/2013  03:46 PM         1,841,305 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual

03/19/2013  11:37 AM    <DIR>          2007
03/19/2013  11:36 AM    <DIR>          2008
03/19/2013  11:37 AM    <DIR>          2009
03/19/2013  11:37 AM    <DIR>          2010
03/19/2013  11:37 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:45 PM         1,841,300 aermod.inp
03/07/2013  06:45 PM         3,181,493 annso207.out
```

```
                                                  dir.dat
03/07/2013  06:45 PM        14,504,228 annso207out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:45 PM         1,841,300 aermod.inp
03/07/2013  06:51 PM         3,181,493 annso208.out
03/07/2013  06:51 PM        14,504,228 annso208out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:46 PM         3,181,493 annso209.out
03/07/2013  06:46 PM        14,504,228 annso209out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:48 PM         3,181,493 annso210.out
03/07/2013  06:48 PM        14,504,228 annso210out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\AERMOD\Single Source
Modeling\SO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
03/07/2013  02:46 PM         1,841,300 aermod.inp
03/07/2013  06:48 PM         3,181,493 annso211.out
03/07/2013  06:48 PM        14,506,097 annso211out.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

*************************************************************************************
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 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling

** This Directory contains the AERMOD input and output files used for modeling the
Facility for the purposes of obtaining maximum modeled impacts
** including offsite sources and vessel sources

05/03/2013  09:16 AM    <DIR>          CO1HR
05/03/2013  09:17 AM    <DIR>          CO8HR
05/03/2013  09:24 AM    <DIR>          NO21HR
05/03/2013  09:23 AM    <DIR>          NO2Annual
05/03/2013  09:29 AM    <DIR>          PM1024HR
05/03/2013  09:26 AM    <DIR>          PM2.524HR
05/03/2013  09:29 AM    <DIR>          PM2.524HR BAH Receptor
```

```
                                                dir.dat
05/03/2013  09:25 AM    <DIR>          PM2.5Annual
05/03/2013  09:43 AM    <DIR>          SO21HR
05/03/2013  09:44 AM    <DIR>          SO21HR BAH Receptor
05/03/2013  09:47 AM    <DIR>          SO224HR
05/03/2013  09:44 AM    <DIR>          SO23HR
05/03/2013  09:42 AM    <DIR>          SO2Annual

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\CO1HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:43 PM         1,944,970 aermod.inp
04/12/2013  08:24 PM        84,856,869 CO1hr.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\CO8HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:50 PM         1,944,244 aermod.inp
04/13/2013  09:24 AM        43,907,767 CO8hr.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\NO21HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:52 PM         1,917,122 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/12/2013  03:37 PM        83,817,172 No21hr.out

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\NO2Annual

05/03/2013  09:23 AM    <DIR>          2007
05/03/2013  09:23 AM    <DIR>          2008
05/03/2013  09:23 AM    <DIR>          2009
05/03/2013  09:23 AM    <DIR>          2010
05/03/2013  09:23 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\NO2Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:51 PM         1,957,013 aermod.inp
04/07/2013  02:58 PM        13,014,020 AnnNo207.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\NO2Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:01 PM         1,957,013 aermod.inp
04/07/2013  03:30 PM        13,014,020 AnnNo208.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\NO2Annual\2009
```

```
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:01 PM         1,957,013 aermod.inp
04/07/2013  01:52 PM        13,014,020 AnnNo209.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\NO2Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,957,013 aermod.inp
04/07/2013  03:09 PM        13,014,020 AnnNo210.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\NO2Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,957,013 aermod.inp
04/07/2013  02:55 PM        13,015,889 AnnNo211.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\PM1024HR

04/13/2013  02:49 AM        23,389,635 24hrPM10.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:56 PM         1,928,742 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\PM2.524HR

04/13/2013  04:21 PM        48,785,315 24hrPM2.5.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:55 PM         1,937,400 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\PM2.524HR
BAH Receptor

04/05/2013  04:37 PM           465,343 24hrPM2.5.out
12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:56 PM           126,079 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\PM2.5Annual

05/03/2013  09:25 AM    <DIR>          2007
05/03/2013  09:25 AM    <DIR>          2008
05/03/2013  09:25 AM    <DIR>          2009
05/03/2013  09:25 AM    <DIR>          2010
05/03/2013  09:25 AM    <DIR>          2011

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\PM2.5Annual\2007

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:53 PM         1,928,811 aermod.inp
```

```
04/07/2013  01:40 PM        12,986,998 AnnPM2.507.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\PM2.5Annual\2008

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:02 PM         1,928,811 aermod.inp
04/07/2013  01:39 PM        12,986,998 AnnPM2.508.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\PM2.5Annual\2009

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  11:54 AM        12,986,998 AnnPM2.509.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\PM2.5Annual\2010

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  01:42 PM        12,986,998 AnnPM2.510.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\PM2.5Annual\2011

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:03 PM         1,928,811 aermod.inp
04/07/2013  02:22 PM        12,988,867 AnnPM2.511.out
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\SO21HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:57 PM         1,933,038 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/12/2013  11:21 PM        84,732,223 So21Hr.out

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\SO21HR BAH
Receptor

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  03:57 PM           121,679 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
04/05/2013  04:35 PM           485,080 SO21hr.out

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource Modeling\SO224HR

12/20/2012  03:20 PM         2,545,152 aermod.exe
04/05/2013  04:00 PM         1,928,280 aermod.inp
12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

```
04/13/2013  12:37 AM        23,389,635 SO224Hr.out

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Modeling\SO2Annual\2007

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 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\SO2Annual\2008

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12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\SO2Annual\2009

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12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\SO2Annual\2010

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12/20/2012  11:37 AM         2,936,208 COOS.PFL
12/20/2012  11:37 AM         7,231,060 COOS.SFC

 Directory of FERC RR9\Modeling Files Appendix\FERC Multisource
Modeling\SO2Annual\2011

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04/07/2013  12:32 PM        12,988,867 AnnSo211.out
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12/20/2012  11:37 AM         7,231,060 COOS.SFC
```

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*************************************************************************************
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 Directory of FERC RR9\Modeling Files Appendix\BPIP

** This Directory contains the BPIP input and output used for the building downwash
analysis

11/02/2012  01:21 PM           720,946 Bpipprm.exe
03/05/2013  12:36 PM           410,099 jcepgep.out
03/05/2013  12:36 PM             6,588 JCEPGEP.PIP
03/05/2013  12:36 PM            37,043 jcepgep.sum

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*********************************


 Directory of FERC RR9\Modeling Files Appendix\VISCREEN

** This Directory contains the VISCREEN input and output files used for screening
visibility modeling

03/08/2013  01:09 PM             7,709 jordan cove LNG viscreen
03/08/2013  01:09 PM             2,209 jordan cove LNG viscreen output
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APPENDIX E-3

1200-C Permit Application

NPDES #1200-C Permit Application Form

Oregon Department of Environmental Quality
APPLICATION FOR NEW NPDES GENERAL PERMIT #1200-C
For stormwater discharges to surface waters from construction activities disturbing 1 acre or more.

Please answer all questions. No line may be left blank. An incomplete application will not be processed and will be returned. If the information requested is not applicable or not yet available, please indicate as such.

A. PROJECT INFORMATION

1. Jordan Cove Energy Project, L.P.
Applicant (Owner, Developer, or General Contractor)
Robert Braddock
Contact Name
125 Central Avenue, Suite 380
Address
Coos Bay — City; Oregon — State; 97420 — Zip
(541) 266-7510 — Telephone; bobbraddock@attglobal.net — E-Mail Address

2. If fee invoicing is different than Applicant, provide contact info:
Same as Item #1.
Invoice Name
Address
City; State; Zip
Telephone; E-Mail Address

3. Black & Veatch Corporation
Architect/Engineering Firm (Erosion & Sediment Control Plan)
Gary Krage
Project Manager
303-256-4046 — Telephone; kragerg@bv.com — E-Mail Address

4. Not Yet Available
Applicant's Designated Erosion and Sediment Control Inspector
Contact Name
Telephone; E-Mail Address

5. South Dunes Power Plant - Jordan Cove Energy Project
Name of Project
North Cove of Coos Bay, Trans Pacific Parkway
Address or Cross Street
North Bend — City; Oregon — State; 97459 — Zip
Coos — County

6. Nature of the Construction Activity

- ☐ Single Family (SIC Code 1521)
- ☐ Multi-Family Residential (SIC Code 1522)
- ☐ Commercial (SIC Code 1542)
- ☐ Industrial (SIC Code 1541)
- ☐ Highway (SIC Code 1611)
- ☐ Utilities (SIC Code 1623):
- ☒ Other: 4911

7. Site Location by Latitude and Longitude:

	Degrees	Minutes	Seconds
Latitude:	43	25	59.613
Longitude:	124	14	23.1

8. Project Size:

Total Site Acreage (acres): 124.47
Total Construction Area (acres): 113.29
Disturbed Area for this phase, if multiple phases: 113.29
Total Number of Lots: 5

DEQ USE ONLY

App. #: ______ File #: ______ LLID #: ______ River Mile: ______
Date Received: ______ Amount: ______ Check Name: ______ Check #: ______
Deposit #: ______ Receipt #: ______ Legal Name Confirmed: ☐

A. PROJECT INFORMATION Continued

9. Runoff from proposed construction activities goes to:
   - ☐ Creek/Stream: ________________
   - ☐ Municipal Storm Sewer or Drainage System
   - ☒ Infiltration device
   - ☐ Ditch: ________________
   - ☐ Other: ________________

10. ☐ Proposed site runoff discharges directly to, or into a storm sewer or drainage system that discharges to, a Total Maximum Daily Load (TMDL) or 303(d) listed water body for turbidity or sedimentation *(if applicable)*. Not Applicable, Coos Bay not 303(d) listed for turbidity or sed.

B. LAND USE COMPATIBILITY STATEMENT

Attach the *original* and complete Land Use Compatibility Statement (LUCS) signed by the local land use authority. The application will not be processed unless the local land use authority approves it and it meets statewide planning goals. (See Attachment C for the LUCS statement)

C. SIGNATURE OF LEGALLY AUTHORIZED REPRESENTATIVE

The legally authorized representative *must* sign the application. The following are authorized to sign the document:

- ♦ **Corporation** — president, secretary, treasurer, vice-president, or any person who performs principal business functions; or a manager of one or more facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million that is assigned or delegated in accordance to corporate procedure to sign such documents
- ♦ **Partnership** — General partner
- ♦ **Sole Proprietorship** — Owner. If more than one person is the sole proprietor, each person must sign the form.
- ♦ **City, County, State, Federal, or other Public Facility** — Principal executive officer or ranking elected official
- ♦ **Limited Liability Company** — Member
- ♦ **Trusts**— Acting trustee

Please see 40 CFR 122.22 for more detail, if needed.

I hereby certify that the information contained in this application is true and correct to the best of my knowledge and belief. In addition, I agree to pay all permit fees required by Oregon Administrative Rules 340-045. This includes a renewal application fee to renew the permit and a compliance determination fee invoiced annually by DEQ to maintain the permit.

Robert L. Braddock	Vice President, Jordan Cove Energy Project, L.P.
Name of Legally Authorized Representative (Type or Print)	**Title**
Signature of Legally Authorized Representative	**Date**

In order to authorize permit registration, the following must be completed and submitted to DEQ office listed below or to a DEQ Agent (see Attachment A for list of Agents):

- ☐ Signed Application form.
- ☐ Land Use Compatibility Statement with signature of the local land use authority
- ☐ Stormwater Erosion and Sediment Control Plan Narrative
- ☐ Stormwater Erosion and Sediment Control Plan Drawings
- ☐ $670 fee to the appropriate DEQ regional office and make the check payable to DEQ of Environmental Quality. If you are sending your application to a DEQ Agent, check with the DEQ Agent for the appropriate fees and make check payable to the DEQ Agent.

DEQ Northwest Region	**DEQ Western Region**	**DEQ Eastern Region**
2020 SW 4th Ave., Suite 400 Portland, OR 97201-4987 503-229-5263 or 1-800-452-4011	750 Front St. NE, Suite 120 Salem, OR 97301-1039 503-378-8240 or 1-800-349-7677	700 SE Emigrant, Suite 330 Pendleton, OR 97801 541-276-4063 or 1-800-452-4011

DEQ AGENT

(Note: See Table A-2 for appropriate local Agent contact information.)

NPDES General Permit 1200-C Application Instructions For Construction Activities

A. PROJECT INFORMATION

A1 Enter the legal name of the applicant. Permit coverage will be issued to this entity. This is the person, business, public organization, or other entity responsible for assuring that erosion and sediment controls are in place and in working order through the life of the project. This must be the **legal** Oregon name (i.e., Acme Products, Inc.) or the **legal** representative of the company if it operates under an assumed business name (i.e., John Smith, dba Acme Products). The name must be a legal, active name registered with the Oregon Department of Commerce, Corporation Division in Salem at 503-378-4752 or http://egov.sos.state.or.us/br/pkg_web_name_srch_inq.login, unless otherwise exempted by their rules. If the name of the applicant is not registered with the Corporation Division and the applicant is a partnership or doing business as a corporate entity, attach legal documents that verify the entity's existence with the application. The applicant may not an assumed business name.

To streamline administration and provide continuous permit coverage, the permit may be transferred from one party to another. For example, if a contractor feels that they will not be able to get a permit before the projected start date, the developer may apply for a permit and then transfer the permit over to the contractor. The transfer fee is $60. Transfer forms are available from DEQ or at http://www.deq.state.or.us/wq/wqpermit/PmtTfrAppl.pdf.

A2 Enter invoicing information for annual fee billing if different from the Applicant in A1 (e.g., "Invoice To: Business Office – Accounts Payable"). Provide permanent address or P.O. Box, if applicable.

A3 Provide the contact information for the Architect or Consulting Engineer who designed the Erosion and Sediment Control Plan (ESCP) so that they may be contacted should questions concerning the ESCP Drawings or Narrative arise.

A4 Provide information on the Erosion and Sediment Control Inspector. This is a person that works for the applicant and not a government employee. If the inspector has not been selected yet, please provide the name of consultant who prepared the Erosion and Sediment Control Plan (ESCP). Upon designating an inspector(s), submit to the DEQ or the Agent an Action Plan, which is an addendum to the ESCP, that identifies their name(s), contact information and training and experience as required in Schedule A, condition 6(b) of the permit.

A5 Provide the common name of the site. What is it to be called? Provide the location of the site with respect to cross roads in the area or a street address if appropriate.

A6 Place a check mark in the box that best describes the use for which the site is being constructed. If other is selected, describe the use.

A7 Enter the latitude and longitude of the approximate center of the facility or site in degrees/minutes/seconds to the nearest 15 seconds. Latitude and longitude can be obtained from United States Geological Survey (USGS) quadrangle topographic maps by calling toll-free at 1-888-ASK-USGS (1-888-275-8747) or by using DEQ's location finder web site at http://deq12.deq.state.or.us/website/findLoc/data.asp. In using DEQ's location finder web site, if you do not know your address, go to "locate place" on the left side of the page and click on "latitude and longitude" and then click on "map it." To get the longitude and latitude to appear you may have to zoom in and re-center until you find the area. You may want to turn off DEQ interests to eliminate the yellow dots and you may want to turn on the Aerial Photos to help you locate the site. The latitude and longitude will be indicated on the left side of the page. Instructions for obtaining latitude and longitude from topographic maps may be obtained at http://www.deq.state.or.us/wq/wqpermit/LatLongInstr.pdf.

A8 Provide property size information. What is the total acreage of the site? Provide an estimate, in the case of a multi-phased project, or if all of the property has not yet been purchased.

A9 Indicate where the runoff goes after leaving the site during construction. If it goes in to the City storm drain system, provide best estimate of the receiving stream in addition to checking the Municipal Storm Sewer box.

A10 Indicate whether stormwater runoff will be discharging directly to, or into a storm sewer or drainage system that discharges to "impaired" waters listed on the 303(d) list or are covered by a Total Maximum Daily Load (TMDL) for sediment or turbidity. A map and table identifying "impaired" water bodies and affected river miles for sediment or turbidity is available on DEQ's web site at: http://www.deq.state.or.us/wq/stormwater/docs/tmdl303dsedturblist.pdf.

B. LAND USE COMPATIBILITY STATEMENT

Land Use Compatibility Statement (LUCS) must be signed by local planning department. If there are any conditions placed on the land use approval, the findings must be included. The LUCS form may be obtained from DEQ at http://www.deq.state.or.us/pubs/permithandbook/lucs.htm.

C. SIGNATURE

The legally authorized representative for the applicant must sign the application. The following are authorized to sign the document

- ♦ **Corporation** — president, secretary, treasurer, vice-president, or any person who performs principal business functions; or a manager of one or more facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million that is assigned or delegated in accordance to corporate procedure to sign such documents.
- ♦ **Partnership** — General partner.
- ♦ **Sole Proprietorship** — Owner. If more than one person is the sole proprietor, each person must sign the form.
- ♦ **City, County, State, Federal, or other Public Facility** — Principal executive officer or ranking elected official.
- ♦ **Limited Liability Company** — Member
- ♦ **Trusts**— Acting trustee

APPLICATION SUBMITTAL AND FEES

If you have a DEQ Agent in the area where your project is located, send the application to the DEQ Agent (See the DEQ Agent list in Attachment A). Otherwise, send the application to the DEQ office in your area (See DEQ office locations in Attachment B).

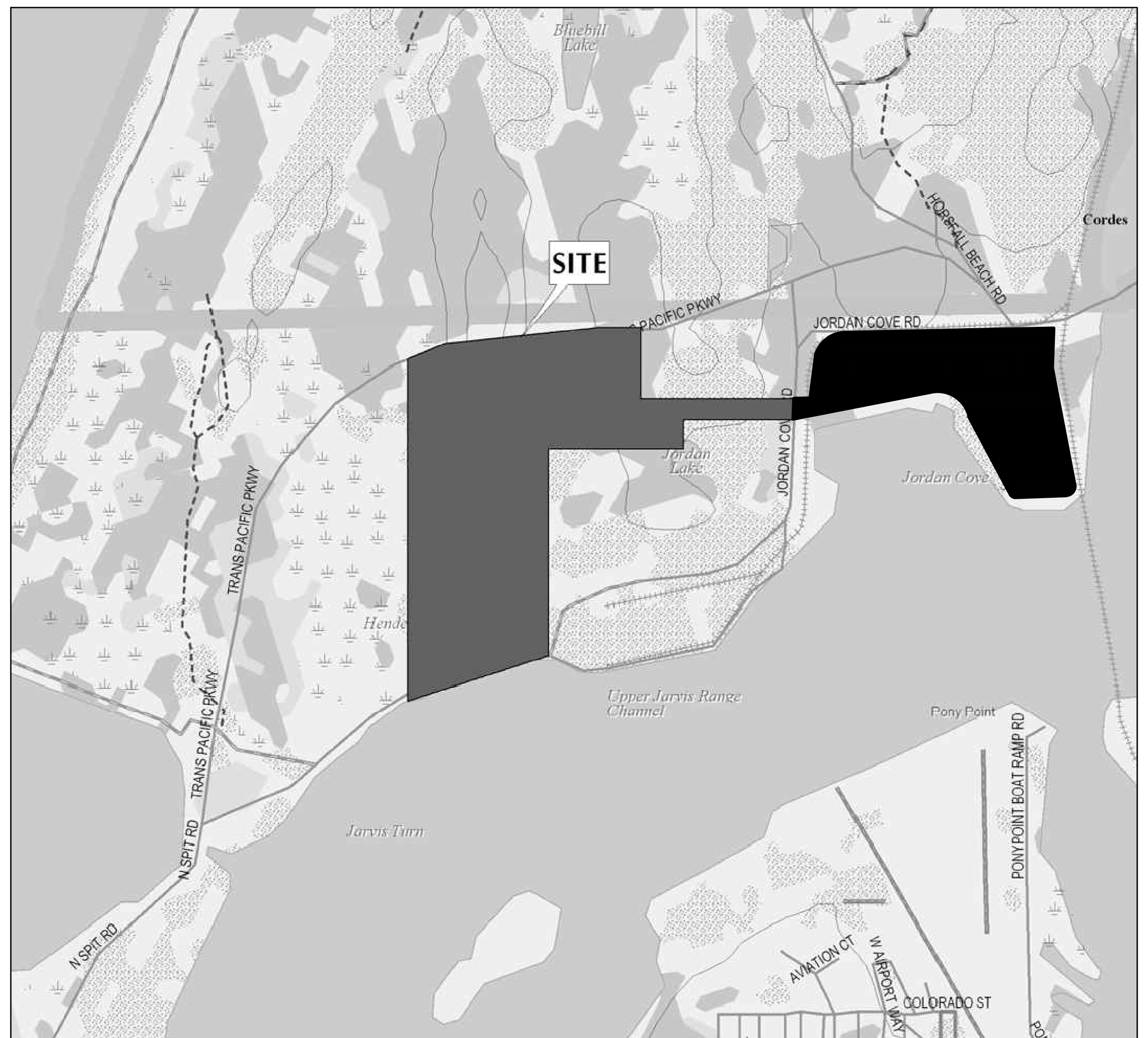
The permit application fee is **$670**, which includes a $60 filing fee, $280 application processing fee, and $330 annual fee. The permittee will also be billed an annual fee for every year the permit is in effect. If you have a DEQ Agent in the area, where your project is located contact them and verify fees. (See Attachment A for list of Agents)

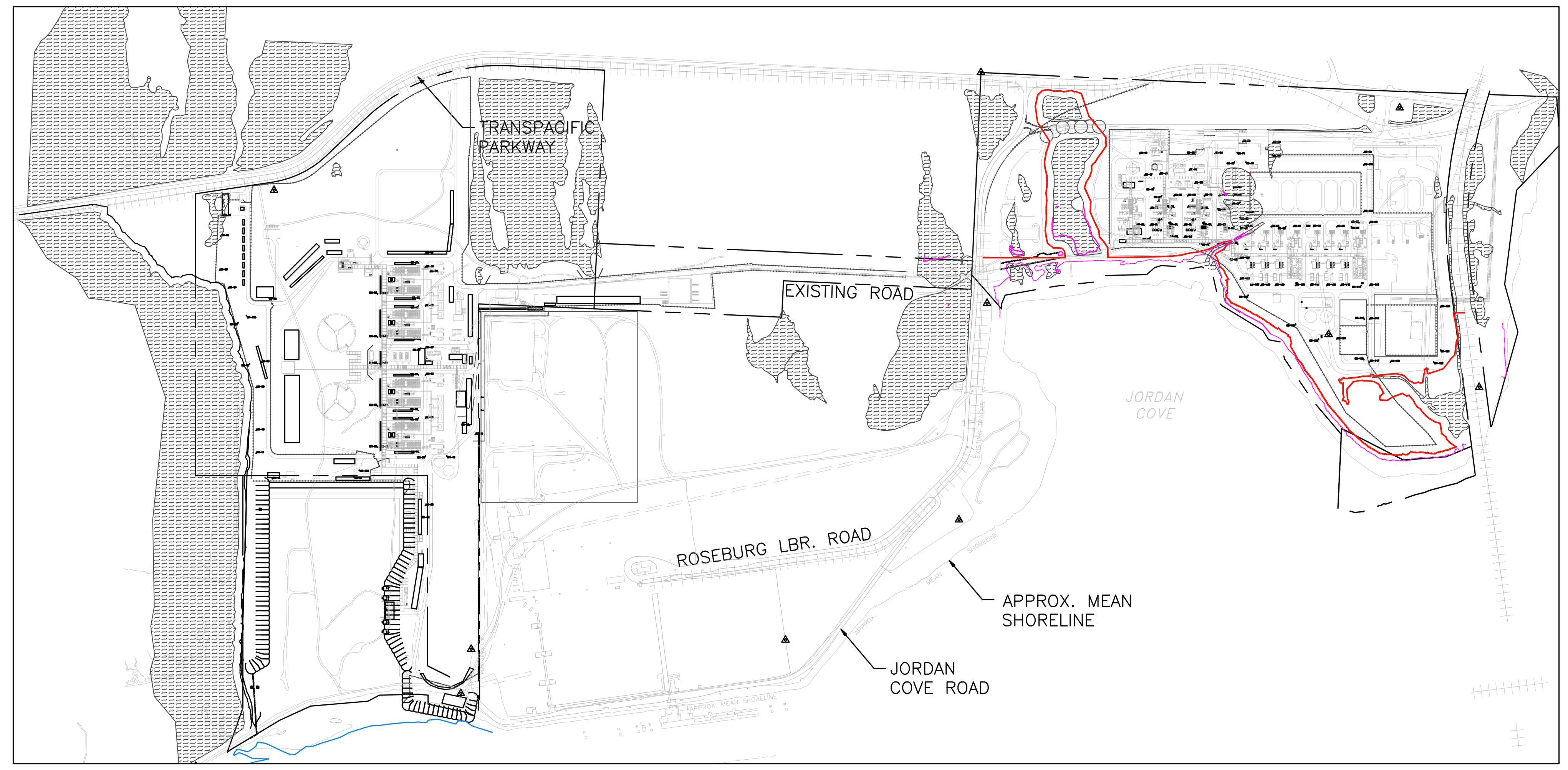
In order to authorize permit registration, the following must be completed and submitted to DEQ office or a DEQ Agent (see Attachment A for list of Agents):

- ☐ Application form with original signature
- ☐ Land Use Compatibility Statement with original signature of the local land use authority
- ☐ Stormwater Erosion and Sediment Control Plan Narrative
- ☐ Stormwater Erosion and Sediment Control Plan Drawings
- ☐ $670 fee to the appropriate DEQ regional office and make the check payable to the Department of Environmental Quality. If you are sending your application to a DEQ Agent, check with the Agent for the appropriate fees.

EROSION AND SEDIMENT CONTROL PLAN

DRAFT





VICINITY MAP
(NOT TO SCALE)

SITE MAP
(NOT TO SCALE)

PROJECT LOCATION

ON THE NORTH SPIT OF COOS BAY, COOS COUNTY, OREGON
LATITUDE = 43° 25' 53" N, LONGITUDE = 124° 15' 56" W

ATTENTION EXCAVATORS

OREGON LAW REQUIRES YOU TO FOLLOW RULES ADOPTED BY THE OREGON UTILITY MODIFICATION CENTER. THOSE RULES ARE SET FORTH IN OAR 952-001-0010 THROUGH OAR 952-001-0090. YOU MAY OBTAIN COPIES OF THESE RULES FROM THE CENTER BY CALLING 503-232-1987. IF YOU HAVE ANY QUESTIONS ABOUT THE RULES, YOU MAY CONTACT THE CENTER. YOU MUST NOTIFY THE CENTER AT LEAST TWO BUSINESS DAYS BEFORE COMMENCING AN EXCAVATION. CALL 503-246-6699.

NARRATIVE DESCRIPTIONS

EXISTING SITE CONDITIONS

- 2 TANKS, FORESTED AREAS, AGGREGATE–SURFACED AREAS, AND AGGREGATE–SURFACED ROADS

DEVELOPED CONDITIONS

- POWER PLANT AND LIQUEFIED NATURAL GAS TERMINAL, INCLUDING TANKS, EQUIPMENT, BUILDINGS, UTILITIES AND ROADS

NATURE OF CONSTRUCTION ACTIVITY AND ESTIMATED TIME TABLE

- CLEARING (JUNE 2014 – END MO/YR)
- ROUGH GRADING (START MO/YR – END MO/YR)
- ROUGH ROAD CONSTRUCTION (START MO/YR – END MO/YR)
- INSTALLATION OF CONSTRUCTION FACILITIES (START MO/YR – END MO/YR)
- UTILITIES CONSTRUCTION (START MO/YR – END MO/YR)
- FOUNDATION CONSTRUCTION (START MO/YR – END MO/YR)
- LNG TANK CONSTRUCTION (START MO/YR – END MO/YR)
- CONSTRUCTION OF OTHER FACILITIES (START MO/YR – END MO/YR)
- FINISH ROAD CONSTRUCTION (START MO/YR – END MO/YR)
- FINISH GRADING (START MO/YR – END MO/YR)
- FINAL STABILIZATION (START MO/YR – FEBRUARY 2018)

TOTAL SITE AREA = 15,890,000 SF = 364.8 ACRES
TOTAL DISTURBED AREA = 12,7300,000 SF = 292.2 ACRES

SITE SOIL CLASSIFICATION

16 – DUNE LANDS, EXCESSIVELY DRAINED
28 – HECETA FINE SAND, POORLY DRAINED
59E – WALDPORT FINE SAND, EXCESSIVELY DRAINED
61D – WALDPORT–HECETA FINE SAND, EXCESSIVELY DRAINED

ALL FILL MATERIAL SHALL BE GENERATED ON–SITE FROM GRADING AND FOUNDATION EXCAVATION AND UTILITY TRENCH SPOILS.

RECEIVING WATER BODIES

COOS BAY

PERMITTEE'S SITE INSPECTOR ______________________

COMPANY/AGENCY: ______________________
PHONE: ______________________
FAX: ______________________
E–MAIL: ______________________
DESCRIPTION OF EXPERIENCE: ______________________

INSPECTION FREQUENCY

- DURING THE ACTIVE CONSTRUCTION PERIOD, CONTROLS WILL BE INSPECTED DAILY WHEN STORM WATER RUNOFF, INCLUDING RUNOFF FROM HIGH PRECIPITATION MONTHS, IS OCCURRING. AND ONCE EVERY TWO (2) WEEKS MINIMUM, IN THE ABSENCE OF STORM WATER RUNOFF.
- PRIOR TO THE SITE BECOMING INACTIVE OR IN ANTICIPATION OF SITE INACCESSIBILITY, CONTROLS WILL BE INSPECTED ONCE TO ENSURE THAT EROSION AND SEDIMENT CONTROL MEASURES ARE IN WORKING ORDER. ANY NECESSARY MAINTENANCE AND REPAIR WILL BE MADE PRIOR TO LEAVING THE SITE.
- DURING INACTIVE PERIODS GREATER THAN SEVEN CONSECUTIVE CALENDAR DAYS, CONTROLS WILL BE INSPECTED ONCE EVERY TWO WEEKS.
- DURING PERIODS IN WHICH THE SITE IS INACCESSIBLE DUE TO INCLEMENT WEATHER, IF PRACTICAL, INSPECTIONS WILL OCCUR DAILY AT A RELEVANT AND ACCESSIBLE DISCHARGE POINT OR DOWNSTREAM LOCATION.

HOLD A PRE–CONSTRUCTION MEETING OF PROJECT CONSTRUCTION PERSONNEL THAT INCLUDES THE ESC PLAN INSPECTOR. ALL INSPECTIONS MUST BE MADE IN ACCORDANCE WITH DEQ 1200–C PERMIT REQUIREMENTS.

INSPECTION LOGS WILL BE KEPT IN ACCORDANCE WITH DEQ'S 1200–C PERMIT REQUIREMENTS.

* SEE DRAWINGS S3100A AND S3100B FOR ADDITIONAL EROSION AND SEDIMENT CONTROL NOTES AND LEGEND.

SHEET INDEX

EROSION AND SEDIMENT CONTROL PLANS

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

OPEN
06/06/14

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
B	–	ISSUED FOR ADMINISTRATIVE REVIEW	RGG	MRP		DJN	DEW
A	13/SEP/13	ISSUED FOR FEED	SCC	SMR		DJN	DEW

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF OREGON.
SIGNED ______________________
DATE ____________ REG NO. ____________

BLACK & VEATCH
Building a world of difference®

DESIGNER DNS | DRAWN HWB
CHECKED | DATE

JORDAN COVE ENERGY PROJECT, L.P.
COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
COVER SHEET

PROJECT / DRAWING NUMBER: 142488–0000–DS3100 | REV: B
CODE
AREA

HIN28791 A1ASL028 06/06/14 D1 08:41:08 ACAD 1=1 18.2s (LMS Tech)

EROSION AND SEDIMENT CONTROL PLAN

DRAFT

JORDAN COVE WILL DEVELOP A DETAILED EROSION PLAN IN ACCORDANCE WITH THE 1200–C PERMIT. THIS DRAFT ESC PLAN AND GENERAL CONDITIONS HAVE BEEN DEVELOPED TO PROVIDE THE AGENCY A GENERAL VIEW OF THE SCOPE AND APPROACH TO THE SITE EROSION CONTROL OF THE PROJECT BY JORDAN COVE.

