Halpin, Mike

From: Halpin, Mike
Sent: Monday, October 22, 2001 8:29 AM
To: David Dee (E-mail)
Subject: Reliant / Indiantown

David -

1) we sent out the extension letter for Indiantown's CO2 Recovery Plant last week. Expiration date is 1/1/2005.
2) Concerning Reliant - I have spoken to Al Linero, and he advises me that the issue concerning *removal* of the gas/oil ratio requirement has come up twice before, and here is how we addressed it in those 2 cases:

a) we removed the provision from Enron Midway in exchange for a "2 for 1" provision (i.e. allowed one MMBtu of oil to be burned for every 2 MMBtu of gas burned).
b) At Enron Pompano, we have agreed to hold off on the gas/oil limitations until after 2004, at which time the Gulfstream pipeline and FGT Phases V and VI will be complete, along with the possibility of an LNG/pipeline feed to Florida.

In order to move forward, can you advise if either one of these solutions is workable for Reliant?

Thanks
Mike

Reliant Energy

1001 Broad Street
P.O. Box 1050
Johnstown, PA 15907-1050
Writer's Direct Dial Number
814-533-8670

October 15, 2001

RECEIVED
OCT 16 2001
BUREAU OF AIR REGULATION

OVERNIGHT MAIL

Mr. Michael P. Halpin, P. E.
Review Engineer
New Source Review
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Reliant Energy Osceola, LLC ;
DEP File No. 0970071-001-AC (PSD-FL-273)
Letter Request for a PSD Permit Modification

Dear Mr. Halpin:

On September 18, 2001, Reliant Energy Osceola, LLC (Reliant Energy or RE) submitted a letter request to the Department of Environmental Protection (Department or DEP) for a modification to the PSD permit (PSD-FL-273) for Reliant Energy's Osceola Power Project. On the same day, you sent us an e-mail request for additional information about Reliant Energy's proposal. Accordingly, we are sending you this letter, which contains the Department's questions and Reliant Energy's answers.

DEP's Question 1: Why the applicant wants the change.

RE's Answer: Reliant Energy wants a permit modification because Specific Condition 14 is unnecessary and unduly restricts Reliant Energy's ability to operate the Osceola Power Project. A more detailed explanation is contained in Reliant Energy's letter (dated September 18, 2001) to the Department.

DEP's Question 2: How (if at all) the applicant may operate differently in the event that the request is approved.

RE's Answer: As explained in Reliant Energy's letter, the permit modification would give Reliant Energy more flexibility when operating the Osceola Power Project, but it would not change the basic operating parameters for the facility that have been approved by the Department.

Reliant Energy is committed to using natural gas as the primary fuel at the Osceola Power Project. Nonetheless, there may be times when it is necessary for Reliant Energy to use fuel oil. These facts are reflected in Specific Condition 13, which authorizes the Osceola Power Project to operate up to 3,000 hours per year, but only allows fuel oil to be used for a maximum of 750 hours.

Reliant Energy has evaluated the "worst case" air quality impacts associated with its proposed use of fuel oil. Reliant Energy's permit application demonstrates that these impacts do not violate any of the state or federal air quality standards.

Given these facts, Specific Condition 14 imposes an artificial and unnecessary restriction on Reliant Energy's ability to use fuel oil. There may be times when natural gas is unavailable, and the electricity from the Osceola Power Project is needed, but Specific Condition 14 would prevent Reliant Energy from using fuel oil to supply power to Florida's citizens. Removing Specific Condition 14 would enhance Reliant Energy's ability to meet Florida's demand for electricity.

DEP's Question 3: How the maximum emissions (P.T.E.) would be increased (if at all).

RE's Answer: The project's maximum emissions (Potential To Emit) will not increase if Reliant Energy's request for a permit modification is granted. On October 28, 1999, Reliant Energy submitted an air quality analysis to FDEP for this project. The air quality analysis was based on "worst case" annual operating conditions—i.e., 2250 hours burning natural gas and 750 hours burning fuel oil for each combustion turbine. These operating conditions will continue to represent the "worst case," even if Specific Condition 14 is deleted from the PSD permit.

DEP's Question 4: How the P.T.E comports with the original application.

RE's Answer: Even if Reliant Energy's request is granted, there will be no changes to the P.T.E calculations for this project.

DEP's Question 5: Whether the original modeling submitted to the Department incorporated the worst case emissions, which could be seen with the requested permit change.

RE's Answer: The modeling submitted to the Department assumed "worst case" emissions (i.e., firing fuel oil for 24 hours). The modeling results will continue to be valid and unchanged, even if Reliant Energy's request for a permit modification is granted.

DEP's Question 6: Any other information believed to be pertinent.

RE's Answer: The Osceola Power Project will continue to be in compliance with all of the applicable state and federal air quality standards, even if Specific Condition 14 is deleted from the facility's PSD permit.

Specific Condition 19

Following the submittal of its letter on September 28, 2001, Reliant Energy realized that it also should use this opportunity to clarify Specific Condition 19 in the PSD permit for the Osceola Power Project.

Specific Condition 19 contains a paragraph that states, among other things, that the "permittee shall develop a NO_x reduction plan when the hours of oil firing on any individual combustion turbine reaches 750 hours." Specific Condition 19 for the Osceola Power Project is almost identical to Specific Condition 19 in the PSD permits for the Vandolah Power Project (DEP File No. 0490043-001-AC; PSD-FL-275) and the Shady Hills Generating Station (DEP File No. 1030373-001-AC; PSD-FL-280). However, the PSD permits for the Vandolah Power Project and the Shady Hills Generating Station make it clear that a NO_x reduction plan only needs to be developed "when the hours of oil firing reach the allowable limit of 1000 hours per year."

Reliant Energy respectfully requests the Department to clarify the PSD permit for the Osceola Power Project to make it consistent with the PSD permits for the Vandolah Power Project and the Shady Hills Generating Station. More precisely, Specific Condition 19 for the Osceola Power Project should state that Reliant Energy must develop a NO_x reduction plan if the oil firing of any individual combustion turbine reaches 750 hours "per year."

This request should be granted because it will make Specific Condition 19 consistent with the Department's requirements for similar facilities, which were approved at approximately the same time as the Osceola Power Project. This clarification of Specific Condition 19 also will help avoid unintended and inappropriate results, as explained below.

Specific Condition 19 requires the development of a NO_x reduction plan if the Osceola Power Project, the Vandolah Power Project, or the Shady Hills Generating Station uses the maximum allowable amount of fuel oil. There is no requirement and no reason to develop a NO_x reduction plan at any of these facilities if the use of fuel oil is limited.

As currently written, Specific Condition 19 for the Osceola Power Project could be interpreted to require Reliant Energy to develop a NO_x reduction plan when the facility's cumulative use of fuel oil exceeds 750 hours, even if the facility's annual use of fuel oil is very limited. For example, the 750 hour threshold would be exceeded in 20 years if the Osceola Power Project used fuel oil at an average rate of only 38 hours per year. Obviously, this result would be inappropriate. This result also would be unfair, given the 1000 hour per year thresholds contained in the permits for the Vandolah Power Project and the Shady Hills Generating Station.

For all of these reasons, Specific Condition 19 should be clarified and should refer to 750 hours of fuel oil firing "per year".

If you have any questions or require additional information about any of these issues, please contact me at (814) 533-8670 or call our local environmental counsel, David S. Dee, at (850) 681-0311.

Sincerely,

Timothy E. McKenzie

Timothy E. McKenzie
Senior Environmental Scientist

TEM/cms/TEM236

cc: David Dee – Landers and Parsons

bcc: A. B. Birbeck
V. J. Brisini
A. H. Deese
J. E. Finck
T. E. Gish
G. J. Kennedy
A. H. Leskovsek
K. E. McClelland
T. E. McKenzie
C. A. Mitchell
K. A. Ripper
T. C. Roberts
M Soltys - B&V
D I. Tecson
B. G. Tullis

Adams, Patty

From: Halpin, Mike

Sent: Monday, October 01, 2001 7:02

To: Adams, Patty

Subject: RE: FW: Reliant

Thanks. I suppose that we ought to add a new letter to the PSD number. Would 273A be the new number?
Mike

-----Original Message-----
From: Adams, Patty
Sent: Friday, September 28, 2001 2:26 PM
To: Halpin, Mike
Subject: RE: FW: Reliant

It's done. The number is 0970071-002-AC. Do we need to modify the PSD permit number (PSD-FL-273A)?

-----Original Message-----
From: Halpin, Mike
Sent: Friday, September 28, 2001 9:22 AM
To: Adams, Patty
Subject: FW: FW: Reliant

Patty -
Can you show this Reliant project as incomplete as of the day it was recorded (see below e-mails)?
Thanks
Mike

-----Original Message-----
From: David S. Dee [mailto:ddee@landersandparsons.com]
Sent: Friday, September 21, 2001 2:46 PM
To: Halpin, Mike
Subject: Re: FW: Reliant

Mike,
Reliant wanted to move quickly with this issue so, yes, they sent in their letter request before I received your e-mail.

I have forwarded your questions to Reliant and they are working on your issues already.

You do not need to send a request for additional information.

My assumption is that the PTE and modeling results will not change, even if Reliant's request is granted, because all of the emissions estimates and modeling presumably were based on maximum oil-firing. The request simply would give Reliant more flexibility in its operations, and help Reliant avoid the use of oil. However, just to be sure, I have asked Reliant to confirm that my assumptions are correct.

I'll get back to you with additional information as soon as possible.

David Dee

Halpin, Mike wrote:

David -
Re: prior e-mail
It appears that my e-mail (below) may have not preceded Reliant's re
which I received today and was dated September 18th. The request does
appear to fully address the issues noted below. I am willing to acce
supplementary (e-mail) response by Reliant to these issues, or will d
to preparing a Request for Additional Information when I can get to i
Let me know your preference.
Thanks
Mike

-----Original Message-----
From: Halpin, Mike
Sent: Tuesday, September 18, 2001 7:31 AM
To: David Dee (E-mail)
Subject: Reliant
Hi David -

Sorry it took me until now to answer your voice-mail:
You asked about the amount of the check and how to make the perm
request. The amount is $250. The applicant's letter should sum
request and include (at a minimum) the following:
1) Why the applicant wants the change
2) How (if at all) the applicant may operate differently in the
the request is approved
3) How the maximum emissions (P.T.E.) would be increased (if at
4) How the P.T.E. comports with the original application
5) Whether the original modeling submitted to the Department inc
the worst case emissions which could be seen with the requested
6) Any other info believed to be pertinent
As I had indicated, a public notice will be re
quired.
Mike

Reliant Energy

1001 Broad Street
P.O. Box 1050
Johnstown, PA 15907-1050

Writer's Direct Dial Number
814-533-8670

RECEIVED
SEP 21 2001
BUREAU OF AIR REGULATION

September 18, 2

set up file
0970071-002-AC
Print Mike's E-Mail

Certified Mail

PSD-273A

Mr. Michael P. Halpin, P. E.
Review Engineer
New Source Review Section
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Reliant Energy Osceola, LLC;
DEP File No. 0970071-001-AC (PSD-FL-273);
Letter Request for a PSD Permit Modification

Dear Mr. Halpin:

Reliant Energy Osceola, LLC (Reliant Energy) hereby requests the Florida Department of Environmental Protection to modify the PSD permit (PSD-FL-273) for Reliant Energy's Osceola Power Project. More precisely, Reliant Energy requests that Section III, Specific Condition 14, be deleted from the permit. This condition states that "the amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period [Rule 62-210.200, F.A.C.(BACT)]."

Specific Condition 14 is unnecessary. Specific Condition 13 already limits the total number of operating hours (maximum of 3,000 hours) for each stationary gas turbine at the site in any consecutive twelve month period. Specific Condition 13 also limits the number of operating hours (maximum of 750 hours) for each turbine when using fuel oil. Thus, Specific Condition 14 does not contain any requirement that will provide additional protection for the environment.

Specific Condition 14 may unduly and inappropriately restrict the operation of the Osceola Power Project. It is easy to envision scenarios where the Osceola Power Project would be in compliance with the hourly limits contained in Specific Condition 13, but unable to comply with the requirements contained in Specific Condition 14. In such cases, Specific Condition 14 would prohibit Reliant Energy from operating the Osceola Power Project, even when the facility is needed to meet the public's demand for electricity.

To avoid these potential problems with Specific Condition 14, the Osceola Power Project would need to maximize its use of fuel oil at the Facility. Obviously, this is an unintended and undesirable result of imposing Specific Condition 14 on the Osceola Power Project. But for Specific Condition 14, Reliant Energy would prefer to minimize the use of fuel oil at the Osceola Power Project.

For all of these reasons, Reliant Energy requests the Department to delete Specific Condition 14 from the PSD permit for the Osceola Power Project.

Enclosed is a check in the amount of $250 to pay the Department's fee for processing this request for a permit modification.

If you have any questions regarding this request or require additional information, please call me at 814-533-8670 or call our environmental counsel, David S. Dee, at (850) 681-0311. Thank you for your assistance with this matter.

Sincerely,

Timothy E. McKenzie

Timothy E. McKenzie
Senior Environmental Scientist

TEM/cms/TEM217R

BEST AVAILABLE COPY

...ess on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

...es (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to: Mr. Christopher Allen, Reliant Energy Osceola, PO Box 4455, Houston, TX 77210-4455	4a. Article Number: Z 031 391 914
	4b. Service Type: ☐ Registered ☒ Certified ☐ Express Mail ☐ Insured ☐ Return Receipt for Merchandise ☐ COD
	7. Date of Delivery JAN 03 2000
5. Received By: *(Print Name)*	8. Addressee's Address *(Only if requested and fee is paid)*
6. Signature: *(Addressee or Agent)* X GEE	

...s your **RETURN ADDRESS** completed on the reverse...

Thank you for using Return Receipt Service.

Z 031 391 914

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Christopher Allen
Street & Number	Reliant Energy Osceola
Post Office, State, & ZIP Code	Houston TX
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: 0970071-001-AC PSD-FI-273	12-28-99

PS Form **3800**, April 1995

Osceola Co.
Chair -

Robert Guevara
Osceola Co Courthouse
17 S. Vernon Ave
Kissimmee Fl
34741

Fold at line over top of envelope to

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1. ☐ Addressee's Address
2. ☐ Restricted Delivery

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3. Article Addressed to:
Christopher Allen
Reliant Energy Oscoda
PO Box 4455
Houston, TX
77210-4455

4a. Article Number
Z 031 391 867

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
FEB 24 2000

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X GEE

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Z 031 391 867

US Postal Service
Receipt for Certified Mail
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Sent to Christopher Allen	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 2-22-00 097 0071-001-AC PSD-F1-273	

PS Form **3800**, April 1995

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2. ☐ Restricted Delivery

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3. Article Addressed to:
Mr. Christopher Allen
Reliant Energy Osceola
PO Box 4455
Houston, TX
77210-4455

4a. Article Number
Z 031 392 003

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery NOV 12 1999

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X

PS Fo...

...Receipt

Thank you for using Return Receipt Service.

Z 031 392 003

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
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Sent to Christopher Allen	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-9-99 0970071-001-AC PSD-FI-273	

PS Form **3800**, April 1995

592
1000

FedEx. USA Airbill FedEx Tracking Number 808307934580

Form I.D. No. 0210 SDA11 **Recipient's Copy**

1 From

Date 07-30-99 [redacted]

Sender's Name Jason Goodwin Phone (713) 945-7167

Company HOUSTON LIGHTING & POWER

Address 12301 KURLAND DR Dept./Floor/Suite/Room

City HOUSTON State TX ZIP 77034

2 Your Internal Billing Reference Information 102431;532010

3 To

Recipient's Name Mr. Al Linero, P.E. Phone ( )

New Source Review Section

Company Florida Department of Environmental Protection

Address 2600 Blair Stone Road Dept./Floor/Suite/Room

(To "HOLD" at FedEx location, print FedEx address here)

☐ Check here if residence (Extra charge applies for FedEx Express Saver)

City Tallahassee State FL ZIP 32399-2400

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☐ FedEx 2Day (Second business day)
☐ FedEx Express Saver (Third business day)

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4b Express Freight Service *Packages over 150 lbs.* Delivery commitment may be later in some areas.

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☐ FedEx 2Day Freight (Second business day)
☐ FedEx Express Saver Freight (Up to 3 business days)

(Call for delivery schedule. See back for detailed descriptions of freight services.)

5 Packaging
☐ FedEx Letter ☐ FedEx Pak (Declared value limit $500) ☐ FedEx Box ☐ FedEx Tube X Other Pkg.

6 Special Handling
Does this shipment contain dangerous goods?* (One box must be checked) ☐ No ☐ Yes (As per attached Shipper's Declaration) ☐ Yes (Shipper's Declaration not required)
☐ Dry Ice Dry Ice, 9, UN 1845 ______ x ______ kg.
☐ Cargo Aircraft Only
*Dangerous Goods cannot be shipped in FedEx packaging.

7 Payment
☐ Obtain Recipient FedEx Account No.
Bill to: X Sender (Account No. in Section 1 will be billed) ☐ Recipient ☐ Third Party ☐ Credit Card ☐ Cash/Check
(Enter FedEx Account No. or Credit Card No. below)

[redacted]

Total Packages	Total Weight	Total Declared Value*	Total Charges
1	50	$ .00	$

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Your signature authorizes Federal Express to deliver this shipment without obtaining a signature and agrees to indemnify and hold harmless Federal Express from any resulting claims.