EROSION AND SEDIMENT CONTROL PLAN DRAWING NOTES:

1. HOLD A PRE–CONSTRUCTION MEETING OF PROJECT CONSTRUCTION PERSONNEL THAT INCLUDES THE INSPECTOR TO DISCUSS EROSION AND SEDIMENT CONTROL MEASURES AND CONSTRUCTION LIMITS. (SCHEDULE A.8.c.i.(3))
2. ALL INSPECTIONS MUST BE MADE IN ACCORDANCE WITH DEQ 1200–C PERMIT REQUIREMENTS.
3. INSPECTION LOGS MUST BE KEPT IN ACCORDANCE WITH DEQ'S 1200–C PERMIT REQUIREMENTS.
4. RETAIN A COPY OF THE ESCP AND ALL REVISIONS ON SITE AND MAKE IT AVAILABLE ON REQUEST TO DEQ, AGENT, OR LOCAL MUNICIPALITY. DURING INACTIVE PERIODS OF GREATER THAN SEVEN (7) CONSECUTIVE CALENDAR DAYS, RETAIN THE ESCP AT THE CONSTRUCTION SITE OR AT ANOTHER LOCATION. (SCHEDULE B.2.a)
5. ALL PERMIT REGISTRANTS MUST IMPLEMENT THE ESCP. FAILURE TO IMPLEMENT ANY OF THE CONTROL MEASURES OR PRACTICES DESCRIBED IN THE ESCP IS A VIOLATION OF THE PERMIT. (SCHEDULE A.8.a)
6. THE ESCP MEASURES SHOWN ON THE PLAN ARE MINIMUM REQUIREMENTS FOR ANTICIPATED SITE CONDITIONS. DURING THE CONSTRUCTION PERIOD, UPGRADE THESE MEASURES AS NEEDED TO COMPLY WITH ALL APPLICABLE LOCAL, STATE, AND FEDERAL EROSION AND SEDIMENT CONTROL REGULATIONS. (SCHEDULE A.8.c.ii.(1)(C))
7. SUBMISSION OF ALL ESCP REVISIONS IS NOT REQUIRED. SUBMITTAL OF ESCP REVISIONS IS ONLY UNDER SPECIFIC CONDITIONS. SUBMIT ALL NECESSARY REVISIONS TO DEQ OR AGENT. (SCHEDULE A.12.C.iii)
8. PHASE CLEARING AND GRADING TO THE MAXIMUM EXTENT PRACTICAL TO PREVENT EXPOSED INACTIVE AREAS FROM BECOMING A SOURCE OF EROSION. (SCHEDULE A.8.c.ii.(1)(d))
9. IDENTIFY, MARK, AND PROTECT (BY FENCING OFF OR OTHER MEANS) CRITICAL RIPARIAN AREAS AND VEGETATION INCLUDING IMPORTANT TREES AND ASSOCIATED ROOTING ZONES, AND VEGETATION AREAS TO BE PRESERVED. IDENTIFY VEGETATIVE BUFFER ZONES BETWEEN THE SITE AND SENSITIVE AREAS (E.G., WETLANDS), AND OTHER AREAS TO BE PRESERVED, ESPECIALLY IN PERIMETER AREAS. (SCHEDULE A.8.c.i.(1)&(2))
10. PRESERVE EXISTING VEGETATION WHEN PRACTICAL AND RE–VEGETATE OPEN AREAS. RE–VEGETATE OPEN AREAS WHEN PRACTICABLE BEFORE AND AFTER GRADING OR CONSTRUCTION. IDENTIFY THE TYPE OF VEGETATIVE SEED MIX USED. (SCHEDULE A.7.b.iii(1) AND A.7.b.iii(3))
11. EROSION AND SEDIMENT CONTROL MEASURES INCLUDING PERIMETER SEDIMENT CONTROL MUST BE IN PLACE BEFORE VEGETATION IS DISTURBED AND MUST REMAIN IN PLACE AND BE MAINTAINED, REPAIRED, AND PROMPTLY IMPLEMENTED FOLLOWING PROCEDURES ESTABLISHED FOR THE DURATION OF CONSTRUCTION, INCLUDING PROTECTION FOR ACTIVE STORM DRAIN INLETS AND CATCH BASINS AND APPROPRIATE NON–STORMWATER POLLUTION CONTROLS. (SCHEDULE A.7.d.i AND A.8.c)
12. ESTABLISH CONCRETE TRUCK AND OTHER CONCRETE EQUIPMENT WASHOUT AREAS BEFORE BEGINNING CONCRETE WORK. (SCHEDULE A.8.c.cl(7))
13. APPLY TEMPORARY AND/OR PERMANENT SOIL STABILIZATION MEASURES IMMEDIATELY ON ALL DISTURBED AREAS AS GRADING PROGRESSES AND FOR ALL ROADWAYS INCLUDING GRAVEL ROADWAYS. (SCHEDULE A.8.c.ii.(2))
14. ESTABLISH MATERIAL AND WASTE STORAGE AREAS, AND OTHER NON–STROMWATER CONTROLS. (SCHEDULE A.8.c.i.(7))
15. PREVENT TRACKING OF SEDIMENT ONTO PUBLIC OR PRIVATE ROADS USING BMP'S SUCH AS: GRAVELED (OR PAVED) EXITS AND PARKING AREAS, GRAVEL ALL UNPAVED ROADS LOCATED ON SITE, OR USE AN EXIT TIRE WASH. THESE BMP'S MUST BE IN PLACE PRIOR TO LAND–DISTURBING ACTIVITIES. (SCHEDULEA.7.d.ii.(1) AND A.8.c.i(4))
16. WHEN TRUCKING SATURATED SOILS FROM THE SITE, EITHER USE WATER–TIGHT TRUCKS OR DRAIN LOADS ON SITE. (SCHEDULE A.7.d.ii.(3))
17. USE BMP'S TO PREVENT OR MINIMIZE STORMWATER EXPOSURE TO POLLUTANTS FROM SPILLS; VEHICLE AND EQUIPMENT FUELING, MAINTENANCE, AND STORAGE; OTHER CLEANING AND MAINTENANCE ACTIVITIES; AND WASTE HANDLING ACTIVITIES. THESE POLLUTANTS INCLUDE FUEL, HYDRAULIC FLUID, AND OTHER OILS FROM VEHICLES AND MACHINERY, AS WELL AS DEBRIS, LEFTOVER PAINTS, SOLVENTS, AND GLUES FROM CONSTRUCTION OPERATIONS. (SCHEDULE A.7.e.i.(2))
18. IMPLEMENT THE FOLLOWING BMP'S WHEN APPLICABLE: WRITTEN SPILL PREVENTION AND RESPONSE PROCEDURES, EMPLOYEE TRAINING ON SPILL PREVENTION AND PROPER DISPOSAL PROCEDURES, SPILL KITS IN ALL VEHICLES, REGULAR MAINTENANCE SCHEDULE FOR VEHICLE AND MACHINERY, MATERIAL DELIVERY AND STORAGE CONTROLS, TRAINING AND SIGNAGE, AND COVERED STORAGE AREAS FOR WASTE AND SUPPLIES. (SCHEDULE A.7.e.iii.)
19. USE WATER, SOIL–BINDING AGENT OR OTHER DUST CONTROL TECHNIQUE AS NEEDED TO AVOID WIND–BLOWN SOIL. (SCHEDULE A.7.b.ii)
20. THE APPLICATION RATE OF FERTILIZERS USED TO REESTABLISH VEGETATION MUST FOLLOW MANUFACTURER'S RECOMMENDATIONS TO MINIMIZE NUTRIENT RELEASES TO SURFACE WATERS. EXERCISE CAUTION WHEN USING TIME–RELEASE FERTILIZERS WITHIN ANY WATERWAYS RIPARIAN ZONE. (SCHEDULE A.9.b.iii)
21. IF STORM WATER TREATMENT SYSTEM (FOR EXAMPLE, ELECTRO–COAGULATION, FLOCCULATION, FILTRATION, ETC.) FOR SEDIMENT OR OTHER POLLUTANT REMOVAL IS EMPLOYED, SUBMIT AN OPERATION AND MAINTENANCE PLAN (INCLUDING SYSTEM SCHEMATIC, LOCATION OF SYSTEM, LOCATION OF INLET, LOCATION OF DISCHARGE, DISCHARGE DISPERSION DEVICE DESIGN, AND A SAMPLING PLAN AND FREQUENCY) BEFORE OPERATING THE TREATMENT SYSTEM. OBTAIN PLAN APPROVAL BEFORE OPERATING THE TREATMENT SYSTEM. OPERATE AND MAINTAIN THE TREATMENT SYSTEM ACCORDING TO MANUFACTURER'S SPECIFICATIONS. (SCHEDULE A.9.d)
22. TEMPORARY STABILIZE SOILS AT THE END OF A SHIFT BEFORE HOLIDAYS AND WEEKENDS, IF NEEDED. THE REGISTRANT IS RESPONSIBLE FOR ENSURING THAT SOILS ARE STABLE DURING RAIN EVENTS AT ALL TIMES OF THE YEAR. (SCHEDULE A.7.b)
23. AT THE END OF EACH WORKDAY SOIL STOCKPILES MUST BE STABILIZED OR COVERED, OR OTHER BMP'S MUST BE IMPLEMENTED TO PREVENT DISCHARGES TO SURFACE WATERS OR CONVEYANCE SYSTEMS LEADING TO SURFACE WATERS. (SCHEDULE A.7.e.ii.(2))
24. CONSTRUCTION ACTIVITIES MUST AVOID OR MINIMIZE EXCAVATION AND CREATION OF BARE GROUND DURING WET WEATHER. (SCHEDULE A.7.a.i)
25. SEDIMENT FENCE: REMOVED TRAPPED SEDIMENT BEFORE IT REACHES ONE THIRD OF THE ABOVE GROUND FENCE HEIGHT AND BEFORE FENCE REMOVAL. (SCHEDULE A.9.c.i)
26. OTHER SEDIMENT BARRIERS (SUCH AS BIOBAGS): REMOVE SEDIMENT BEFORE IT REACHES TWO INCHES DEPTH ABOVE GROUND HEIGHT. AND BEFORE BMP REMOVAL. (SCHEDULE A.9.c.ii)
27. CATCH BASIN: CLEAN BEFORE RETENTION CAPACITY HAS BEEN REDUCED BY FIFTY PERCENT. SEDIMENT BASINS AND SEDIMENT TRAPS: REMOVE TRAPPED SEDIMENTS BEFORE DESIGN CAPACITY HAS BEEN REDUCED BY FIFTY PERCENT AND AT COMPLETION OF PROJECT. (SCHEDULE A.9.c.iii & iv))

EROSION AND SEDIMENT CONTROL PLAN DRAWING NOTES CONTINUED:

28. WITHIN 24 HOURS, SIGNIFICANT SEDIMENT THAT HAS LEFT THE CONSTRUCTION SITE, MUST BE REMEDIATED. INVESTIGATE THE CAUSE OF THE SEDIMENT RELEASE AND IMPLEMENT STEPS TO PREVENT A RECURRENCE OF THE DISCHARGE WITHIN THE SAME 24 HOURS. ANY IN–STEAM CLEAN UP OF SEDIMENT SHALL BE PERFORMED ACCORDING TO THE OREGON DIVISION OF STATE LANDS REQUIRED TIMEFRAME. (SCHEDULE A.9.b.i)
29. INTENTIONAL WASHING OF SEDIMENT INTO STORM SEWERS OR DRAINAGE WAYS MUST NOT OCCUR. VACUUMING OR DRY SWEEPING AND MATERIAL PICKUP MUST BE USED TO CLEANUP RELEASED SEDIMENTS. (SCHEDULE A.9.b.ii)
30. THE ENTIRE SITE MUST BE TEMPORARILY STABILIZED USING VEGETATION OR HEAVY MULCH LAYER, TEMPORARY SEEDING, OR OTHER METHODS SHOULD ALL CONSTRUCTION ACTIVITIES CEASE FOR 30 DAYS OR MORE. (SCHEDULE A.7.f.i)
31. PROVIDE TEMPORARY STABILIZATION FOR THAT PORTION OF THE SITE WHERE CONSTRUCTION ACTIVITIES CEASE FOR 14 DAYS OR MORE WITH A COVERING OF BLOWN STRAW AND A TACKIFIER, LOOSE STRAW, OR AN ADEQUATE COVERING OF COMPOST MULCH UNTIL WORK RESUMES ON THAT PORTION OF THE SITE (SCHEDULE A.7.f.ii)
32. PROVIDE PERMANENT EROSION CONTROL MEASURES ON ALL EXPOSED AREAS. DO NOT REMOVE TEMPORARY SEDIMENT CONTROL PRACTICES UNTIL PERMANENT VEGETATION OR OTHER COVER OF EXPOSED AREAS IS ESTABLISHED. HOWEVER, DO REMOVE ALL TEMPORARY EROSION CONTROL MEASURES AS EXPOSED AREAS BECOME STABILIZED, UNLESS DOING SO CONFLICTS WITH LOCAL REQUIREMENTS. PROPERLY DISPOSE OF CONSTRUCTION MATERIALS AND WASTE, INCLUDING SEDIMENT RETAINED BY TEMPORARY BMP'S (SCHEDULE A.7.b.iii(2) AND A.8.c.iii)

LOCAL AGENCY–SPECIFIC EROSION CONTROL NOTES:

1. OWNER OR DESIGNATED PERSON SHALL BE RESPONSIBLE FOR PROPER INSTALLATION AND MAINTENANCE OF ALL EROSION AND SEDIMENT CONTROL MEASURES, IN ACCORDANCE WITH LOCAL, STATE, AND FEDERAL REGULATIONS.
2. PRIOR TO ANY LAND DISTURBING ACTIVITIES, THE BOUNDARIES OF THE CLEARING LIMITS, VEGETATED BUFFERS, AND ANY SENSITIVE AREAS SHOWN ON THIS PLAN SHALL BE CLEARLY DELINEATED IN THE FIELD. DURING THE CONSTRUCTION PERIOD, NO DISTURBANCE IS PERMITTED BEYOND THE CLEARING LIMITS. THE OWNER/PERMITTEE MUST MAINTAIN THE DELINEATION FOR THE DURATION OF THE PROJECT.
3. PRIOR TO ANY LAND DISTURBING ACTIVITIES, THE BMP'S THAT MUST BE INSTALLED ARE THE CONSTRUCTION ENTRANCE/EXIT, PERIMETER SEDIMENT CONTROL, AND INLET PROTECTION. THESE BMP'S MUST BE MAINTAINED FOR THE DURATION OF THE PROJECT.
4. IF VEGETATIVE SEED MIXES ARE SPECIFIED, SEEDING MUST TAKE PLACE NO LATER THAN SEPTEMBER 1; THE TYPE AND PERCENTAGES OF SEED IN THE MIX MUST BE IDENTIFIED ON THE PLANS.
5. THE ESC PLAN MUST BE KEPT ON SITE. ALL MEASURES SHOWN ON THE PLAN MUST BE INSTALLED PROPERLY TO ENSURE THAT SEDIMENT OR SEDIMENT LADEN WATER DOES NOT ENTER A SURFACE WATER SYSTEM, ROADWAY, OR OTHER PROPERTIES.
6. THE ESC MEASURES SHOWN ON THIS PLAN ARE MINIMUM REQUIREMENTS FOR ANTICIPATED SITE CONDITIONS. DURING THE CONSTRUCTION PERIOD, THESE MEASURES MAY BE UPGRADED AS NEEDED TO COMPLY WITH ALL APPLICABLE LOCAL, STATE, AND FEDERAL EROSION CONTROL REGULATIONS. CHANGES TO THE APPROVED ESC PLAN MUST BE SUBMITTED IN THE FORM OF AN ACTION PLAN TO DEQ PER THE 1200–C PERMIT.
7. IN AREAS SUBJECT TO WIND EROSION, APPROPRIATE BMP'S MUST BE USED WHICH MAY INCLUDE THE APPLICATION OF FINE WATER SPRAYING, PLASTIC SHEETING, MULCHING, OR OTHER APPROVED MEASURES.
8. ALL PUMPING OF SEDIMENT LADEN STORMWATER SHALL BE DISCHARGED OVER AN UNDISTURBED, PREFERABLY VEGETATED AREA, AND THROUGH A SEDIMENT CONTROL BMP (I.E. FILTERING).
9. <u>ALL</u> EXPOSED SOILS MUST BE COVERED DURING THE WET WEATHER PERIOD.

* SEE DRAWINGS S3100 AND S3100B FOR ADDITIONAL EROSION AND SEDIMENT CONTROL NOTES AND LEGEND

SHEET INDEX

EROSION AND SEDIMENT CONTROL PLANS

NOT TO BE USED FOR CONSTRUCTION

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B	–	ISSUED FOR ADMINISTRATIVE REVIEW	RGG	MRP		DJN	DEW
A	13/SEP/13	ISSUED FOR FEED	SCC	SMR		DJN	DEW

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JORDAN COVE ENERGY PROJECT, L.P.
COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN NOTES

PROJECT | DRAWING NUMBER 142488–0000–DS3100A | REV B

CODE | AREA

HIN28791 D1 ACAD 18.2s (LMS Tech)
A1ASL028 1=1
06/06/14 08:43:53

GENERAL NOTES

1. SEE DRAWING S3100 AND S3100A FOR ADDITIONAL EROSION AND SEDIMENT CONTROL PLAN INFORMATION.
2. SEE DRAWING 3150 AND/OR THE FOLLOWING FOR EROSION AND SEDIMENT CONTROL PLAN DETAILS:

DETAIL:	CLEAN WATER SERVICES DWG
CHECK DAM	840
CONSTRUCTION ENTRANCE	855
TIRE WASH	870
SILT FENCE	875

3. THESE EROSION AND SEDIMENT CONTROL PLANS ASSUME "DRY WEATHER" CONSTRUCTION. "WET WEATHER CONSTRUCTION MEASURES NEED TO BE APPLIED BETWEEN OCTOBER 1 AND MAY 31.
4. ALL BASE ESC MEASURES (PERIMETER SEDIMENT CONTROL, CONSTRUCTION ENTRANCE/EXIT, ETC.) MUST BE IN PLACE, FUNCTIONAL, AND APPROVED IN AN INITIAL INSPECTION, PRIOR TO COMMENCEMENT OF CONSTRUCTION ACTIVITIES.
5. SEDIMENT BARRIERS APPROVED FOR USE INCLUDE SEDIMENT FENCE, BERMS CONSTRUCTED OF MULCH, CHIPPINGS, OR OTHER SUITABLE MATERIAL, STRAW WATTLES, OR OTHER APPROVED MATERIALS.
6. RUN-ON AND RUN-OFF CONTROLS SHALL BE IN PLACE AND FUNCTIONING PRIOR TO BEGINNING SUBSTANTIAL CONSTRUCTION ACTIVITIES. RUN-ON AND RUN-OFF CONTROL MEASURES INCLUDE: SLOPE DRAINS (WITH OUTLET PROTECTION), CHECK DAMS, SURFACE ROUGHENING, AND BANK STABILIZATION.
7. ALL "SEDIMENT BARRIERS (TO BE INSTALLED AFTER GRADING)" SHALL BE INSTALLED IMMEDIATELY FOLLOWING ESTABLISHMENT OF ROUGH GRADE AS SHOWN ON THESE PLANS.
8. LONG TERM SLOPE STABILIZATION MEASURES, INCLUDING MATTING, SHALL BE IN PLACE OVER ALL EXPOSED SOILS BY OCTOBER 1.
9. SEED USED FOR TEMPORARY OR PERMANENT SEEDING SHALL BE COMPOSED OF ONE OF THE FOLLOWING MIXTURES, UNLESS OTHERWISE AUTHORIZED:
   - A. DWARF GRASS MIX (MIN. 100 LB./AC.)
     1. DWARF PERENNIAL RYGRASS (80% BY WEIGHT)
     2. CREEPING RED FESCUE (20% BY WEIGHT)
   - B. STANDARD HEIGHT GRASS MIX (MIN. 100 LB./AC.)
     1. ANNUAL RYEGRASS (40% BY WEIGHT)
     2. TURF-TYPE FESCUE (60% BY WEIGHT)
10. SLOPES TO RECEIVE TEMPORARY OR PERMANENT SEEDING SHALL HAVE THE SURFACE ROUGHENED BY MEANS OF TRACK-WALKING OR THE USE OF OTHER APPROVED IMPLEMENTS. SURFACE ROUGHENING IMPROVES SEED BEDDING AND REDUCES RUN-OFF VELOCITY.
11. LONG TERM SLOPE STABILIZATION MEASURES SHALL INCLUDE THE ESTABLISHMENT OF PERMANENT VEGETATIVE COVER VIA SEEDING WITH APPROVED MIX AND APPLICATION RATE.
12. TEMPORARY SLOPE STABILIZATION MEASURES SHALL INCLUDE: COVERING EXPOSED SOIL WITH STRAW MULCHING, WOOD CHIPS, OR OTHER APPROVED MEASURES.
13. STOCKPILED SOIL OR STRIPPINGS SHALL BE PLACED IN A STABLE LOCATION AND CONFIGURATION DURING "WET WEATHER" PERIODS. STOCKPILES SHALL BE COVERED WITH STRAW MULCH. SEDIMENT FENCE IS REQUIRED AROUND THE PERIMETER OF THE STOCKPILE.
14. CUT OR FILL AREAS EXPOSED FOR AT LEAST 14 DAYS SHALL BE STABILIZED THROUGH THE USE OF TEMPORARY SEEDING AND MULCHING, EROSION CONTROL BLANKETS OR MATS, MID-SLOPE SEDIMENT FENCES OR WATTLES, OR OTHER APPROPRIATE MEASURES. SLOPES EXCEEDING 25% MAY REQUIRE ADDITIONAL EROSION CONTROL MEASURES.
15. AREAS SUBJECT TO WIND EROSION SHALL USE APPROPRIATE DUST CONTROL MEASURES INCLUDING THE APPLICATION OF A FINE SPRAY OF WATER, STRAW MULCHING, OR OTHER APPROVED MEASURES.
16. ACTIVE INLETS TO STORM WATER SYSTEMS SHALL BE PROTECTED THROUGH THE USE OF APPROVED INLET PROTECTION MEASURES. ALL INLET PROTECTION MEASURES ARE TO BE REGULARLY INSPECTED AND MAINTAINED AS NEEDED.
17. USE BMP's SUCH AS CHECK-DAMS, BERMS, AND INLET PROTECTION TO PREVENT RUN-OFF FROM REACHING DISCHARGE POINTS.
18. SENSITIVE RESOURCES INCLUDING, BUT NOT LIMITED TO, TREES, WETLANDS, AND RIPARIAN PROTECTION AREAS SHALL BE CLEARLY DELINEATED WITH ORANGE CONSTRUCTION FENCING OR CHAIN LINK FENCING IN A MANNER THAT IS CLEARLY VISIBLE TO ANYONE IN THE AREA. NO ACTIVITIES ARE PERMITTED TO OCCUR BEYOND THE CONSTRUCTION BARRIER.
19. CONSTRUCTION ENTRANCES/EXITS SHALL BE INSTALLED AT THE BEGINNING OF CONSTRUCTION AND MAINTAINED FOR THE DURATION OF THE PROJECT. ADDITIONAL MEASURES INCLUDING, BUT NOT LIMITED TO, STREET SWEEPING AND VACUUMING, MAY BE REQUIRED TO ENSURE THAT ALL PAVED AREAS ARE KEPT CLEAN FOR THE DURATION OF THE PROJECT.
20. SATURATED MATERIALS THAT ARE HAULED OFF-SITE MUST BE TRANSPORTED IN WATER-TIGHT TRUCKS TO ELIMINATE SPILLAGE OF SEDIMENT AND SEDIMENT-LADEN WATER.
21. AN AREA SHALL BE PROVIDED FOR THE WASHING OUT OF CONCRETE TRUCKS IN A LOCATION THAT DOES NOT PROVIDE RUN-OFF THAT CAN ENTER THE STORM WATER SYSTEM. IF THE CONCRETE WASH-OUT AREA CAN NOT BE CONSTRUCTED GREATER THAN 50' FROM ANY DISCHARGE POINT, SECONDARY MEASURES SUCH AS BERMS OR TEMPORARY SETTLING PITS MAY BE REQUIRED. THE WASH-OUT SHALL BE LOCATED WITHIN 6' OF TRUCK ACCESS AND BE CLEANED WHEN IT REACHES 50% OF CAPACITY.
22. SWEEPINGS FROM EXPOSED AGGREGATE CONCRETE SHALL NOT BE TRANSFERRED TO THE STORM WATER SYSTEM. SWEEPINGS SHALL BE PICKED UP AND DISPOSED IN THE TRASH.
23. AVOID PAVING IN WET WEATHER WHEN PAVING CHEMICALS CAN RUNOFF INTO THE STORM WATER SYSTEM.
24. COVER CATCH BASINS, MANHOLES, AND OTHER DISCHARGE POINTS WHEN APPLYING SEAL COAT, TACK COAT, ETC. TO PREVENT INTRODUCING THESE MATERIALS TO THE STORM WATER SYSTEM.
25. PLACE CHECK DAMS ALONG ROCK LINED DITCHES IN ACCORDANCE WITH CLEAN WATER SERVICES DRAWING 940.

RATIONALE STATEMENT

A COMPREHENSIVE LIST OF AVAILABLE BEST MANAGEMENT PRACTICES (BMP) OPTIONS BASED ON DEQ's 1200-C PERMIT APPLICATION AND ESCP GUIDANCE DOCUMENT HAS BEEN REVIEWED TO COMPLETE THIS EROSION AND SEDIMENT CONTROL PLAN. SOME OF THE BMP's WERE NOT CHOSEN BECAUSE THEY WERE DETERMINED TO NOT EFFECTIVELY MANAGE EROSION PREVENTION AND SEDIMENT CONTROL FOR THIS PROJECT BASED ON SPECIFIC SITE CONDITIONS, INCLUDING SOIL CONDITIONS, TOPOGRAPHIC CONSTRAINTS, ACCESSIBILITY TO THE SITE, AND OTHER RELATED CONDITIONS. AS THE PROJECT PROGRESSES AND THERE IS A NEED TO REVISE THE ESC PLAN, AN ACTION PLAN WILL BE SUBMITTED.

INITIAL

BMP MATRIX FOR CONSTRUCTION PHASES

REFER TO DEQ GUIDANCE MANUAL FOR A COMPREHENSIVE LIST OF AVAILABLE BMP'S.

YEAR:																			
BMP'S MONTH#:																			
PIPE SLOPE DRAINS																			
ENERGY DISSIPATERS																			
TEMPORARY DIVERSION DIKES																			
CHECK DAMS																			
TEMPORARY SEEDING AND PLANTING																			
PERMANENT SEEDING AND PLANTING																			
MYCORRHIZAE/BIOFERTILIZERS																			
MULCHES (SPECIFY TYPE)																			
CONSTRUCTION ENTRANCE																			
COMPOST BLANKETS																			
COMPOST SOCKS																			
COMPOST BERM																			
SOIL TACKIFIERS																			
SODDING VEGETATIVE BUFFER STRIPS																			
SEDIMENT FENCING																			
EROSION CONTROL BLANKETS & MATS (SPECIFY TYPE)																			
EARTH DIKES (STABILIZED)																			
DRAINAGE SWALES																			
ROCK OUTLET PROTECTION																			
SEDIMENT TRAP																			
STRAW WATTLES (LOOSE COMPACTION RICE STRAW)																			
STORM DRAIN INLET PROTECTION																			
TEMPORARY OR PERMANENT SEDIMENTATION BASINS																			
CONSTRUCTION ENTRANCE																			
UNPAVED ROADS GRAVELED OR OTHER BMP ON THE ROAD																			
DEWATERING (TREATMENT LOCATION, SCHEMATIC, & SAMPLING PLAN REQUIRED)																			
PAVING OPERATIONS CONTROL																			
CONCRETE TRUCK WASHOUT																			

GENERAL LEGEND

- PROPERTY BOUNDARY
- NEW SECURITY FENCE
- 80 EXISTING CONTOUR
- 40 NEW CONTOUR
- SEDIMENT FENCE (PERIMETER)
- SEDIMENT FENCE (INTERIOR)
- ORANGE CONSTRUCTION FENCE
- DRAINAGE FLOW DIRECTION
- C-? NEW CULVERT
- INLET PROTECTION
- OUTLET PROTECTION
- SEDIMENT BASIN
- ROCK LINED DITCH
- REMOVED
- DITCH/SWALE FLOW INDICATOR
- COMPOST FILTER SOCK
- ROCK FILTER BERM
- TEMPORARY SLOPE STABILIZATION MEASURES
- LONG TERM SLOPE STABILIZATION MEASURES
- MATTING (GREENFIX STRAW/ COCONUT MAT TYPE: CFS072R)
- NEW AGGREGATE SURFACING
- NEW PAVEMENT

DRAFT

SHEET INDEX

EROSION AND SEDIMENT CONTROL PLANS

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C	-	ISSUED FOR ADMINISTRATIVE REVIEW	RGG	MRP		DJN	DEW
B	13/SEP/13	ISSUED FOR FEED	SCC	SMR		DJN	DEW
A	29/MAR/13	ISSUED FOR REVIEW	RRH	SMR			

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COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
NOTES AND LEGEND

PROJECT / DRAWING NUMBER: 142488-0000-DS3100B | REV: C

CODE

AREA

HIN28791 D1 ACAD 18.2s (LMS Tech)
A1ASL028 1=1
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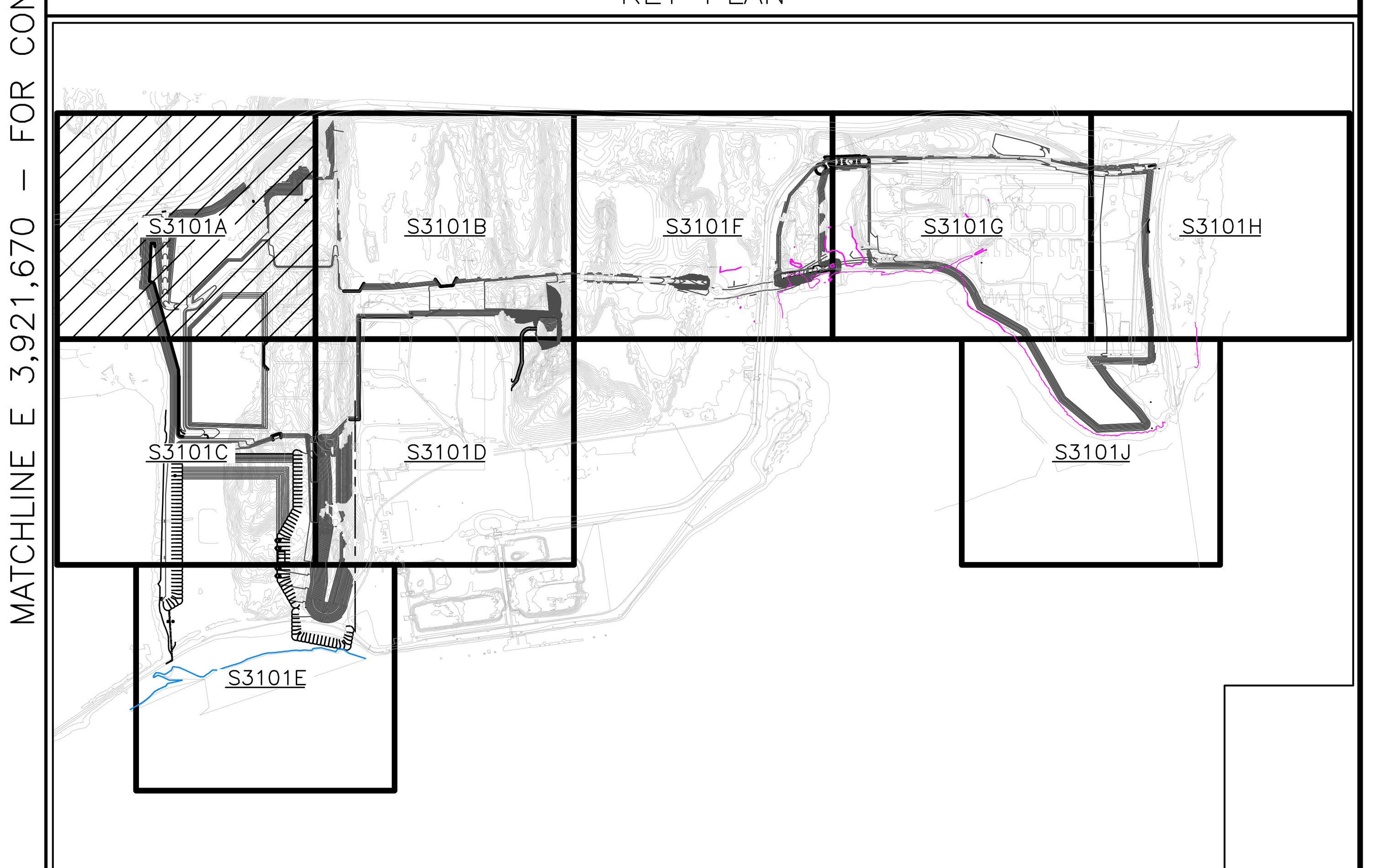
NOTES

1. SEE DRAWINGS S3100, S3100A & S3100B FOR LOCATION MAP, GENERAL LAYOUT, NOTES & LEGEND.
2. PERIMETER SILT FENCE AT TOE OF SLOPE SHALL BE REMOVED AFTER SIDE SLOPE VEGETATION HAS BEEN ADEQUATELY ESTABLISHED WHERE SILT FENCE IS INSTALLED AT TOP OF SLOPE.

DRAFT

KEY PLAN



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EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA A

PROJECT / DRAWING NUMBER: 142488–0000–DS3101A
REV: B
CODE
AREA

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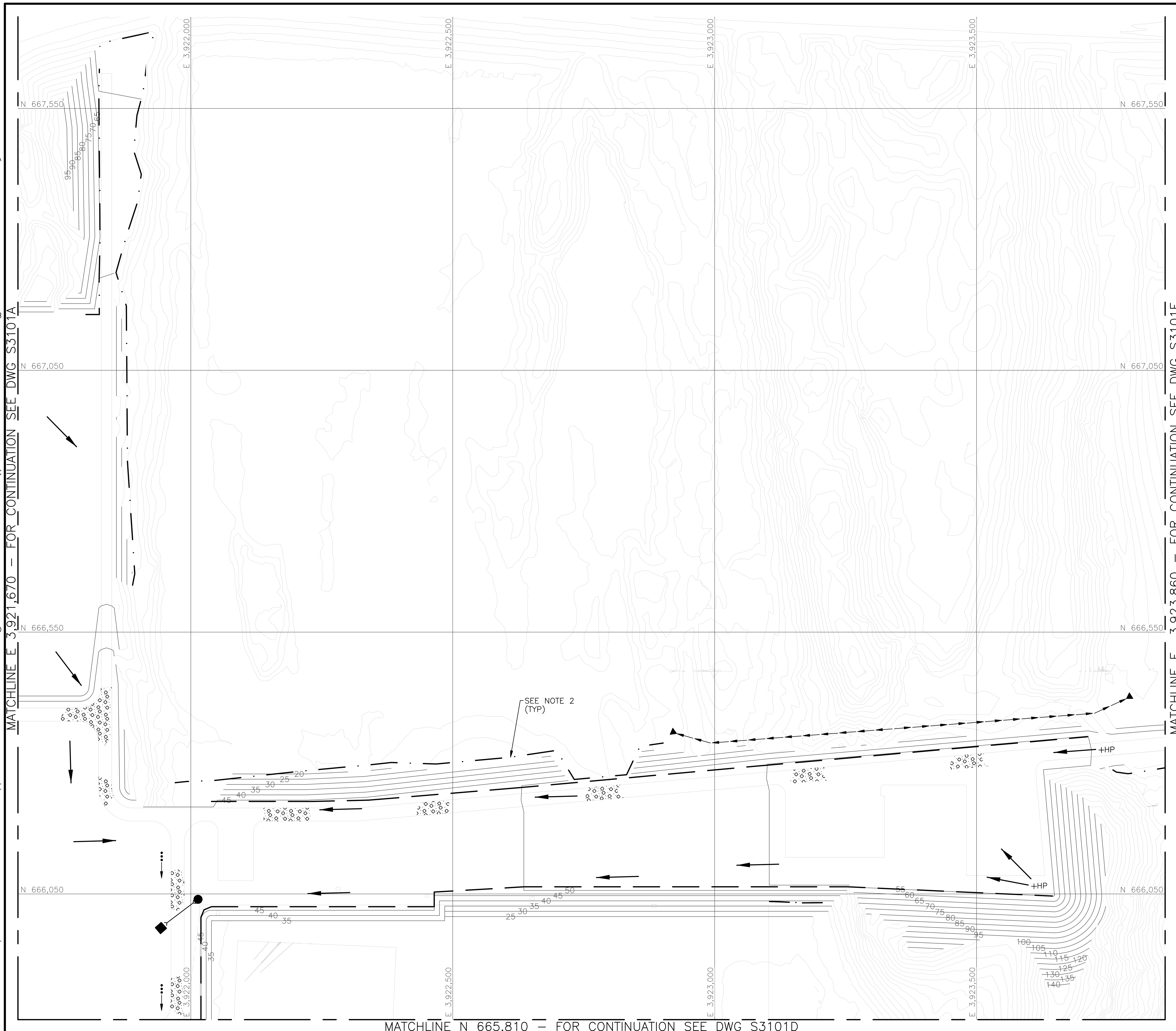

NOTES

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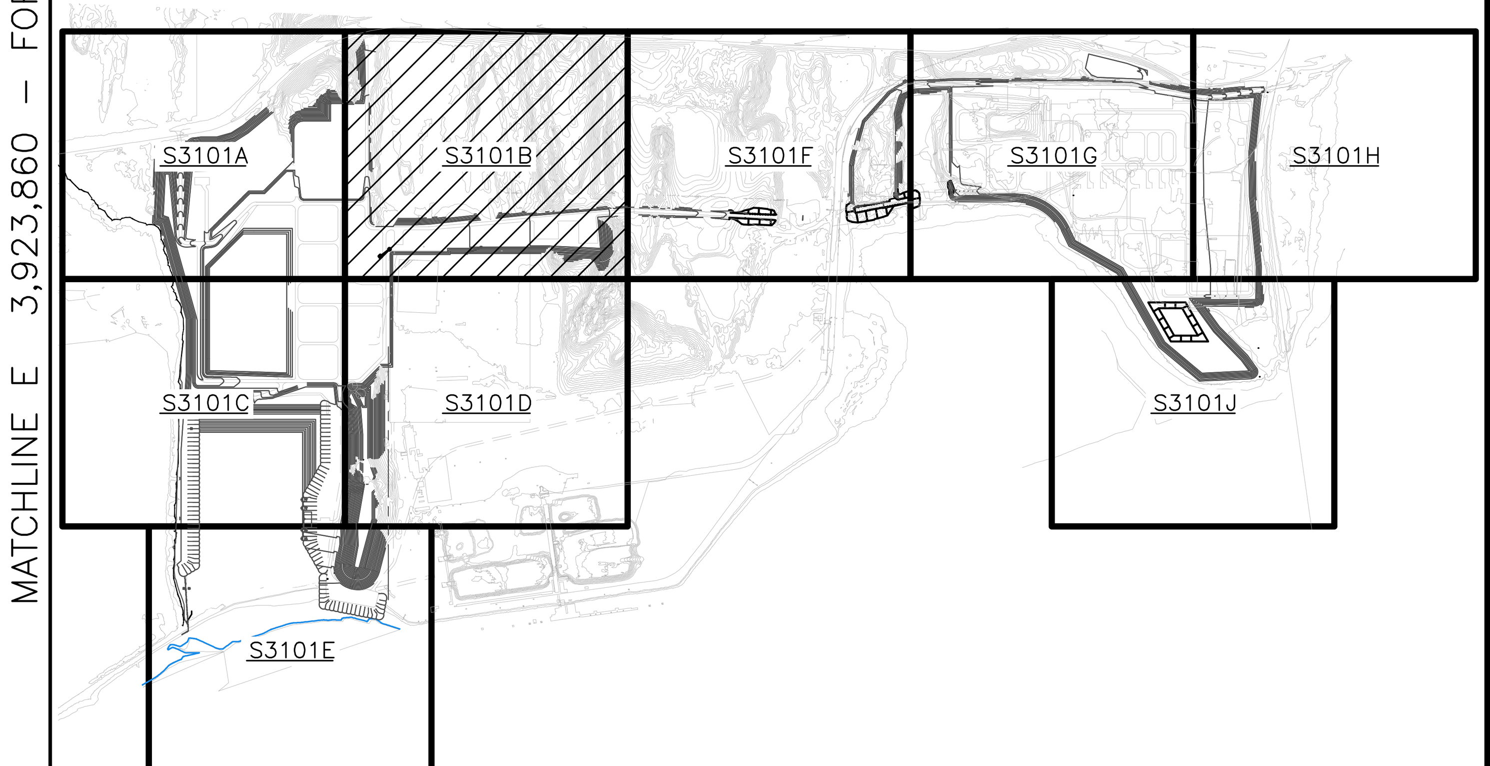
DRAFT

KEY PLAN



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EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA B

PROJECT DRAWING NUMBER REV
142488–0000–DS3101B B
CODE
AREA

HIN28791 D1 1=1
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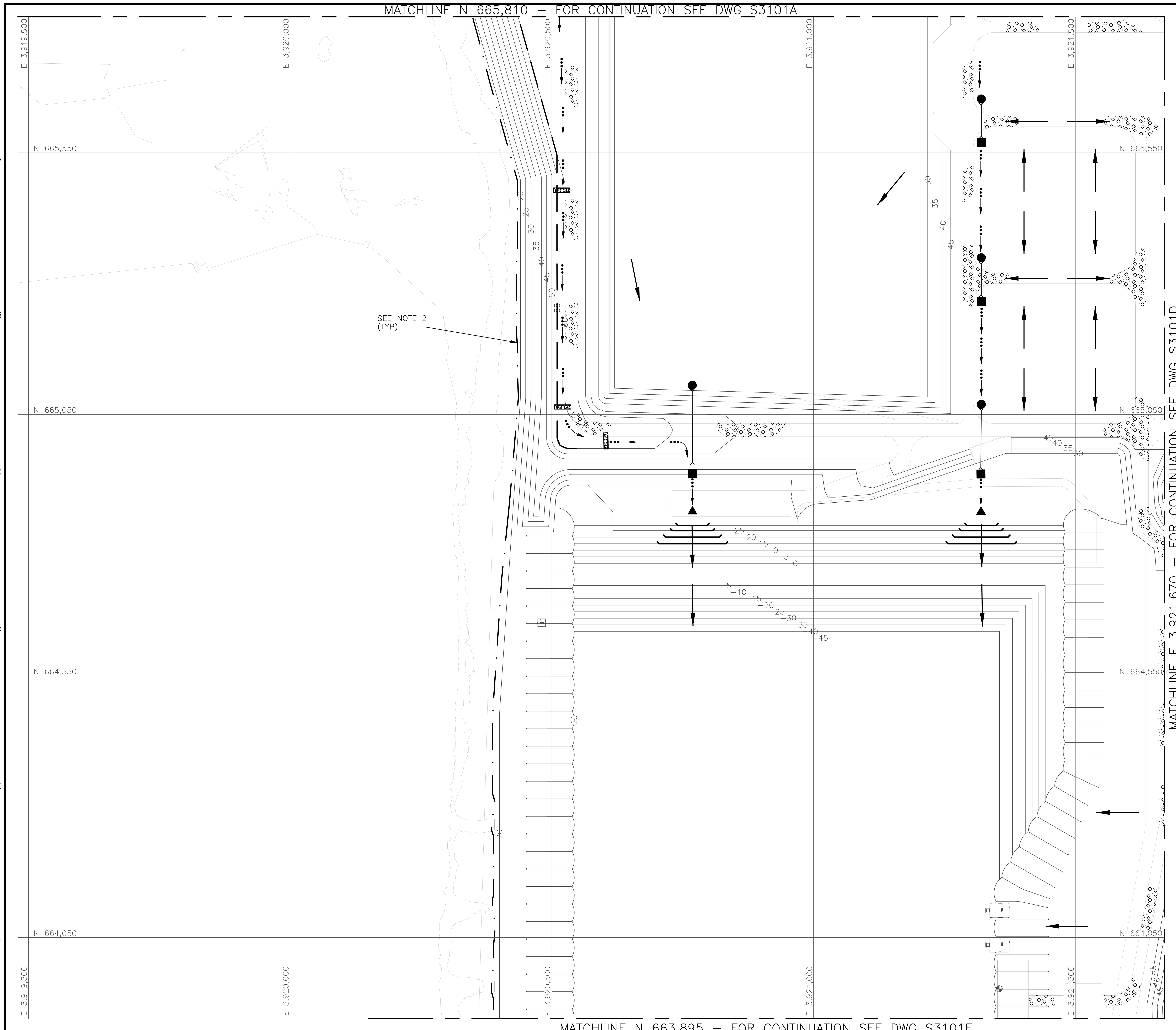

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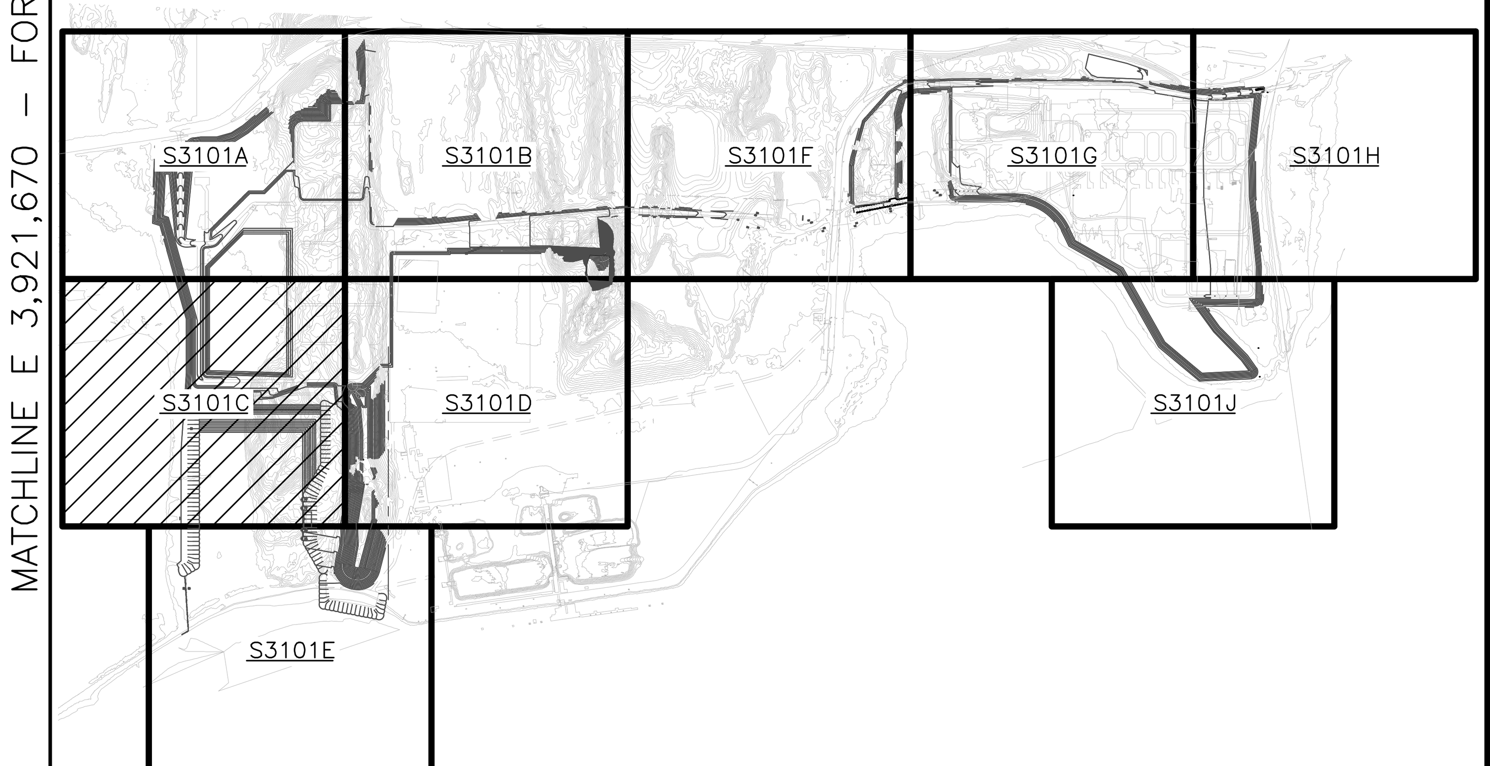
KEY PLAN



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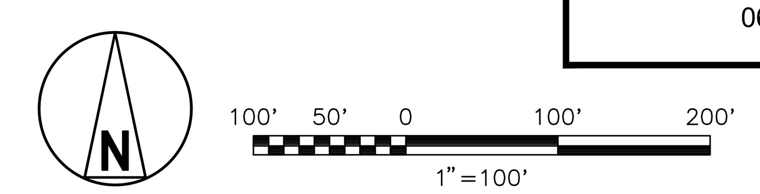
06/06/14



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COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA C

PROJECT / DRAWING NUMBER: 142488–0000–DS3101C | REV: B

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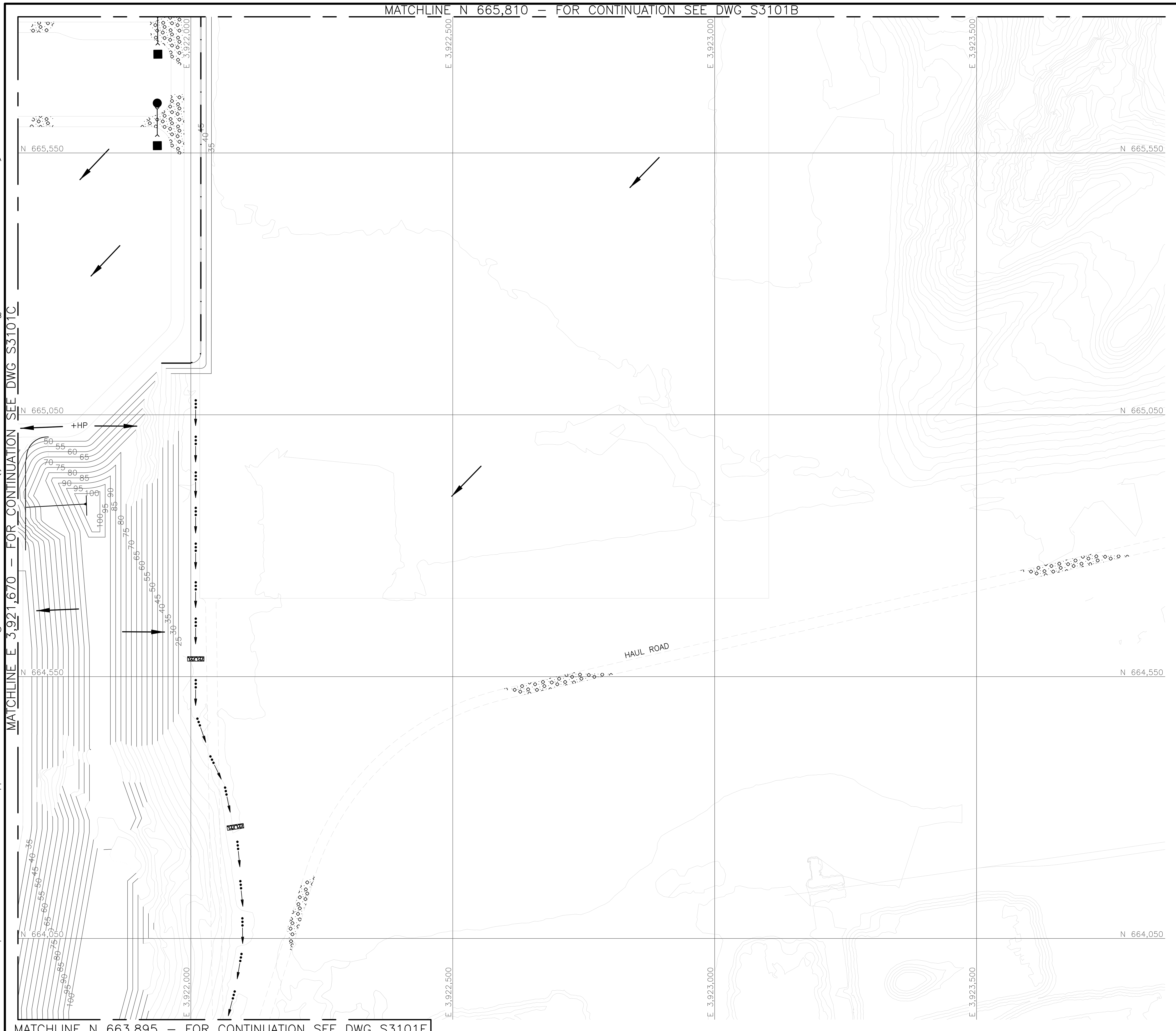

NOTES

1. SEE DRAWINGS S3100, S3100A & S3100B FOR LOCATION MAP, GENERAL LAYOUT, NOTES & LEGEND.
2. PERIMETER SILT FENCE AT TOE OF SLOPE SHALL BE REMOVED AFTER SIDE SLOPE VEGETATION HAS BEEN ADEQUATELY ESTABLISHED WHERE SILT FENCE IS INSTALLED AT TOP OF SLOPE.

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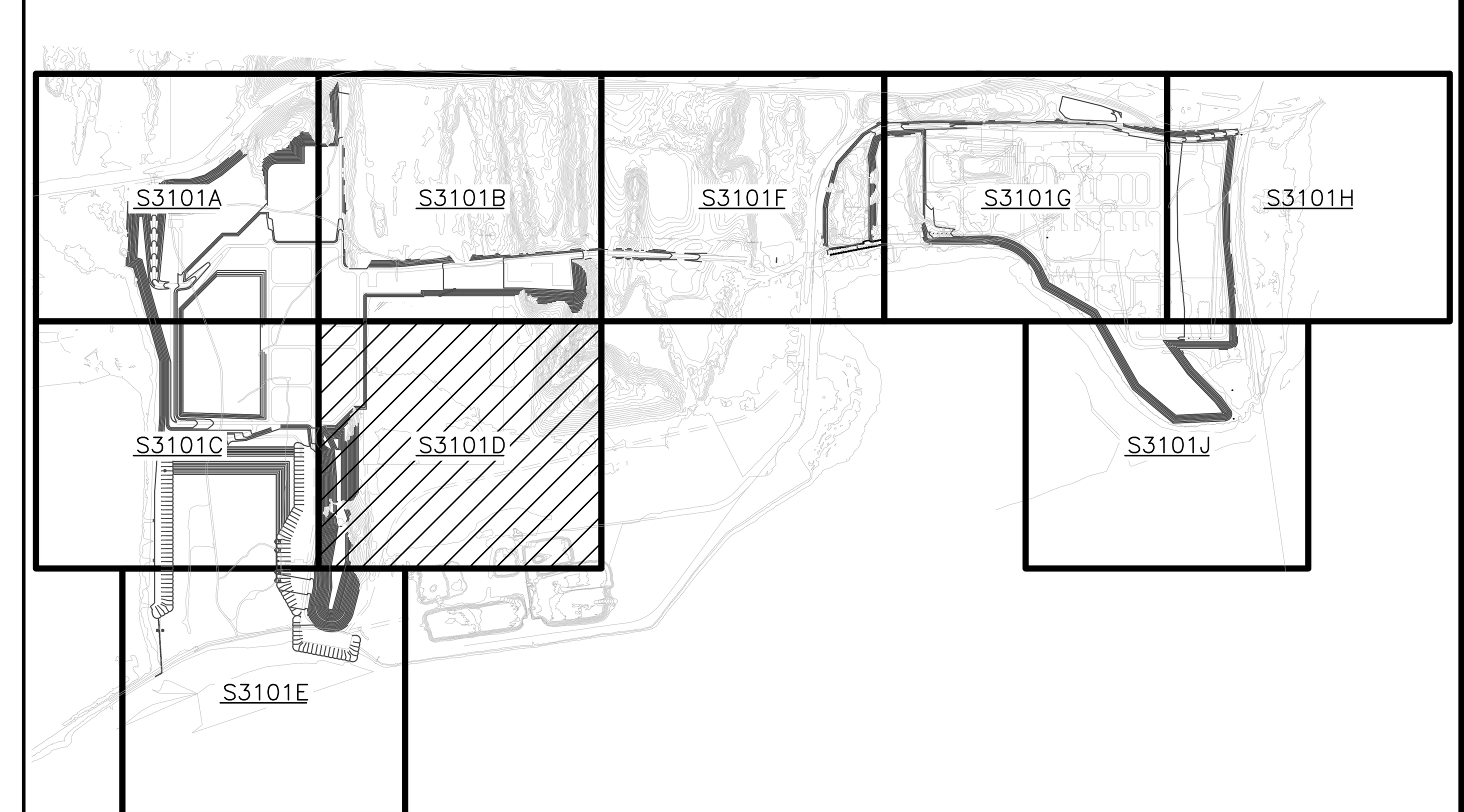

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JORDAN COVE ENERGY PROJECT, L.P.
COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA D

PROJECT: 142488–0000
DRAWING NUMBER: DS3101D
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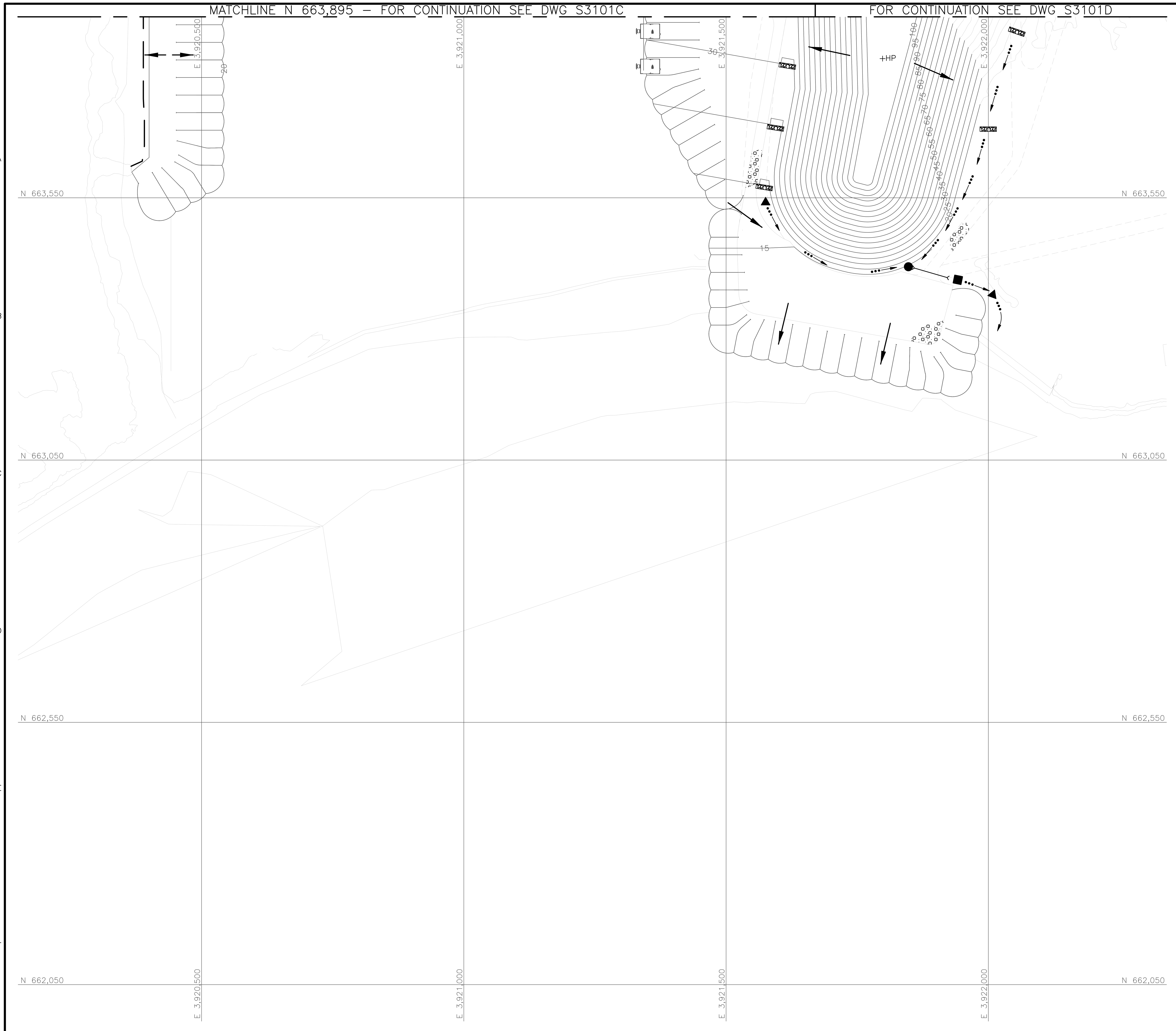

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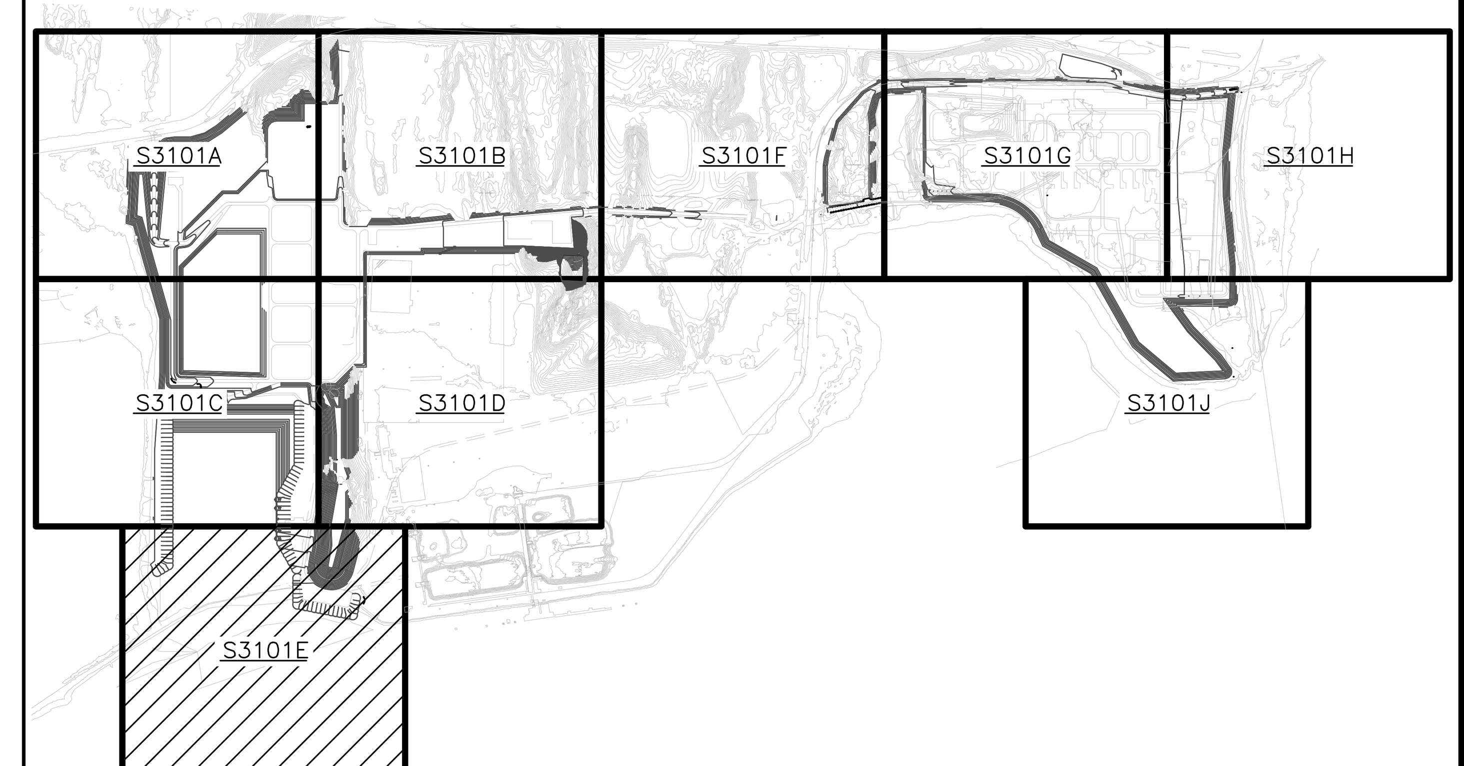

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EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA E

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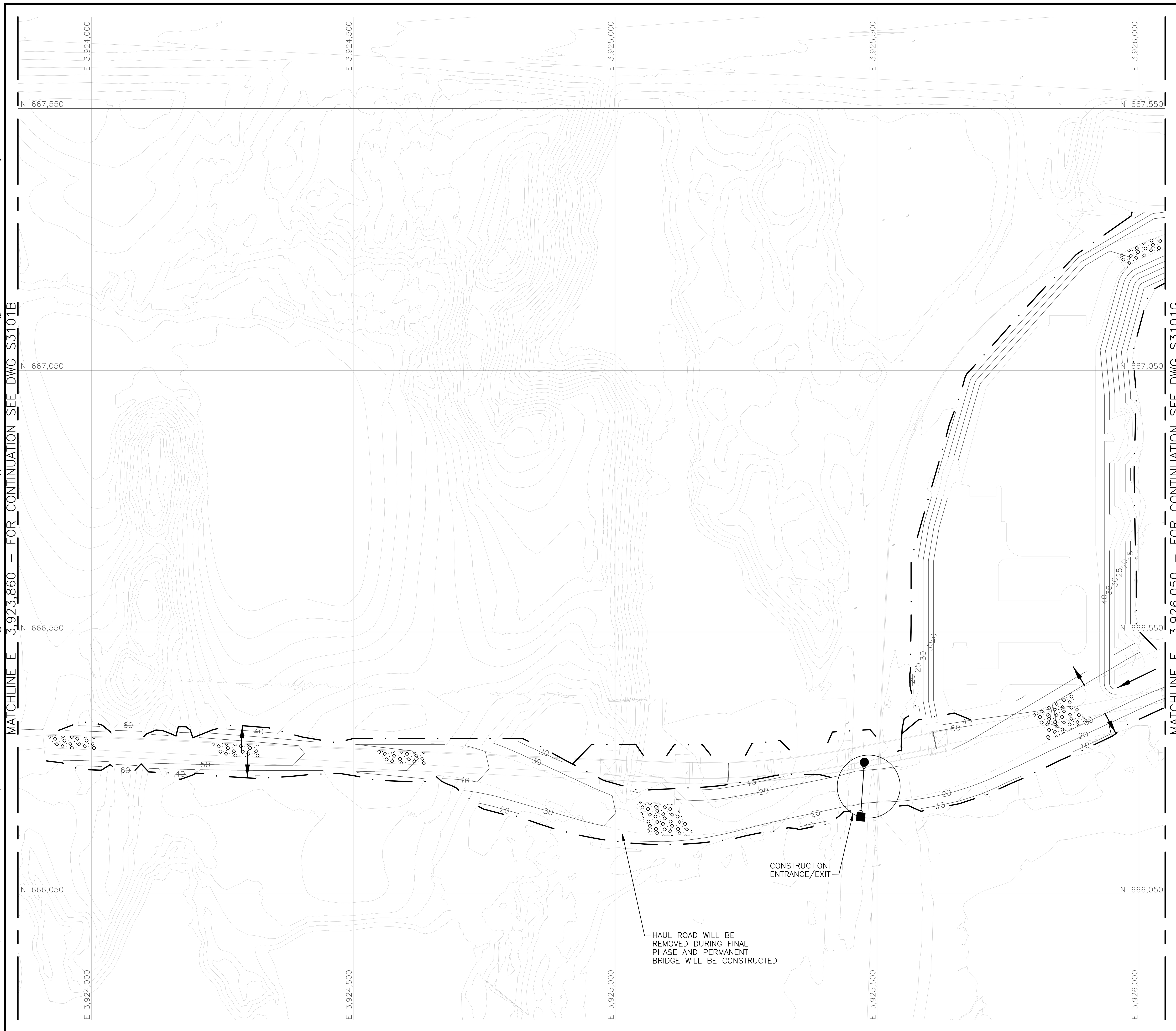

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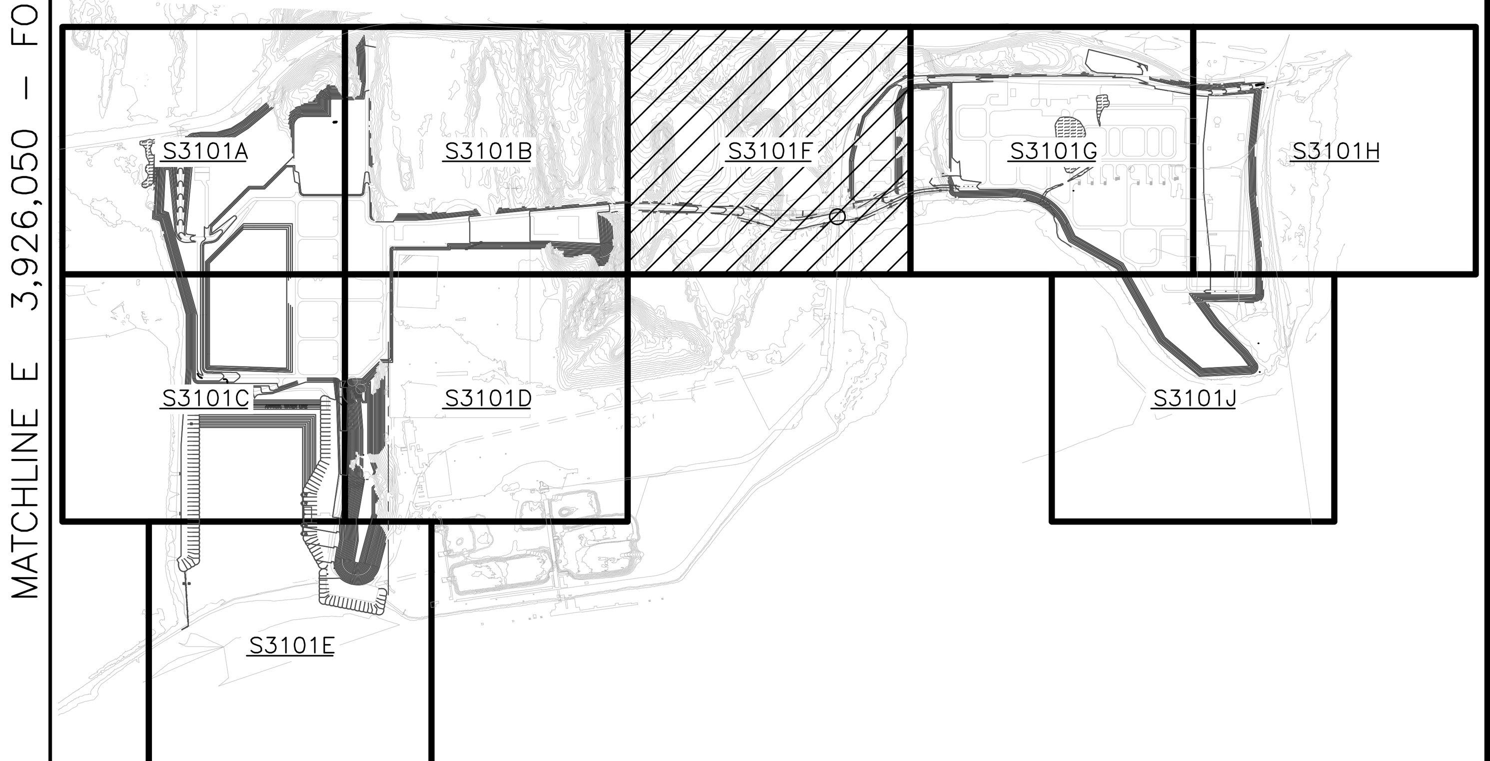