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1. ☐ Addressee's Address
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3. Article Addressed to:

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

CENTRAL CITY CARRIER
NOV 12 1999
ATLANTA, GA 30303

4a. Article Number Z 031 392 004

4b. Service Type
- ☐ Registered
- ☒ Certified
- ☐ Express Mail
- ☐ Insured
- ☐ Return Receipt for Merchandise
- ☐ COD

7. Date of Delivery 11-12-99

5. Received By: *(Print Name)* Bruce Klose

6. Signature: *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

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Z 031 392 004

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
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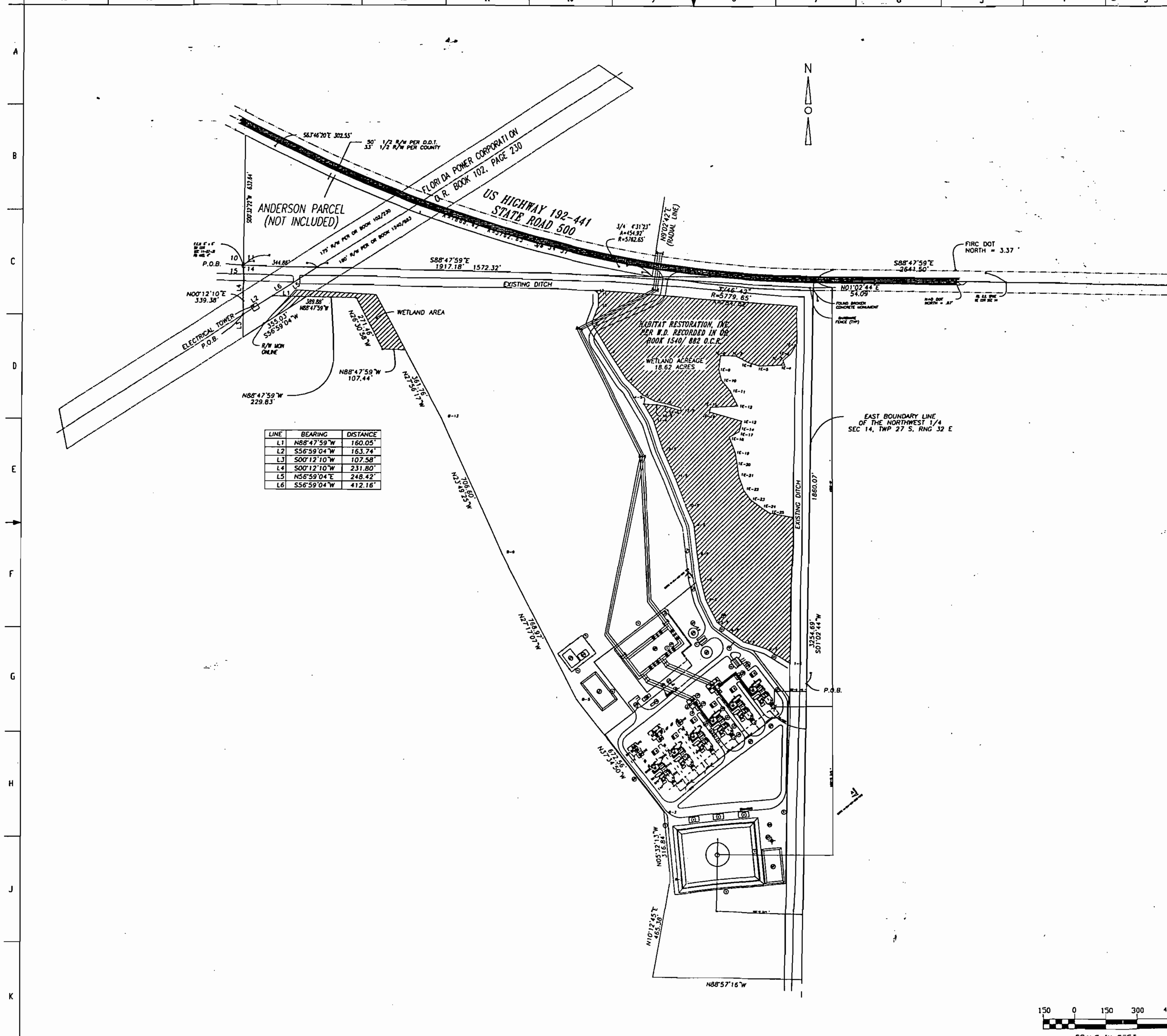
Sent to Gregg Worley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
Postage	$
Certified Fee	
Special Delivery Fee	Reliant
Restricted Delivery Fee	Energy
Return Receipt Showing to Whom & Date Delivered	Osceola
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-9-99 0970071-001-AC PSD-FI-273	

PS Form **3800**, April 1995

NOTES:

LEGEND:

1. FUEL OIL STORAGE TANK
2. FUEL OIL OFF-LOADING
3. FUEL OIL CONTAINMENT BERM
4. 230KV CIRCUIT BREAKER
5. PERIMETER FENCE
6. COOLING MODULE
7. WATER TREATMENT TRAILER PARKING
8. EMPLOYEE PARKING
9. FIREWALL
10. DEMINERALIZED WATER STORAGE TANK
11. ELECTRICAL EQUIPMENT, OFFICE AND PARTS STORAGE
12. STEP-UP TRANSFORMER
13. COMBUSTION GAS TURBINE GENERATOR
14. COMBUSTION GAS TURBINE
15. FIRE / RAW WATER TANK
16. FIREWATER PUMPS
17. STORMWATER BASIN
18. SWITCHYARD CONTROL BUILDING
19. 230KV DISC. SWITCH
20. GENERATOR BREAKER
21. CT ELECTRICAL PACKAGE
22. SWITCHYARD
23. GAS METERING STATION
24. GAS HEATER AND SCRUBBER
25. ROAD
26. LAYDOWN AREA
27. ENTRANCE ROAD
28. PROPERTY BOUNDARY
29. ACCESSORY MODULE
30. WETLAND BOUNDARY
31. 25' BUFFER
32. HYDROGEN TUBE TRAILER PARKING
33. HYDROGEN VALVE MANIFOLD
34. CO2 STORAGE
35. AUXILIARY TRANSFORMER
36. WATER WELL No. 1
37. WATER WELL No. 2
38. CT AIR INLET FILTER
39. NOT USED
40. OILY/WATER SEPARATOR
41. CT STACK
42. GATE



LINE	BEARING	DISTANCE
L1	N88°47'59"W	160.05'
L2	S56°59'04"W	163.74'
L3	S00°12'10"W	107.58'
L4	S00°12'10"W	231.80'
L5	N56°59'04"E	248.42'
L6	S56°59'04"W	412.16'

REV	DATE	DESCRIPTION
C		MOVED ENTRANCE ROAD AND RELOCATED TRANS. LINES
B		ADDED BDL TO STACK & OIL TANK REROUTED TRANS. LINE
A		ISSUED FOR REVIEW

DRAWN BY: VJB DATE: 10-05-99

CHECKED BY / LEAD DESIGNER / ENGINEER / LEAD DISCIPLINE ENGR. / PROJECT ENGINEERING MANAGER / PROJECT MANAGER

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.

CLIENT/PROJECT TITLE

Reliant Energy. OSCEOLA PROJECT

OSCEOLA COUNTY, FLORIDA
SIMPLE CYCLE PLANT

SITE PLAN

SCALE 1" = 150'

PARSONS DWG NO. OSCE-1-SK-110-002-001 REV C

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1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
James M. Goodwin, PE
Reliant Energy W. G.
PO Box 4455
Houston, TX 77034

4a. Article Number
Z 333 618 129

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
AUG 30 1999

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 129

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to James Goodwin	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Osceola	
Postage Houston	$ TX
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 0970071-001-AC PSD-FI-273	8-25-99

PS Form **3800**, April 1995

Reliant Energy Osceola, L.L.C.
Osceola Power Project
Enveloped Stack Parameters

BEST AVAILABLE COPY

Last Revised: 7/23/99
Date Printed: 7/28/99 3:48 PM

Special Comments:

Load Turbine Ambient Temperature (F)	100 Percent (Base) (NG) PG7241(FA) - GE 19	 59	 94	Representative 100 Percent Load	
Exit Velocity (ft/s)	163.05	157.91	151.95	151.95 ft/s	46.33 m/s
Exit Temperature (F)	1071.00	1111.00	1137.00	1071.00 F	850.37 K
Emissions (lb/h)					
NOx	73.50	70.00	65.33	73.50 lb/h	9.26 g/s
CO	36.20	33.80	31.50	36.20 lb/h	4.56 g/s
SO2	1.14	1.08	1.01	1.14 lb/h	0.14 g/s
PM[1]	18.00	18.00	18.00	18.00 lb/h	2.27 g/s

Load Turbine Ambient Temperature (F)	80 Percent (NG) PG7241(FA) - GE 19	 59	 94	Representative 80 Percent Load	
Exit Velocity (ft/s)	138.11	134.55		134.55 ft/s	41.02 m/s
Exit Temperature (F)	1116.00	1145.00		1116.00 F	875.37 K
Emissions (lb/h)					
NOx	61.83	58.33		61.83 lb/h	7.79 g/s
CO	29.20	28.00		29.20 lb/h	3.68 g/s
SO2	0.96	0.90		0.96 lb/h	0.12 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for NG Across 3 Load	
119.79 ft/s	36.52 m/s
1071.00 F	850.37 K
73.50 lb/h	9.26 g/s
36.20 lb/h	4.56 g/s
1.14 lb/h	0.14 g/s
18.00 lb/h	2.27 g/s

Load Turbine Ambient Temperature (F)	60 Percent (NG) PG7241(FA) - GE 19	 59	 94	Representative 60 Percent Load	
Exit Velocity (ft/s)	122.67	119.79		119.79 ft/s	36.52 m/s
Exit Temperature (F)	1153.00	1180.00		1153.00 F	895.93 K
Emissions (lb/h)					
NOx	52.50	49.00		52.50 lb/h	6.61 g/s
CO	25.70	24.50		25.70 lb/h	3.24 g/s
SO2	0.82	0.77		0.82 lb/h	0.10 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for both NG and FO Across 3 Loads	
119.79 ft/s	36.52 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	8.82 g/s
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load Turbine Ambient Temperature (F)	100 Percent (Base) (FO) PG7241(FA) - GE 19	 59	 94	Representative 100 Percent Load	
Exit Velocity (ft/s)	168.22	161.59	155.03	155.03 ft/s	47.27 m/s
Exit Temperature (F)	1053.00	1084.00	1115.00	1053.00 F	840.37 K
Emissions (lb/h)					
NOx	343.00	323.00	300.00	343.00 lb/h	43.22 g/s
CO	70.00	65.00	61.00	70.00 lb/h	8.82 g/s
SO2	104.38	98.41	91.25	104.38 lb/h	13.15 g/s
PM[1]	34.00	34.00	34.00	34.00 lb/h	4.28 g/s

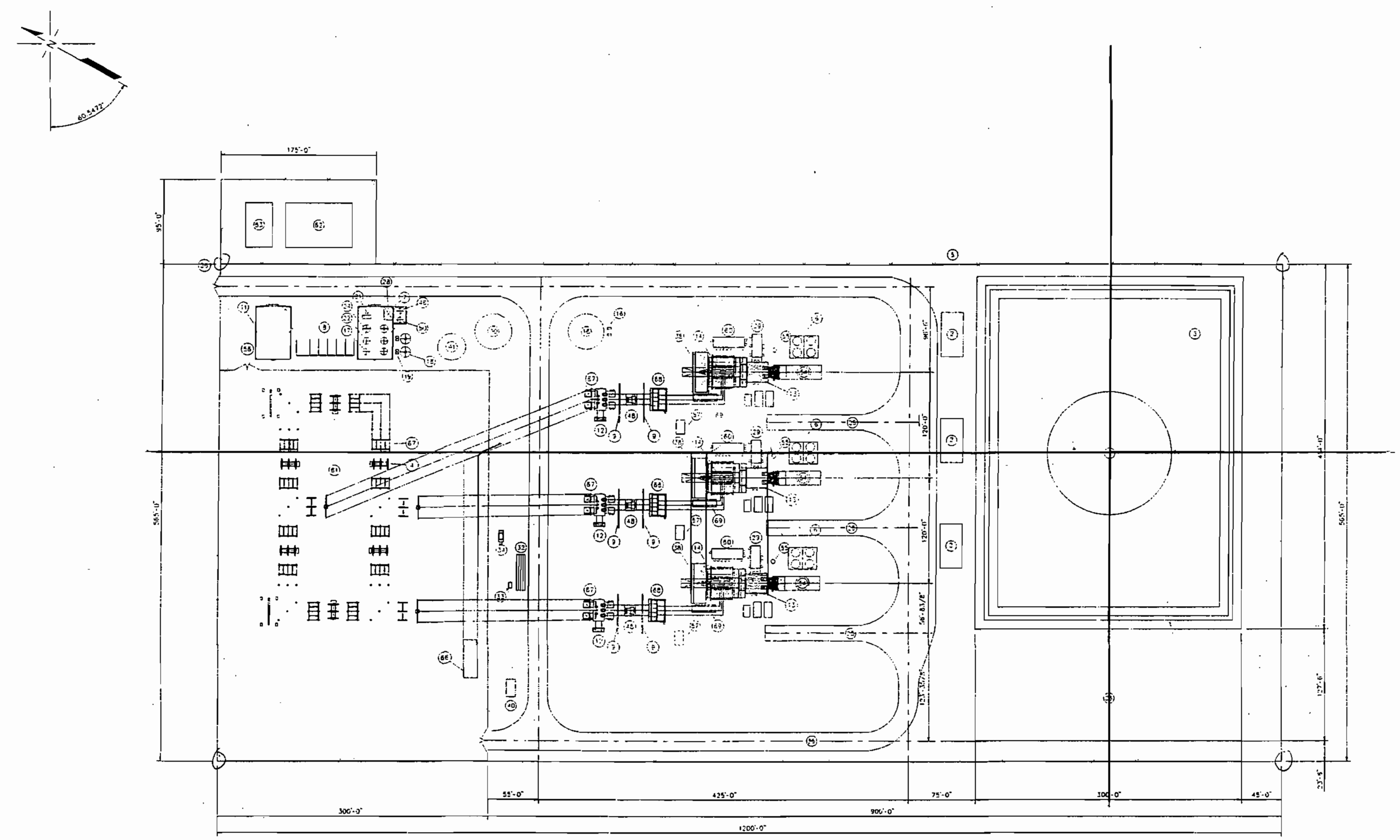
Load Turbine Ambient Temperature (F)	80 Percent (FO) PG7241(FA) - GE 19	 59	 94	Representative 80 Percent Load	
Exit Velocity (ft/s)	139.85	136.01		136.01 ft/s	41.47 m/s
Exit Temperature (F)	1163.00	1175.00		1163.00 F	901.48 K
Emissions (lb/h)					
NOx	288.00	269.00		288.00 lb/h	36.29 g/s
CO	54.00	52.00		54.00 lb/h	6.80 g/s
SO2	88.10	82.57		88.10 lb/h	11.10 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

Representative Worst-Case Stack for FO Across 3 Loads	
121.26 ft/s	36.97 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	8.82 g/s
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load Turbine Ambient Temperature (F)	60 Percent (FO) PG7241(FA) - GE 19	 59	 94	Representative 60 Percent Load	
Exit Velocity (ft/s)	124.01	121.26		121.26 ft/s	36.97 m/s
Exit Temperature (F)	1200.00	1200.00		1200.00 F	922.04 K
Emissions (lb/h)					
NOx	241.00	226.00		241.00 lb/h	30.37 g/s
CO	48.00	56.00		56.00 lb/h	7.06 g/s
SO2	74.44	69.83		74.44 lb/h	9.38 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

[1] PM emissions are front and back half

Best Available Copy



LEGEND:

1 FUEL OIL STORAGE TANK
2. FUEL OIL OFF-LOADING
3. FUEL OIL CONTAINMENT BERM
4. 230KV CIRCUIT BREAKER
5 PERIMETER FENCE
6. COOLING MODULE
7 PRE-ENGINEERED WATER TREATMENT BLDG
8 EMPLOYEE PARKING
9 FIREWALL
10. DEMINERALIZED WATER STORAGE TANK
11. ELECTRICAL EQUIPMENT, OFFICE, PARTS STORAGE
12 STEP-UP TRANSFORMER
13. COMBUSTION GAS TURBINE GENERATOR
14. COMBUSTION GAS TURBINE
15. FIRE / RAW WATER TANK
16. FIREWATER PUMPS
17. ACID CATION EXCHANGERS
18. DECARBONATOR
19. DECARBONATOR FORWARDING PUMPS
20. NOT USED
21. DEMINERALIZER CONTROL PANEL
22. ANTON EXCHANGERS
23. NOT USED
24. MIXED BED EXCHANGERS
25. ROAD
26. LAYDOWN AREA
27. NOT USED
28. CHEMICAL FEED SKID
29 ACCESSORY MODULE
30 NOT USED
31. NOT USED
32. HYDROGEN TUBE TRAILER PARKING
33. HYDROGEN VALVE MANIFOLD
34 CO2 STORAGE
35. NOT USED
36 NOT USED
37. NOT USED
38. CT AIR INLET FILTER
39 NOT USED
40. OILY/WATER SEPARATOR
41. NEUTRALIZATION TANK
42. NOT USED
43 NOT USED
44 NOT USED
45. FUEL SKID
46. ACID TANK
47 NOT USED
48. AUXILIARY TRANSFORMER
49. ACID REGEN. SYSTEM
50. CAUSTIC TANK
51 CAUSTIC REGEN. SYSTEM
52 NOT USED
53. NOT USED
54. CT STACK
55 FUEL GAS FILTER SEPARATOR
56 GATE
57. MV SWITCHGEAR
58. NOT USED
59 NOT USED
60. CT ELECTRICAL PACKAGE
61. SWITHYARD
62. FUEL GAS SCRUBBER SKID
63 FUEL GAS METERING SKID
64 WATER WASH SKID
65. COMBUSTION TURBINE DRAIN TANK
66. SWITCHYARD CONTROL BUILDING
67. 230KV DISC. SWITCH
68. GENERATOR BREAKER
69. EXCITATION TRANSFORMER

NOT FOR EXTERNAL RELEASE
ISSUED FOR INTERNAL APPROVAL

BY ______ DATE ______

BY ______ DATE ______

PRELIMINARY

-50 -25 0 50 150 200 250 300
SCALE IN FEET

Reliant Energy. Wholesale Group

Escondido Project
Holopaw, Florida Site
Proposed Equipment Arrangement
3 & 3 Future -GE 7FAs Simple Cycle Installation

Drawn by : J.C.Reyes Jr	06-18-99	Scale : 1"=50'-0"	
Checked by		Filename 904EPM05.DWG	
Approved by		904-EP-M-05	
Approved by			

Rev	Date	Description	By	Check	Apprv	Apprv

Reliant Energy

P.O. Box 4567
Houston, TX 77210-4567
713 207 3000

RECEIVED
OCT 16 2000
BUREAU OF AIR REGULATION

October 6, 2000

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Reliant Energy Osceola – Permit No. PSD-FL-273
File No. 0970071-001-AC
Notification of Start of Construction

Dear Mr. Halpin:

As required by 40 CFR 60.7 (a)(1) of the New Source Performance Standards (NSPS), Reliant Energy Osceola, L.L.C. (Reliant Energy) is required to submit notification to the Florida Department of Environmental Protection (DEP) and the U.S. Environmental Protection Agency (EPA) within 30 days that construction has begun. Construction activities for the Reliant Energy Osceola electric generating facility began on Tuesday, October 3, 2000.