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COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA F

PROJECT / DRAWING NUMBER: 142488–0000–DS3101F
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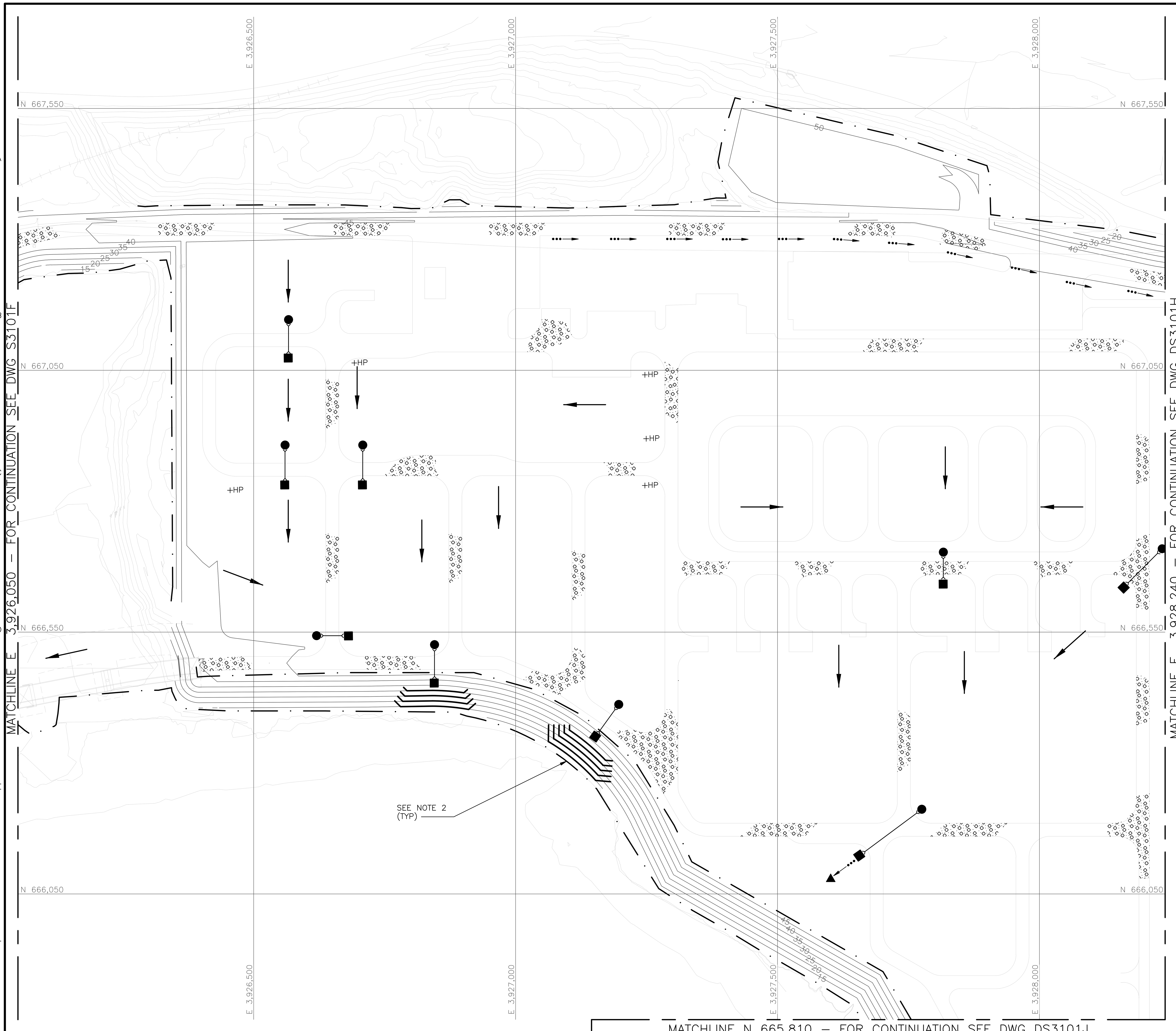

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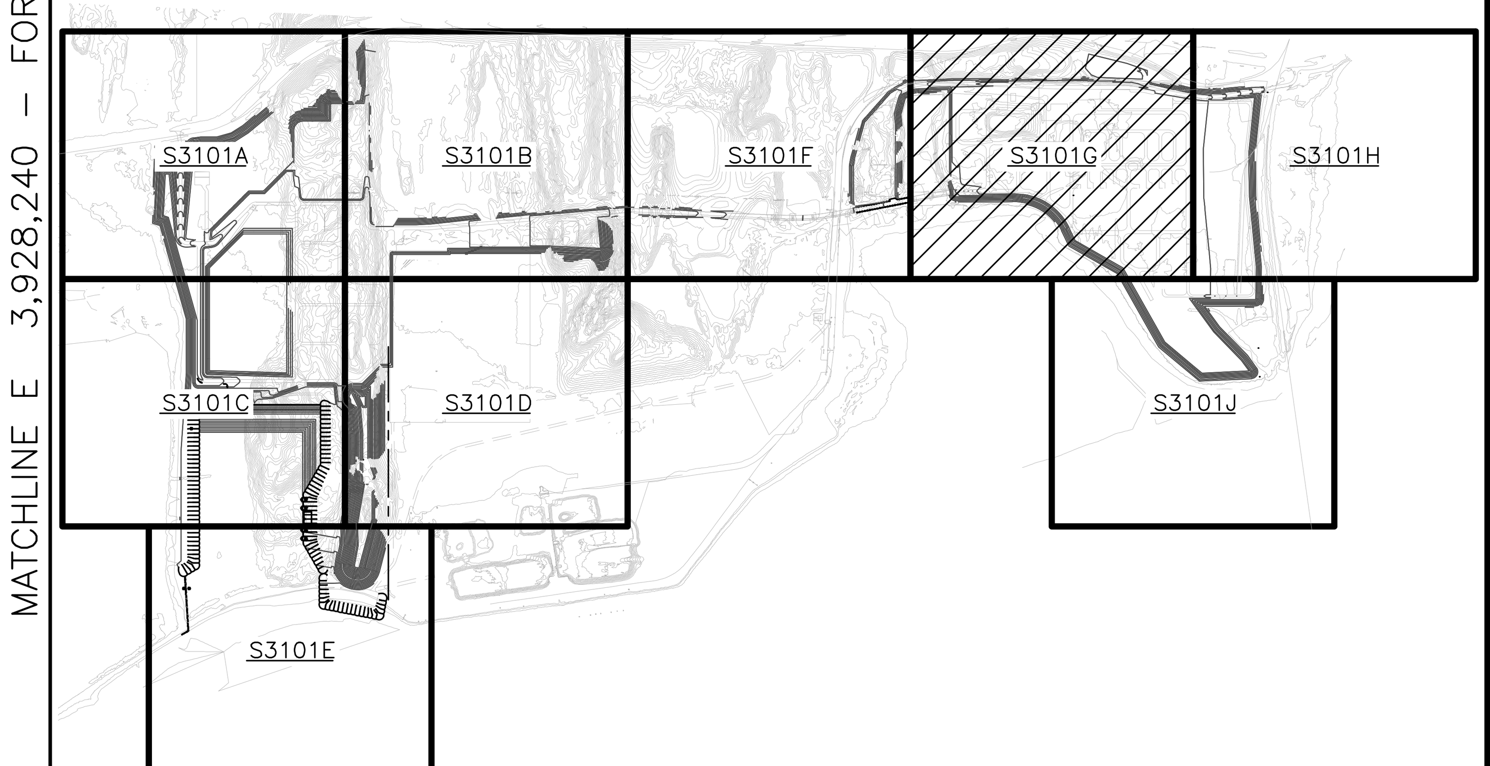

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JORDAN COVE ENERGY PROJECT, L.P.
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EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA G

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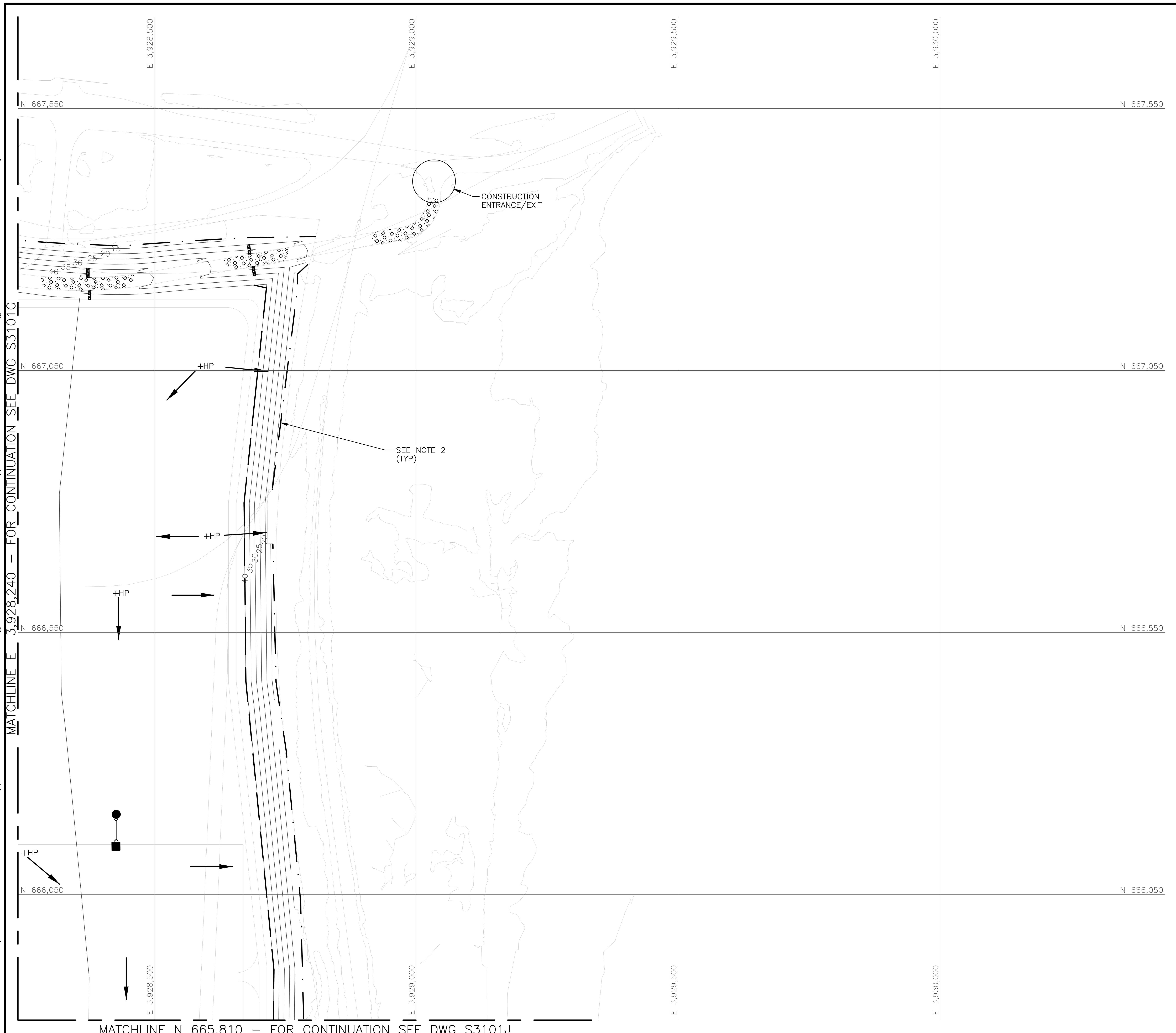

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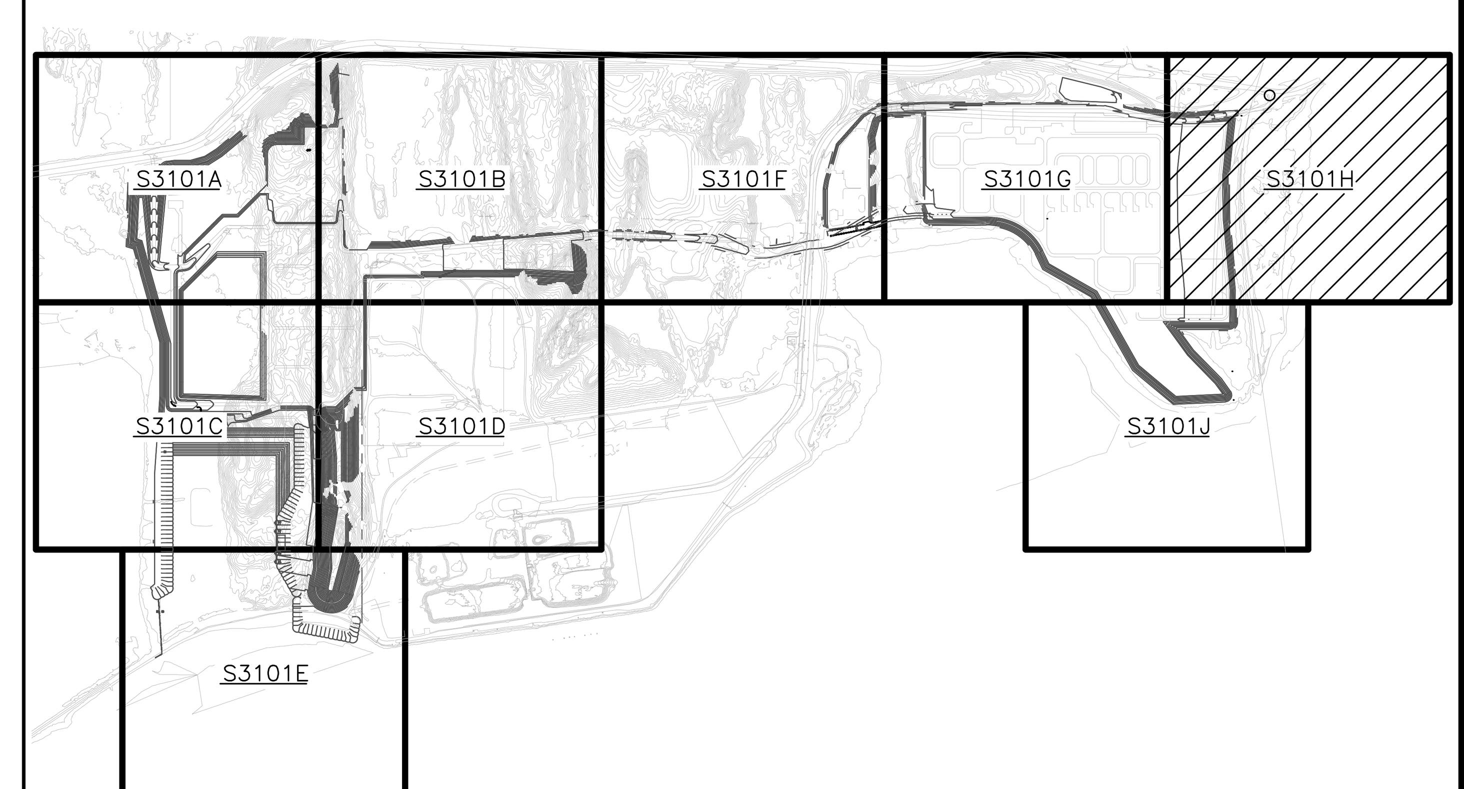

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JORDAN COVE ENERGY PROJECT, L.P.
COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA H

PROJECT | DRAWING NUMBER | REV
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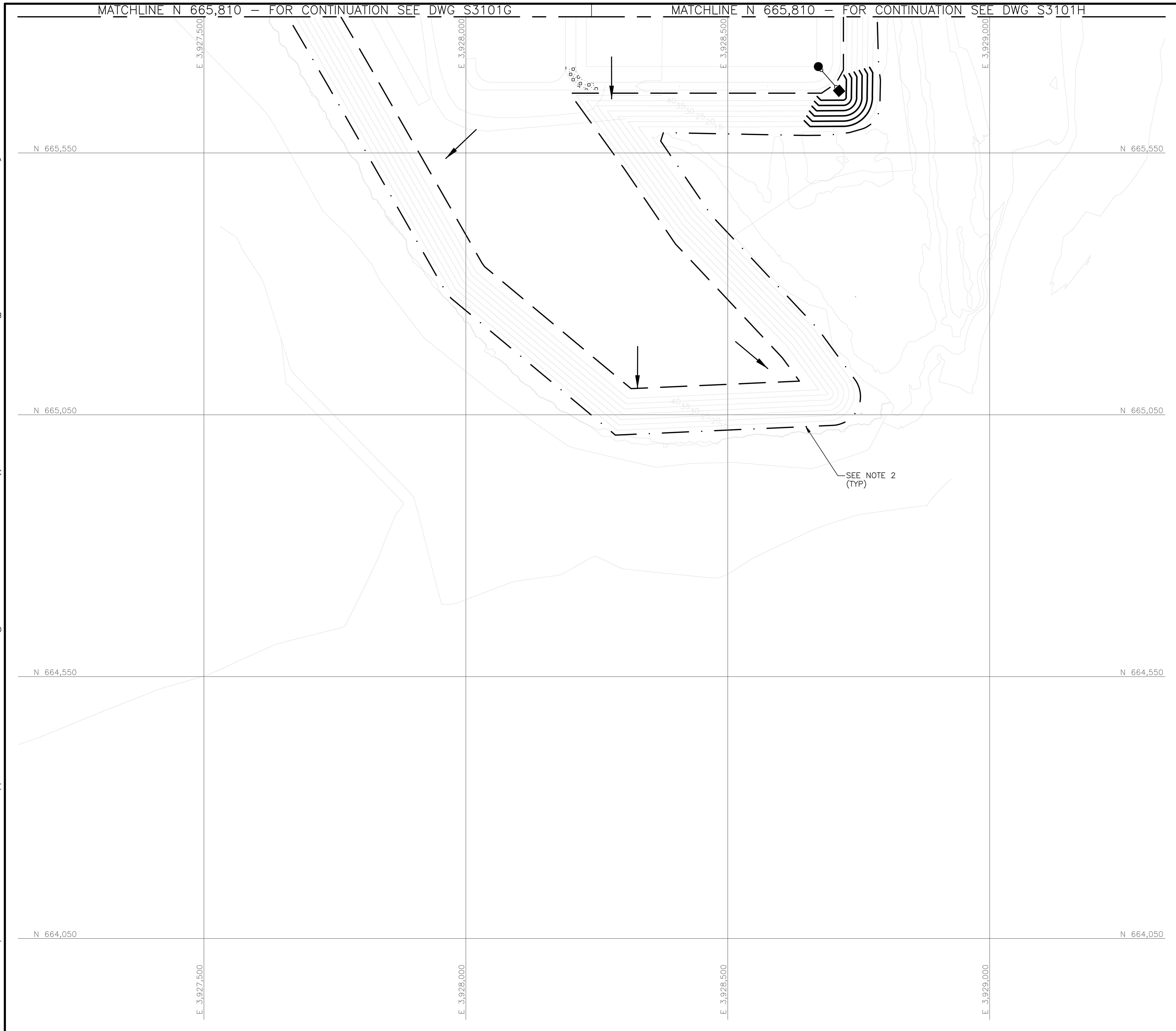

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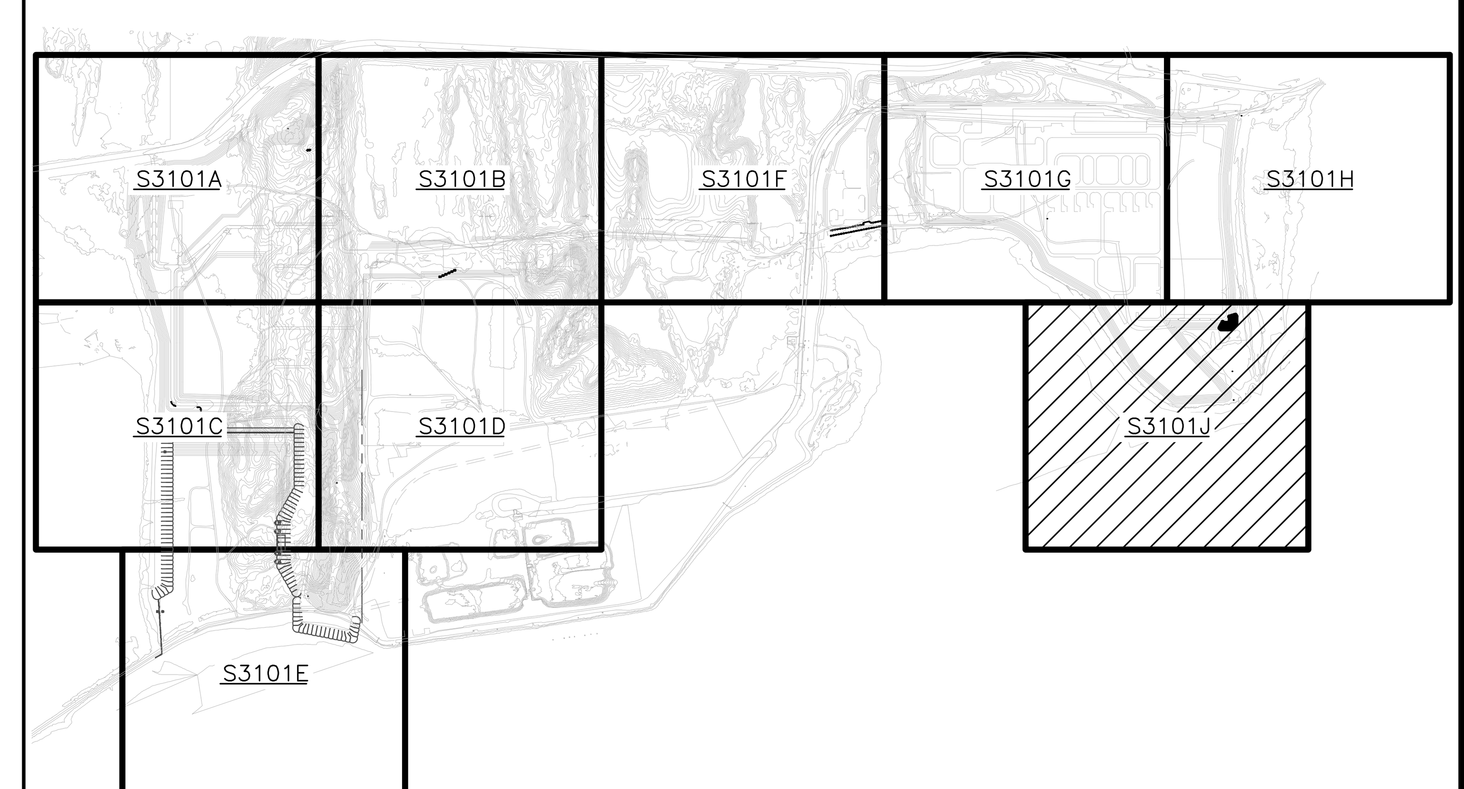

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COOS BAY, OREGON

EROSION AND SEDIMENT CONTROL PLAN
FINAL FILLING PHASE PLAN – AREA J

PROJECT | DRAWING NUMBER: 142488–0000–DS3101J | REV: C
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APPENDIX E-4

NPDES Modification Application

Jordan Cove Energy Project, L.P.

July 22, 2014

Mr. Robert Braddock, Project Manager
Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420

Ms. Mary Camarata
Oregon Department of Environmental Quality
165 East 7th Avenue, Suite 100
Eugene, Oregon 97401

Subject: Modification of National Pollutant Discharge Elimination System Industrial Wastewater Discharge Permit 101499

Dear Ms. Camarata:

Jordan Cove Energy Project, L.P. (Applicant) has prepared this letter to initiate a proposed modification of National Pollutant Discharge Elimination System (NPDES) Waste Discharge Permit 101499 (Permit 101499). The modifications are necessary to accommodate changes in waste discharge that are anticipated with the operation and maintenance of the Jordan Cove Energy Project (JCEP). The identifying information associated with Permit 101499 is provided below for reference:

Permit Number: 101499
File Number/Oregon Department of Environmental Quality (DEQ) Site ID #: 96255
U.S. Environmental Protection Agency Reference No. OR-000211-9

Applicant:

Jordan Cove Energy Project, L.P.
c/o Mr. Robert Braddock, Project Manager
125 Central Avenue, Suite 380
Coos Bay, Oregon 97420

Facility Location:

Fort Chicago Holdings II U.S. LLC
92770 Trans Pacific Lane
North Bend, Oregon 97459

INTRODUCTION

The Applicant is submitting this proposed modification of existing Permit 101499 for development of the JCEP. Permit 101499 was renewed by the Weyerhaeuser Company (Weyerhaeuser) and subsequently transferred to the ownership of Fort Chicago Holdings II U.S. LLC (a company under common control with the Applicant) that currently holds the property title to the lands that will be developed as the JCEP. The Applicant will be the owner and operator of all facilities associated with the JCEP.

The JCEP will be developed on the former Weyerhaeuser Container Board Mill industrial complex on the North Spit of Coos Bay, across the Coos Bay estuary to the north from the City of North Bend, Oregon at the address of the Facility Location (herein referred to as the Site). The Weyerhaeuser Container Board Mill was demolished in 2004. Debris from the demolition remains on the Site as an industrial waste landfill under DEQ Solid Waste Permit 1142 for the North Spit Landfill. Current activities at the Site are associated with the maintenance of the industrial waste landfill and management of the stormwater. Permit 101499 allows for the discharge of landfill leachate, residual paper mill waste, miscellaneous wash water, deflation plane stormwater, deflation plane seepage, and seepage associated with the North and South Ponds on the Site.

The proposed modification for Permit 101499 adds industrial process water, contact stormwater, and domestic sewage as post-treatment effluent to the ocean outfall. Hydrostatic test water for JCEP facilities and pipelines within the JCEP project boundary also will be included in the discharge to the ocean outfall. Some stormwater may be discharged to outfalls associated with Coos Bay during greater than 50-year storm events. All discharged waters will be treated or managed to meet DEQ requirements under modified Permit 101499 and an approved DEQ Stormwater Management Plan. The modification also removes discharge from the North and South Pond, as the ponds will be closed under the current closure plan for the North Spit Landfill (Solid Waste Permit 1142).

JORDAN COVE ENERGY PROJECT

The Applicant proposes to develop a Liquefied Natural Gas (LNG) export terminal and associated facilities at the Site. Major JCEP facility components that will contribute wastewater and stormwater under the proposed permit modification include the following:

- The South Dunes Power Plant (SDPP);
- The Gas Conditioning Facility;
- The Jordan Cove LNG Plant (LNG Plant);
- The LNG Barge Berth and Marine Terminal; and
- The Southwest Oregon Regional Safety Center (SORSC).

The Applicant also proposes to discharge wastewater generated from hydrostatic testing of facilities throughout the JCEP. These facilities include approximately 1.6 miles of 36-inch-diameter natural gas supply pipeline and 12-inch-diameter boil-off-gas pipeline, LNG storage tanks, and associated pressure vessels, boilers, steam lines, and miscellaneous systems that require pressure-testing.

Design of the JCEP facilities is currently in progress. Each facility in the JCEP will have a unique process wastewater profile and will generate stormwater runoff. Some of the facilities will generate domestic sewage. The final estimates for wastewater and stormwater flow rates and water quality are not available at the current level of design. Available preliminary rate estimates of wastewater or stormwater generation are provided in the facility descriptions in the sections that follow.

The preliminary estimate of the JCEP average day wastewater flow and discharge to the ocean outfall during operation is 3 to 4 million gallons per day. This estimate will be reassessed during final design and the development of the final NPDES permit modification with DEQ. JCEP process wastewater will be conveyed to one or more treatment systems, depending on the waste stream, and then pumped to the Port of Coos Bay Industrial Wastewater Pipeline (IWP). The IWP will discharge to the outfall to the Pacific Ocean at the existing diffuser offshore.

JCEP stormwater collection features will separate stormwater generated on the Site into two categories: 1) contact stormwater; and 2) non-contact stormwater.

Contact stormwater is defined as stormwater that has the potential to come into direct contact with equipment, lubrication oil, or any other potential industrial chemicals that might accumulate on impervious surface areas. Contact stormwater will be collected primarily from contained impervious areas (e.g., equipment pads, truck-loading areas, liquids-storage areas) for treatment and discharge to the Pacific Ocean via the IWP. In smaller areas remote from the IWP, contact stormwater will be collected and diverted to vault-treatment systems and discharged to Coos Bay.

Non-contact stormwater is defined as stormwater runoff from other impervious areas of the Site (e.g., parking lots, roads, roof drains) that does not come into contact with industrial processes. Non-contact stormwater will be collected and conveyed to infiltration swales or ponds under the provisions of a DEQ-approved Stormwater Management Plan. The Stormwater Management Plan will be provided for DEQ review and approval as an attachment to the 401 Water Quality Certificate for the JCEP and is not part of this modification.

A schematic of wastewater flow from the JCEP is presented as a line diagram on Figure 1. The major facilities of the JCEP are described in the sections that follow.

SOUTH DUNES POWER PLANT

The SDPP will be a natural-gas-fueled combined-cycle generating plant producing a nominal 420 megawatts of electrical power and will deliver process steam to the Gas Conditioning Facility as a cogeneration project. The SDPP generation station will consist of two 210-megawatt blocks of high-efficiency combined-cycle combustion turbines.

The preliminary estimate of average daily water use for the power plant facility is approximately 806,400 gallons per day, with a maximum anticipated rate of 1,031,000 gallons per day. Process wastewater generated from the SDPP will consist of filter backwash, reverse osmosis reject, steam generation blowdown water, and contact stormwater collected by the in-floor drainage system. Wastewater pre-treatment processes will be included in the SDPP system to clean process water prior to discharge to the IWP.

Anticipated domestic sewage for the SDPP is approximately 4,100 gallons per day, which will be pumped to a treatment and disinfection system before release to the IWP and ocean outfall.

Non-contact stormwater will be collected and infiltrated in vegetated swales along roads and associated with parking lots. Overflow from swales will be captured and directed to a stormwater retention pond sized to retain and infiltrate contributing Site flows up to a 50-year storm event. During a greater than 50-year storm event, the infiltration pond will fill and overflow to Coos Bay via engineered bypasses that discharge either onto the naturally vegetated deflation plane, through wetlands, or directly into Coos Bay. Non-contact stormwater will be managed under the provisions of a DEQ-approved Stormwater Management Plan.

Wash water will be generated at the SDPP during routine maintenance of the combustion turbine generator and other equipment subject to fouling. To maintain combustion turbine generator efficiency, the compressor section of the combustion turbine generator will be periodically washed to remove any fouling of the compressor blades. Wash water generated from this procedure will be collected in a holding tank for disposal. The wash water will contain detergents and other reagents necessary to aid in the cleaning and removal of substances accumulated on equipment subject to fouling. The wastewater generated from these industrial cleaning events will be transported off the Site for processing and disposal at a licensed and permitted facility, and will not be discharged under Permit 101499.

GAS CONDITIONING FACILITY

Natural gas that arrives at the JCEP will first be treated at the Gas Conditioning Facility to make it suitable for liquefaction at the LNG plant. Natural gas conditioning will use a standard amine stripping process to remove carbon dioxide and other potential trace chemicals from the natural gas. Carbon dioxide is removed prior to the liquefaction process to prevent solid carbon dioxide from forming in the LNG facility. The primary by-product from the amine stripping process is an acid gas stream that is treated by incineration to oxidize the trace sulfur and hydrocarbons that are vented out the amine stripping towers under a separate air quality permit. The treated natural gas becomes saturated with water in the process; after cooling and dehydration, all water is extracted and returned to the SDPP process to minimize water loss. No process wastewater discharges are anticipated for the natural gas conditioning process.

Solid and liquid wastes (non-wastewater) generated in the natural gas conditioning process will be collected for transport by a licensed disposal contractor to appropriate disposal or treatment facilities. The disposal frequency will vary depending on the quantity of natural gas conditioned and the quality of the interstate pipeline gas received.

Other classifications of wastewater expected to discharge from the Gas Conditioning Facility include contact stormwater, which will be routed through oil-water separators before discharge to the Port of Coos Bay IWP, and non-contact stormwater that will discharge to localized bioswales and stormwater retention and infiltration ponds. Non-contact stormwater will be handled under the provisions of the Stormwater Management Plan for the JCEP. No domestic sewage generation is anticipated at the Gas Conditioning Facility.

JORDAN COVE LIQUEFIED NATURAL GAS PLANT

The LNG Plant will consist of two identical liquefaction process trains for compressing, super cooling, and storing liquefied natural gas in two on-Site storage tanks. The process systems installed at the LNG Plant will include the following equipment:

- Natural gas liquids-removal facilities, including storage and handling;
- Liquefaction facilities, including refrigerant storage and handling;
- Cooling facilities, including convection cooling towers;
- In-tank low-pressure LNG send-out pumps to send LNG to the storage tanks; and
- Two aboveground LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters and full secondary-containment design.

Process water consumption and wastewater generation estimates for the LNG Plant have not been developed at this point in the design. All process wastewater will be treated and conveyed to the IWP for discharge to the ocean outfall. The quantity of domestic sanitary sewage is estimated to be approximately 2,560 gallons per day. Domestic sanitary sewage will be transferred by grinder pumps to a centralized 12,000-gallon septic tank for primary settling, and then pumped to a septic leach field under a separate Water Pollution Control Facility permit. Contact stormwater will be collected from contained areas and routed through oil-water-separator treatment vaults before discharge to the Port of Coos Bay IWP. Non-contact stormwater will be collected and conveyed to on-Site swales and ponds for infiltration on the Site. The non-contact stormwater will be handled under the provisions of the Stormwater Management Plan.