Please contact me at 713-945-7167 if you have any questions or require additional information.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Start of Construction.doc

c: Mr. Winston Smith - Air, Pesticides and Toxics Management Division, U.S. EPA Region 4 – Atlanta
Mr. Leonard Kozlov – Central Region, Florida DEP - Orlando

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

February 17, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. J. Christopher Allen
Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

Re: DEP File No. 0970071-001-AC (PSD-FL-273)
Osceola Power Project
Three Simple Cycle Combustion Turbines

Dear Mr. Allen:

The Department reviewed your request dated February 7, 2000 to correct the number of fuel oil storage tanks allowed for in the construction permit No. PSD-FL-273, Osceola Power Project to be located at Holopaw, Osceola County. This correction allows for the construction of two fuel oil storage tanks with a capacity of 1.5 million gallons each, rather than one fuel oil storage tank with a 3 million-gallon capacity. As indicated by your submittals, this was included within your final site configuration change and this correction is issued as a minor, administrative change. The Department hereby authorizes this change and has attached the pertinent (corrected) pages of the permit.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2-22-00 to the person(s) listed:

J. Christopher Allen, Reliant*
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
Chair, Osceola County BCC
Donald Schultz, P.E., Black & Veatch

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 2-22-00
(Date)

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

File No.	PSD-FL-273
FID No.	0970071
SIC No.	4911
Expires:	July 1, 2002
Corrected:	February 17, 2000

Authorized Representative:

J. Christopher Allen

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators; two 1.5-million gallon fuel oil storage tanks; and three 75-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located on the south edge of a local road, approximately 7,000 feet west of U.S. 441. The local road intersects U.S. 441 approximately 5,000 feet south of the intersection of U.S. 192 and U.S. 441, Osceola County. UTM coordinates are: Zone 17; 490.429 km E; 3111.307 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

for Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site.. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 75-foot stacks and two 1.5-million gallon fuel oil storage tanks. Additionally a gas pipeline heater and a diesel fire pump are authorized for installation. Emissions from the new CT's will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	Two 1.5 Million Gallon Fuel Oil Storage Tanks

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 11/19/99 Notice of Intent published in The Orlando Sentinel
- 11/01/99 Distributed Intent to Issue Permit
- 10/29/99 Application deemed complete
- 08/03/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on August 3, 1999
- Applicant's response dated October 6, 1999 to Department Request dated August 25, 1999
- Applicant's e-mail dated October 20, 1999
- Applicant's additional submittal dated October 28, 1999
- Department's Intent to Issue and Public Notice Package dated November 8, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.
- Applicant's request for Administrative Change, received February 10, 2000 providing for 2 each 1.5-million gallon fuel oil storage tanks rather than 1 each 3-million gallon tank

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with evaporative coolers) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 004, Fuel Storage, consisting of two 1.5 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

Memorandum

Florida Department of Environmental Protection

ISSUED 2-18

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero 2/16

FROM: Mike Halpin

DATE: February 14, 2000

SUBJECT: Reliant Energy Osceola, L.L.C. Corrected PSD Permit

Attached for approval and signature are four pertinent pages related to a previously issued air construction permit for the subject (new) facility. A copy of the applicant's request is also attached.

The original application incorporated one 3-million gallon fuel oil storage tank. As indicated in the applicant's submittal, a late change to the facility layout during the public comment period (which I understand was prompted by a local desire to minimize noise) caused the applicant's final engineering design to utilize two tanks of 1.5-million gallons each.

I recommend your approval and signature.

Attachments

/mph

Reliant Energy

P.O. Box 4567
Houston, Texas 77210-4567
Phone [illegible]

February 7, 2000

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Reliant Energy Osceola – Permit No. PSD-FL-273 / File No. 0970071-001-AC
Request for Administrative Change

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. (Reliant Energy) was recently issued a Prevention of Significant Deterioration (PSD) Permit by the Florida Department of Environmental Protection (FDEP) authorizing construction and operation of the Osceola Power Project (Osceola), which is to be located near Holopaw, Florida. As we discussed by telephone recently, the final PSD permit for Osceola contained an error that was not identified prior to its issuance on December 28, 1999. The purpose of this correspondence is to request an administrative change to Permit No. PSD-FL-273 such that the permit conditions are consistent with Reliant Energy's construction plan for the Osceola facility.

You will recall that, due to potential noise impacts, Reliant Energy revised the proposed location of the Osceola facility by moving it approximately 5,000 feet to the south-southwest with respect to its previously planned location. As noted in correspondence to your office dated December 15, 1999, Reliant Energy performed an air dispersion modeling analysis on this new location and site configuration, and submitted a report to FDEP verifying that ambient impacts from emissions of all PSD pollutants would remain below the applicable significant impact levels.

Along with the revised project site location, Reliant Energy also revised the plant site layout to eliminate the single 3.0 million gallon fuel oil storage tank, which was part of the original facility plan. The final version of the facility plan, which was used as the basis for the final air modeling analysis, featured two fuel oil storage tanks with a capacity of 1.5 million gallons each. Accordingly, Reliant Energy is requesting that Permit No. PSD-FL-273 be modified to reflect the intent to construct two fuel oil storage tanks with a maximum storage capacity of 1.5 million gallons each, in lieu of the currently authorized single 3.0 million gallon-capacity fuel oil storage tank.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\FOST Revision.doc

c: Al Linero – Florida DEP – Tallahassee, FL

Fold at line over top of envelope to

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Christopher Allen
Reliant Energy Osceola
PO Box 4455
Houston, TX
77210-4455

4a. Article Number
Z 031 391 867

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
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PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

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US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Christopher Allen	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 2-22-00 097CO71-001-AC PSD-F1-273	

PS Form **3800**, April 1995

Reliant Energy

P.O. Box 4567
Houston, Texas 77210-4567
Phone 713 207 3000

February 7, 2000

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Reliant Energy Osceola – Permit No. PSD-FL-273 / File No. 0970071-001-AC
Request for Administrative Change

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. (Reliant Energy) was recently issued a Prevention of Significant Deterioration (PSD) Permit by the Florida Department of Environmental Protection (FDEP) authorizing construction and operation of the Osceola Power Project (Osceola), which is to be located near Holopaw, Florida. As we discussed by telephone recently, the final PSD permit for Osceola contained an error that was not identified prior to its issuance on December 28, 1999. The purpose of this correspondence is to request an administrative change to Permit No. PSD-FL-273 such that the permit conditions are consistent with Reliant Energy's construction plan for the Osceola facility.

You will recall that, due to potential noise impacts, Reliant Energy revised the proposed location of the Osceola facility by moving it approximately 5,000 feet to the south-southwest with respect to its previously planned location. As noted in correspondence to your office dated December 15, 1999, Reliant Energy performed an air dispersion modeling analysis on this new location and site configuration, and submitted a report to FDEP verifying that ambient impacts from emissions of all PSD pollutants would remain below the applicable significant impact levels.

Along with the revised project site location, Reliant Energy also revised the plant site layout to eliminate the single 3.0 million gallon fuel oil storage tank, which was part of the original facility plan. The final version of the facility plan, which was used as the basis for the final air modeling analysis, featured two fuel oil storage tanks with a capacity of 1.5 million gallons each. Accordingly, Reliant Energy is requesting that Permit No. PSD-FL-273 be modified to reflect the intent to construct two fuel oil storage tanks with a maximum storage capacity of 1.5 million gallons each, in lieu of the currently authorized single 3.0 million gallon-capacity fuel oil storage tank.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\FOST Revision.doc

c: Al Linero – Florida DEP – Tallahassee, FL

Florida Department of
Environmental Protection

Memorandum

TO: Howard L. Rhodes

THRU: Clair Fancy
~~Al Linero~~

FROM: Mike Halpin

DATE: December 21, 1999

SUBJECT: Reliant Energy Osceola, L.L.C. PSD Permit

Attached for approval and signature is an air construction permit for the subject (new) facility. The Public Notice requirements have been met on November 19, 1999 by publishing in the Orlando Sentinel.

Comments were received by the US EPA, US Fish and Wildlife Service as well as the applicant and are addressed within the Final Determination.

I recommend your approval and signature.

Day 90 is 1/22/99.

Attachments

/mph

Reliant Energy

P.O. Box 4567
Houston, Texas 77210-4567
Phone: 713 207 3000

December 20, 1999

RECEIVED

DEC 21 1999

BUREAU OF AIR REGULATION

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Submittal of Professional Engineer Certification for Reliant Energy Osceola Revised Ambient Air Quality Analysis

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. submitted a revised air quality impact analysis to your office for review on December 15, 1999 in support of a PSD air permit application for the Reliant Energy Osceola facility. As required by Florida DEP regulations, that submittal requires certification by a Florida registered professional engineer. Please find enclosed the required certification statement that pertains to the revised impact analysis.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Model PE Cert – v2.doc
Encl.

c: Al Linero – Florida DEP – Tallahassee, FL
(w/o encl.)

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✓], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D O Schultz | 12/17/99
Signature | Date

(seal)

DONALD EAM SCHULTZ
CERTIFICATE
NO. 30304
STATE OF
FLORIDA
REGISTERED ENGINEER

* Attach any exception to certification statement.

Reliant Energy

P.O. Box 4567
Houston, Texas 77210-4567
Phone: 713 207 3000

RECEIVED

DEC 16 1999

BUREAU OF AIR REGULATION

December 15, 1999

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Submittal of Revised Ambient Air Quality Analysis
Reliant Energy Osceola

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. recently submitted a Prevention of Significant Deterioration (PSD) Air Permit Application for the Osceola Power Project, to be located near Holopaw, Florida. As we discussed by telephone recently, the air quality impact analysis (AQIA) for Osceola has been modified to account for changes made to the proposed site layout that resulted from the movement of the plant island approximately 1 mile to the south-southwest of the original location.

The enclosed report discusses the results of the revised AQIA, and the enclosed compact disc includes the electronic files used in the revised analysis. The results of this revised analysis are consistent with the previously submitted analyses and indicate that emissions from the proposed Osceola facility will not exceed the applicable PSD significant impact levels for any regulated pollutant.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Revised Model Trans #3.doc
Encl.

c: Al Linero – Florida DEP – Tallahassee, FL

cc: C. Holladay, BAR
CD
NPS
EPA

Reliant Energy Osceola, L.L.C.
Revised Air Dispersion Modeling Analysis

Recent engineering and design changes to the proposed Reliant Energy Osceola facility have prompted additional air dispersion modeling to be performed for the proposed facility. These changes include a relocation of the entire facility approximately 1 mile south-southwest of the original location as well as modifications to the locations of on-site structures and the fenceline. There were no operational or performance related modifications made to the facility. The changes and their associated impacts were assessed with the Industrial Source Complex (ISCST3 Version 99155) air dispersion model. The methodology of this air dispersion modeling, including specific air dispersion model defaults, terrain, and meteorological data, remain unchanged from the original air dispersion modeling report submitted in the original Construction Permit Application of July 30, 1999, as well as a supplemental dispersion modeling report submitted on October 28, 1999.

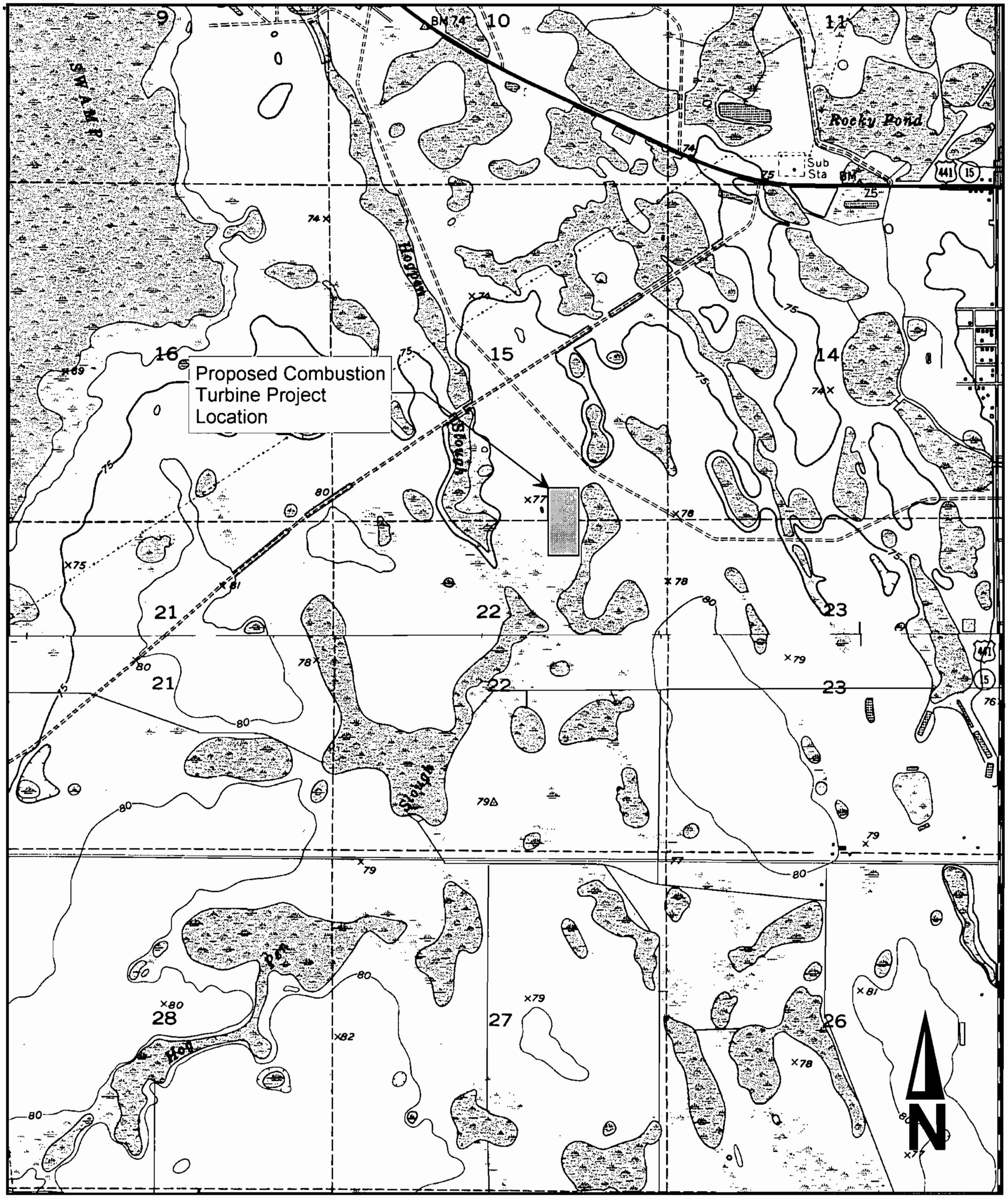
The facility was relocated approximately 1 mile south-southwest of the original site of the proposed generating facility. Figure 1 presents the current proposed location of the facility on a USGS topographic map. Figure 2 illustrates the revised nested rectangular grid, fence line receptors and the relative location of the emission sources and downwash structures.

All sources (including the fuel gas heater) and operating scenarios modeled in the two previous air dispersion modeling analyses were again modeled in this new arrangement. Maximum model predicted concentrations for each pollutant and applicable averaging period are presented in Table 1. This table also provides the PSD Class II significant impact levels and required preconstruction monitoring levels. As indicated in Table 1, the facility's maximum predicted concentrations for all pollutants from all sources and modeled operating scenarios are less than the PSD Class II Significant Impact Level (SIL) for each pollutant and applicable averaging period. These results are similar to those found in the previous air dispersion modeling analyses where the maximum predicted modeled impacts also were less than the respective PSD SILs for all pollutants and applicable averaging periods. The changes to the proposed facility will have an insignificant impact on the environment, and the PSD program requires no further air quality impact analyses. In addition, because the maximum predicted concentrations are all less than the PSD SILs for each pollutant and applicable averaging period and are not significantly greater than the original predicted maximum concentrations, the previously submitted Additional Impacts Analysis and Class I Area Impact Analysis were not updated, and the conclusions of these analyses remain valid.

A copy of the revised input (*.DAT) files and the output (*.LST) files from this updated analysis are included as an attachment.

Table 1 Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimus Monitoring Levels				
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimus Monitoring Level
NO_x	Annual	0.54	1	14
SO_2	Annual	0.40	1	-
	3-Hour	12.92	25	-
	24-Hour	4.33	5	13
CO	1-Hour	40.71	2,000	-
	8-Hour	22.07	500	575
PM_{10}	Annual	0.07	1	-
	24-Hour	1.50	5	10

Figure 1
Topographic Site Location



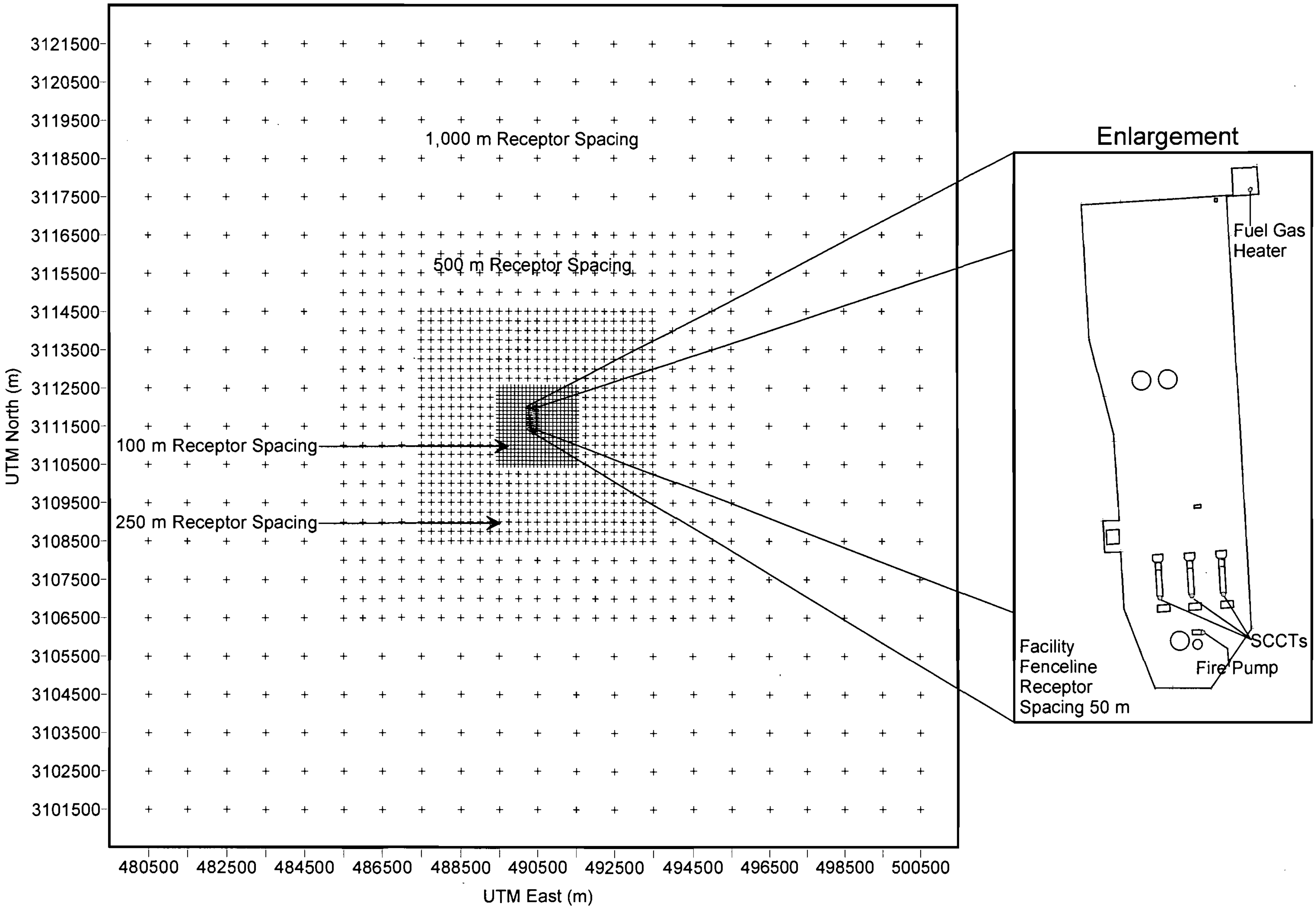
Base Map: 7.5 minute Quadrangles (Holopaw and Holopaw SE, FL)

Reliant Energy Proposed
Combustion Turbine Project Location

Figure 1

SiteLoc121099.srf

Figure 2
Receptor Locations and Facility Layout



Receptor Grid and Facility Layout

Figure 2

Site_Grid121099.srf

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. J. Christopher Allen
Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

DEP File No. 0970071-001-AC, PSD-FL-273
Reliant Energy Osceola Power Project
Osceola County

Enclosed is Final Permit Number 0970071-001-AC. This permit authorizes Reliant Energy Osceola, L.L.C. to construct the Osceola Power Project. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-28-99 to the person(s) listed:

J. Christopher Allen, Reliant*
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
Chair, Osceola County BCC
Donald Schultz, P.E., Black & Veatch

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 12-28-99 (Date)

FINAL DETERMINATION

Reliant Energy
Reliant Energy Osceola, L.L.C./ Osceola County
DEP File No.0970071, PSD-FL-273

The Department distributed a public notice package on November 9, 1999 to allow the applicant to construct a new plant known as the Reliant Energy Osceola Project located near Holopaw, Osceola County. The Public Notice of Intent to Issue was published in Orlando Sentinel on November 19, 1999.

COMMENTS/CHANGES

Comments were received from the EPA by letters dated November 19, 1999 and December 8, 1999.

Comments were received on the application from the Fish and Wildlife Service by letter dated September 15, 1999.

Comments were received from the applicant by electronic correspondences dated December 15 and December 7 as well as by letters dated December 6 and December 15, 1999.

The applicant commented on the Technical Evaluation and Preliminary Determination (TEPD), the Draft BACT and the DRAFT Permit. The comments related to the BACT and permit are summarized below and the Department's responses are included following each comment. Comments related to the TEPD are noted and maintained in the file.

The Fish and Wildlife Service commented on the applicant's proposed BACT Analysis, specifically on the NO_X emission rate while firing natural gas.

EPA commented on the proposed Custom Fuel Monitoring Schedule as well as the Draft BACT and Draft Permit.

GENERAL COMMENT BY THE DEPARTMENT

As a result of local input, Reliant Energy Osceola moved the proposed site about 1.5 km southwest of the original location near Holopaw, Osceola County (New UTM coordinates: Zone 17, 3111.307 North, 490.429 East). Accordingly, new modeling was submitted to show that the proposed facility would still meet all ambient air quality standards. All stack parameters remained the same in the new modeling except for the locations, however entirely new building locations and boundary parameters were input into the model. The results of the revised modeling were consistent with the modeling that was submitted for the original location. There were a few minor differences, which can be attributed to the new building and boundary receptor locations. All predicted modeled impacts for the new facility location were still less than the respective PSD Significant Impact Levels for all pollutants and all averaging periods. Also, since the facility was moved by only 1.5 km from the original location, there was no need to conduct a Class I analysis.

DRAFT Permit Facility Description:

The applicant noted that the Facility Description did not mention the gas pipeline heater nor the emergency diesel fire pump and requested that these be noted therein.

RESPONSE: The Facility Description will be revised to incorporate these pieces of equipment, as they were provided for within the applicant's request.

DRAFT Permit Specific Conditions:

1. *Specific Conditions 10, 27 and 42*: The applicant requested that up to 5 working days be allowed in which to submit a report to FDEP regarding emission limit exceedances. The submitted rationale included "additional time will provide an opportunity for facility staff to fully characterize the nature of the emission exceedance, develop an appropriate response to correct the situation and provide a comprehensive description of the event to FDEP."

RESPONSE: Rule 62-4.130, F.A.C. states "...the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause...". The Department has consistently construed the *immediately* requirement in this rule to mean within one day. The permit condition (as worded) expands the one-day requirement to "...(1) working day, excluding weekends and holidays." This requirement is consistent with and standard for all similar permits issued by the Department. Accordingly, these permit conditions will not be revised.

2. *Specific Condition 19*: The USEPA commented that the 24-hour block average as measured by CEMS is an excessive averaging period for determining compliance with a unit which will run intermittently.

RESPONSE: The Department believes that a 24-hour block average is a reasonable averaging time for compliance with the NO_X emission rate for combustion of the primary fuel on an intermittently run unit. These units are being permitted for operation up to 3000 hours per year. On average, this equates to just over 8 hours per day. Since the 24-hour block average applies only to each calendar day, it has the effect of being reasonably equivalent to an 8-hour block average. However, by setting the averaging time at 24 hours, compliance becomes more manageable by both the permittee as well as the compliance office as there will be one compliance period per operating day, regardless of operating hours. Conversely, for the secondary fuel (oil) the permitted hours of operation are 750 per year. On average, this equates to about 2 hours per day of oil operation suggesting that a shorter averaging period may be appropriate.

3. *Specific Condition 19B*: The applicant requested that the condition be removed. The applicant indicated the requirement "...reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd..." in light of the proposed permit limit of 10.5 ppmvd may lead to future disagreements on the interpretation of the limit.

RESPONSE: The Department agrees with the applicant concerning potential interpretation issues. However, the Fish and Wildlife Service noted that "...emissions in the 9-ppm range are readily achievable and feasible on the overwhelming majority of newer simple cycle units with DLN". The Department wishes to ensure that the permit condition allow for a 10.5 ppmvd limit in the event that actual operation yields this emission rate. However, the Department also wishes to ensure that emissions are maintained in the 9-ppmvd range should actual operation support this emission rate. Accordingly, the Department will eliminate the referenced language, but will provide for its concerns in specific condition 29 (discussed below).

4. *Specific Condition 19D*: The applicant requested that this requirement be removed. The applicant noted that a 42 ppmvd limit "...is justified and appropriate for the Osceola facility while firing fuel oil." The applicant additionally noted that the proposed "...750 hours cumulatively" requirement for developing the proposed NO_X reduction plan for oil firing was an inadequate amount of operating time. Lastly, the applicant requested that (if the condition

must remain) it should "...address the likely event that no new NO_X emission limit is justified while the units fire fuel oil."

RESPONSE: The purpose of the requirement is precisely to ensure that the 42 ppmvd NO_X limit while firing oil is appropriate and that the applicant takes all measures to minimize these emissions. Therefore, the condition will not be eliminated, but will be revised to require this plan after any individual combustion turbine reaches 750 hours of operation on fuel oil.

5. *Specific Condition 20*: The applicant noted that the 70.0 lb/hr CO emission rate referenced in the condition should specifically state "while firing fuel oil".

RESPONSE: The Department concurs with this request.

6. *Specific Condition 25 and 26*: The applicant requested that operation below 50% output should be allowed for up to two hours for each startup or shutdown event. The proposed condition required that "Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open)." Rationale cited by the applicant included operational flexibility and minimization of reliability impacts. The USEPA commented that the allowance for excess emissions of up to 2 hours in a 24-hour period is excessive and should be reduced to 1-hour in 24. Rationale included citing the January, 1999 preliminary determination for KUA Cane Island Power Park, which allowed for only 1 hour.

RESPONSE: Department does not concur with the applicant's request. Emissions of the proposed machines are significantly higher at outputs below 50%, prompting the Department's requirement. Allowing for the applicant's request could lead to as many as 1460 hours per year (based upon 4 hours per day for 365 days per year) out of with the permitted 3000 hours per year of operation to be at these higher emission rates. Additionally, a day during which CT operating time is less than 4 hours could be completely within the requested time allotment. Concerning the EPA's comments, the Florida Administrative Code, Rule 62-210.700 allows for excess emissions up to two hours in a 24-hour period provided that certain criteria are met.

7. *Specific Condition 29*: The applicant requested that the annual stack testing requirement for demonstrating NO_X compliance should be deleted based upon several factors including the concurrent (and more representative) proposed requirement of compliance via CEMS.

RESPONSE: [Refer to Department's comments on *Specific Condition 19B* above]. The permit condition will be revised to allow for the elimination of the requirement for an annual NO_X compliance test (however an annual CEMS RATA will still be required). This allowance will be granted annually upon satisfactory submittal to the Department (within the notification letter described in Specific Condition 35) that an average of 9 ppmvd NO_X emissions is being achieved while firing natural gas. This demonstration shall consist of an average of all valid CEMS 24-hour block average compliance periods (described in Specific Condition 30) during which the unit operated on gas since the last compliance test requirement.

8. *Specific Conditions 31, 45 and 45B*: The applicant requested clarification on issues related to a Custom Fuel Monitoring Schedule.

RESPONSE: The Department believes that the EPA's letter dated November 19, 1999 on this subject satisfies the clarification required by the applicant. This letter was sent via facsimile to the applicant on December 7, 1999.

DRAFT BACT Determination:

1. *BACT Determination Requested by the Applicant*: The applicant requested that the summary table be revised to reflect 2.0 gr/scf for the natural gas sulfur content and that the textual description of the annual emission limits be based upon 59°F ambient temperature.

RESPONSE: The Department concurs.

2. *Standards of Performance for New Stationary Sources*: The final sentence in the first paragraph should be revised to read "...which allows NO_x emissions over 110 ppmvd...".

RESPONSE: The Department concurs.

3. *Review of Sulfur Dioxide (SO_2) and Sulfuric Acid Mist*: The applicant noted that the annual emission limit should be 123 tons/year.

RESPONSE: The Department concurs and will additionally revise the text below the table on page BD-1 to indicate the same.

4. *Rationale for Department's Determination:* The USEPA noted that several GE 7FA dual-fuel simple cycle CT's have been permitted with NO_X emission rates of 9 ppmvd. The Agency recommended that the Department address the difference between the Reliant Osceola facility and those other facilities if indeed differences exist.

RESPONSE: The Department concurs and will buttress its rationale accordingly.

CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

PERMITTEE:

Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

File No.	PSD-FL-273
FID No.	0970071
SIC No.	4911
Expires:	July 1, 2002

Authorized Representative:

J. Christopher Allen

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators; one 3-million gallon fuel oil storage tank; and three 75-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located on the south edge of a local road, approximately 7,000 feet west of U.S. 441. The local road intersects U.S. 441 approximately 5,000 feet south of the intersection of U.S. 192 and U.S. 441, Osceola County UTM coordinates are: Zone 17; 490.429 km E; 3111.307 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

CH Fancy
for Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 75-foot stacks and a 3-million gallon fuel oil storage tank. Additionally a gas pipeline heater and a diesel fire pump are authorized for installation. Emissions from the new CT's will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	One 3 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 11/19/99 Notice of Intent published in The Orlando Sentinel
- 11/01/99 Distributed Intent to Issue Permit
- 10/29/99 Application deemed complete
- 08/03/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on August 3, 1999
- Applicant's response dated October 6, 1999 to Department Request dated August 25, 1999
- Applicant's e-mail dated October 20, 1999
- Applicant's additional submittal dated October 28, 1999
- Department's Intent to Issue and Public Notice Package dated November 8, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District office, 3319 Maguire Boulevard, Orlando, Florida 32803-3767 and phone number 407/894-7555.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

SECTION II. ADMINISTRATIVE REQUIREMENTS

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District office. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District office by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1998 version), shall be submitted to the DEP's Central District office. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with evaporative coolers) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]
5. ARMS Emission Unit 004, Fuel Storage, consisting of one 3 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]
6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District.

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 19°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,709 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,942 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c)., F.A.C.]

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 3,000 hours in any consecutive twelve month period, of which up to 750 hours may be on fuel oil. See Specific Condition 40. for compliance requirements. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period [Rule 62-210.200, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	18/34 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC	As Above	1.5 ppmvw (Gas) 3.7 ppmvw (Fuel Oil)
CO	As Above	10.5 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	10.5 ppmvd (Gas) 42 ppmvd (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:

- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 10.5 ppmvd @15% O_2 on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 60 pounds per hour (at ISO conditions) and 9 ppmvd @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. [Rule 62-212.400, F.A.C.]

- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 323 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- The permittee shall develop a NO_X reduction plan when the hours of oil firing on any individual combustion turbine reaches 750 hours. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 10.5 ppmvd and 36.2 lb/hr (at ISO conditions) while firing gas and neither 20 ppmvd and 70.0 lb/hr (at ISO conditions) while firing oil. The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.5 ppmvw nor 3.0 lb/hr (ISO conditions) and neither 3.7 ppmvw nor 8.0 lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]
22. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 750 hours per year per unit. Emissions of SO_2 (at ISO conditions) shall not exceed 1.1 lb/hr (natural gas) and 104.3 lb/hr (fuel oil) as measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]
23. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 18.0 lb/hr when operating on natural gas and shall not exceed 34.0 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]
24. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions and shall not exceed 10 opacity. Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be

minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

26. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Central District within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or

RATA test data may be used to demonstrate compliance for annual test requirements). Annual compliance demonstration via EPA Method 7E shall not be required upon satisfactory demonstration that the emission unit is operating at 9 ppmvd NO_X emissions or less. This demonstration shall consist of an average of each of all valid CEMS 24-hour block average compliance periods (described in Specific Condition 30.) for which the unit operated on natural gas since the last compliance test requirement. This demonstration shall be provided within the test notification letter (described in Specific Condition 35.); but does not relieve the permittee of the annual CEMS RATA requirement.

- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

   - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity

when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

35. Test Notification: The DEP's Central District shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

36. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to the DEP's Central District no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by Reliant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

39. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.37 above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

40. Hours of Operation and Fuel Usage: Reliant shall maintain records on-site of each CT's "hours of operation by fuel type" and "BTU input by fuel type" for each month. These shall

be tabulated for each consecutive 12-month period (as per specific permit conditions identified herein) and made available upon request for Department use. Additionally, this data shall be submitted annually with the AOR.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on these Units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C, 40 CFR 75and 40 CFR 60.7 (1998 version)].

42. CEMS for reporting excess emissions: Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Central District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

43. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS

44. Continuous Monitoring Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 2 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

47. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Case-by-Case Maximum Achievable Control Technology (X)
c) Determination of Prevention of Significant Deterioration (X); and
d) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Reliant Energy Osceola Power Project
PSD-FL-273 and 0970071-001-AC
Osceola County, Florida

BACKGROUND

The applicant, Reliant Energy Osceola, L.L.C. (Reliant) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Osceola Power Project at Holopaw, Osceola County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 75-foot stacks. Reliant proposes to operate these units up to 3,000 hours per year per unit of which 750 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 8, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on August 3, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch.

REVIEW GROUP MEMBERS:

M.P.Halpin, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	10.5 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (750 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	10.5 ppmvd (gas, baseload) 20 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2.0 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

According to the application, the maximum emissions from the facility (based upon a 59° F ambient temperature) will be approximately 569 tons per year (TPY) of NO_X, 185 TPY of CO, 99 TPY of PM/PM_{10}, 123 TPY of SO_2, 19 TPY of SAM, and 20 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Reliant is within the NSPS limit, which allows NO_X emissions over 110 ppmvd for the high efficiency units to be purchased for the Osceola Power Project.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed Reliant Osceola Power Project is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Vandolah Hardee, FL	680 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application 8/99. 1000 hrs on oil
Oleander Brevard, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Baldwin, FL	510 MW SC INT	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510 MW SC INT	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 8/99. 750 hrs on oil
TEC Polk Power, FL	330 MW SC INT	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	1.5 – NG 3.7 – FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the Fish and Wildlife Service dated September 15, 1999
- Comments from EPA Region IV dated November 19, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for JEA Brandy Branch Station Project
- GE Combustion Turbine Startup Curves
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Osceola project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 750 hours per year (per CT).