LNG BARGE BERTH AND MARINE TERMINAL

Activities at the Marine Terminal are focused primarily on transfer of LNG from the adjacent LNG Plant to docked marine vessels. Facilities include a single barge berth, terminal facilities for loading tanker ships, LNG pipe conveyance facilities, vapor-recovery equipment, a tow vessel terminal, and emergency support equipment associated with loading activities.

Wastewater quantity estimates have not been completed at this time, but are assumed to include contact stormwater, non-contact stormwater, and domestic sewage. Contact stormwater generated from contained areas within the terminal will be collected and conveyed through oil-water separators to the IWP under Permit 101499. Non-contact stormwater will be collected and conveyed to on-Site swales or ponds for water-quality treatment and infiltration under the Stormwater Management Plan. Some stormwater catchments in this area, which may include both contact and non-contact stormwater, will be directed to vault-system stormwater treatment facilities. Each potential stormwater discharge directed to vault-based treatment systems will be characterized and treated to meet all DEQ requirements. Following treatment, this stormwater may discharge directly to Coos Bay. Domestic sewage will be captured in a holding tank and occasionally pumped out for treatment at the LNG septic system, the SDPP domestic sewage treatment facility, or a permitted off-Site facility.

SOUTHWEST OREGON REGIONAL SAFETY CENTER

The SORSC will be a full-time professionally staffed fire station with crews dedicated to the LNG Plant. Additional uses are planned for the SORSC and will include:

- Offices and a substation for the Coos County Sheriff;
- Offices for the Port of Coos Bay;
- Offices for the U.S. Coast Guard; and
- Training rooms and an outdoor training area.

Anticipated wastewater sources and quantities have not been fully developed at this time, but are expected to include domestic sewage and stormwater discharges. Domestic sewage discharges are estimated at 2,000 gallons per day and will be pumped to the SDPP domestic sewage treatment facility for treatment, conveyed to the IWP, and discharged to the ocean outfall. Contact stormwater from the SORSC will run through an oil-water separator and will be conveyed to the IWP for discharge at the ocean outfall. Non-contact stormwater will be collected and conveyed to on-Site swales and ponds for water-quality treatment and infiltration under the Stormwater Management Plan proposed for the JCEP.

HYDROSTATIC TESTING—PIPELINES AND FACILITIES

Hydrostatic testing of pipelines, tanks, pressure vessels, and other processing equipment is anticipated throughout the JCEP facilities. Wastewater generated from hydrostatic testing of pressurized systems will be contained and managed under this Permit 101499 modification. The quantity and quality of wastewater generated by hydrostatic testing has not been estimated for the JCEP. The Applicant proposes to manage the discharge of hydrostatic testing wastewater by on-Site infiltration, or collection and conveyance to the IWP and the ocean outfall. The final disposition of hydrostatic testing wastewater and identification of any outfalls will be developed for DEQ review and approval as a modification to Permit 101499.

CLOSING

The Applicant looks forward to working with DEQ to complete this modification of Permit 101499. Please direct any questions regarding the current understanding of the design and wastewater generation to the undersigned at the JCEP offices in Coos Bay at the address above, or by telephone at Jordan Cove Energy Project L.P.: (541) 266-7510.

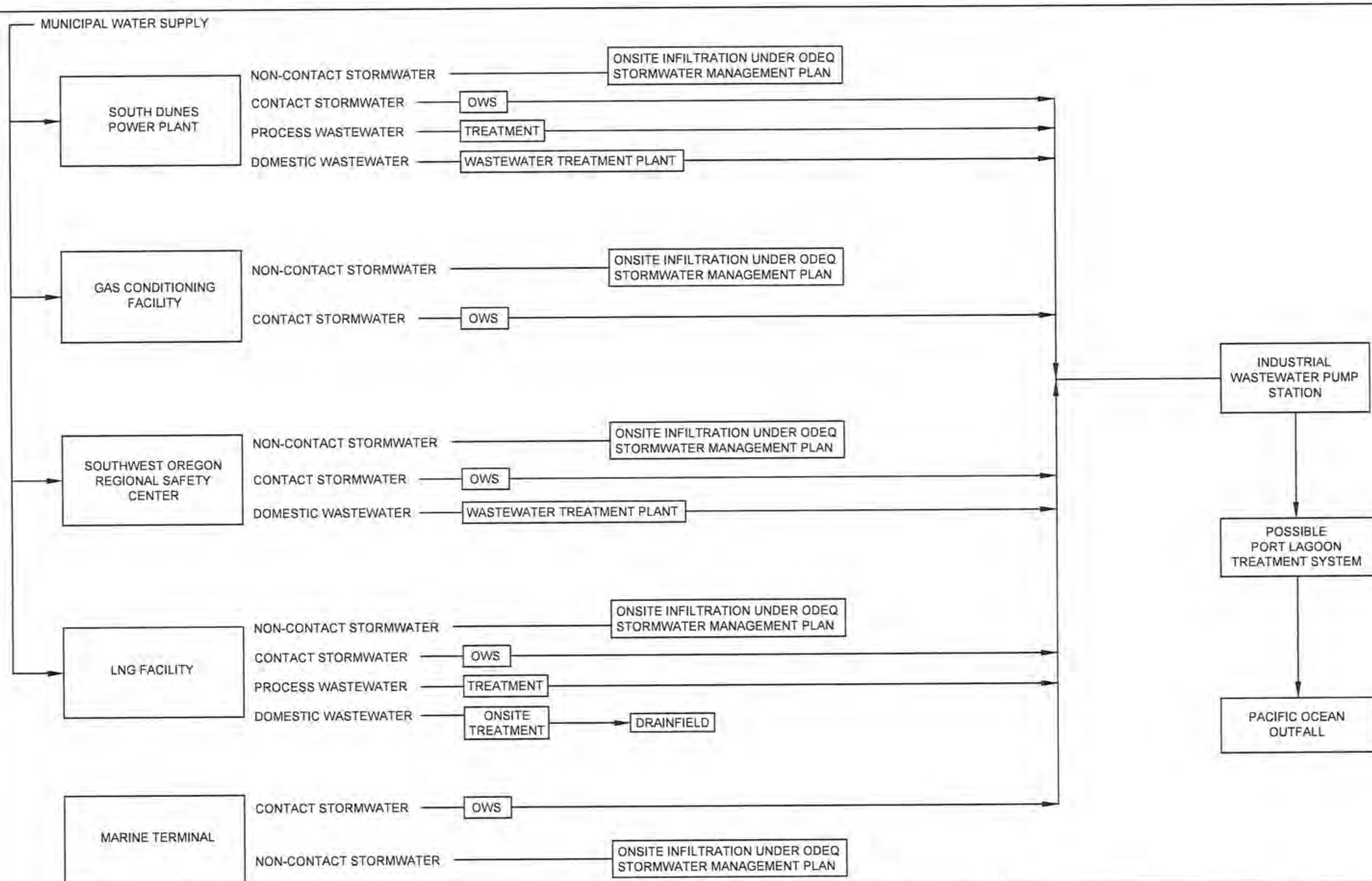
Sincerely,

Robert L Braddock

Robert Braddock
Project Manager
Jordan Cove Energy Project L.P.

Attachment: Figure 1, *Wastewater Line Diagram*

cc: Mr. Tim McFetridge, Oregon Department of Environmental Quality
Mr. Bob Long, R.G., L.H.G., CWRE, Farallon Consulting, L.L.C.
Mr. Jeff Hamlin, P.E., Farallon Consulting, L.L.C.
Mr. Mark Denning, SHN Engineers and Geologists Inc.



LEGEND

OWS OIL-WATER SEPARATOR

Jordan Cove Energy Project, L.P.

FARALLON CONSULTING
975 5th Avenue Northwest
Issaquah, WA 98027

FIGURE 1

WASTEWATER LINE DIAGRAM
JORDON COVE ENERGY PROJECT

FARALLON PN:1265–002

Drawn By: DEW	Checked By: JH	Date:7/18/14	Disk Reference: 1265002

APPENDIX E-5

Letter from the Department of Environmental Quality

Oregon
John A. Kitzhaber, MD, Governor

Department of Environmental Quality
Western Region Eugene Office
165 East 7th Avenue, Suite 100
Eugene, OR 97401
(541) 686-7838
FAX (541) 686-7551
TTY 711

September 16, 2014

Andrea Goodwin
Siting Analyst
Oregon Department of Energy
625 Marion Street NE
Salem, OR 97301

Re: South Dunes Power Plant Site Certificate Application

Dear Ms. Goodwin:

In accordance with OAR 345-021-0000(7) the Department of Environmental Quality ("DEQ") is providing the following information with respect to the South Dunes Power Plant environmental applications.

Federally-delegated Prevention of Significant Deterioration ("PSD") and Air Contaminant Discharge Permit ("ACDP")

- The application was received on March 29, 2013.
- DEQ has not identified any additional information needs at this time, but we may request additional information at any time during the permit process.
- The time to issue this type of permit ranges from 10 to 18 months from the time the application was deemed administratively complete. The application was deemed complete on December 18, 2013. DEQ's best estimate is the spring 2015; however, there are many factors which may affect the actual issuance date and the permit may be issued earlier or later.

Federally-delegated Title V Operating Permit

- The application cannot be submitted until the facility has been in operation for one year.
- The time to issue this type of permit ranges from 6 to 12 from the time the application is received.

Federally-delegated National Pollutant Discharge Elimination System ("NPDES") Stormwater Discharge 1200-C Permit

- The application was received on June 23, 2014.
- The application was deemed administratively incomplete for the following reasons: the application fee was not submitted; there was no signature on the application; there were no hard copies of drawings, erosion and sediment control plans, or site vicinity maps; there was no land use compatibility statement; and there was no erosion control inspector listed.
- The time to issue this type of permit ranges from 2 to 4 months from the time the application is deemed administratively complete. However, there are many factors which may affect the actual issuance date and the permit may be issued earlier or later.

Federally-delegated National Pollutant Discharge Elimination System ("NPDES") Permit renewal and addendum to renewal application to reflect the new conditions regarding wastewater

- The wastewater renewal application was received on July 28, 2010 and the addendum was received on July 22, 2014. The addendum was submitted to include industrial process water, contact stormwater, domestic sewage, and hydrostatic water testing discharge.
- DEQ has not begun drafting the permit. It takes about 6 months to issue this type of permit. We are scheduled to begin drafting the permit in the summer of 2015. During the permit process, we may request additional information.

Federally-delegated Section 401 Water Quality Certification (WQC) for removal-fill (includes a post-construction storm water management plan)

- The application was received on October 11, 2013.
- Because DEQ's 401 WQC is a part of a federal license or permit, DEQ's one year timeframe for review will begin when those federal agencies request a 401 WQC from DEQ. As of the date of this letter, there has been no formal request from a federal agency for a 401 WQC. We anticipate that the US Army Corps of Engineers will make such as request when the Federal Energy Regulatory Commission (FERC) issues their draft environmental impact statement (EIS).
- DEQ 401 staff have been fully engaged in pre-application activities, such as participating in several internal agency meetings, and coordinating with our state and federal agency partners.

Federally-delegated Resource Conservation and Recovery Act (RCRA) Site Identification Number for hazardous waste activities

- The application was received on September 1, 2014.

- The application was deemed administratively incomplete for the following reasons: the application fee was not submitted and there was no signature on the application.
- The time to issue hazardous waste identification number is about 10 days from the time the application is deemed administratively complete. Annual reporting is required when the facility begins to generate hazardous waste.

If you have any questions regarding the above permits, please contact me at (541) 687-7435.

Sincerely,

Mary Camarata

Mary Camarata
Project Coordinator

ec: Meagan Masten, Perkins Coie
Juna Hickner, DLCD

APPENDIX E-6

Federal Aviation Administration Notices of Proposed Construction

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243965-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 2L - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1748-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 ATTACH 5 JCEP Loc...
Public Comments:	None		07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 JCEP FAA Form 201...

Project Documents:
None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	2L - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 25' 59.60" N
Longitude:	124° 15' 44.68" W
Horizontal Datum:	NAD83
Site Elevation (SE):	33 (nearest foot)
Structure Height (AGL):	106 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

← Previous Back to Search Result Next →

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243966-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 2R - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1749-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 ATTACH 5 JCEP Loc... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 JCEP FAA Form 201...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	2R - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 25' 59.36" N
Longitude:	124° 15' 44.57" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	96 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

← Previous Back to Search Result Next →

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243967-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 3 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1750-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 JCEP FAA Form 201...
Public Comments:	None		07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	3 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 0.02" N
Longitude:	124° 15' 38.57" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	86 (nearest foot)
Current Height (AGL): *** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): *** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): *** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243969-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 4 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1751-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 JCEP FAA Form 201...
Public Comments:	None		07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

****For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.***

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	4 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 0.56'' N
Longitude:	124° 15' 32.53'' W
Horizontal Datum:	NAD83
Site Elevation (SE):	50 (nearest foot)
Structure Height (AGL):	86 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest City:	North Bend and Coos Bay
Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243971-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 5 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1752-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 JCEP FAA Form 201...
Public Comments:	None		07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	5 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 1.08" N
Longitude:	124° 15' 26.68" W
Horizontal Datum:	NAD83
Site Elevation (SE):	53 (nearest foot)
Structure Height (AGL):	86 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243973-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 6 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1753-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201...
			07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary **:**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

***For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.**

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	6 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 1.53" N
Longitude:	124° 15' 20.20" W
Horizontal Datum:	NAD83
Site Elevation (SE):	60 (nearest foot)
Structure Height (AGL):	81 (nearest foot)
Current Height (AGL): ** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal*	(nearest foot)
Max Operating Height (AGL): ** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.*	(nearest foot)
Nacelle Height (AGL): ** For Wind Turbines 500ft AGL or greater*	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other **:**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other **:**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243974-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 7 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1754-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 JCEP FAA Form 201...
Public Comments:	None		07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	7 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 1.59" N
Longitude:	124° 15' 13.67" W
Horizontal Datum:	NAD83
Site Elevation (SE):	53 (nearest foot)
Structure Height (AGL):	81 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243975-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 8 - SUSPENSION

Show Project Summary

Case Status

ASN:	2013-ANM-1755-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	None
		Documents:	07/10/2013 JCEP FAA Form 201...
Public Comments:	None		07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	8 - SUSPENSION
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 1.65" N
Longitude:	124° 15' 7.15" W
Horizontal Datum:	NAD83
Site Elevation (SE):	32 (nearest foot)
Structure Height (AGL):	96 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243976-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 9L - DEADEND

Show Project Summary

Case Status

ASN: 2013-ANM-1756-OE
Status: Work In Progress
Public Comments: None

Date Accepted: 07/19/2013
Date Determined:
Letters: 01/09/2014 ADD
Documents:
07/10/2013 JCEP FAA Form 201...
07/10/2013 ATTACH 1 JCEP Ove...
07/10/2013 ATTACH 4A JCEP Hi...
07/10/2013 ATTACH 4B JCEP Hi...
07/10/2013 ATTACH 5 JCEP Loc...

Project Documents:
None

Construction / Alteration Information

Notice Of: Construction
Duration: Permanent
***if Temporary* :** Months: Days:
Work Schedule - Start: 10/01/2014
Work Schedule - End: 12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type: Transmission Line
Structure Name: 9L - DEADEND
NOTAM Number:
FCC Number:
Prior ASN:

Structure Details

Latitude:	43° 26' 2.29" N
Longitude:	124° 15' 0.01" W
Horizontal Datum:	NAD83
Site Elevation (SE):	21 (nearest foot)
Structure Height (AGL):	126 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243977-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 9R - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1757-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	9R - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.05" N
Longitude:	124° 14' 59.93" W
Horizontal Datum:	NAD83
Site Elevation (SE):	25 (nearest foot)
Structure Height (AGL):	126 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243978-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 10L - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1758-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201...
			07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	10L - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 3.67" N
Longitude:	124° 14' 54.65" W
Horizontal Datum:	NAD83
Site Elevation (SE):	32 (nearest foot)
Structure Height (AGL):	120 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243979-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 10R - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1759-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201...
			07/10/2013 ATTACH 1 JCEP Ove...
			07/10/2013 ATTACH 4A JCEP Hi...
			07/10/2013 ATTACH 4B JCEP Hi...
			07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	10R - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 3.48" N
Longitude:	124° 14' 54.43" W
Horizontal Datum:	NAD83
Site Elevation (SE):	29 (nearest foot)
Structure Height (AGL):	120 (nearest foot)
Current Height (AGL): ** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal*	(nearest foot)
Max Operating Height (AGL): ** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.*	(nearest foot)
Nacelle Height (AGL): ** For Wind Turbines 500ft AGL or greater*	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243980-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 11L - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1761-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	11L - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 10.62" N
Longitude:	124° 14' 49.28" W
Horizontal Datum:	NAD83
Site Elevation (SE):	44 (nearest foot)
Structure Height (AGL):	111 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243982-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 11R - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1762-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 5 JCEP Loc... Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	11R - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 10.41" N
Longitude:	124° 14' 49.11" W
Horizontal Datum:	NAD83
Site Elevation (SE):	44 (nearest foot)
Structure Height (AGL):	111 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243983-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 12 - SUSPENSION

Show Project Summary

Case Status

ASN: 2013-ANM-1763-OE

Status: Work In Progress

Public Comments: None

Date Accepted: 07/19/2013

Date Determined:

Letters: 01/09/2014 ADD

Documents:
07/10/2013 JCEP FAA Form 201...
07/10/2013 ATTACH 1 JCEP Ove...
07/10/2013 ATTACH 4A JCEP Hi...
07/10/2013 ATTACH 4B JCEP Hi...
07/10/2013 ATTACH 5 JCEP Loc...

Project Documents:
None

Construction / Alteration Information

Notice Of: Construction

Duration: Permanent

***if Temporary* :** Months: Days:

Work Schedule - Start: 10/01/2014

Work Schedule - End: 12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type: Transmission Line

Structure Name: 12 - SUSPENSION

NOTAM Number:

FCC Number:

Prior ASN:

Structure Details

Latitude: 43° 26' 10.43" N

Longitude: 124° 14' 40.73" W

Horizontal Datum: NAD83

Site Elevation (SE): 47 (nearest foot)

Structure Height (AGL): 116 (nearest foot)

Current Height (AGL): (nearest foot)
**** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***

Max Operating Height (AGL): (nearest foot)
**** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***

Nacelle Height (AGL): (nearest foot)
**** For Wind Turbines 500ft AGL or greater***

Requested Marking/Lighting: Dual-red and high intensity white

***Other* :**

Recommended Marking/Lighting:

Current Marking/Lighting: N/A Proposed Structure

***Other* :**

Nearest City: North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243984-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 13L - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1764-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	13L - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 9.97" N
Longitude:	124° 14' 32.22" W
Horizontal Datum:	NAD83
Site Elevation (SE):	47 (nearest foot)
Structure Height (AGL):	101 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000243985-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : 13R - DEADEND

Show Project Summary

Case Status

ASN:	2013-ANM-1765-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/10/2013 JCEP FAA Form 201... 07/10/2013 ATTACH 1 JCEP Ove... 07/10/2013 ATTACH 4A JCEP Hi... 07/10/2013 ATTACH 4B JCEP Hi... 07/10/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Transmission Line
Structure Name:	13R - DEADEND
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 9.70" N
Longitude:	124° 14' 32.62" W
Horizontal Datum:	NAD83
Site Elevation (SE):	47 (nearest foot)
Structure Height (AGL):	101 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	Jordan Cove Energy Project (JCEP) proposes to build an LNG export terminal at the location shown in ATTACHMENT 1&2. LNG will arrive by pipeline, liquefied, and then be stored in one of the two LNG storage tanks. Power will be transmitted via elevated high voltage power poles. See ATTACHMENT 4A&4B.

← Previous Back to Search Result Next →

Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000244821-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 2

Show Project Summary

Case Status

ASN:	2013-ANM-1769-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/18/2013 JCEP Overall with... 07/18/2013 JCEP FAA Form 201... 07/18/2013 JCEP FAA PERMIT A... 07/18/2013 ATTACH 1 JCEP Ove... 07/18/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Stack
Structure Name:	TURB/HRSG STACK 2
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.51" N
Longitude:	124° 14' 34.36" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000244825-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 3

Show Project Summary

Case Status

ASN:	2013-ANM-1770-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/18/2013 JCEP FAA Form 201... 07/18/2013 JCEP Overall with... 07/18/2013 JCEP FAA PERMIT A... 07/18/2013 ATTACH 1 JCEP Ove... 07/18/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Tower
Structure Name:	TURB/HRSG STACK 3
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.55" N
Longitude:	124° 14' 33.01" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000244826-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 1

Show Project Summary

Case Status

ASN:	2013-ANM-1771-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	
		Letters:	01/09/2014 ADD
Public Comments:	None	**Documents:**	07/18/2013 JCEP FAA Form 201... 07/18/2013 JCEP Overall with... 07/18/2013 JCEP FAA PERMIT A... 07/18/2013 ATTACH 1 JCEP Ove... 07/18/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
if Temporary :	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Stack
Structure Name:	TURB/HRSG STACK 1
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.47'' N
Longitude:	124° 14' 35.72'' W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
Other :	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
Other :	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000244988-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 4

Show Project Summary

Case Status

ASN: 2013-ANM-1772-OE
Status: Work In Progress
Public Comments: None

Date Accepted: 07/19/2013
Date Determined:
Letters: 01/09/2014 ADD
Documents:
07/18/2013 JCEP FAA Form 201...
07/18/2013 JCEP Overall with...
07/18/2013 JCEP FAA PERMIT A...
07/18/2013 ATTACH 1 JCEP Ove...
07/18/2013 ATTACH 5 JCEP Loc...

Project Documents:
None

Construction / Alteration Information

Notice Of: Construction
Duration: Permanent
***if Temporary* :** Months: Days:
Work Schedule - Start: 10/01/2014
Work Schedule - End: 12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type: Stack
Structure Name: TURB/HRSG STACK 4
NOTAM Number:
FCC Number:
Prior ASN:

Structure Details

Latitude:	43° 26' 2.67" N
Longitude:	124° 14' 29.54" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure
***Other* :**	
Nearest City:	North Bend and Coos Bay

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000244998-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 5

Show Project Summary

Case Status

ASN:	2013-ANM-1773-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	12/27/2013
		Letters:	01/09/2014 ADD
			12/27/2013 TER
Public Comments:	None		09/27/2013 NPH
		Documents:	07/18/2013 JCEP FAA Form 201...
			07/18/2013 JCEP Overall with...
			07/18/2013 JCEP FAA PERMIT A...
			07/18/2013 ATTACH 1 JCEP Ove...
			07/18/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Stack
Structure Name:	TURB/HRSG STACK 5
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.71" N
Longitude:	124° 14' 28.19" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

***Other* :**	
Nearest City:	North Bend and Coos Bay
Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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Federal Aviation Administration

« OE/AAA

Notice of Proposed Construction or Alteration - Off Airport

Project Name: JORDA-000245001-13 **Sponsor:** Jordan Cove Energy Project

Details for Case : TURB/HRSG STACK 6

Show Project Summary

Case Status

ASN:	2013-ANM-1774-OE	**Date Accepted:**	07/19/2013
Status:	Work In Progress	**Date Determined:**	12/27/2013
		Letters:	01/09/2014 ADD
			12/27/2013 TER
Public Comments:	None		09/27/2013 NPH
		Documents:	07/18/2013 JCEP FAA Form 201...
			07/18/2013 JCEP Overall with...
			07/18/2013 JCEP FAA PERMIT A...
			07/18/2013 ATTACH 1 JCEP Ove...
			07/18/2013 ATTACH 5 JCEP Loc...
			Project Documents: None

Construction / Alteration Information

Notice Of:	Construction
Duration:	Permanent
***if Temporary* :**	Months: Days:
Work Schedule - Start:	10/01/2014
Work Schedule - End:	12/01/2018

For temporary cranes-Does the permanent structure require separate notice to the FAA? To find out, use the Notice Criteria Tool. If separate notice is required, please ensure it is filed. If it is not filed, please state the reason in the Description of Proposal.

State Filing:

Structure Summary

Structure Type:	Stack
Structure Name:	TURB/HRSG STACK 6
NOTAM Number:	
FCC Number:	
Prior ASN:	

Structure Details

Latitude:	43° 26' 2.76" N
Longitude:	124° 14' 26.84" W
Horizontal Datum:	NAD83
Site Elevation (SE):	46 (nearest foot)
Structure Height (AGL):	119 (nearest foot)
Current Height (AGL): **** For notice of alteration or existing provide the current AGL height of the existing structure. Include details in the Description of Proposal***	(nearest foot)
Max Operating Height (AGL): **** For aeronautical study of a crane or construction equipment the maximum height should be listed above as the Structure Height (AGL). Additionally, provide the maximum operating height to avoid delays if impacts are identified that require negotiation to a reduced height. If the Structure Height and maximum operating height are the same enter the same value in both fields.***	(nearest foot)
Nacelle Height (AGL): **** For Wind Turbines 500ft AGL or greater***	(nearest foot)
Requested Marking/Lighting:	Dual-red and high intensity white
***Other* :**	
Recommended Marking/Lighting:	
Current Marking/Lighting:	N/A Proposed Structure

Common Frequency Bands

Low Freq	High Freq	Freq Unit	ERP	ERP Unit

Specific Frequencies

***Other* :**	
Nearest City:	North Bend and Coos Bay
Nearest State:	Oregon
Description of Location: ***On the Project Summary page upload any certified survey.***	The proposed site for the Jordan Cove LNG project is approximately Mile 7.5 of the Coos Bay federally maintained navigation channel and is located slightly northwest and across Coos Bay from the Southwest Oregon Regional Airport. The South Dunes Power Plant is also associated with this project.
Description of Proposal:	The South Dunes PP is a 420 MW NG fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

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APPENDIX E-7

Federal Aviation Administration No Hazard Determinations

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1748-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 2L - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-25-59.60N NAD 83
Longitude:	124-15-44.68W
Heights:	33 feet site elevation (SE)
	106 feet above ground level (AGL)
	139 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

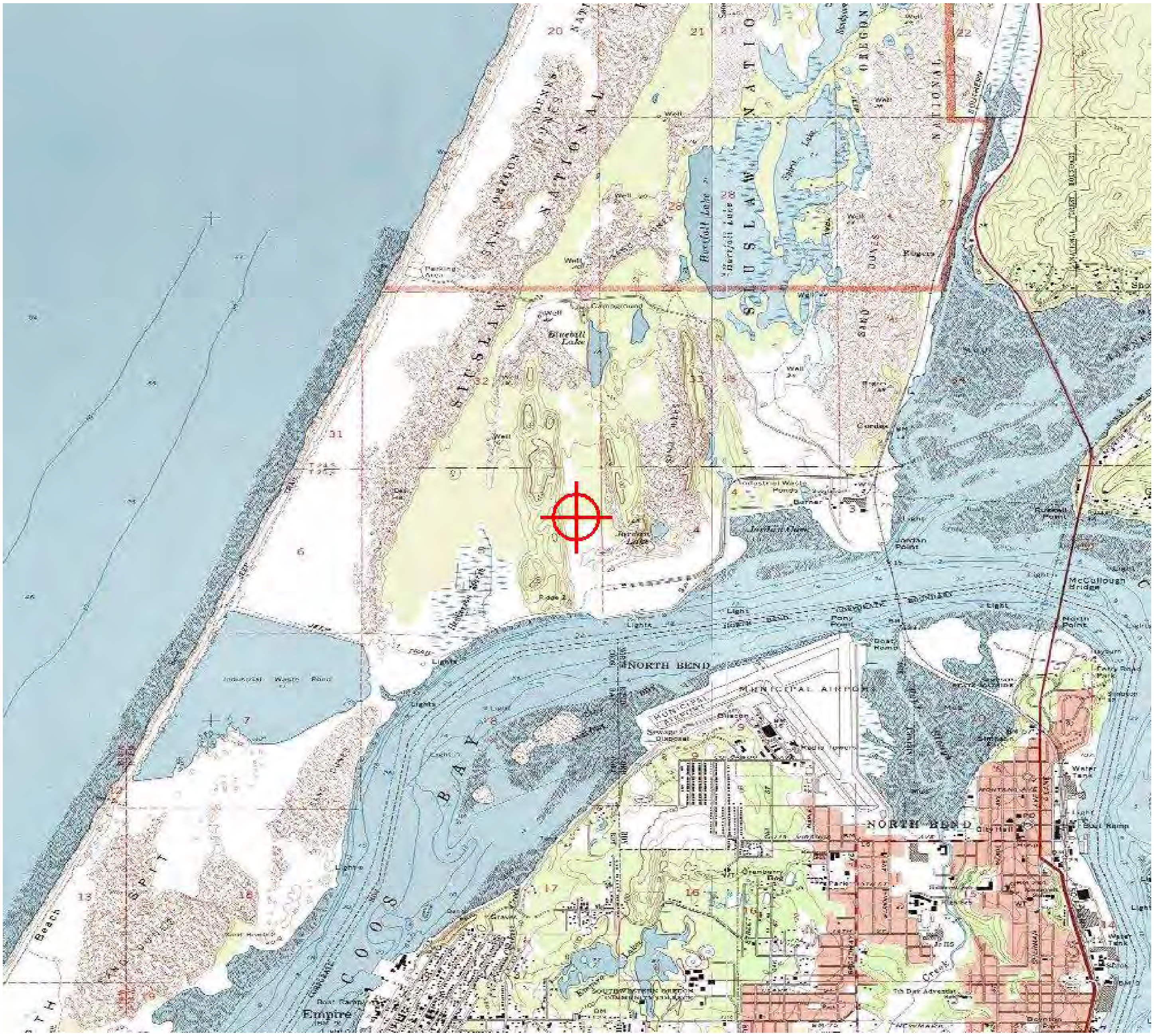
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1748-OE.

Signature Control No: 194337948-224817238 (DNE)

Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1748-OE



Sectional Map for ASN 2013-ANM-1748-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1749-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 2R - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-25-59.36N NAD 83
Longitude:	124-15-44.57W
Heights:	46 feet site elevation (SE) 96 feet above ground level (AGL) 142 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

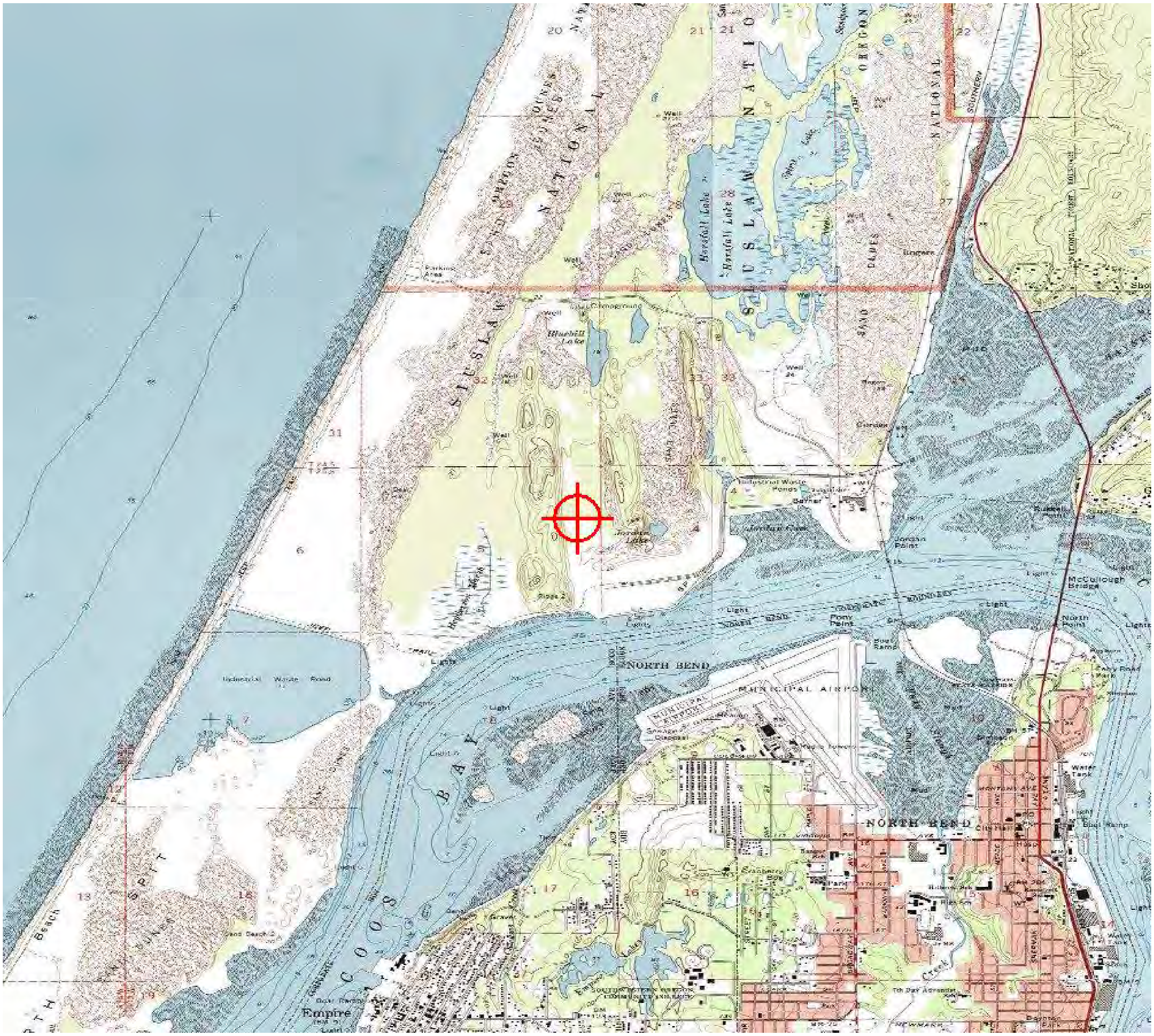
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1749-OE.