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the Osceola Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the Osceola project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the Osceola project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[1], but their performance on fuel oil is not known to the Department.

<u>Selective Catalytic Combustion</u>

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects firing natural gas throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[2] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at PG&E's La Paloma Plant near Bakersfield.[3] The overall project includes several more 250 MW blocks with SCR for control.[4] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). $SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONONtm Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The Department estimated total emissions for the project at 123 TPY of SO_2 and 19 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100 scf). This value is well below the "default" maximum value of 20 gr S/100 scf, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 750 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 99 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[5]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 10.5 and 20 ppm for gas and oil respectively at baseload proposed in Reliant's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Reliant for this project are 1.5 ppmvw for gas and 3.7 ppmvw for oil firing at baseload and fall well below the PSD significance rate of 40 TPY. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[6]

BACKGROUND ON PROPOSED GAS TURBINE

Reliant plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F (or 7FA) unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[9] The City of Tallahassee received a permit in 1998 to install a GE PG7231FA combustion turbine at its Purdom Plant.[10] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[11]

FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for fourteen GE 7241FA turbines to be installed at the Fort Myers and Sanford Repowering Projects.[12, 13] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241FA turbine with DLN-2.6 burners.[14] Draft BACT determinations of 9 ppmvd were proposed for the proposed combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities).[15, 16]

Most recently, the Department issued a draft BACT determination for the simple cycle Oleander project in Brevard County and final BACT determinations for the simple cycle TEC project in Polk County and the JEA Brandy Branch Project in Duval. These three draft permits also include "new and clean" NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units. The Oleander Project will meet 9 ppmvd on a 24-hour basis and will be allowed to burn fuel oil for 1000 hr/yr/unit. The TEC and JEA projects will meet 10.5 ppmvd on a 24-hour basis, but will limited in oil firing to 750 hr/yr/unit.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combustion turbines in Florida. When required by BACT determinations of most states, General Electric incorporates SCR in combined cycle projects.[17] In its recent permits, Florida has included separate and lower limits in the event that GE's DLN technology does not achieve 9 ppmvd or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[18] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[19] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the Reliant Osceola Power Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[20]

The 10.5-ppmvd NO_X limit on natural gas proposed by Reliant is quite reasonable for simple cycle 7FA combustion turbines. Typically, companies obtain a guarantee from GE to achieve 9 ppmvd during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation.

With the frequent start-ups and shutdowns of the unit, Reliant (as are TEC and JEA) is concerned about the ability to maintain the low NO_X values for long periods of time. As a result, TEC and JEA agreed to a "new and clean" limit of 9 ppmvd but a continuing limit of 10.5 ppmvd. Their permits reflect fewer hours on oil (than Oleander and Vandolah) for the higher NO_X value on gas. Presumably, their concern would be lessened should these units be converted to baseload combined cycle operation. Although the Department is not fully aware of the details of the GE guarantees for Oleander or Vandolah (proposed 9 ppmvd on simple cycle units), the Department is aware from discussions with other applicants that a continuing guarantee may be available at a substantial cost.[21]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[22]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Reliant project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 18/34 lb/hr – Gas/Fuel Oil
CO	As Above	10.5 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42 ppmvd – F.O. for 750 of 3,000 hours

RATIONALE FOR DEPARTMENT'S DETERMINATION

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. Given the little amount of actual operating hours for these dual-fuel machines and the lack of a long-term guarantee by the vendor, both the applicant and the Department find themselves in the position of estimating the actual long-term emission rate, which may be continuously achievable. The Department believes that the long-term emission rate is nearly certain to be less than 15 ppmvd, with likely values closer to 9 ppmvd. However, an increasing amount of risk is borne by the applicant for accepting the lower values. Accordingly, the Department attempts, on a case-by-case basis, to find that point of permitting where the evaluation of all variables combined (including such things as the requested hours of total operation, the amount of back-up fuel operation being requested, the requested limits of interrelated pollutants such as NO_X and CO, averaging times for compliance, etc.) provides ample reasonable assurance that the combined permit conditions can be met. For this application, the Department believes that a continuous emission rate limit of 10.5 ppmvd for NO_X is that point.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was <u>proposed</u> by Oleander for five GE7 FA units and is reflected in the Department's Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander, Vandolah, and Virginia Power while firing natural gas is the lowest known <u>Draft</u> BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department issued permits for the TEC Polk Power and the JEA Brandy Branch Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander and Vandolah.
- The proposed BACT limit of 10.5 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible only for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst (around 1125 °F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.
- The levelized costs of NO_X removal by Hot SCR for the JEA project were estimated by Black & Veatch at $28,509 per ton assuming 1000 hours of operation on natural gas and a reduction from 10.5 to 5 ppmvd. The Department estimates that this figure is actually closer to $10,000 per ton by including oil operation (up to 750 hours per year), 2250 hours per year of gas operation and other criteria.

- TEC estimated the cost of Hot SCR at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle oil-fired projects (PREPA).
- Although the Department does not have a "bright line" cost-effectiveness figure and does not adopt the supplied cost calculations for the Osceola Power Project, Hot SCR is not cost-effective for this project.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[23]
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.75 lb./MW-hr NO_X emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb/MW-hr for simple cycle CT's and less than 0.5 lb/MW-hr for combined cycle units.
- Although not determined by BACT, proposed VOC emissions of 1.5 ppmvd while firing gas and 3.7 ppmvw firing oil reflect BACT.
- The Department will set CO limits achievable by good combustion at full load as 10.5 ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units. These limits are better than or equal to those proposed by the Department for the Oleander, JEA Brandy Branch, and TEC Polk Power projects.
- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88/83 percent control efficiency (oil/gas) and having a three-year catalyst life. Levelized costs for CO catalyst control were calculated at $12,888 per ton. The Department estimates this figure to be closer to $4,000 per ton, but it does not appear to be cost-effective for removal of CO.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the

City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power and quite a number of combined cycle projects.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

M.P. Halpin, P.E. Review Engineer MPHalpin, P.E.

A. A. Linero, P.E. Administrator MPHalpin for AAL

New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

CHFancy
C. H. Fancy, P.E., Chief
Bureau of Air Regulation

12/23/99
Date:

Approved By:

for CHFancy
Howard L. Rhodes, Director
Division of Air Resources Management

12/23/99
Date:

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[11] Application. City of Tallahassee. PSD/Site Certification Application. April, 1997.

[12] Permit. Florida DEP. FPL Fort Myers Repowering Project. File 0710002-004-AC. November, 1998.

[13] Permit. Florida DEP. FPL Sanford Repowering Project. File 1270009-004-AC. September, 1998.

[14] Permit. Florida DEP. Santa Rosa Energy Center. File 1130168-001-AC. December, 1998.

[15] Draft Permit. Florida DEP. Duke Energy New Smyrna Project. File PSD-FL-257. January, 1999.

[16] Draft Permit. Florida DEP. KUA Cane Island Unit 3. File PSD-FL-254. January, 1999.

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[19] Monthly Report. Florida DEP Bureau of Air Regulation. June, 1998.

[20] Telecon. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

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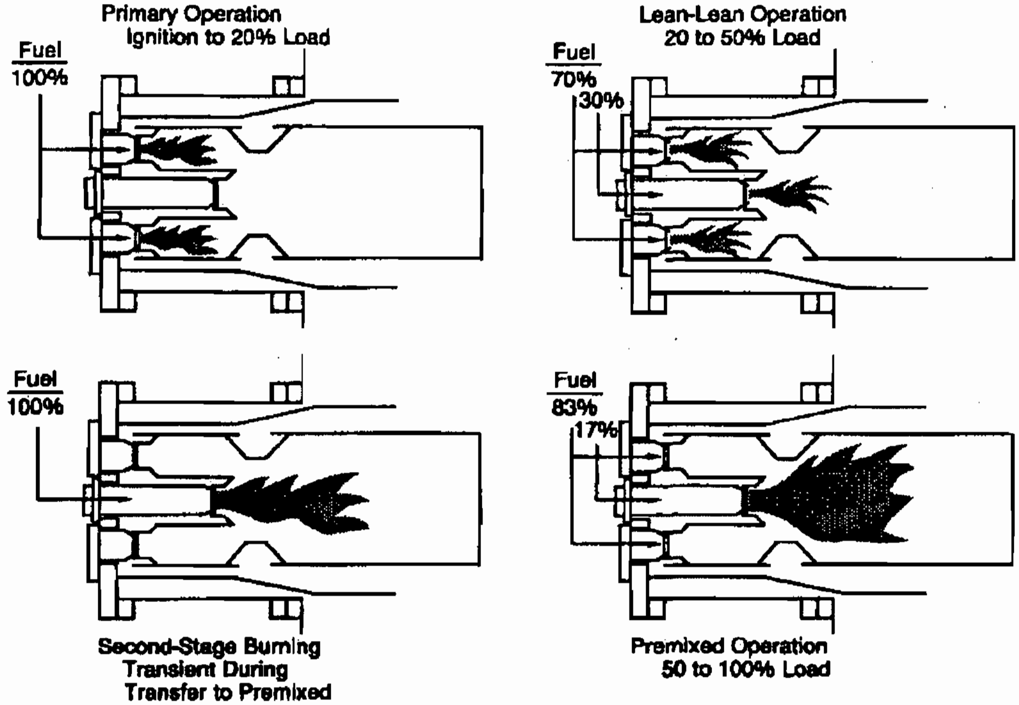

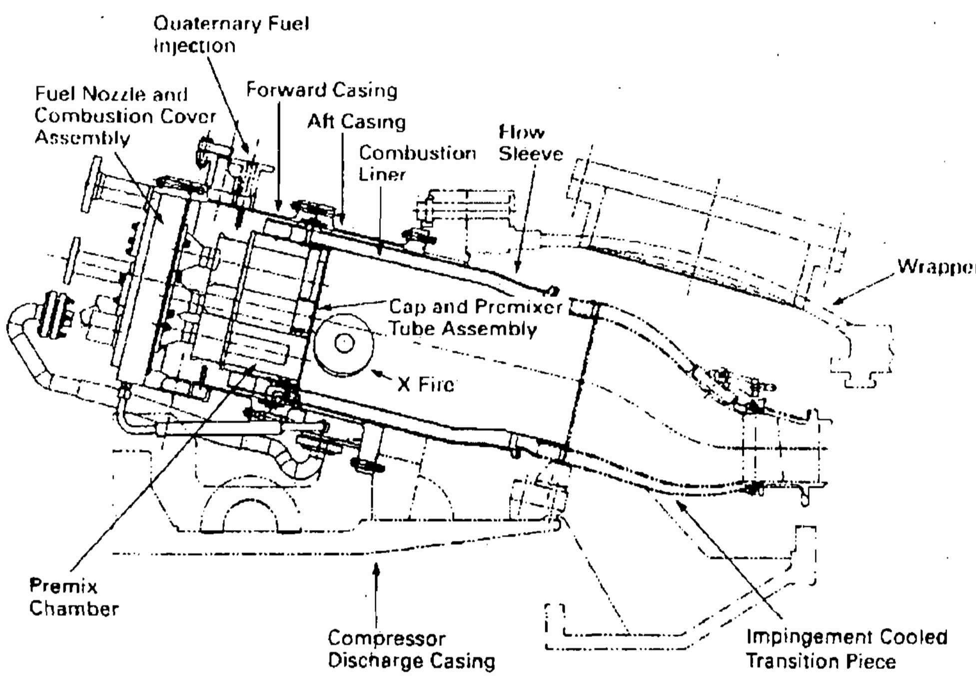

Figure 1 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

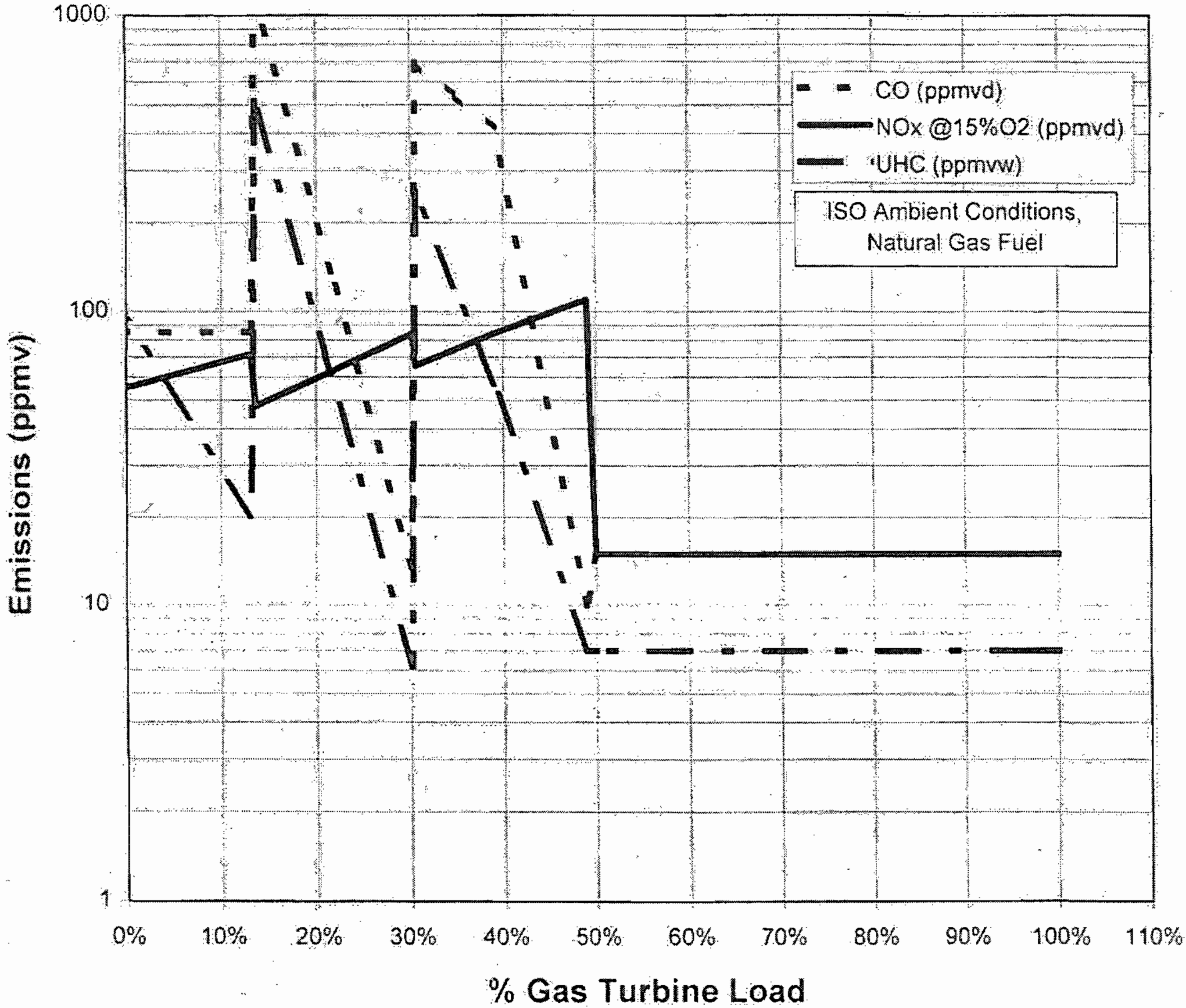

Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

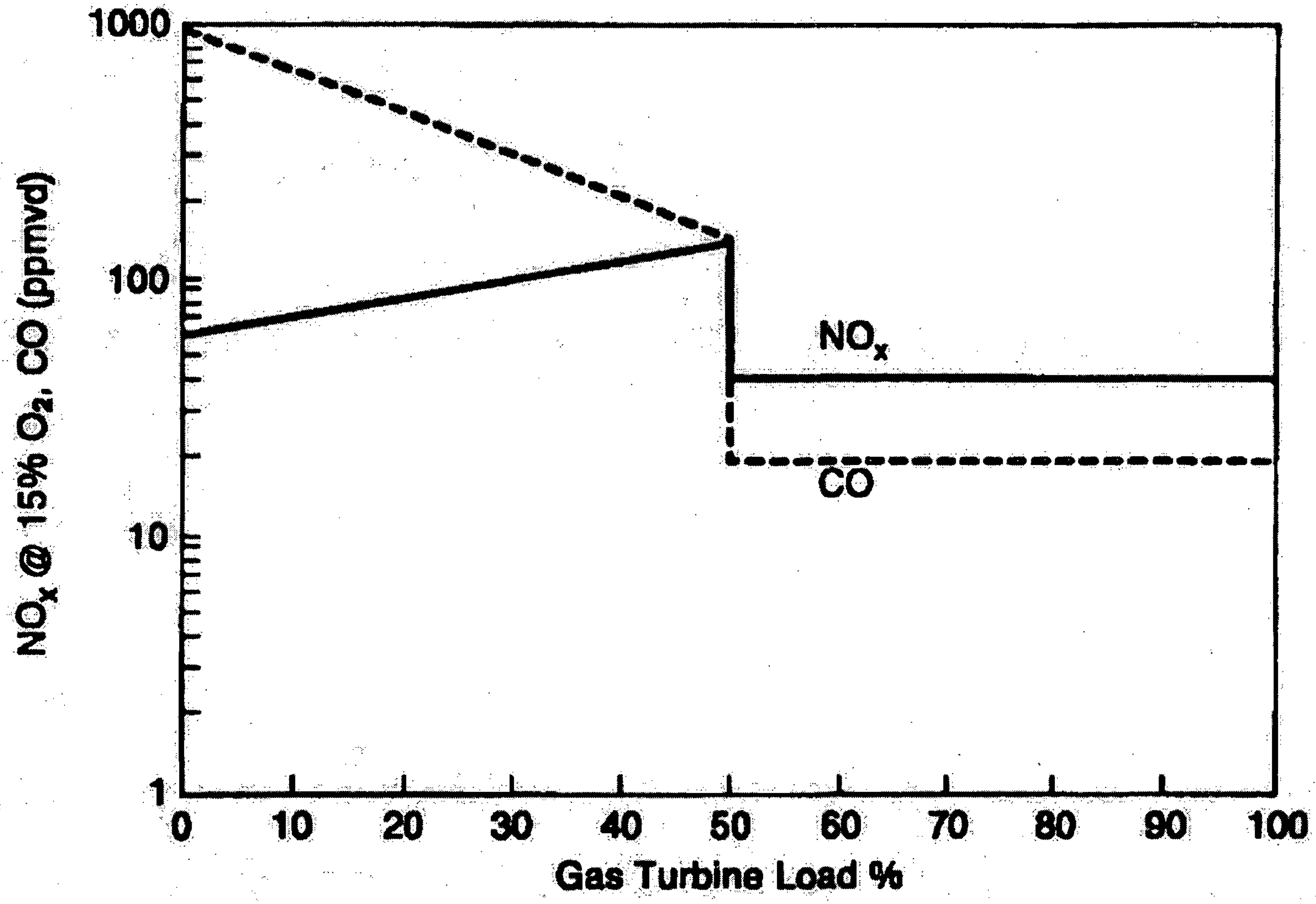

Figure 3 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

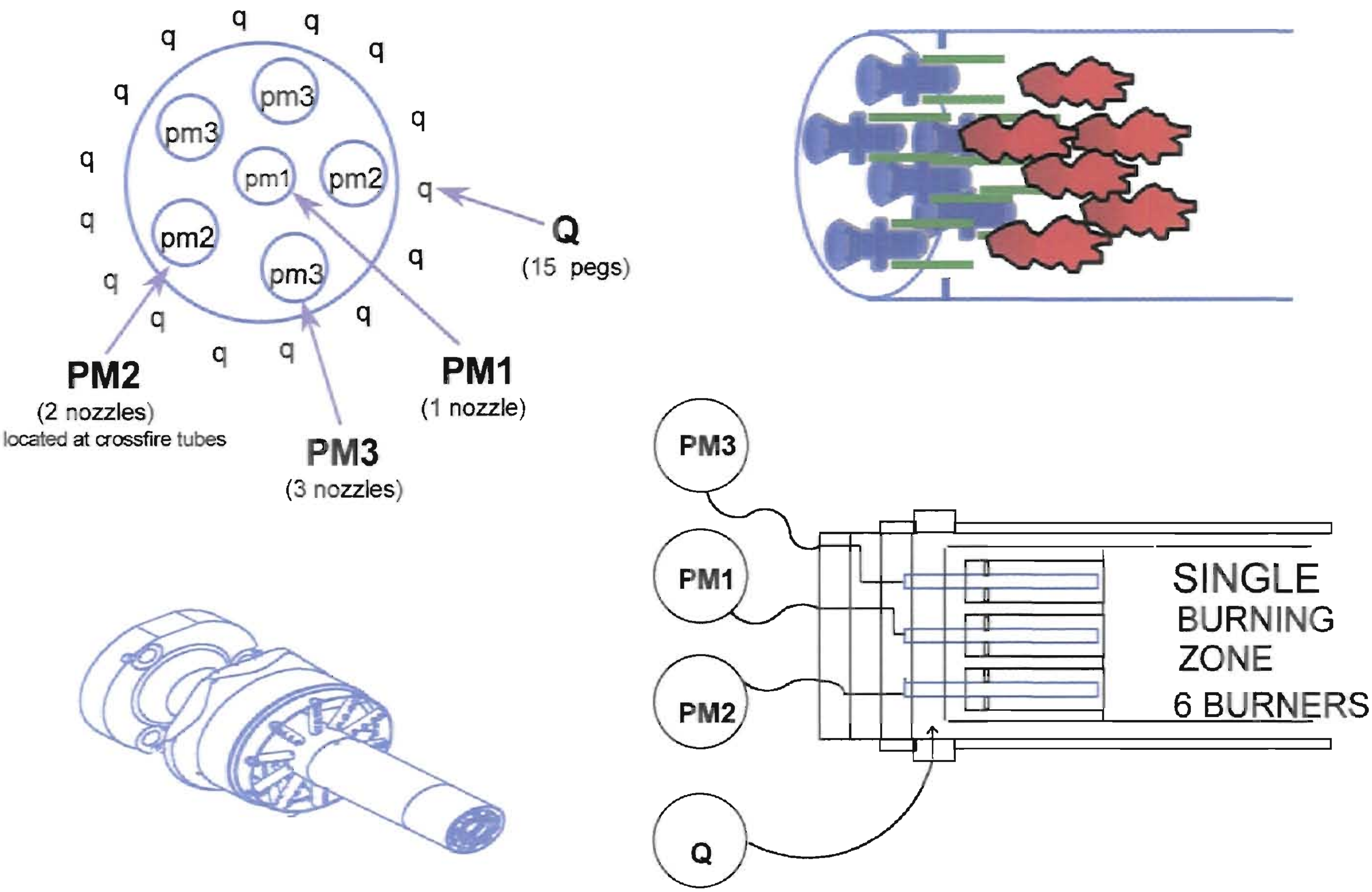

Figure 4 - DLN2.6 Fuel Nozzle Arrangement

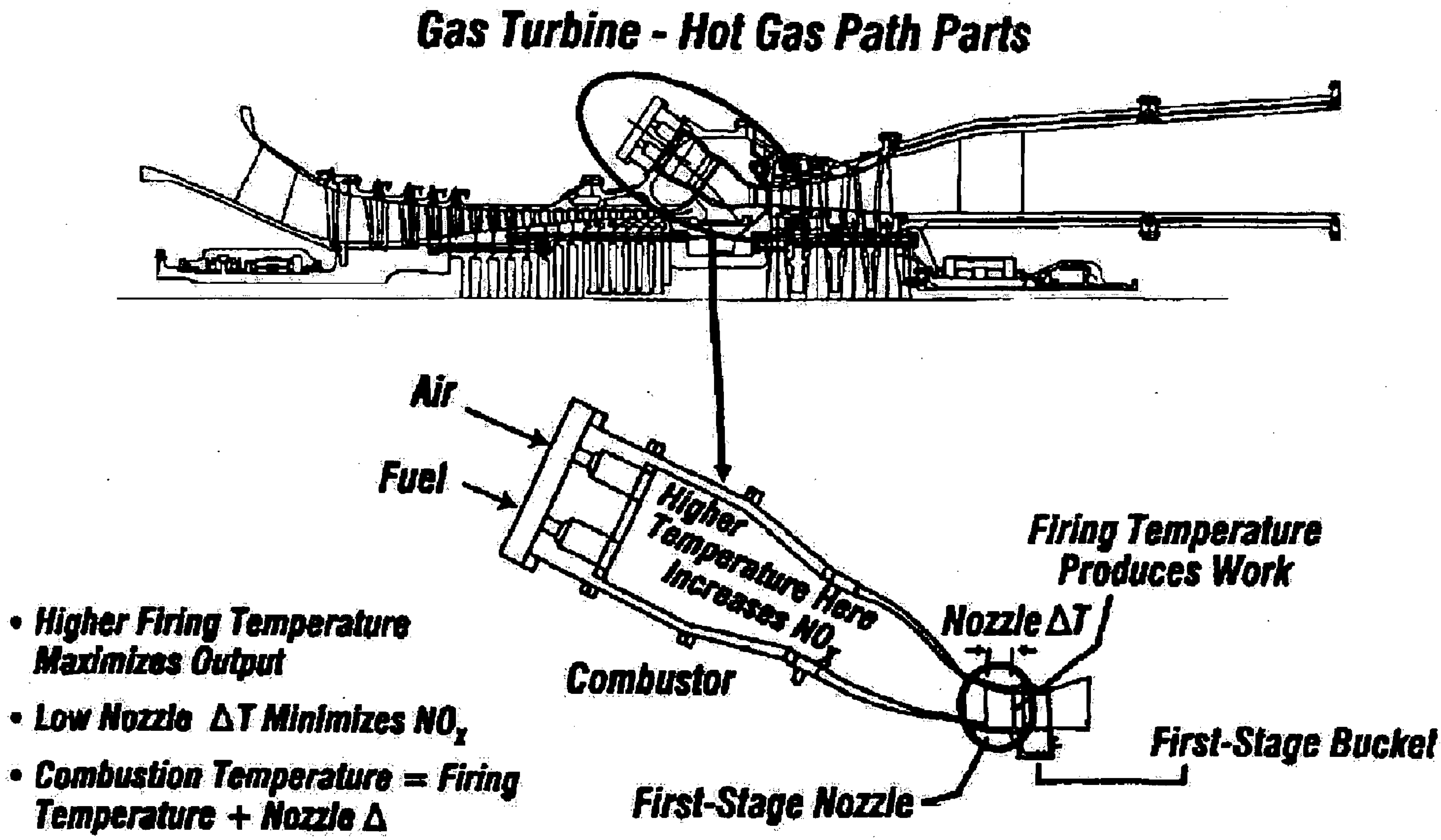

Figure 5 – Relation Between Flame Temperature and Firing Temperature

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Osceola Co.
Chair -

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DEC 13 1999

BUREAU OF AIR REGULATION

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for Jacksonville Electric Authority - Reliant Energy Osceola, LLC (PSD-FL-273) located in Osceola County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit dated November 8, 1999, for the above referenced facility. The preliminary determination is for the proposed construction and operation of a power project consisting of three simple cycle combustion turbines (CTs) with a nominal generating capacity of 170 MW each. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. Additional equipment will include the following: one 3 million gallon fuel oil storage tank, one small diesel fire-water pump and a 9.8 mmBtu/hr natural gas pre-heater. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. The fire-water pump will combust only diesel fuel. Each CT will be allowed to fire natural gas a maximum of 3,000 hours per year and will be allowed to fire No. 2 fuel oil a maximum of 750 hours per year. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM).

Based on our review of the preliminary determination and draft permit, we have the following comments:

1. The NO_x BACT emission limit, when burning natural gas in the combustion turbines, is 10.5 ppmvd (15% oxygen). The Environmental Protection Agency (EPA) Region 4 has recently reviewed several GE 7FA dual-fuel simple cycle combustion turbine projects with a proposed BACT emissions limit of 9 ppmvd for NO_x, three of which are located in Florida (Oleander, FPC-Intercession City, IPS Vandolah). If the Reliant Osceola facility is significantly different from these other facilities, documentation of this difference should be included in the department's final determination.

2. In condition 19 of the draft permit, the emission rate for NO_x is set as 60.0 lb/hr on a 24-hour block average as measured by CEMS. Since the proposed CTs will run intermittently in

simple cycle mode and will seldom operate for 24 consecutive hours, the averaging period for this emission limit should be much shorter, consistent with the 3-hour averaging period proposed for fuel oil combustion.

3. We are pleased to see that FDEP re-performed the cost analysis for the SCR and CO Oxidation add-on control systems. FDEP concluded the cost effectiveness for the add-on controls were approximately $10,000/ton removed of NO_x and $4,000/ton removed of CO. The original application's cost analysis calculated the cost effectiveness of SCR as $28,000/ton removed of NO_x and $12,800/ton removed of CO and contained several items which should not have been included in the cost analysis or needed further clarification. For instance, an interest rate of 10% was used to calculate the cost recovery factor, a "lost power generation" penalty was included in the annual costs, a 15% contingency fee was included in the indirect capital costs, and an engineering cost of 10% seems to be double counted (included in both the direct and indirect capital cost section).

4. As indicated in conditions 25 and 26 of the draft permit, FDEP is proposing to allow excess emissions due to startup, shutdown or malfunction for up to 2 hours in any 24-hour period. This proposal is inconsistent with FDEP's preliminary determination for Kissimmee Utility's Cane Island Power Park (January 1999) which only allowed excess emissions from a simple cycle combustion turbine for 1 hour in any 24-hour period. Additionally, it is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

Thank you for the opportunity to comment on the Reliant Energy Osceola facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to either Katy Forney at (404) 562-9130 or Jim Little at (404) 562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: M. Halpin, BAR
CD
NPS

Reliant Energy

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Phone: 713 207 3000

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BUREAU OF AIR REGULATION

December 6, 1999

Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road – MS #5505
Tallahassee, Florida 32399-2400

Subject: Reliant Energy Osceola, L.L.C. – Comments on Draft Air Quality Permit
Reliant Energy Osceola Facility – Osceola County, Florida

Reliant Energy Osceola, L.L.C. (Reliant Energy) appreciates the opportunity to provide written comments to the Florida Department of Environmental Protection (FDEP) on the draft air construction permit for the Reliant Energy Osceola (Osceola) facility. These comments are in response to the draft air quality permit/Notice of Intent that was issued to Reliant Energy on November 8, 1999 and are being submitted for consideration by FDEP during the 30-day public notice and comment period. The comments have been apportioned to the various documents that were provided to Reliant Energy as part of the Notice of Intent package.

Technical Evaluation and Preliminary Determination

Item No. Comment

6.2. The table that provides a summary of annual emission limits for various pollutants appears to be incorrect. Specifically, it appears that emission calculations were based on unit heat input at an ambient temperature of 19°F instead of the 59°F ambient condition that is typically used as the basis for annual emission limit calculations. According to Reliant Energy's calculations, the table should be revised as follows:

Pollutant	Gas	Oil	Total
CO	113	72	185
NO_x	233	336	569
SO_2	4	119	123

Reliant Energy requests that the annual emission limit summary table be revised to reflect emission calculations that are based on ISO reference conditions at 59°F ambient temperature.

Air Construction Permit

Facility Description

As noted in correspondence submitted to FDEP on October 28, 1999, Reliant Energy elected to add a fuel gas pipeline heater to the proposed Osceola facility. In earlier submittals to FDEP, Reliant Energy also represented the construction of a diesel engine used to power pumps used for fire protection service. However, the draft construction permit for Osceola contains no discussion of these items in either the facility description or in the summary of emission units. To eliminate any confusion about what sources are authorized under this construction permit, Reliant Energy requests that the permit be revised to reflect the authorization to construct the aforementioned fuel gas pipeline heater and diesel fire pump engine.

Specific Conditions

SC	Comment
10	Revise this specific condition to allow five (5) working days in which to submit a report to FDEP regarding emission limit exceedences caused by equipment failure or other causes. This additional time will provide an opportunity for facility staff to fully characterize the nature of the emission exceedence, develop an appropriate response to correct the situation and provide a comprehensive description of the event to FDEP.
19-B	Reliant Energy requests that this condition be removed. Reliant Energy has demonstrated through air dispersion modeling and a BACT analysis that a NO_x emission limitation of 10.5 ppm is justified and appropriate for the Osceola facility. Although the condition specifies that "reasonable" efforts are required to maintain NO_x emissions below 9 ppm, this term could lend itself to different interpretations under various circumstances. Furthermore, the second portion of this requirement also represents a significant additional burden to the Osceola facility. Tuning of the combustors may become necessary to optimize unit performance at some time after the initial compliance test as part of periodic inspection and maintenance activities, and the requirement to demonstrate that the unit can again meet the NO_x emission levels required at initial start-up represents a significant and possibly unachievable burden. This condition also could be viewed as a hindrance to performance improvement since any attempt to optimize unit performance through combustor adjustments could trigger this more stringent emission standard. Additionally, this post-modification emission requirement could become more difficult to achieve after several years of operation by the combustion turbine due to performance degradation of various components. This factor is a prime consideration in why the emission performance guarantee for the model 7FA combustion turbine applies only to a single demonstration in a "new and clean" condition. Given these concerns, Reliant Energy strongly suggests that this requirement be eliminated and that the demonstration of compliance with a 9 ppm emission limit for NO_x only be required at the initial demonstration of compliance.
19-D	Reliant Energy requests that this specific condition be deleted. As discussed above with respect to Specific Condition 19-B, it has been demonstrated through air dispersion modeling as well as a BACT analysis that a NO_x emission limitation of 42 ppm is justified and appropriate for the Osceola facility while firing fuel oil. Should FDEP decide to retain this specific condition, the associated provisions should be further clarified as they pertain to the development of a monitoring and testing protocol for emissions of NO_x during periods of fuel oil firing. Specifically, Reliant Energy requests that the condition be revised to require the aforementioned emissions and performance review after the combustion turbine units reach 750 hours of operation on fuel oil **individually**. Also, Reliant Energy suggests that the condition be revised to address the likely event that no new NO_x emission limit is justified while the units fire fuel oil.
20	Revise this specific condition to read: "...and neither 20 ppmvd and 70.0 lb/hr **while firing fuel oil**..."