Signature Control No: 194337956-224817250 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1749-OE



Sectional Map for ASN 2013-ANM-1749-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1750-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 3 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-00.02N NAD 83
Longitude:	124-15-38.57W
Heights:	46 feet site elevation (SE)
	86 feet above ground level (AGL)
	132 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

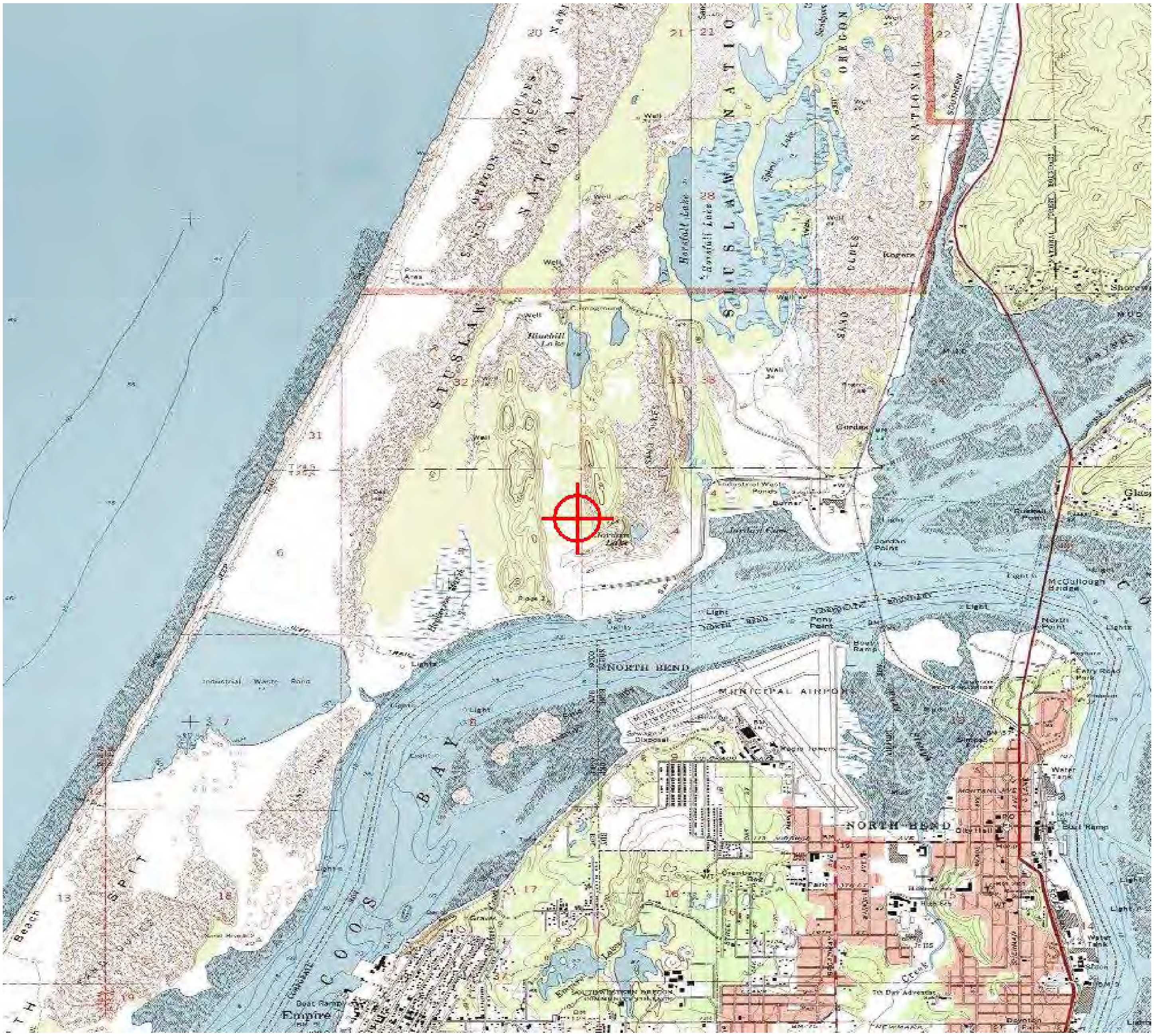
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1750-OE.

Signature Control No: 194337969-224817237 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1750-OE



Sectional Map for ASN 2013-ANM-1750-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1751-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 4 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-00.56N NAD 83
Longitude:	124-15-32.53W
Heights:	50 feet site elevation (SE)
	86 feet above ground level (AGL)
	136 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

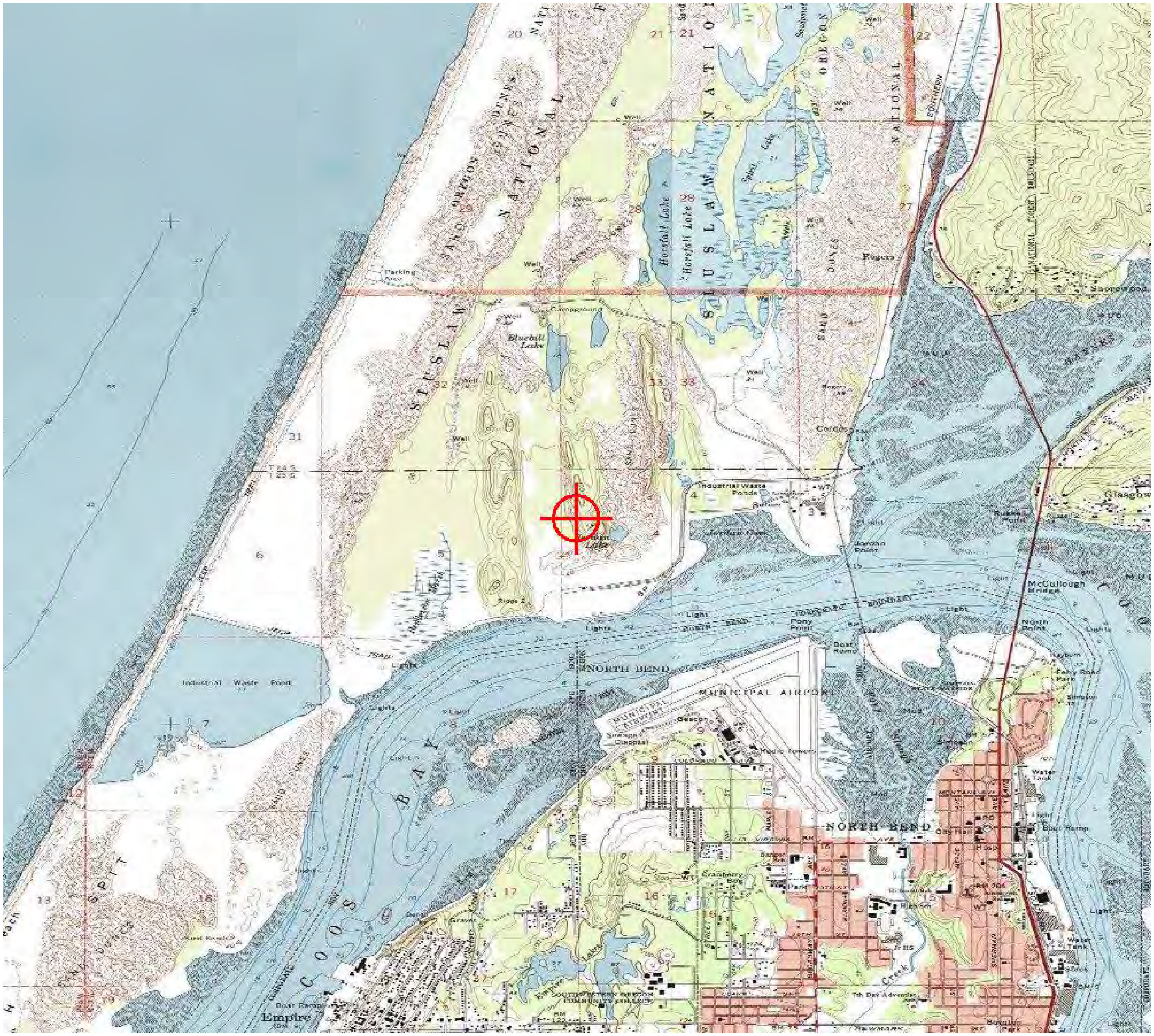
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1751-OE.

Signature Control No: 194337978-224817241 (DNE)

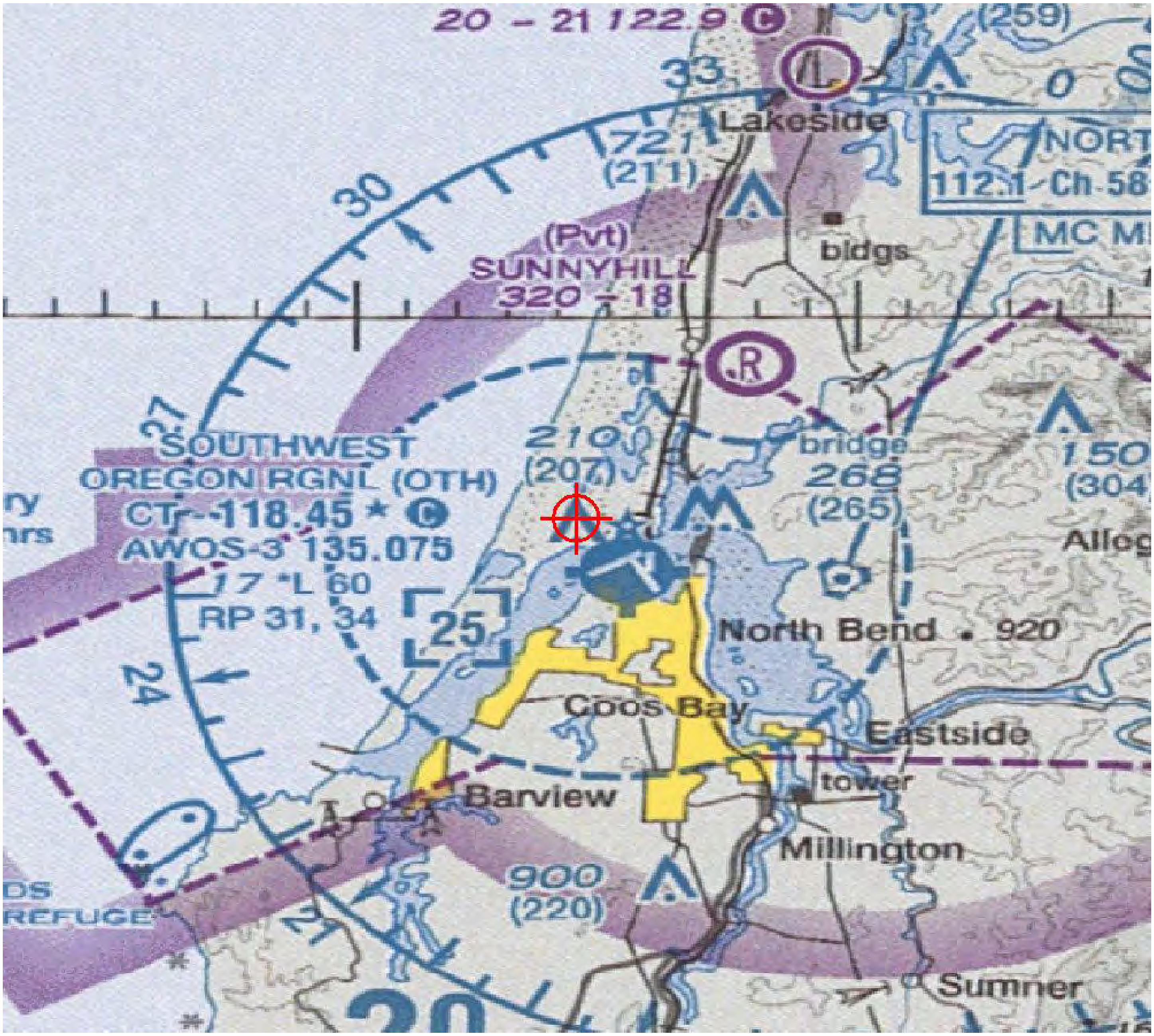
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1751-OE



Sectional Map for ASN 2013-ANM-1751-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1752-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 5 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-01.08N NAD 83
Longitude:	124-15-26.68W
Heights:	53 feet site elevation (SE)
	86 feet above ground level (AGL)
	139 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

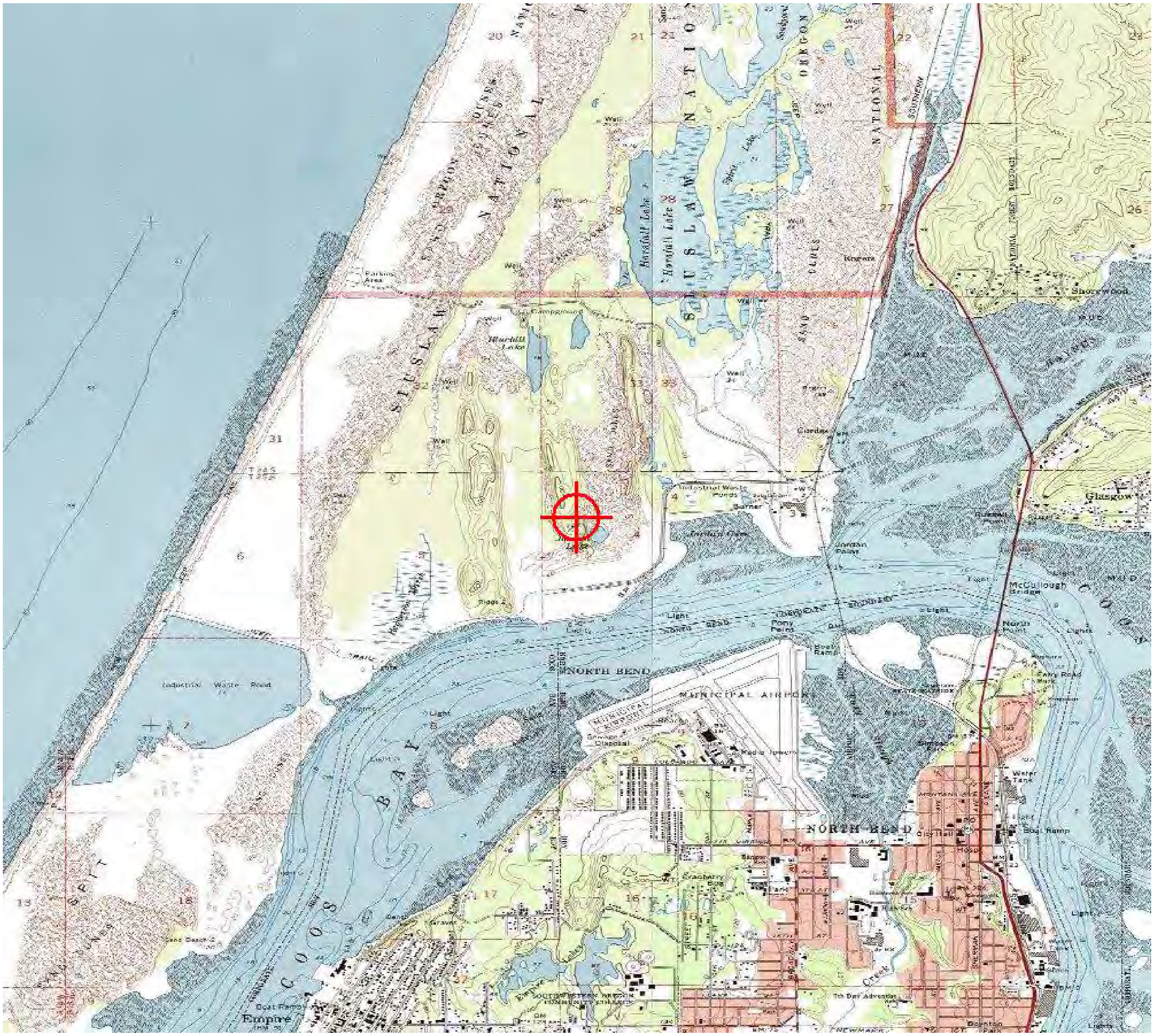
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1752-OE.

Signature Control No: 194337989-224817235 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1752-OE



Sectional Map for ASN 2013-ANM-1752-OE

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Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1753-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 6 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-01.53N NAD 83
Longitude:	124-15-20.20W
Heights:	60 feet site elevation (SE)
	81 feet above ground level (AGL)
	141 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

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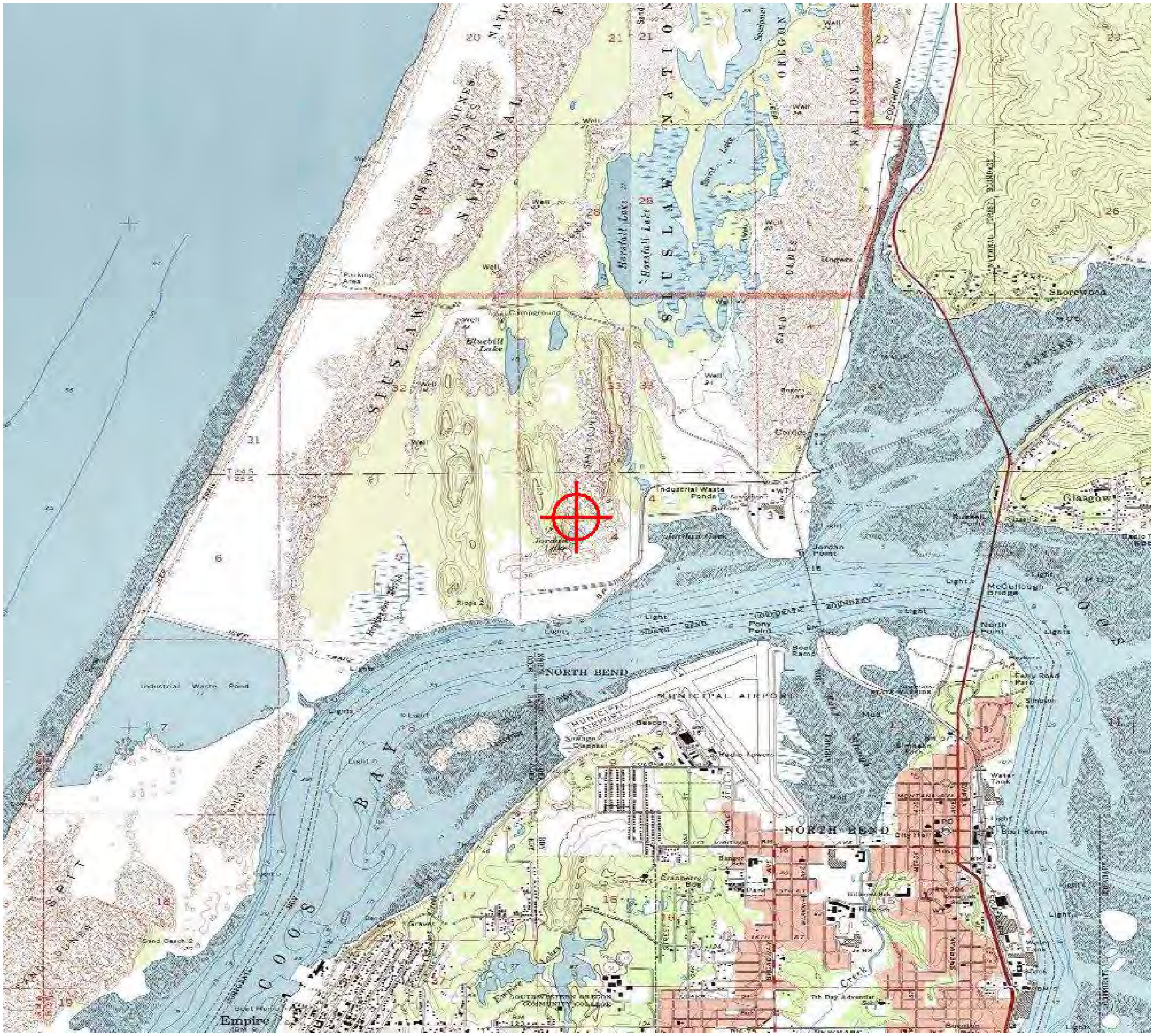
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1753-OE.

Signature Control No: 194337998-224817239 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1753-OE



Sectional Map for ASN 2013-ANM-1753-OE

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Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1754-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 7 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-01.59N NAD 83
Longitude:	124-15-13.67W
Heights:	53 feet site elevation (SE)
	81 feet above ground level (AGL)
	134 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

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This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

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This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

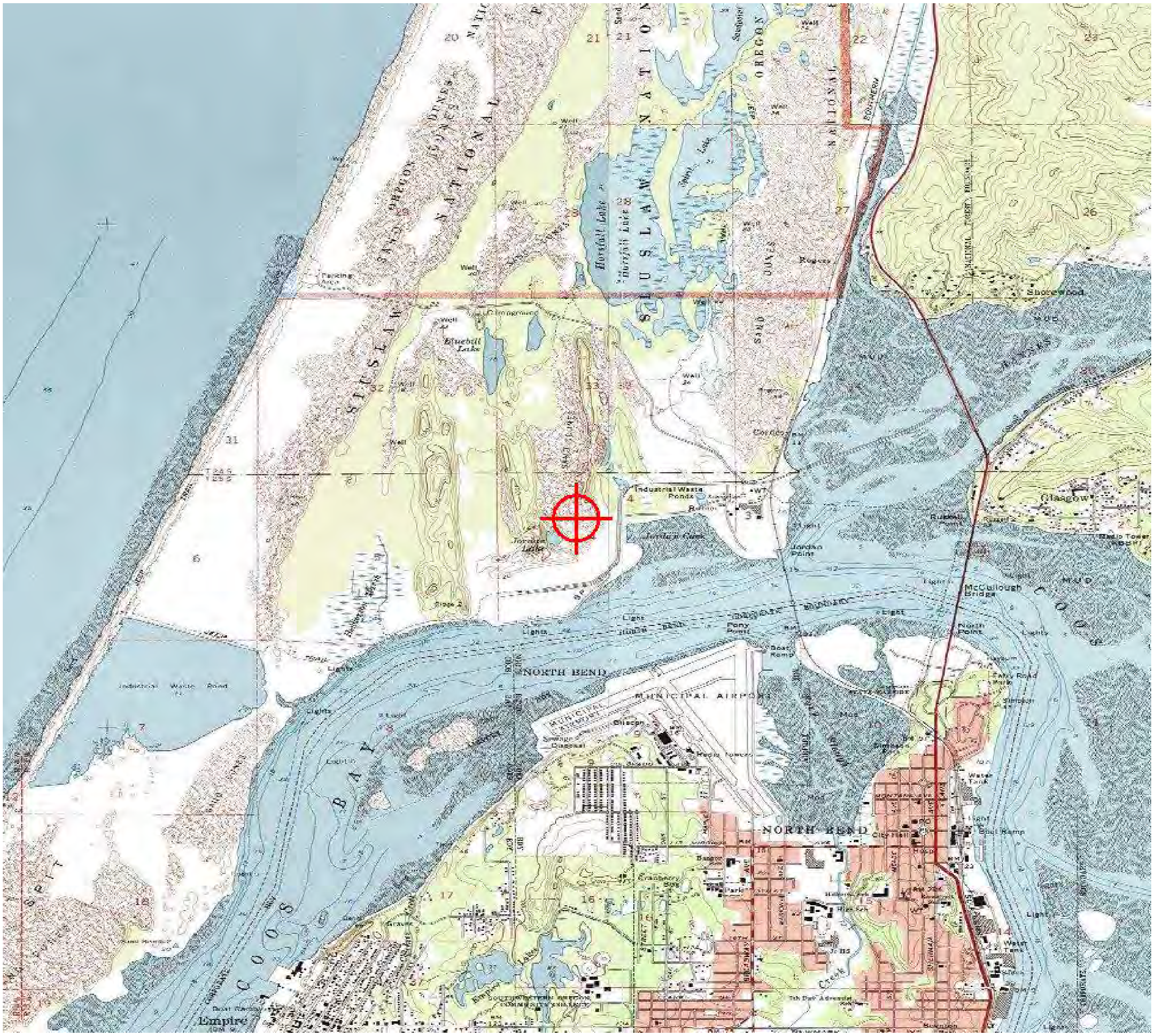
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1754-OE.

Signature Control No: 194338000-224817249 (DNE)

Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1754-OE



Sectional Map for ASN 2013-ANM-1754-OE

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Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1755-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 8 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-01.65N NAD 83
Longitude:	124-15-07.15W
Heights:	32 feet site elevation (SE) 96 feet above ground level (AGL) 128 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

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This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

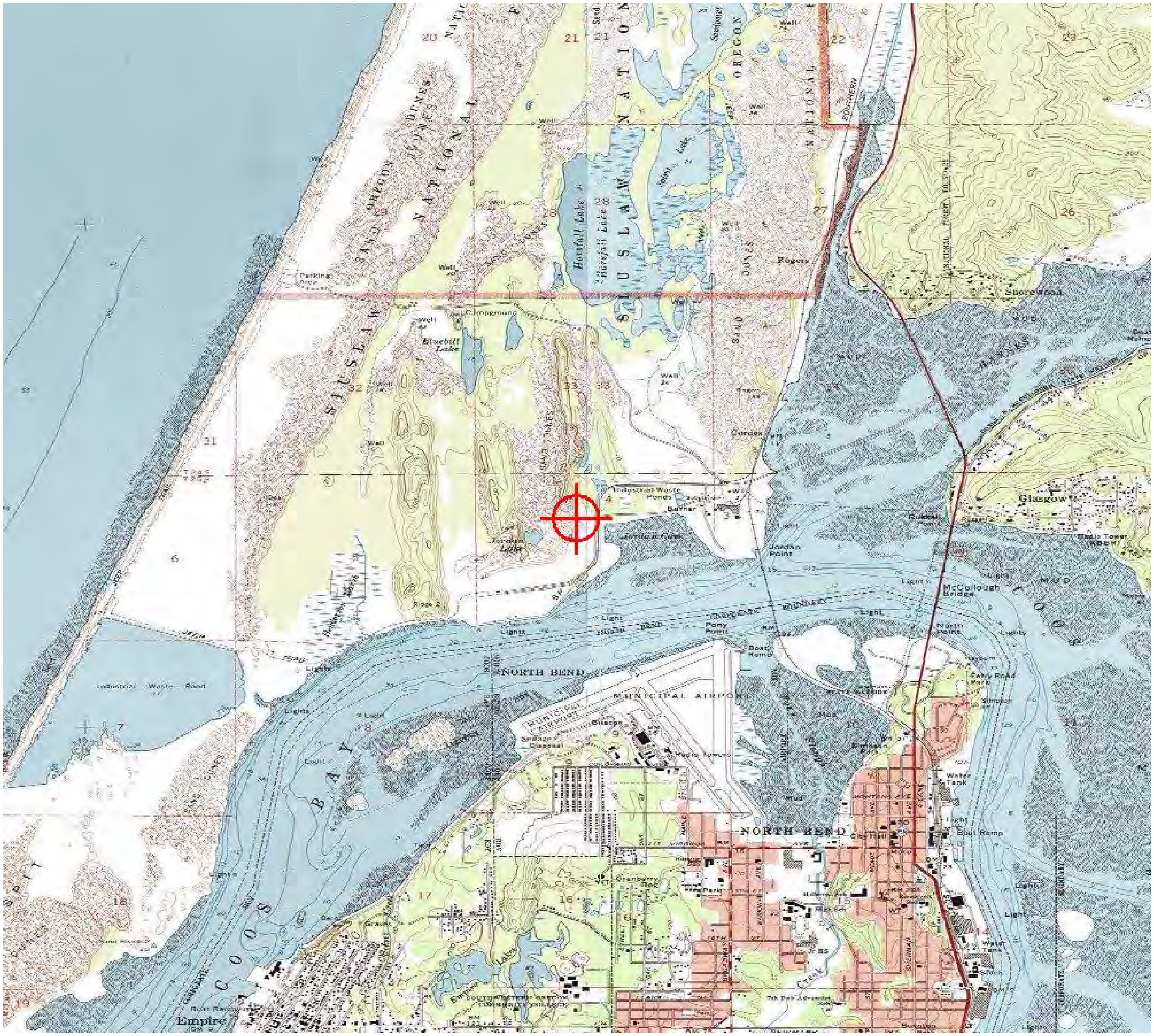
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1755-OE.

Signature Control No: 194338001-224817246 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1755-OE



Sectional Map for ASN 2013-ANM-1755-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1756-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 9L - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.29N NAD 83
Longitude:	124-15-00.01W
Heights:	21 feet site elevation (SE)
	126 feet above ground level (AGL)
	147 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

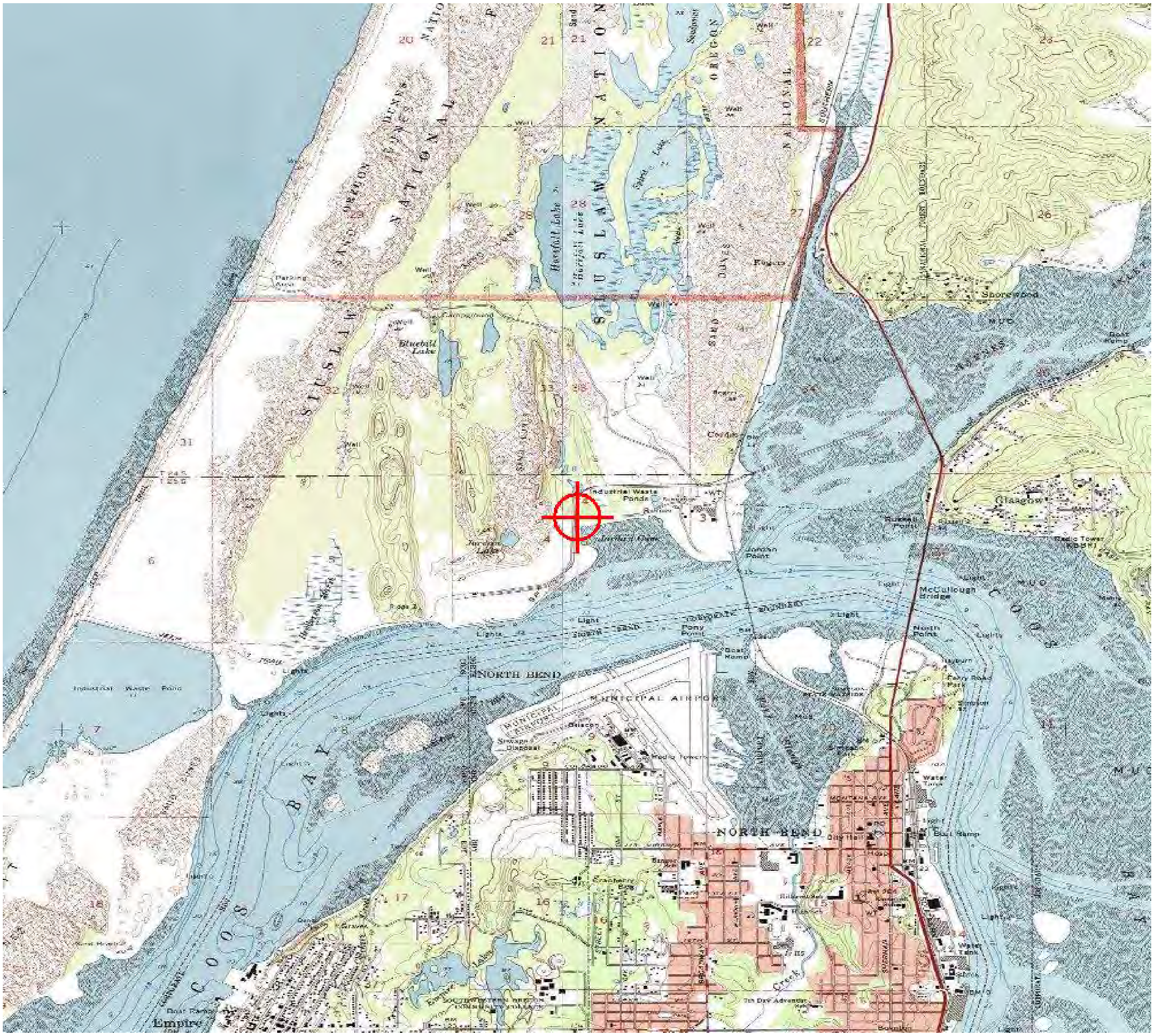
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1756-OE.

Signature Control No: 194338003-224817242 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1756-OE



Sectional Map for ASN 2013-ANM-1756-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1757-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 9R - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.05N NAD 83
Longitude:	124-14-59.93W
Heights:	25 feet site elevation (SE)
	126 feet above ground level (AGL)
	151 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

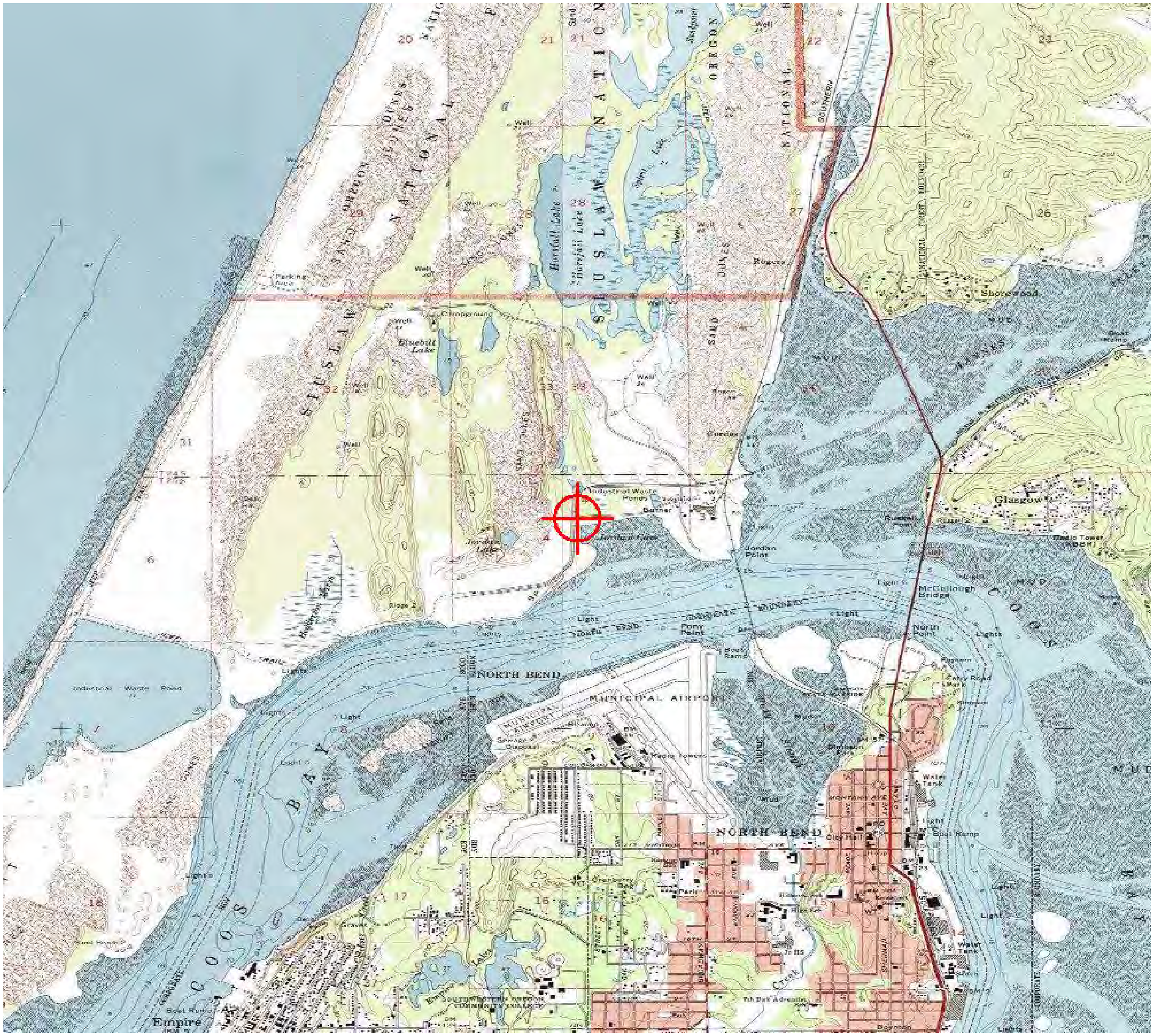
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1757-OE.