SC	Comment
25	Revise this specific condition to limit each startup or shutdown event to no more than two (2) hours as applied to each startup or shutdown event. This extension of time will allow additional operational flexibility to the facility as well as minimize reliability impacts that may occur due to frequent cycling and abbreviated ramp up/ramp down periods that are associated with combustion turbine units that operate in peaking service, such as Osceola.
27	Consistent with the comment noted above for Specific Condition 10, this condition should be revised to require notifications for excess emissions within five (5) days of the event. This additional time will provide an opportunity for facility staff to fully characterize the nature of the emission exceedence, develop an appropriate response to correct the situation and provide a comprehensive description of the event to FDEP
29	Reliant Energy requests that FDEP delete the specific condition requiring annual NO_x compliance testing of the proposed generating units. The proposed units are subject to 40 CFR 75 and are thereby required to install, maintain and operate a continuous emissions monitoring system (CEMS) for emissions of NO_x from each of the three proposed generating units. Because the Part 75 monitoring requirements represent the "gold standard" for emissions monitoring QA/QC practices, Reliant Energy believes that the continuous monitoring of NO_x emissions in accordance with the requirements of Part 75 provides a reliable and comprehensive indicator of compliance with the applicable NO_x emission limits. Furthermore, continuous emission monitoring also is a more representative indicator of compliance that reflects unit operating performance at all operating loads and ambient conditions. In contrast, an annual compliance test represents a limited data set that provides emission data only at a single load point over a limited timeframe – usually no more than three hours – and presents an additional expense to the facility while providing limited additional benefit to the environment.
31	This specific condition should be clarified with respect to the use of a Custom Fuel Monitoring Schedule (CFMS), as it pertains to the fuel nitrogen and sulfur sampling requirements of 40 CFR 60.334, by including a reference to Specific Condition 45 that provides discussion of requirements associated with the CFMS.
42	As discussed previously under Specific Conditions 10 and 27, revise this condition to require written notification of emission exceedences within five (5) days.
45	Revise this specific condition to provide more detail on the requirements to obtain or comply with a CFMS. Specifically, this condition should either state clearly that a CFMS for nitrogen and sulfur sampling in natural gas fuel has been approved for the Osceola facility, or provide specific guidelines, requirements and information on how Osceola can apply for such a CFMS. Reliant Energy suggests that a CFMS for the Osceola facility should include the following provisions: - fuel nitrogen sampling should not be required; - fuel sulfur analysis should be required on a reduced schedule upon demonstration that sulfur content of the gas supply is below 2 gr/100 scf; and - fuel sulfur content may be demonstrated according to Gas Processors Association Standard 2377-86 ("length of stain tube" method).
45-B	Revise the specific condition to allow certification of a monitoring plan, as it pertains to any proposed or applicable CFMS, by the Alternate Designated Representative of the Osceola facility. Delegation of this authority is consistent with the intent and practice of the Acid Rain program and should be extended to the proposed permit.

BACT Determination

BACT Determination Requested by the Applicant

The reference to the sulfur content of pipeline-quality natural gas as noted in the summary table should be revised to 2.0 gr/100 scf. Also, the textual description of the annual emission limits should be based on the 59°F ambient temperature condition according to the following table.

Pollutant	Total
CO	185
NO_x	569
SO_2	123

Standards of Performance for New Stationary Sources

The final sentence in the first paragraph should be revised to read:

"...which allows NO_x emissions over 110 ppmvd..."

Review of Nitrogen Oxides Control Technologies

- NO_x Control Techniques

  First paragraph, third sentence, should be revised to read:

  "...which is operated as lean as stable combustion..."

Review of Sulfur Dioxide (SO_2) and Sulfuric Acid Mist

The annual emission limit for SO_2 emissions should be 123 tons/year.

Reliant Energy appreciates your consideration of the aforementioned issues. Please contact me at 713-945-7167 if there are any questions or if additional information is required.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Draft Permit Comments.doc

c: Mr. Michael Halpin, P.E. – Florida DEP – Tallahasse, FL
Mr. Joe Welborn – Seminole Electric Cooperative – Tampa, FL

cc: CD
EPA
NPS

Reliant Energy

November 2, 1999

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Submittal of Professional Engineer Certification for Reliant Energy Osceola Revised Ambient Air Quality Analysis

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. submitted a revised air quality impact analysis to your office for review on October 28, 1999 in support of a PSD air permit application for the Reliant Energy Osceola facility. As required by Florida DEP regulations, that submittal requires certification by a Florida registered professional engineer. Please find enclosed the required certification statement that pertains to the revised impact analysis.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Model PE Cert.doc
Encl.

c: Al Linero – Florida DEP – Tallahassee, FL

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D D Schultz
Signature
(seal)

October 29, 1999
Date

DONALD DEAN SCHULTZ
CERTIFICATE
NO. 30304
STATE OF
REGISTERED ENGINEER

Reliant Energy

P.O. Box 4567
Houston, Texas 77210-4567
Phone: 713 207 3000

November 22, 1999

Mr. Michael P. Halpin, P.E.
New Source Review Division
Florida Department of Environmental Protection
2600 Blair Stone Road – MS #5505
Tallahassee, Florida 32399-2400

Subject: Submittal of Publisher's Affidavit for Public Notification
Reliant Energy Osceola – Draft Air Construction Permit

Dear Mr. Halpin:

Pursuant to the letter from the Florida Department of Environmental Protection (FDEP) dated November 8, 1999, Reliant Energy Osceola, L.L.C. (Reliant Energy) has provided public notification regarding its application for an air quality construction permit for the proposed Reliant Energy Osceola (Osceola) facility. In accordance with FDEP Rule 62-110.106 (7)(a)1, Reliant Energy published a notification in the *Orlando Sentinel* on November 19, 1999. Enclosed you will find a copy of the published notice and the corresponding publisher's affidavit.

Please contact me at 713-945-7167 if you have any questions regarding this matter or require any additional information.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Public Notice Submittal.doc
Encl.

c: Mr. Al Linero – Florida DEP – Tallahasse, FL
Mr. Joe Wellborn – Seminole Electric Cooperative – Tampa, FL
(all w/ encl.)

cc: M. Halpin
CD
EPA
NPS

RECEIVED
NOV 24 1999
BUREAU OF AIR REGULATION

The Orlando Sentinel

Published Daily

State of Florida
COUNTY OF ORANGE } S.S.

Before the undersigned authority personally appeared Denise Little, who on oath says that he/she is the Legal Advertising Representative of The Orlando Sentinel, a daily newspaper published at Kissimmee in Osceola County, Florida; that the attached copy of advertisement, being a Notice Of Intent in the matter of Permit in the OSCEOLA Court, was published in said newspaper in the issue; of 11/19/99

Affiant further says that the said Orlando Sentinel is a newspaper published at Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, each Week Day and has been entered as second-class mail matter at the post office in Kissimmee in said Osceola County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Denise Little

The foregoing instrument was acknowledged before me this 22 day of November, 19 99 by Denise Little, who is personally known to me and who did take an oath.

Beverly C. Simmons

(SEAL)

STATE OF FLORIDA NOTARY PUBLIC

BEVERLY C. SIMMONS
My Comm Exp. 3/10/2001
Bonded By Service Ins
No. CC619266
[ ] Personally Known [ ] Other I D

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Reliant Energy Osceola, L.L.C. The permit is to construct three nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 75-foot stacks and a 3 million gallon fuel oil storage tank for the proposed Osceola Power project. The facility will be located approximately 0.75 miles west of the intersection of U.S. 192 and U.S. 441, Holopaw, Osceola County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO2), particulate matter (PM/PM10), nitrogen oxides (NOx), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Reliant Energy Osceola, L.L.C., P.O. Box 4455, Houston, Texas 77210-4455.

The new units will be General Electric nominal 170 MW PG7241FA combustion turbines-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate 3,000 hours per year of which no more than 750 hours per year will be using 0.05 percent sulfur distillate fuel oil.

NOx emissions will be controlled by Dry Low NOx (DLN-2/6) combustors. The units must meet a continuous emission limit of 10.5 parts per million by volume at 15 percent oxygen (ppm.) NOx will be controlled 42 ppm by wet injection when firing fuel oil Sulfuric acid mist, SO2, and PM/PM 10 will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emission in tons per year based on information provided to the Department is summarized below.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10	99	25/15
CO	201	100
NOx	634	40
VOC	20	40
SO2	121	40
Sulfuric Acid Mist	19	7

Air quality and regional haze impact analyses were conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed under sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3) however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number if known; (b) The name, address and telephone number of the petitioner; the name and address, and telephone number of the petitioner's representative, if any; which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A state of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts on which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m. Monday through Friday, except legal holidays, at:

Department of Environmental Protection	Department Environmental Protection
Bureau of Air Regulation	Central District Office
111 S. Magnolia Drive, Suite 4	3319 Maguire Boulevard, Suite 232
Tallahassee, Florida 32301	Orlando, Florida 32803-3767
Telephone: 850/488-0114	Telephone: 407/894-7555
Fax: 850/922-6979	Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

OSC3019483 NOVEMBER 19,1999

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

NOV 1 9 1999

4APT-ARB

Mr. A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: Custom Fuel Monitoring Schedule Proposed for Reliant Energy Osceola located in Osceola County, Florida

Dear Mr. Linero:

This letter is in response to your November 8, 1999, request for approval of a custom fuel monitoring schedule for Reliant Energy. Reliant will operate three natural gas-fired simple cycle combustion turbines subject to 40 C.F.R. Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. As requested, Specific Conditions 41, 42, 43, 45 and 46 have been reviewed. The Environmental Protection Agency (EPA) Region 4 has concluded that the use of acid rain nitrogen oxides (NO_X) continuous emission monitoring system (CEMS) for demonstrating compliance, as described in Specific Conditions 41, 42 and 43, is acceptable. Region 4 has also concluded that the natural gas custom fuel monitoring schedule proposed in Specific Condition 45 and the fuel oil monitoring schedule described in Specific Condition 46 are both acceptable.

According to 40 C.F.R. 60.334(b)(2), owners and operators of stationary gas turbines subject to Subpart GG are required to monitor fuel nitrogen and sulfur content on a daily basis if a company does not have intermediate bulk storage for its fuel. 40 C.F.R. 60.334(b)(2) also contains provisions allowing owners and operators of turbines that do not have intermediate bulk storage for their fuel to request approval of custom fuel monitoring schedules that require less frequent monitoring of fuel nitrogen and sulfur content.

Region 4 reviewed Specific Condition 45 which allows SO_2 emissions to be quantified using procedures in 40 C.F.R. 75 Appendix D in lieu of daily sampling as required by 40 C.F.R. 60.334(b). Since the specific limitations listed in the permit condition are consistent with previous determinations, we have concluded that the use of this custom fuel monitoring schedule is acceptable.

Specific Conditions 41, 42 and 43 involve the method used to monitor NO_X excess emissions. Under the provisions for 40 C.F.R. 60.334(c)(1), the operating parameters used to identify NO_X excess emissions for Subpart GG turbines are water-to-fuel injection rates and fuel nitrogen content. As an alternative to monitoring NO_X excess emissions using these parameters, Reliant is proposing to use a NO_X CEMS that is certified for measuring NO_X emissions under 40 C.F.R. Part 75. Based upon a determination issued by EPA on March 12, 1993, NO_X CEMS can be used to monitor excess emissions from Subpart GG turbines if a number of conditions specified in the determination are met and included in the permit condition.

Specific Condition 41 addresses the potential for correcting results to ISO standard day conditions. The basis for this requirement is that, under the provisions of 40 C.F.R. 60.335(c), NO_x results from performance tests must be converted to ISO standard day conditions. As an alternative to continuously correcting results to ISO standard day conditions, Reliant plans to keep records of the data needed to make this conversion, so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of EPA or the Florida DEP. This approach is acceptable, since the construction permit contains NO_x limits that are more stringent than those in Subpart GG, and compliance with Subpart GG for these units would be a concern only in cases when a turbine is in violation of the NO_x limits in its permit.

Finally, Specific Condition 46 addresses the monitoring schedule for fuel oil. According to 40 C.F.R. 60.334(b)(1), the nitrogen and sulfur content of the fuel oil must be monitored each time a new shipment of fuel oil is transferred to bulk storage. Reliant is proposing to use the fuel analysis provided by the fuel vendor instead of sampling each shipment directly. Provided that all the oil received at the plant complies with the applicable sulfur content limit of 0.8 weight percent, this approach is acceptable, since the specific condition states that the fuel vendor's analyses will comply with the test method requirements of 40 C.F.R. 60.335(d).

If you have any questions about the determination provided in this letter, please contact Ms. Katy R. Forney of the EPA Region 4 staff at (404) 562-9130.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: M. Halpin
CD
NPS

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Jeb Bush
Governor

Department of Environmental Protection

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

November 8, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. J. Christopher Allen
Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

Re: DEP File No. 0970071-001-AC (PSD-FL-273)
Osceola Power Project
Three Simple Cycle Combustion Turbines

Dear Mr. Allen:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Osceola Power Project to be located at Holopaw, Osceola County. The Department's Intent to Issue Air construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address or contact Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/mph

Enclosures

In the Matter of an
Application for Permit by:

Mr. J. Christopher Allen
Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, TX 77210-4455
_______________________________________/

DEP File No. 0970071-001-AC (PSD-273)
Osceola Power Project, Units 1 – 4
Osceola County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of DRAFT Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Reliant Energy Osceola, L.L.C., applied on August 3, 1999 to the Department for an air construction permit to construct three 170-MW dual-fuel "F" class combustion turbines and one 3 million gallon fuel oil storage tank for the Osceola Power Project, located at Holopaw, Osceola County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11-9-99 to the person(s) listed:

J. Christopher Allen, Reliant*
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
Chair, Osceola County BCC
Donald Schultz, P.E., Black & Veatch

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 11-9-99
(Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0970071-001-AC (PSD-FL-273)

Osceola Power Project – Units 1-4
Osceola County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Reliant Energy Osceola, L.L.C. The permit is to construct three nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 75-foot stacks and a 3 million gallon fuel oil storage tank for the proposed Osceola Power Project. The facility will be located approximately 0.75 miles west of the intersection of U.S. 192 and U.S. 441, Holopaw, Osceola County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Reliant Energy Osceola, L.L.C., P.O. Box 4455, Houston, Texas 77210-4455.

The new units will be General Electric nominal 170 MW PG7241FA combustion turbines-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate 3,000 hours per year of which no more than 750 hours per year will be using 0.05 percent sulfur distillate fuel oil.

NO_X emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors. The units must meet a continuous emission limit of 10.5 parts per million by volume at 15 percent oxygen (ppm). NO_X will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO_2, and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions in tons per year based on information provided to the Department is summarized below.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	99	25/15
CO	201	100
NO_X	634	40
VOC	20	40
SO_2	121	40
Sulfuric Acid Mist	19	7

Air quality and regional haze impact analyses were conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-2966

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Reliant Energy Osceola Power Project Units 1 - 4

Three 170-Megawatt Combustion Turbines
One 3-Million Gallon Fuel Oil Storage Tank
Osceola County

DEP File No. 0970071-001-AC (PSD-FL-273)

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

November 8, 1999

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

Authorized Representative: *Mr. J. Christopher Allen*

1.2 Reviewing and Process Schedule

08-03-99:	Date of Receipt of Application
10-25-99:	Application Complete
11-1-99:	Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The Reliant Osceola Power Project will be located 0.75 miles west of the intersection of US 192 and US 441 in Holopaw, Osceola County. This site is approximately 155 kilometers southeast of the Chassahowitzka Class I National Wilderness Area. UTM coordinates for this facility are Zone 17; 491.36 km E; 3112.71 km N.

Figure 1 – Location in Florida

Figure 2 – Location in Osceola County

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This proposed facility will generate 510 megawatts (nominal MW) of electrical power. The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is <u>not</u> within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available control Technology determination is required. Given that emissions of at least one single criteria pollutant will exceed 250 TPY, PSD Review and a BACT determination are required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. These values are: 40 TPY for NO_X, SO_2, and VOC; 25/15 TPY of PM/PM_{10}; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	One 3-Million Gallon Fuel Oil Storage Tank

Reliant proposes to construct three nominal 170 MW General Electric PG7241FA simple cycle, intermittent duty combustion turbine-electrical-generators with 75-foot stacks and one 3-million gallon fuel oil storage tank at the planned Osceola Power Project.

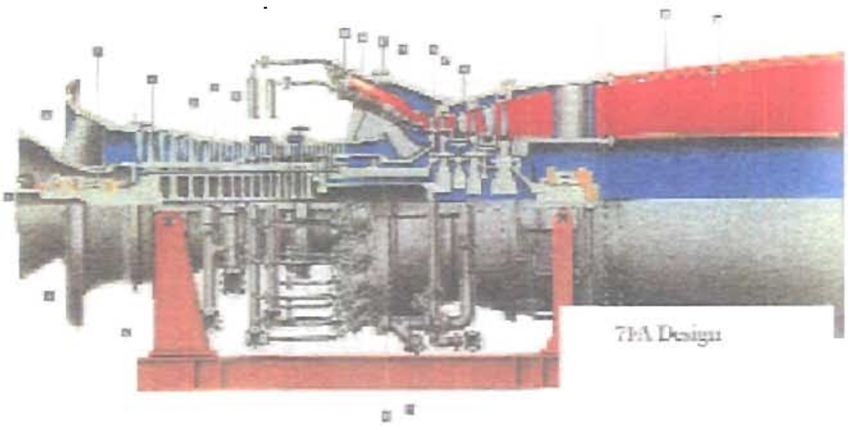
According to the application, the facility will emit approximately 634 tons per year (TPY) of NO_X, 201 TPY of CO, 99 TPY of PM/PM_{10}, 121 TPY of SO_2, 19 TPY of VOC, and 19 TPY of SAM.

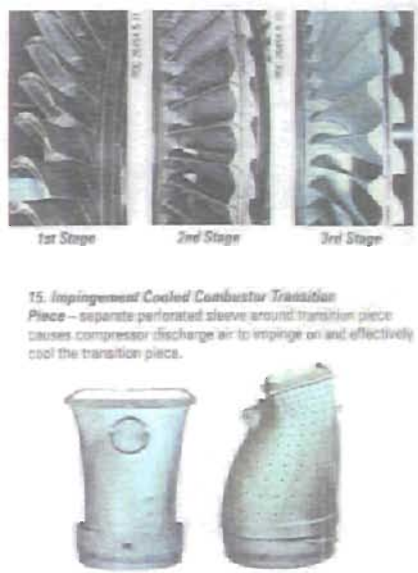
Significant emission rate increases per Table 212.400-2, F.A.C. will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM/PM_{10}) and nitrogen oxides (NO_X). A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, PM/PM_{10}, NO_X, and SO_2.

Each turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 10.5 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. Each turbine will have a maximum heat input rating of 1,709 (gas) and 1,942 (oil) MMBtu/hr lower heating value (LHV) at 19°F while operating at 100% load. The main fuel will be natural gas and the units are proposed to operate up to 3,000 hours per year per unit of which 750 hours per year per unit may be on maximum 0.05 percent sulfur distillate fuel oil.