Signature Control No: 194338044-224817236 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1757-OE



Sectional Map for ASN 2013-ANM-1757-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1758-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 10L - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-03.67N NAD 83
Longitude:	124-14-54.65W
Heights:	32 feet site elevation (SE)
	120 feet above ground level (AGL)
	152 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

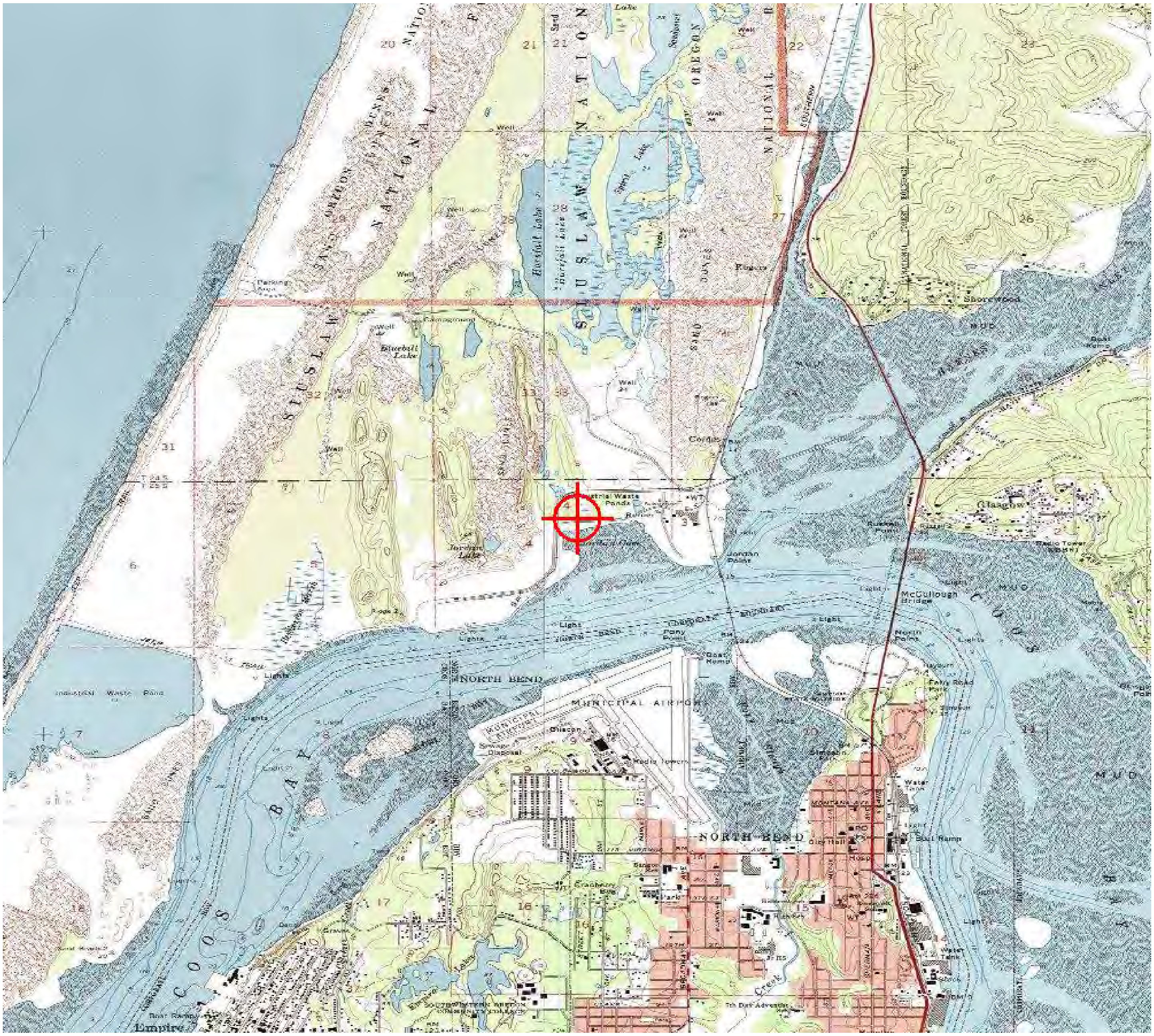
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1758-OE.

Signature Control No: 194338047-224817253 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1758-OE



Sectional Map for ASN 2013-ANM-1758-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1759-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 10R - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-03.48N NAD 83
Longitude:	124-14-54.43W
Heights:	29 feet site elevation (SE)
	120 feet above ground level (AGL)
	149 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

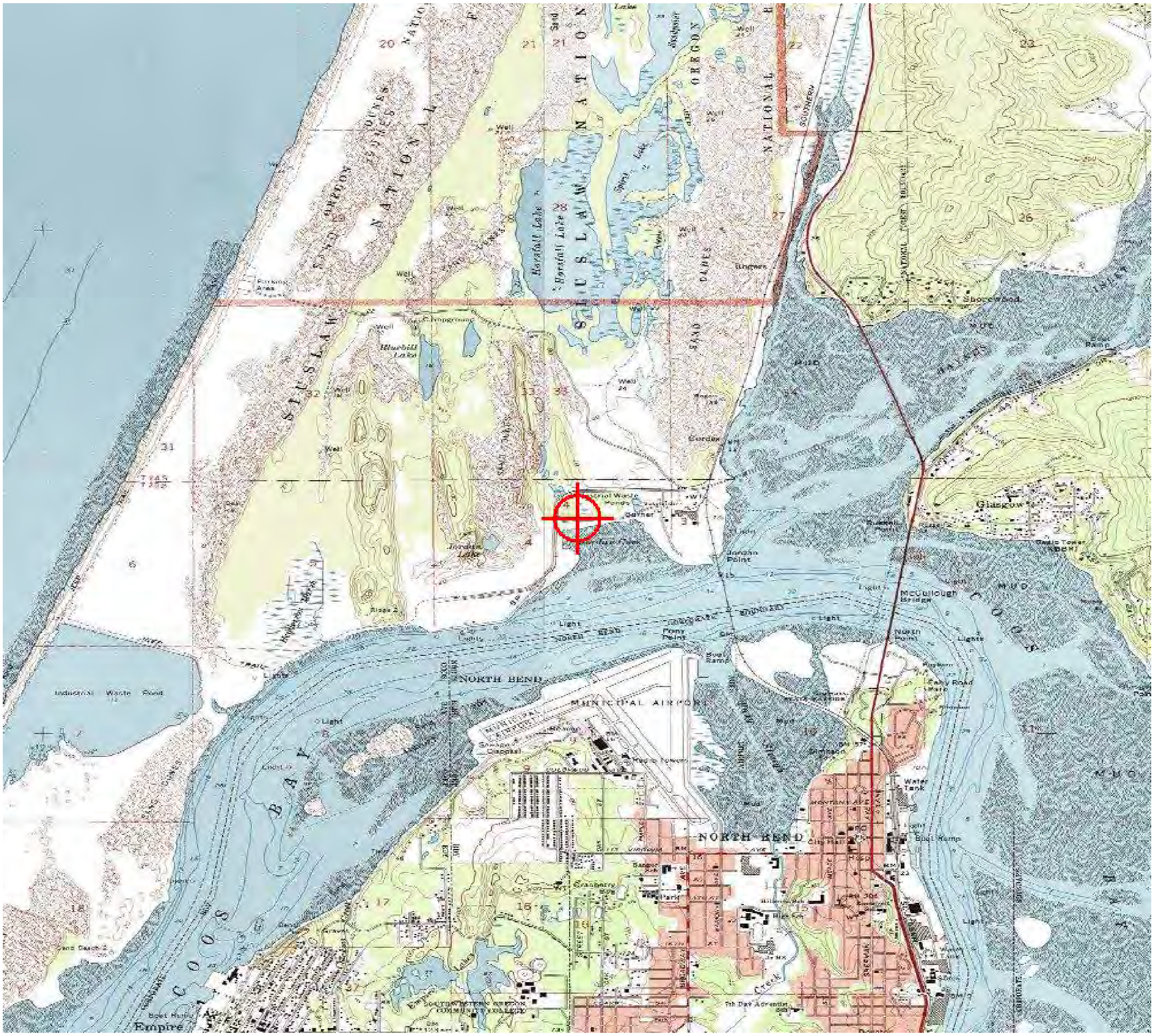
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1759-OE.

Signature Control No: 194338048-224817251 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1759-OE



Sectional Map for ASN 2013-ANM-1759-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1761-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 11L - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-10.62N NAD 83
Longitude:	124-14-49.28W
Heights:	44 feet site elevation (SE)
	111 feet above ground level (AGL)
	155 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

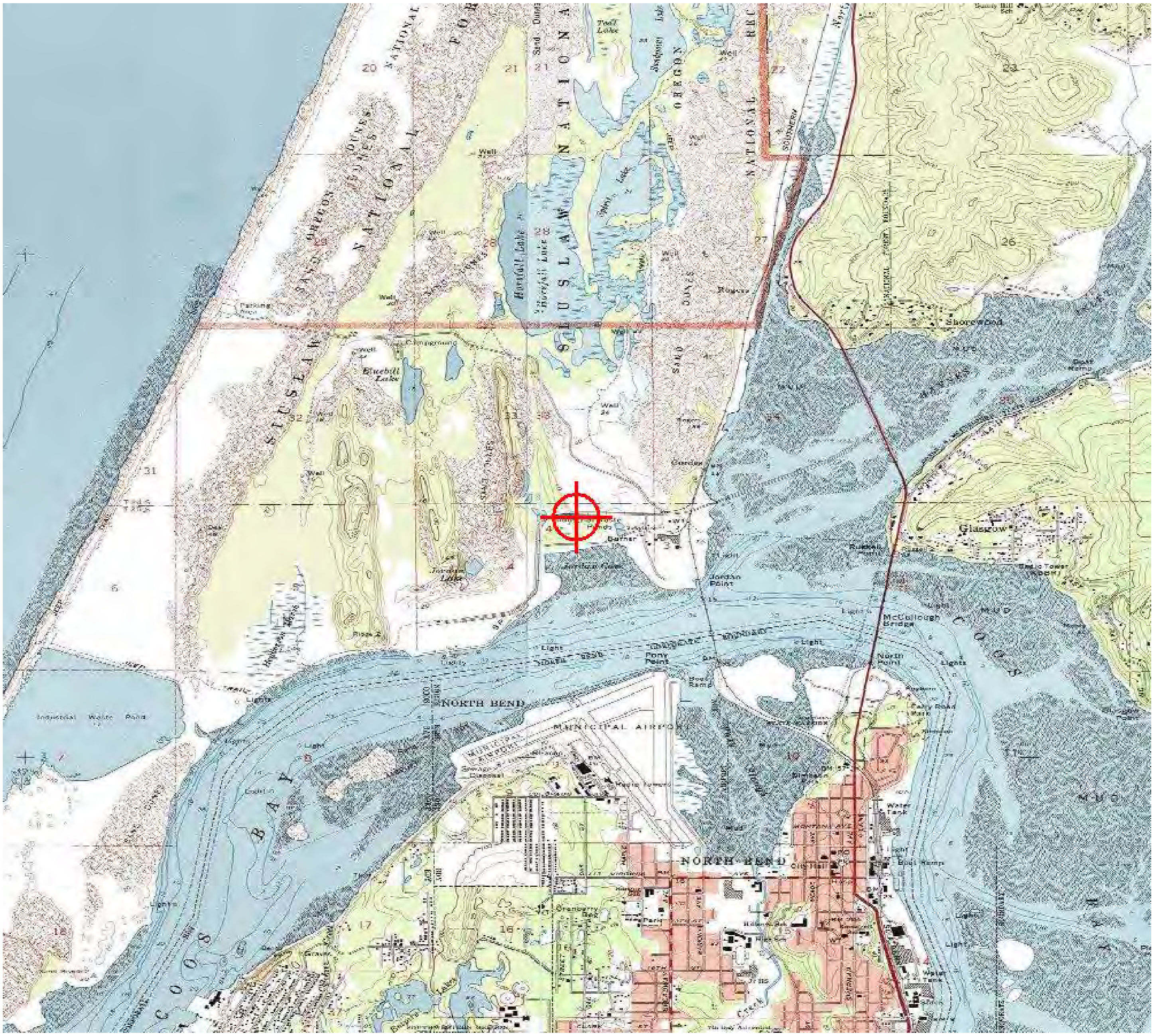
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1761-OE.

Signature Control No: 194338083-224817244 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1761-OE



Sectional Map for ASN 2013-ANM-1761-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1762-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 11R - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-10.41N NAD 83
Longitude:	124-14-49.11W
Heights:	44 feet site elevation (SE)
	111 feet above ground level (AGL)
	155 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

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This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

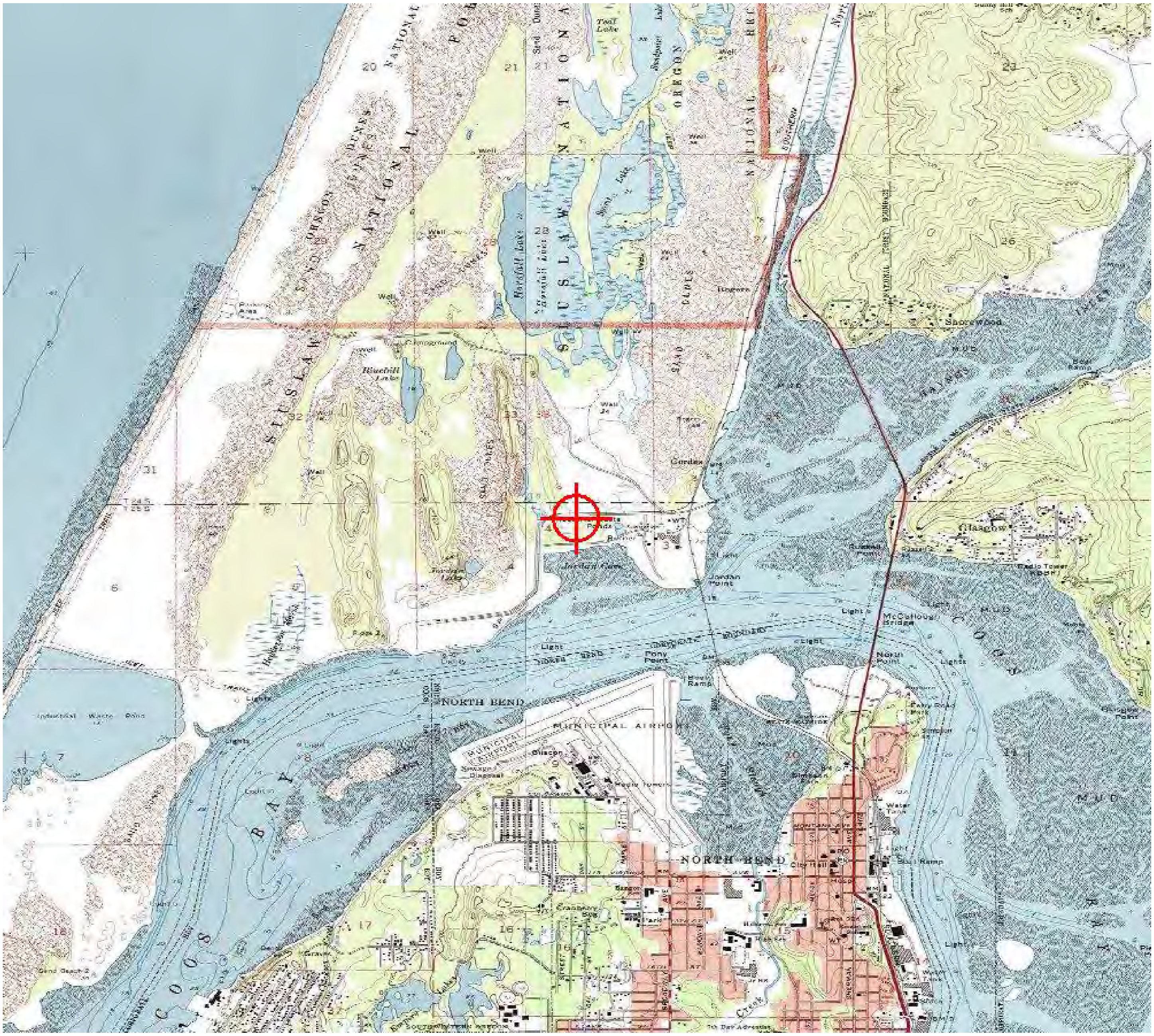
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1762-OE.

Signature Control No: 194338087-224817243 (DNE)

Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1762-OE



Sectional Map for ASN 2013-ANM-1762-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1763-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 12 - SUSPENSION
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-10.43N NAD 83
Longitude:	124-14-40.73W
Heights:	47 feet site elevation (SE)
	116 feet above ground level (AGL)
	163 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

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This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1763-OE.

Signature Control No: 194338092-224817240 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1763-OE

Sectional Map for ASN 2013-ANM-1763-OE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1764-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 13L - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-09.97N NAD 83
Longitude:	124-14-32.22W
Heights:	47 feet site elevation (SE)
	101 feet above ground level (AGL)
	148 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

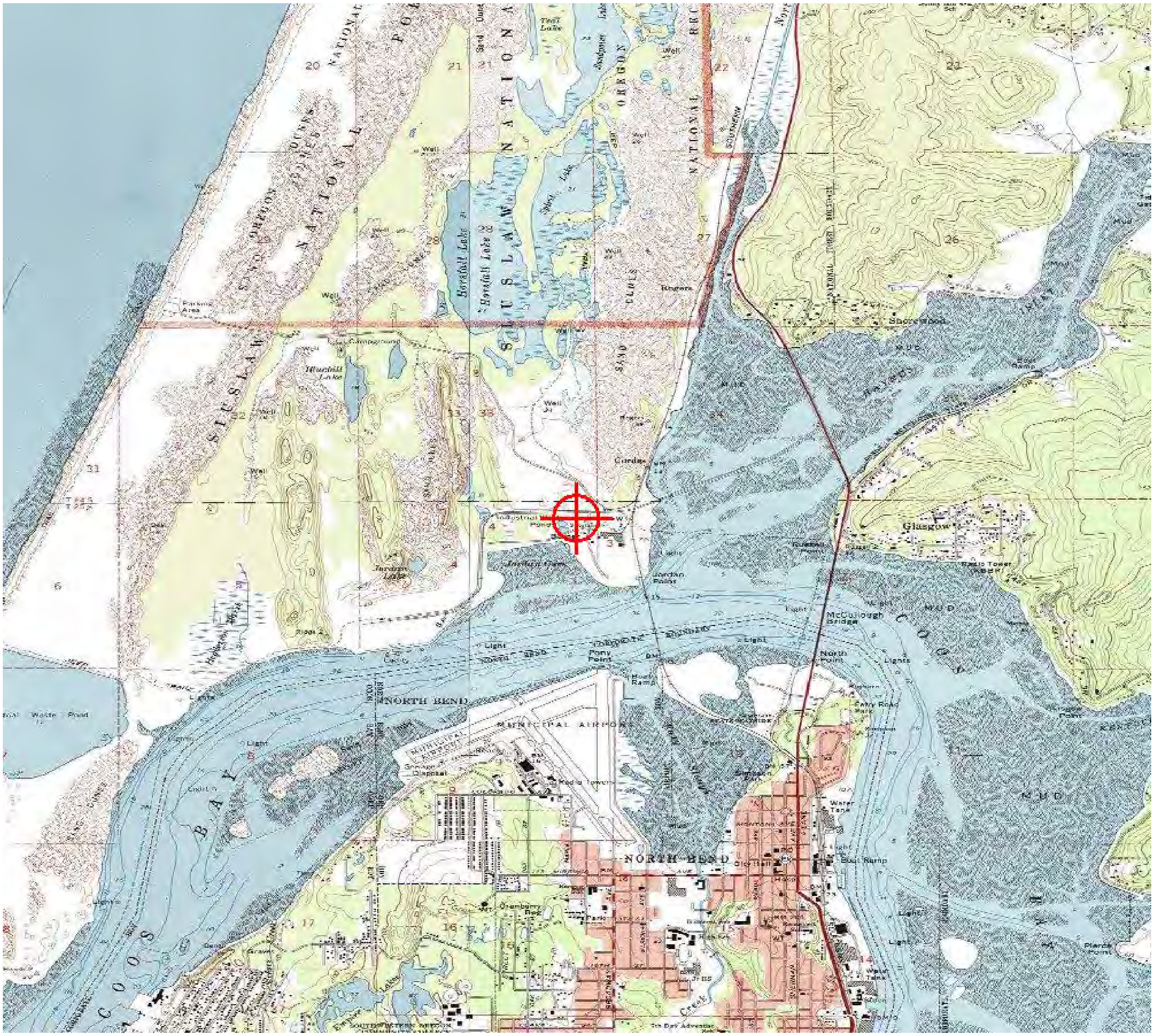
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1764-OE.

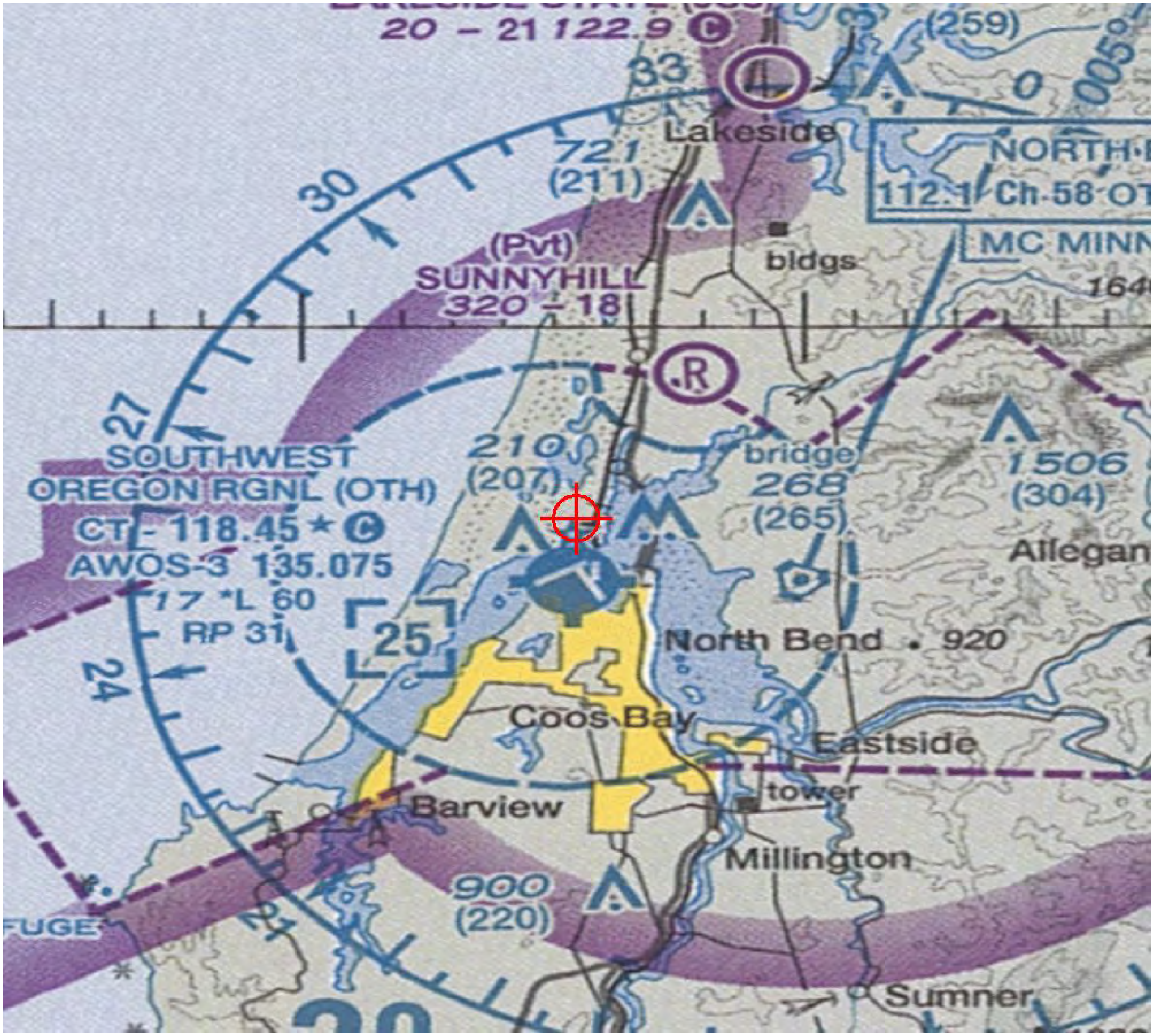
Signature Control No: 194338096-224817245 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1764-OE



Sectional Map for ASN 2013-ANM-1764-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1765-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Transmission Line 13R - DEADEND
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-09.70N NAD 83
Longitude:	124-14-32.62W
Heights:	47 feet site elevation (SE)
	101 feet above ground level (AGL)
	148 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

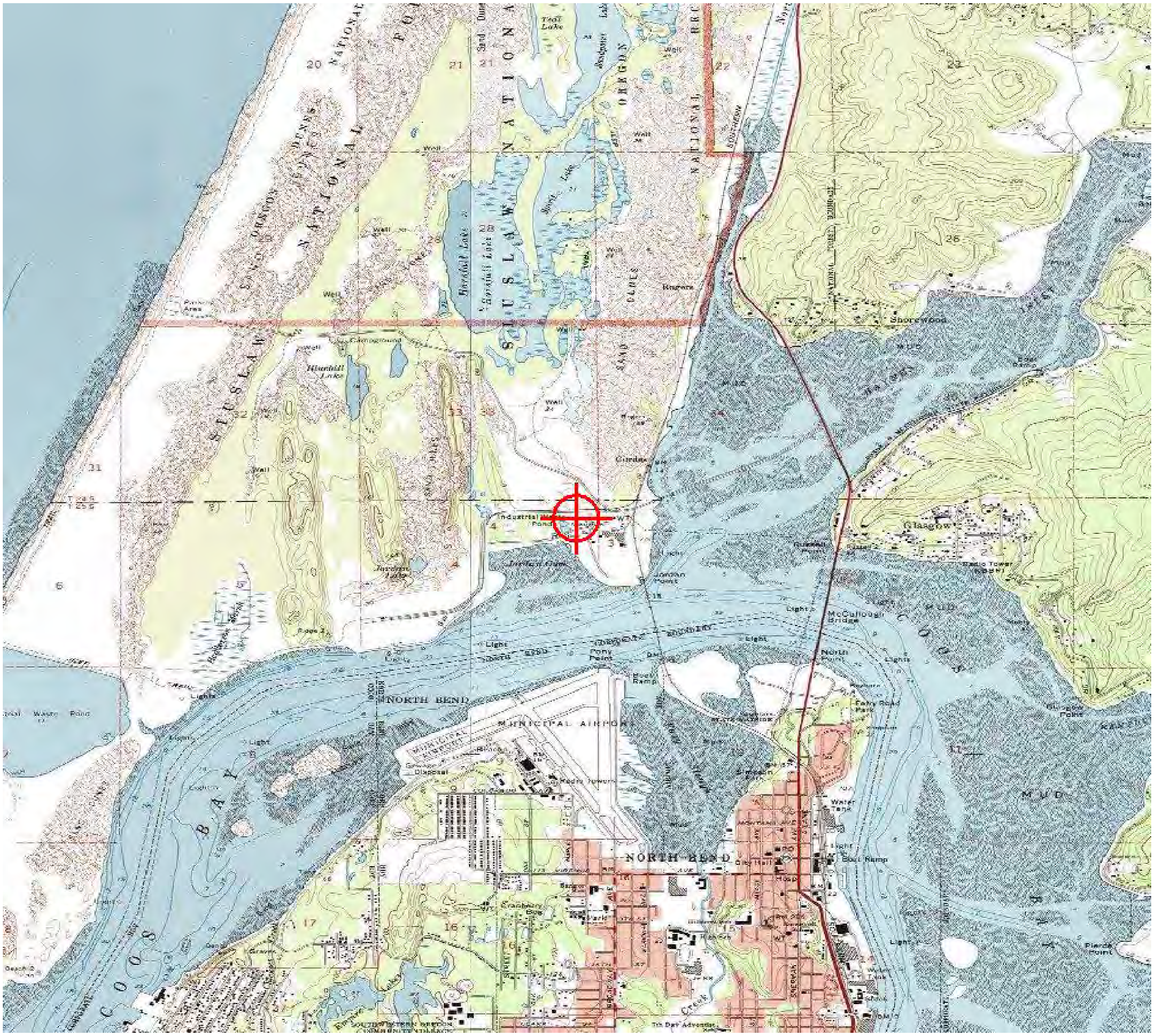
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1765-OE.

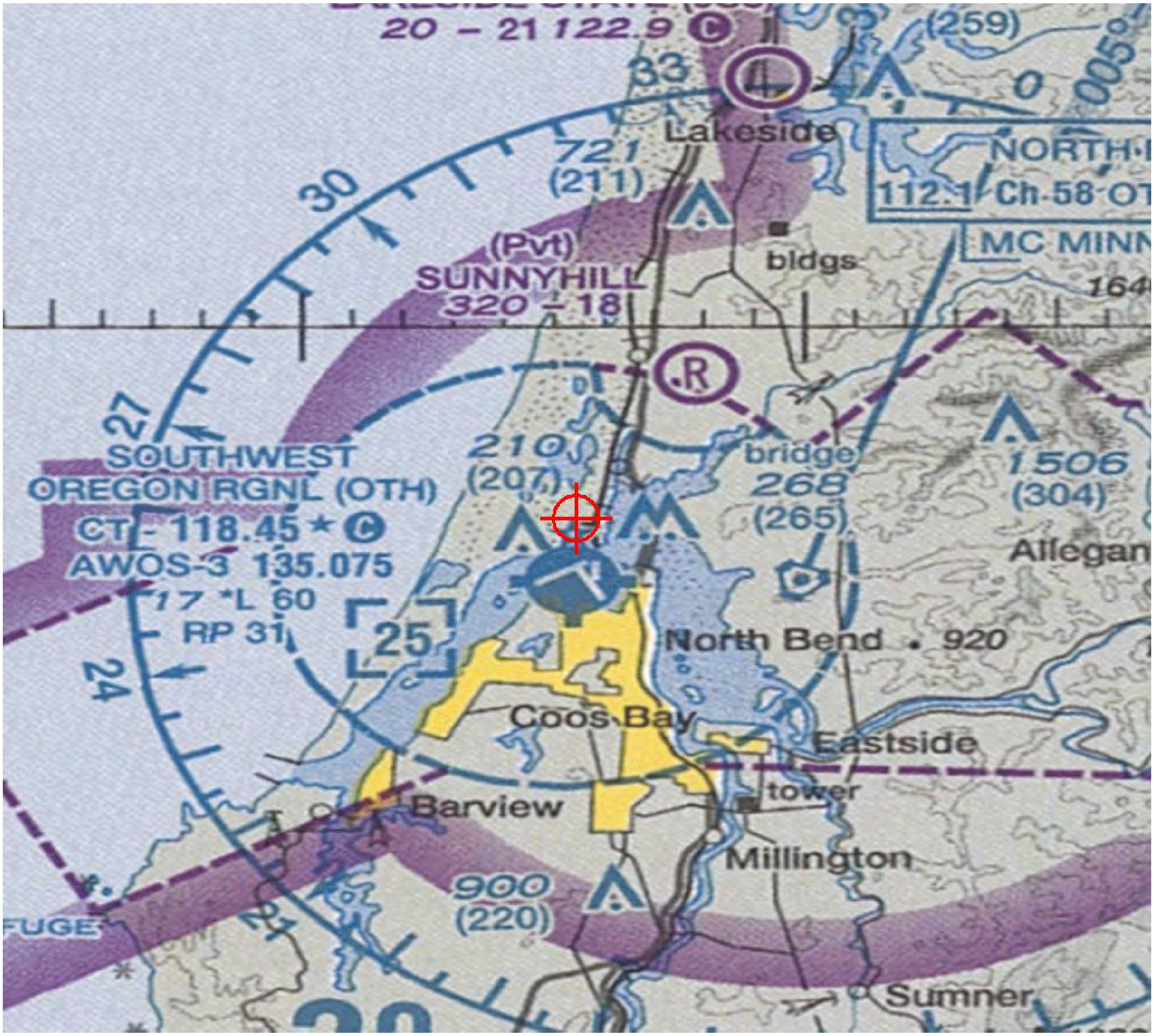
Signature Control No: 194338098-224817252 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1765-OE



Sectional Map for ASN 2013-ANM-1765-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1769-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Stack TURB/HRSG STACK 2
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.51N NAD 83
Longitude:	124-14-34.36W
Heights:	46 feet site elevation (SE)
	119 feet above ground level (AGL)
	165 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

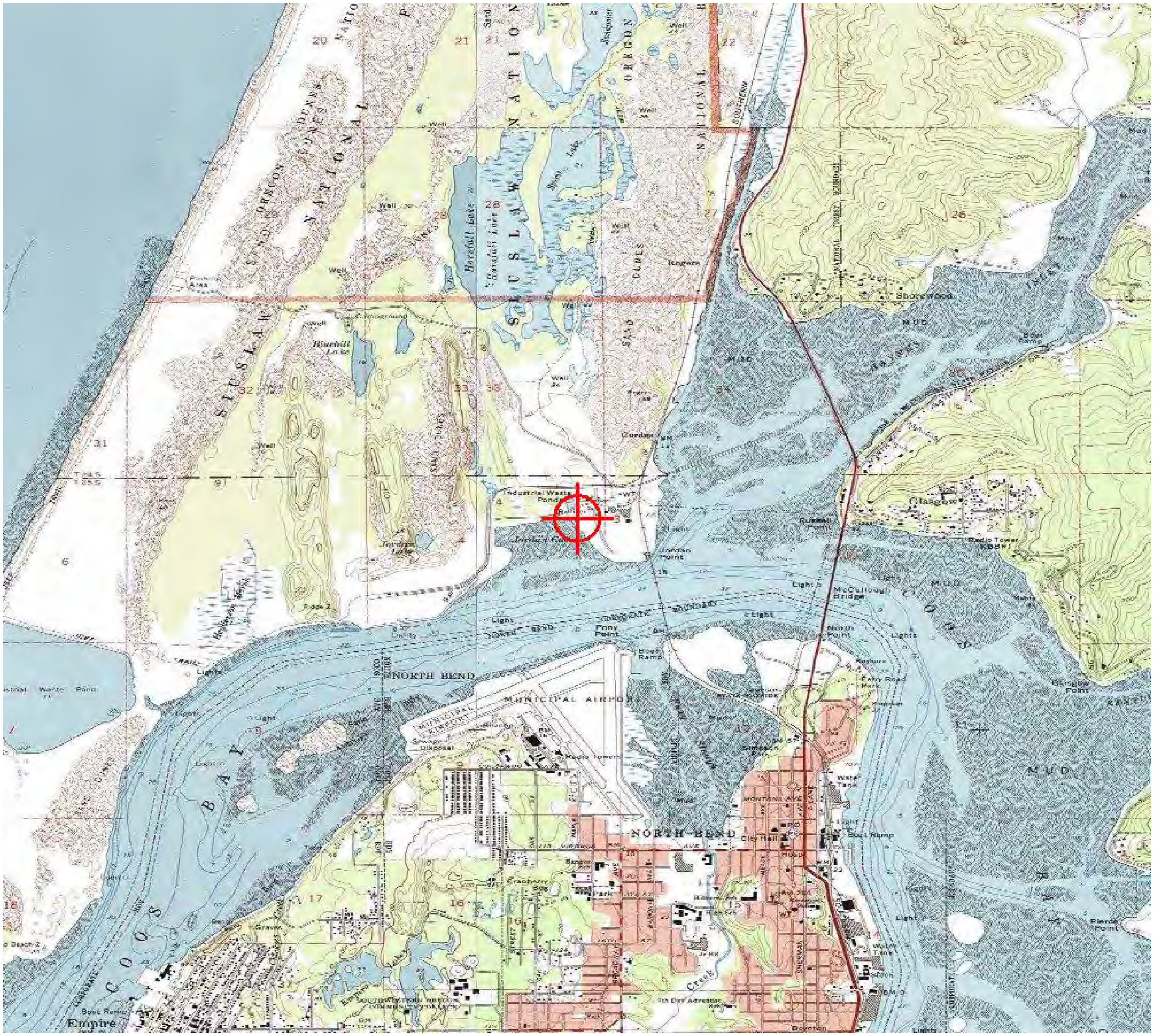
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1769-OE.

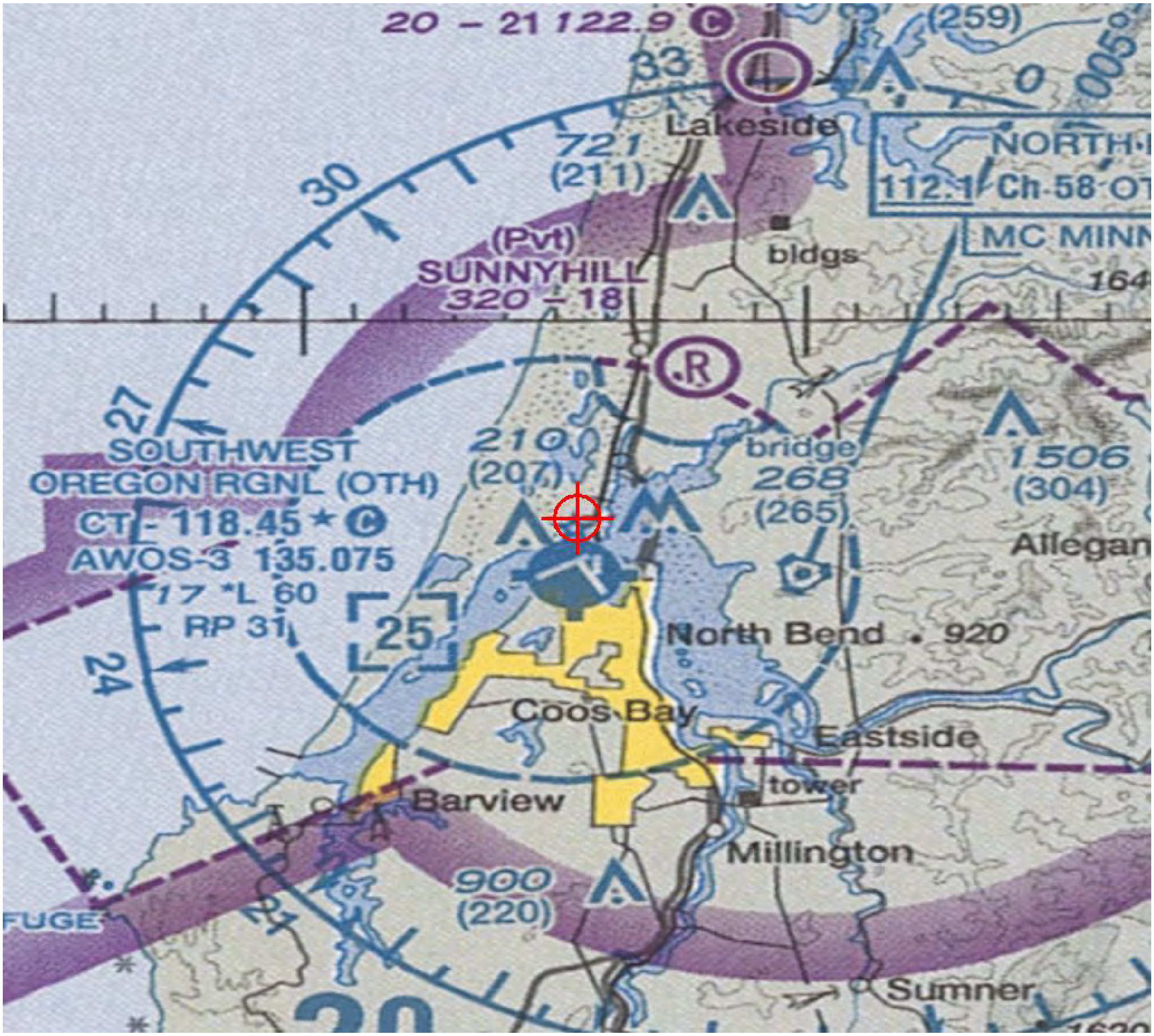
Signature Control No: 194340280-224860693 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1769-OE



Sectional Map for ASN 2013-ANM-1769-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1770-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Tower TURB/HRSG STACK 3
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.55N NAD 83
Longitude:	124-14-33.01W
Heights:	46 feet site elevation (SE)
	119 feet above ground level (AGL)
	165 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

A copy of this determination will be forwarded to the Federal Communications Commission (FCC) because the structure is subject to their licensing authority.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1770-OE.

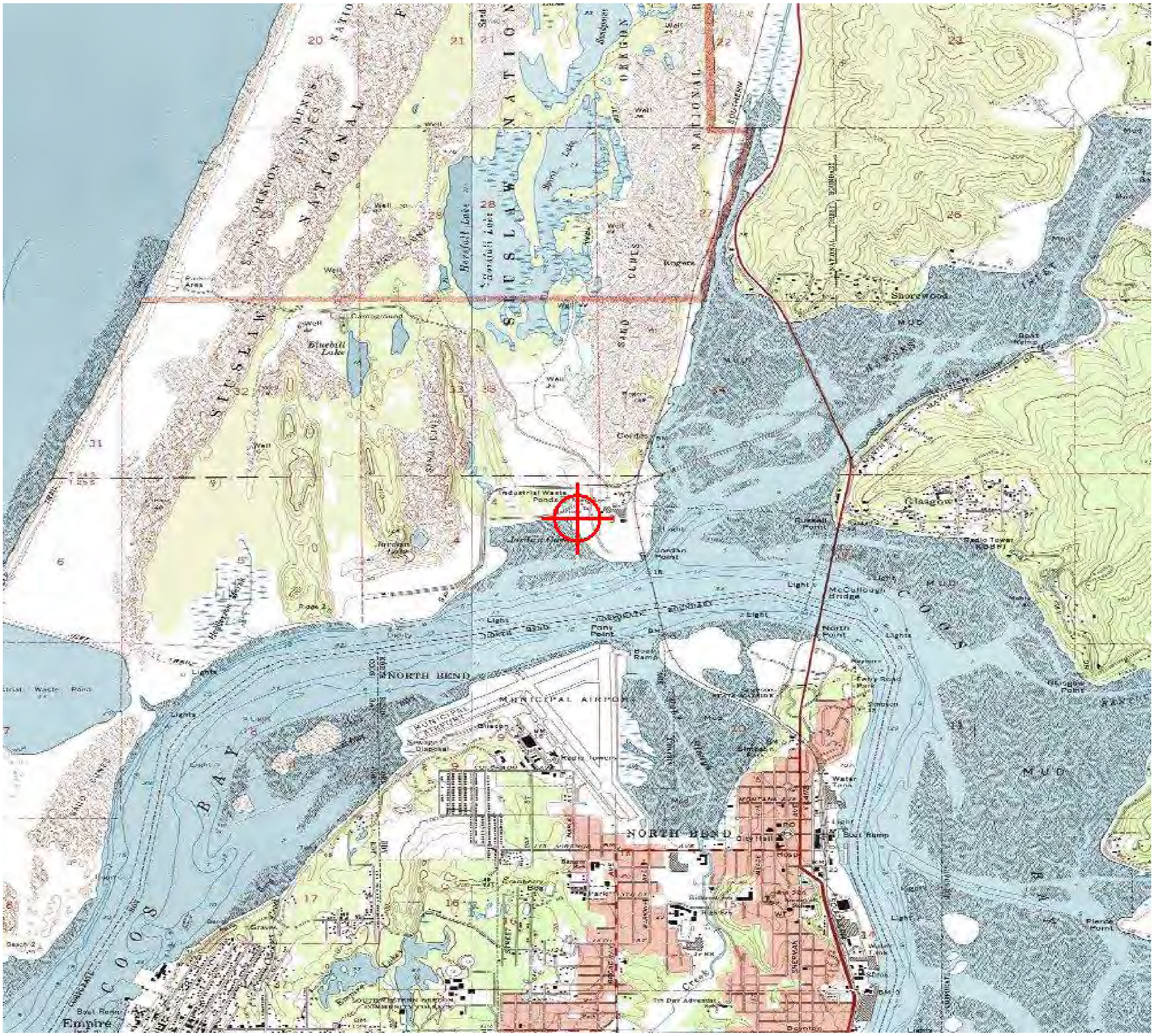
Signature Control No: 194340287-224860705 (DNE)

Robert van Haastert
Specialist

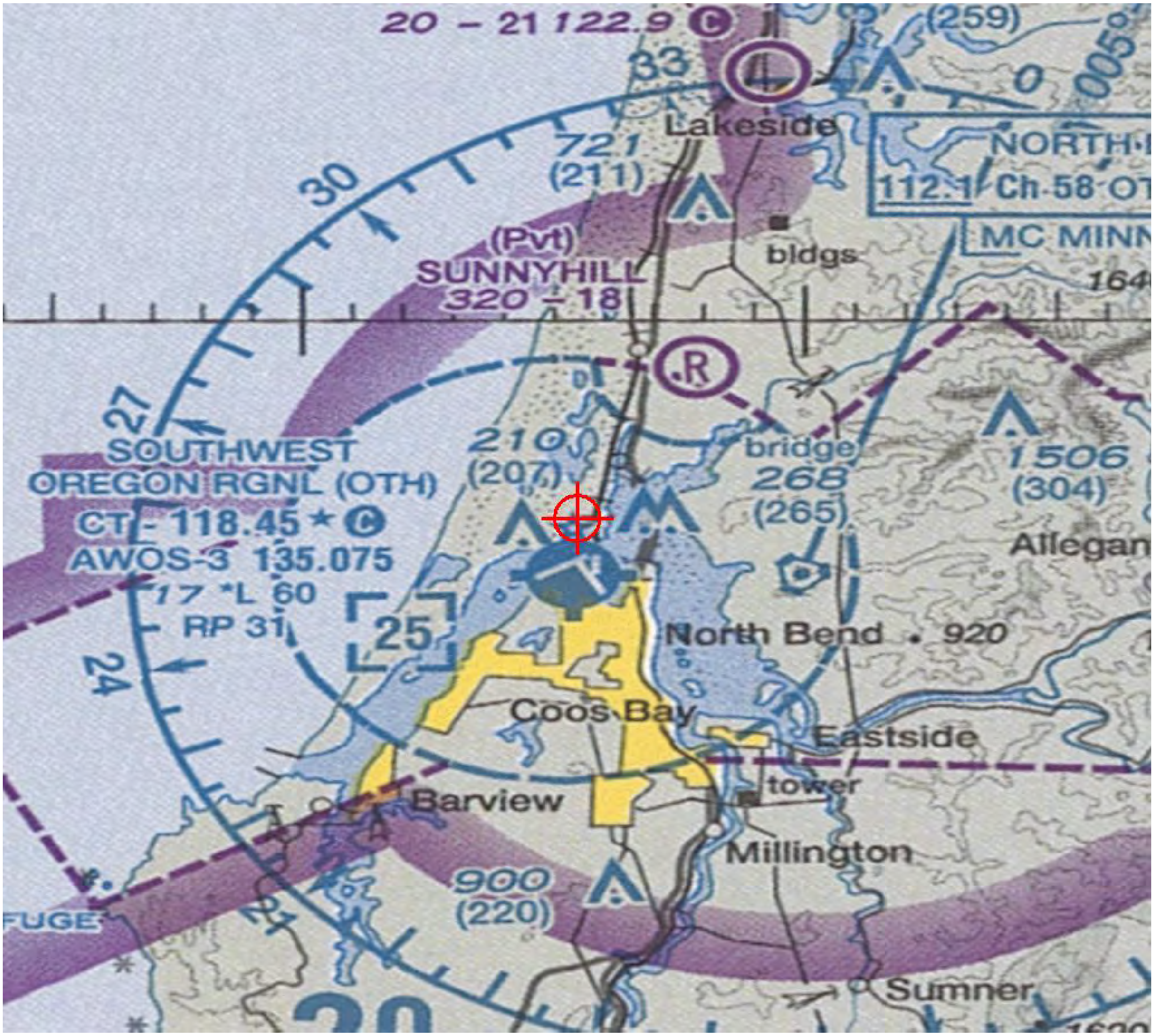
Attachment(s)
Map(s)

cc: FCC

TOPO Map for ASN 2013-ANM-1770-OE



Sectional Map for ASN 2013-ANM-1770-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1771-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Stack TURB/HRSG STACK 1
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.47N NAD 83
Longitude:	124-14-35.72W
Heights:	46 feet site elevation (SE)
	119 feet above ground level (AGL)
	165 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

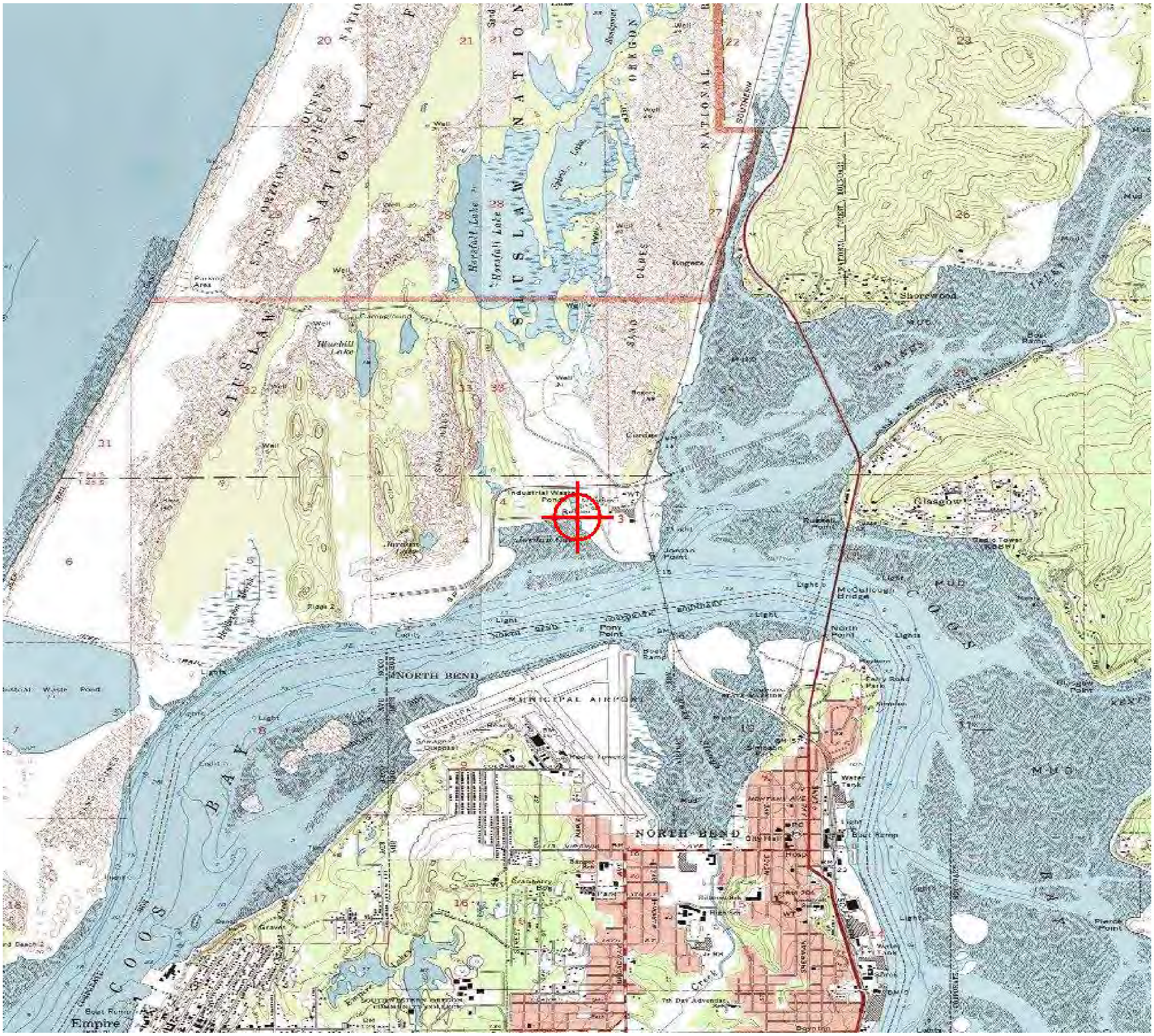
If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1771-OE.

Signature Control No: 194340290-224860703 (DNE)

Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1771-OE



Sectional Map for ASN 2013-ANM-1771-OE

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Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1772-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Stack TURB/HRSG STACK 4
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.67N NAD 83
Longitude:	124-14-29.54W
Heights:	46 feet site elevation (SE)
	119 feet above ground level (AGL)
	165 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

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This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

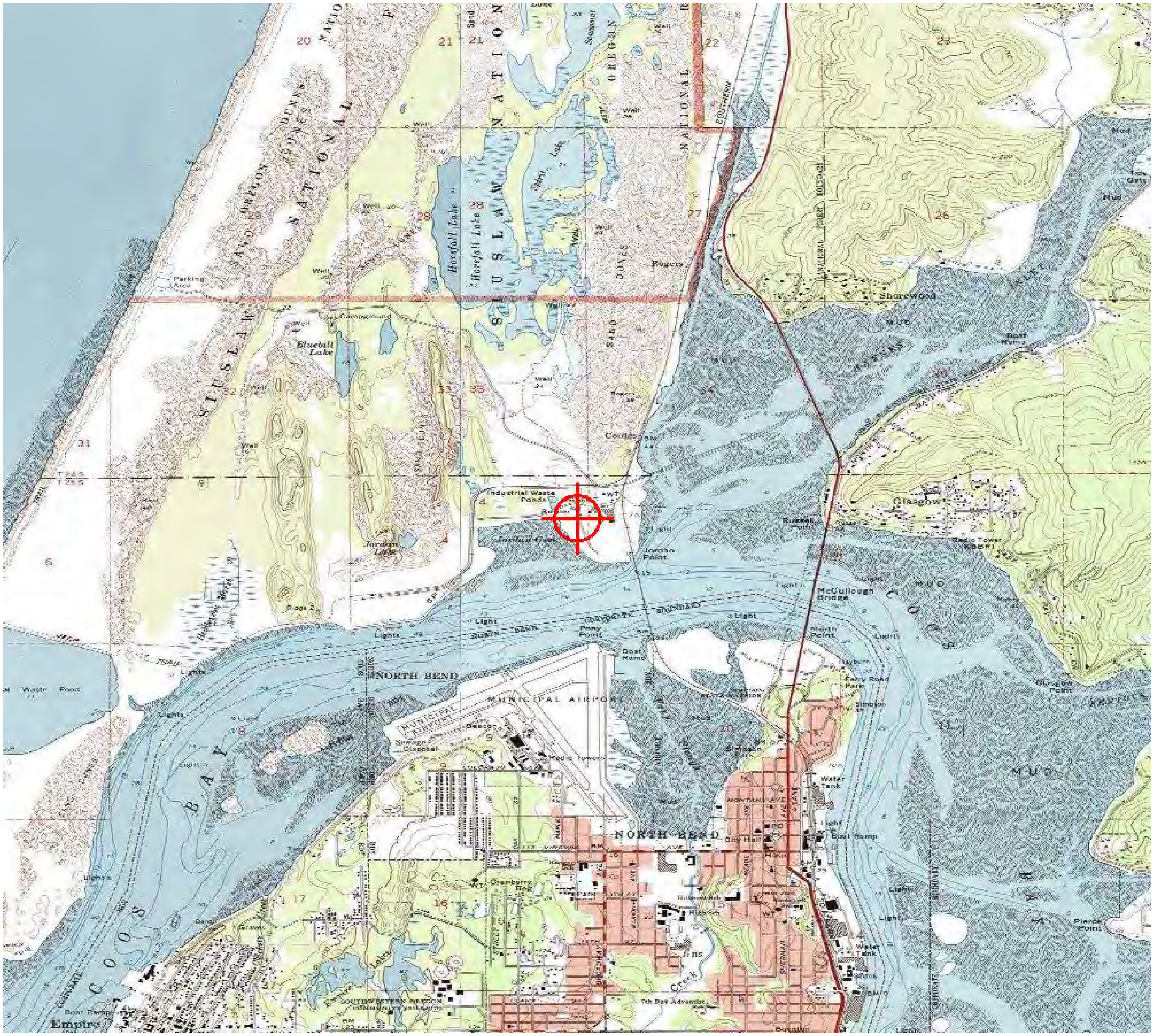
Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1772-OE.

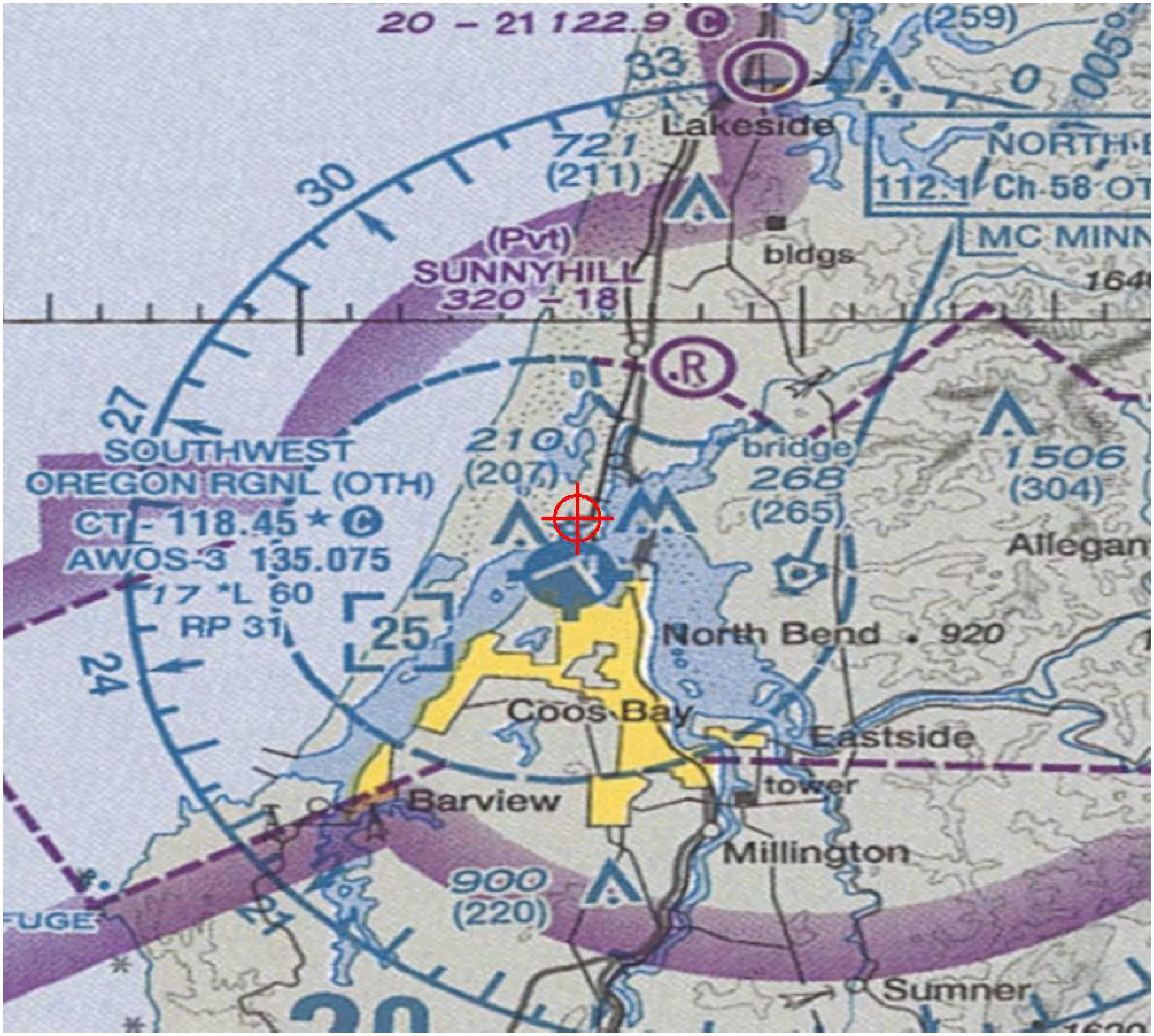
Signature Control No: 194340310-224860696 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1772-OE



Sectional Map for ASN 2013-ANM-1772-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1773-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Stack TURB/HRSG STACK 5
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.71N NAD 83
Longitude:	124-14-28.19W
Heights:	46 feet site elevation (SE) 150 feet above ground level (AGL) 196 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. However, this equipment shall not exceed the overall heights as indicated above. Equipment which has a height greater than the studied structure requires separate notice to the FAA.

This determination concerns the effect of this structure on the safe and efficient use of navigable airspace by aircraft and does not relieve the sponsor of compliance responsibilities relating to any law, ordinance, or regulation of any Federal, State, or local government body.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1773-OE.

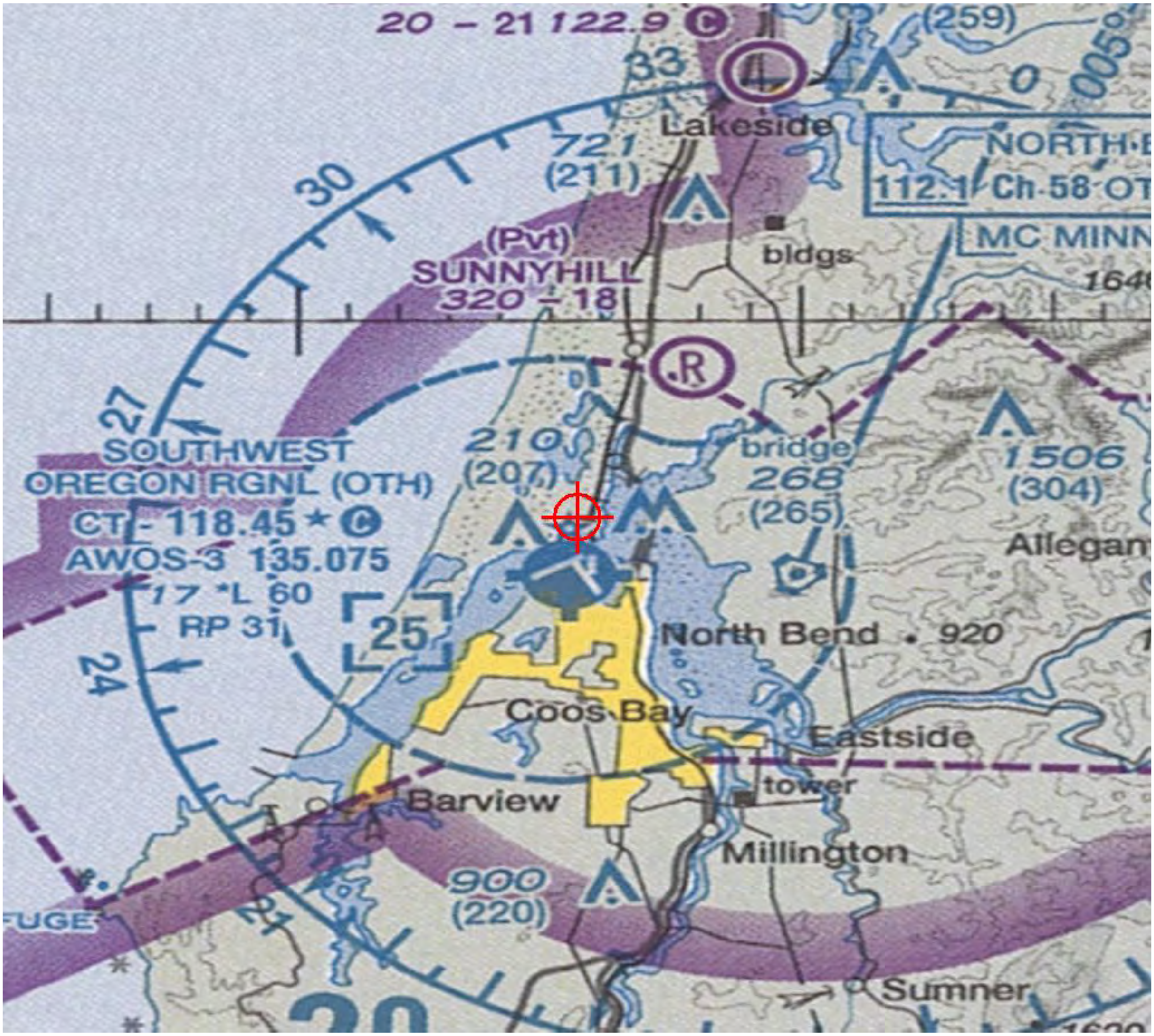
Signature Control No: 194340340-224860700 (DNE)

Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1773-OE

Sectional Map for ASN 2013-ANM-1773-OE



Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
2601 Meacham Boulevard
Fort Worth, TX 76193

Aeronautical Study No.
2013-ANM-1774-OE

Issued Date: 07/24/2014

Jerzy Kichner
Jordan Cove Energy Project
125 Central Ave
Suite 380
Coos Bay, OR 97420

**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Stack TURB/HRSG STACK 6
Location:	North Bend and Coos Bay, OR
Latitude:	43-26-02.76N NAD 83
Longitude:	124-14-26.84W
Heights:	46 feet site elevation (SE) 150 feet above ground level (AGL) 196 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure does not exceed obstruction standards and would not be a hazard to air navigation provided the following condition(s), if any, is(are) met:

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

Based on this evaluation, marking and lighting are not necessary for aviation safety. However, if marking/ lighting are accomplished on a voluntary basis, we recommend it be installed and maintained in accordance with FAA Advisory circular 70/7460-1 K Change 2.

This determination expires on 01/24/2016 unless:

(a) the construction is started (not necessarily completed) and FAA Form 7460-2, Notice of Actual Construction or Alteration, is received by this office.
(b) extended, revised, or terminated by the issuing office.
(c) the construction is subject to the licensing authority of the Federal Communications Commission (FCC) and an application for a construction permit has been filed, as required by the FCC, within 6 months of the date of this determination. In such case, the determination expires on the date prescribed by the FCC for completion of construction, or the date the FCC denies the application.

NOTE: REQUEST FOR EXTENSION OF THE EFFECTIVE PERIOD OF THIS DETERMINATION MUST BE E-FILED AT LEAST 15 DAYS PRIOR TO THE EXPIRATION DATE. AFTER RE-EVALUATION OF CURRENT OPERATIONS IN THE AREA OF THE STRUCTURE TO DETERMINE THAT NO SIGNIFICANT AERONAUTICAL CHANGES HAVE OCCURRED, YOUR DETERMINATION MAY BE ELIGIBLE FOR ONE EXTENSION OF THE EFFECTIVE PERIOD.

This determination is based, in part, on the foregoing description which includes specific coordinates , heights, frequency(ies) and power . Any changes in coordinates , heights, and frequencies or use of greater power will void this determination. Any future construction or alteration , including increase to heights, power, or the addition of other transmitters, requires separate notice to the FAA.

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If we can be of further assistance, please contact our office at (907) 271-5863. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2013-ANM-1774-OE.

Signature Control No: 194342174-224860694 (DNE)
Robert van Haastert
Specialist

Attachment(s)
Map(s)

TOPO Map for ASN 2013-ANM-1774-OE

Sectional Map for ASN 2013-ANM-1774-OE