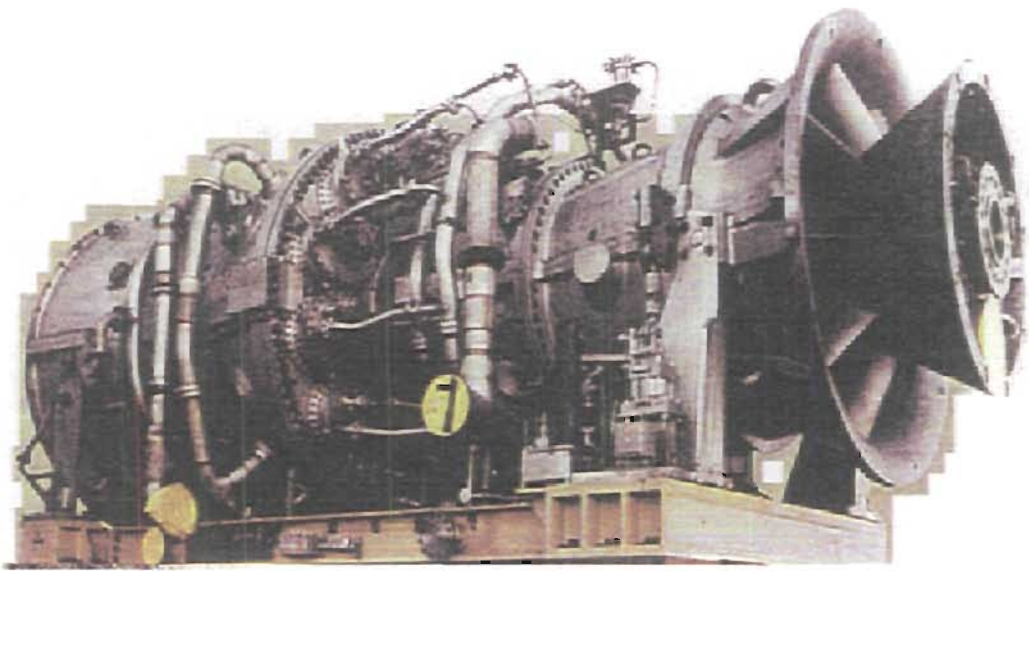
The key components of the GE MS 7001FA (a predecessor of the PG 7241FA) are identified in Figure 3. An exterior view is also shown. Each unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of the earlier-generation combustors supplied with the MS7001FA.

FIGURE 3





EXTERIOR VIEW



4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

In the Reliant Power Project, the units will operate as peaking units in the simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

In combined cycle projects, the gas turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator. The steam, in-turn, drives another electrical generator producing an additional 80-90 MW. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an evaporative inlet cooler (fogger) can be installed ahead of the combustion turbine inlet. At an ambient temperature of 95 °F, roughly 7-14 MW of power can be regained per unit by using the foggers.

Additional process information related to the combustor design, and control measures to minimize pollutant emissions are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility will be located in Osceola County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) for the reasons given in Section 2.3, Facility Category, above.

This PSD review consists of an evaluation of resulting ambient air pollutant concentrations, and increases with respect to the National Ambient Air Quality Standards and Increments as well as a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, SO_2, SAM and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth

The emission units affected by this air construction permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 60	Applicable sections of Subpart A, General Requirements, NSPS Subparts GG and Kb
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Units 1-3 will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM_{10}, VOC, SO_2, NO_X, CO, SAM, and negligible quantities of fluorides (F), mercury (Hg) and lead (Pb). The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for Units 1-3 are summarized in the Draft BACT document and Specific Condition Nos. 18-23 of Draft Permit PSD-FL-273.

6.2 Emission Summary

The annual emissions increases for all PSD pollutants as a result of the project are presented below:

PROJECT EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Gas Firing[1]	Oil Firing[1]	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	61	38	99	25	Yes
SO_2	4	117	121	40	Yes
NO_X	248	386	634	250 (Major)	Yes
CO	122	79	201	100	Yes
Ozone (VOC)	10	9	19	40	No
Sulfuric Acid Mist	1	18	19	7	Yes
Total Fluorides	~0	2.2	2.2	3	No
Mercury	0.0026	0.002	0.0046	0.1	No
Lead	0.0961	0.1259	0.222	0.6	No

1. Based on 2,250 hours of gas firing and 750 hours of fuel oil firing per year per unit. Reference ambient temperature is 59 °F.

6.3 Control Technology

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may be potentially emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_X, SO_2, CO, SAM, and PM/PM_{10}. Emissions control will be accomplished primarily by good combustion of clean natural gas and the limited use of low sulfur (0.05 percent) distillate fuel oil. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, SO_2, NO_X, and SAM. PM_{10}, SO_2, and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for SAM. Instead, the BACT requirement will establish the SAM emission limit for this project.

A review of the applicant's initial PM_{10}, CO, SO_2 and NO_X air quality impact analyses for this project revealed no predicted significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO, SO_2 and NO_X;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando International Airport, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst load conditions the ISCST3 model was used to evaluate dispersion of emissions from the simple cycle facility for three loads (50%, 75%, and 100%) using worst case or "enveloped" stack parameters. Receptors were placed along the fence line of the facility at 50-meter intervals. The receptor grid for predicting maximum concentrations in the vicinity of the project was a Cartesian receptor grid that contained close field, near field, mid field, and far field receptors with dimensions centered on the simple-cycle facility stacks. The inner portion of the grid had receptors at 100 m spacing out to 1 km. A 250 m spacing was used from 1 km to 3 km; a 500 m spacing was used from 3 km to 5 km; and a 1,000 m spacing was used from 5 km to 10 km. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this preliminary modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility. If this modeling at worst load conditions shows significant impacts, additional multi facility modeling is required to determine the project's impacts on the existing air quality, any applicable AAQS, and PSD increments. The table below shows the results of this modeling.

Maximum Project Air Quality Impacts for Comparison to the PSD Class II Significant Impact Levels in the Vicinity of the Facility

Pollutant	Averaging Time	Max Predicted Impact (ug/m)	Significant Impact Level (ug/m)	Significant Impact?
PM_{10}	Annual	0.06	1	NO
	24-hour	2.0	5	NO
CO	8-hour	20.4	500	NO
	1-hour	44.9	2000	NO
NO_2	Annual	0.7	1	NO
SO_2	Annual	0.3	1	NO
	24-hour	4.6	5	NO
	3-hour	11.7	25	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, Visibility, And Wildlife

The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area.

Impact On Visibility

Natural gas and No. 2 fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment (with associated reagents) is required, there will be no tendency to form ammoniated particulate species.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require 6 more permanent employees, which will cause no significant impact on the local area.

Over the past few years the Public Service Commission has determined that a number of power projects are needed will help meet the low electrical reserve capacity throughout the State of Florida. The project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," low water requirements, and the among the lowest air emissions per unit of electric power generating capacity for intermittent duty.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

M.P. Halpin, P.E., Review Engineer
A. A. Linero, P.E., Administrator
Chris Carlson, Meteorologist

PERMITTEE:

Reliant Energy Osceola, L.L.C.
P.O. Box 4455
Houston, Texas 77210-4455

File No.	PSD-FL-273
FID No.	0970071
SIC No.	4911
Expires:	January 1, 2002

Authorized Representative:

J. Christopher Allen

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators; one 3-million gallon fuel oil storage tank; and three 75-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located approximately 0.75 miles west of the intersection of U.S. 192 and U.S. 441, Osceola County. UTM coordinates are: Zone 17; 491.36 km E; 3112.71 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 75-foot stacks and a 3-million gallon fuel oil storage tank. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	One 3 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- mm/dd/99 Notice of Intent published in ____________
- 11/01/99 Distributed Intent to Issue Permit
- 10/29/99 Application deemed complete
- 08/03/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on August 3, 1999
- Applicant's response dated October 6, 1999 to Department Request dated August 25, 1999
- Applicant's e-mail dated October 20, 1999
- Applicant's additional submittal dated October 28, 1999
- Department's Intent to Issue and Public Notice Package dated November 8, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District office, 3319 Maguire Boulevard, Orlando, Florida 32803-3767 and phone number 407/894-7555.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

SECTION II. ADMINISTRATIVE REQUIREMENTS

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District office. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District office by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District office. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with evaporative coolers) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 004, Fuel Storage, consisting of one 3 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District.

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 19°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,709 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,942 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c)., F.A.C.]

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 3,000 hours in any consecutive twelve month period, of which up to 750 hours may be on fuel oil. See Specific Condition 40. for compliance requirements. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period [Rule 62-210.200, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	18/34 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC	As Above	1.5 ppmvw (Gas) 3.7 ppmvw (Fuel Oil)
CO	As Above	10.5 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	10.5 ppmvd (Gas) 42 ppmvd (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:

- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 10.5 ppmvd @15% O_2 on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 60 pounds per hour (at ISO conditions) and 9 ppmvd @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. [Rule 62-212.400, F.A.C.]

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

- Notwithstanding the applicable NO_X limits noted above, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]

- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 shall not exceed 323 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

- The permittee shall develop a NO_X reduction plan when the hours of oil firing at the facility reach 750 hours cumulatively. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 10.5 ppmvd and 36.2 lb/hr (at ISO conditions) while firing gas and neither 20 ppmvd and 70.0 lb/hr (at ISO conditions). The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.5 ppmvw nor 3.0 lb/hr (ISO conditions) and neither 3.7 ppmvw nor 8.0 lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

22. Sulfur Dioxide (SO_2) Emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 750 hours per year per unit. Emissions of SO_2 (at ISO conditions) shall not exceed 1.1 lb/hr (natural gas) and 104.3 lb/hr (fuel oil) as measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 18.0 lb/hr when operating on natural gas and shall not exceed 34.0 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

24. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions and shall not exceed 10 opacity. Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

26. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Central District within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements).
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

   - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity

when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

35. Test Notification: The DEP's Central District shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

36. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to the DEP's Central District no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by Reliant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

39. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.37 above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

40. Hours of Operation and Fuel Usage: Reliant shall maintain records on-site of each CT's "hours of operation by fuel type" and "BTU input by fuel type" for each month. These shall

be tabulated for each consecutive 12-month period (as per specific permit conditions identified herein) and made available upon request for Department use. Additionally, this data shall be submitted annually with the AOR.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on these Units shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C, 40 CFR 75and 40 CFR 60.7 (1998 version)].

42. CEMS for reporting excess emissions: Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Central District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

43. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS

44. Continuous Monitoring Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 2 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

47. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Reliant Energy Osceola Power Project
PSD-FL-273 and 0970071-001-AC
Osceola County, Florida

BACKGROUND

The applicant, Reliant Energy Osceola, L.L.C. (Reliant) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Osceola Power Project at Holopaw, Osceola County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 75-foot stacks. Reliant proposes to operate these units up to 3,000 hours per year per unit of which 750 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 8, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on August 3, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch.

REVIEW GROUP MEMBERS:

M.P.Halpin, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	10.5 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (750 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	10.5 ppmvd (gas, baseload) 20 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	0.2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

According to the application, the maximum emissions from the facility will be approximately 634 tons per year (TPY) of NO_X, 201 TPY of CO, 99 TPY of PM/PM_{10}, 121 TPY of SO_2, 19 TPY of SAM, and 20 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Reliant is within the NSPS limit, which allows NO_X emissions, over 110 ppmvd for the high efficiency units to be purchased for the Osceola Power Project.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed Reliant Osceola Power Project is included to facilitate comparison.

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Vandolah Hardee, FL	680 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application 8/99. 1000 hrs on oil
Oleander Brevard, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Baldwin, FL	510 MW SC INT	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510 MW SC INT	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 8/99. 750 hrs on oil
TEC Polk Power, FL	330 MW SC INT	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	1.5 – NG 3.7 – FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the Fish and Wildlife Service dated November XX, 1999
- Comments from EPA Region IV dated November XX, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for JEA Brandy Branch Station Project
- GE Combustion Turbine Startup Curves
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Osceola project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 750 hours per year (per CT).

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the Osceola Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the Osceola project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the Osceola project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[1], but their performance on fuel oil is not known to the Department.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects firing natural gas throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[2] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at PG&E's La Paloma Plant near Bakersfield.[3] The overall project includes several more 250 MW blocks with SCR for control.[4] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). $SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The Department estimated total emissions for the project at 121 TPY of SO_2 and 19 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 750 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 99 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[5]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 10.5 and 20 ppm for gas and oil respectively at baseload proposed in Reliant's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Reliant for this project are 1.5 ppmvw for gas and 3.7 ppmvw for oil firing at baseload and fall well below the PSD significance rate of 40 TPY. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[6]

BACKGROUND ON PROPOSED GAS TURBINE

Reliant plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F (or 7FA) unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[9] The City of Tallahassee received a permit in 1998 to install a GE PG7231FA combustion turbine at its Purdom Plant.[10] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[11]

FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for fourteen GE 7241FA turbines to be installed at the Fort Myers and Sanford Repowering Projects.[12, 13] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241FA turbine with DLN-2.6 burners.[14] Draft BACT determinations of 9 ppmvd were proposed for the proposed combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities).[15, 16]

Most recently, the Department issued a draft BACT determination for the simple cycle Oleander project in Brevard County and final BACT determinations for the simple cycle TEC project in Polk County and the JEA Brandy Branch Project in Duval. These three draft permits also include "new and clean" NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units. The Oleander Project will meet 9 ppmvd on a 24-hour basis and will be allowed to burn fuel oil for 1000 hr/yr/unit. The TEC and JEA projects will meet 10.5 ppmvd on a 24-hour basis, but will limited in oil firing to 750 hr/yr/unit.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combustion turbines in Florida. When required by BACT determinations of most states, General Electric incorporates SCR in combined cycle projects.[17] In its recent permits, Florida has included separate and lower limits in the event that GE's DLN technology does not achieve 9 ppmvd or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[18] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[19] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the Reliant Osceola Power Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[20]

The 10.5-ppmvd NO_X limit on natural gas proposed by Reliant is quite reasonable for simple cycle 7FA combustion turbines. Typically, companies obtain a guarantee from GE to achieve 9 ppmvd during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation.

With the frequent start-ups and shutdowns of the unit, Reliant (as are TEC and JEA) is concerned about the ability to maintain the low NO_X values for long periods of time. As a result, TEC and JEA agreed to a "new and clean" limit of 9 ppmvd but a continuing limit of 10.5 ppmvd. Their permits reflect fewer hours on oil (than Oleander and Vandolah) for the higher NO_X value on gas. Presumably, their concern would be lessened should these units be converted to baseload combined cycle operation. Although the Department is not fully aware of the details of the GE guarantees for Oleander or Vandolah (proposed 9 ppmvd on simple cycle units), the Department is aware from discussions with other applicants that a continuing guarantee may be available at a substantial cost.[21]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[22]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Reliant project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 18/34 lb/hr – Gas/Fuel Oil
CO	As Above	10.5 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42 ppmvd – F.O. for 750 of 3,000 hours

RATIONALE FOR DEPARTMENT'S DETERMINATION

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was proposed by Oleander for five GE7 FA units and is reflected in the Department's Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander, Vandolah, and Virginia Power while firing natural gas is the lowest known Draft BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department issued permits for the TEC Polk Power and the JEA Brandy Branch Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander and Vandolah.
- The proposed BACT limit of 10.5 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible only for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst (around 1125 °F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.
- The levelized costs of NO_X removal by Hot SCR for the JEA project were estimated by Black & Veatch at $28,509 per ton assuming 1000 hours of operation on natural gas and a reduction from 10.5 to 5 ppmvd. The Department estimates that this figure is actually closer to $10,000 per ton by including oil operation (up to 750 hours per year), 2250 hours per year of gas operation and other criteria.
- TEC estimated the cost of Hot SCR at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle oil-fired projects (PREPA).

- Although the Department does not have a "bright line" cost-effectiveness figure and does not adopt the supplied cost calculations for the Osceola Power Project, Hot SCR is not cost-effective for this project.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[23]
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.75 lb./MW-hr NO_X emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb/MW-hr for simple cycle CT's and less than 0.5 lb/MW-hr for combined cycle units.
- Although not determined by BACT, proposed VOC emissions of 1.5 ppmvd while firing gas and 3.7 ppmvw firing oil reflect BACT.
- The Department will set CO limits achievable by good combustion at full load as 10.5 ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units. These limits are better than or equal to those proposed by the Department for the Oleander, JEA Brandy Branch, and TEC Polk Power projects.
- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88/83 percent control efficiency (oil/gas) and having a three-year catalyst life. Levelized costs for CO catalyst control were calculated at $12,888 per ton. The Department estimates this figure to be closer to $4,000 per ton, but it does not appear to be cost-effective for removal of CO.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power and quite a number of combined cycle projects.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

M.P. Halpin, P.E. Review Engineer ______________________

A. A. Linero, P.E. Administrator ______________________

New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

______________________ ______________________
C. H. Fancy, P.E., Chief — Howard L. Rhodes, Director
Bureau of Air Regulation — Division of Air Resources Management

______________________ ______________________
Date: Date:

REFERENCES

[1] Telecom. Linero, A.A., FDEP and Chalfin, J., GE. NO_X control technology for fuel oil.

[2] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[3] "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[4] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

[5] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[6] Telecon. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."

[7] Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.

[8] Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.

[9] Report. Florida Power & Light. "Final Dry Low NO_X Verification Testing at Martin Combine Cycle Plant." August 7, 1995.

[10] Permit. Florida DEP. City of Tallahassee Purdom Unit 8. File PSD-FL-239. May, 1998.

[11] Application. City of Tallahassee. PSD/Site Certification Application. April, 1997.

[12] Permit. Florida DEP. FPL Fort Myers Repowering Project. File 0710002-004-AC. November, 1998.

[13] Permit. Florida DEP. FPL Sanford Repowering Project. File 1270009-004-AC. September, 1998.

[14] Permit. Florida DEP. Santa Rosa Energy Center. File 1130168-001-AC. December, 1998.

[15] Draft Permit. Florida DEP. Duke Energy New Smyrna Project. File PSD-FL-257. January, 1999.

[16] Draft Permit. Florida DEP. KUA Cane Island Unit 3. File PSD-FL-254. January, 1999.

[17] Permit. State of Alabama. Alabama Power Plant Barry. 1998.

[18] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program

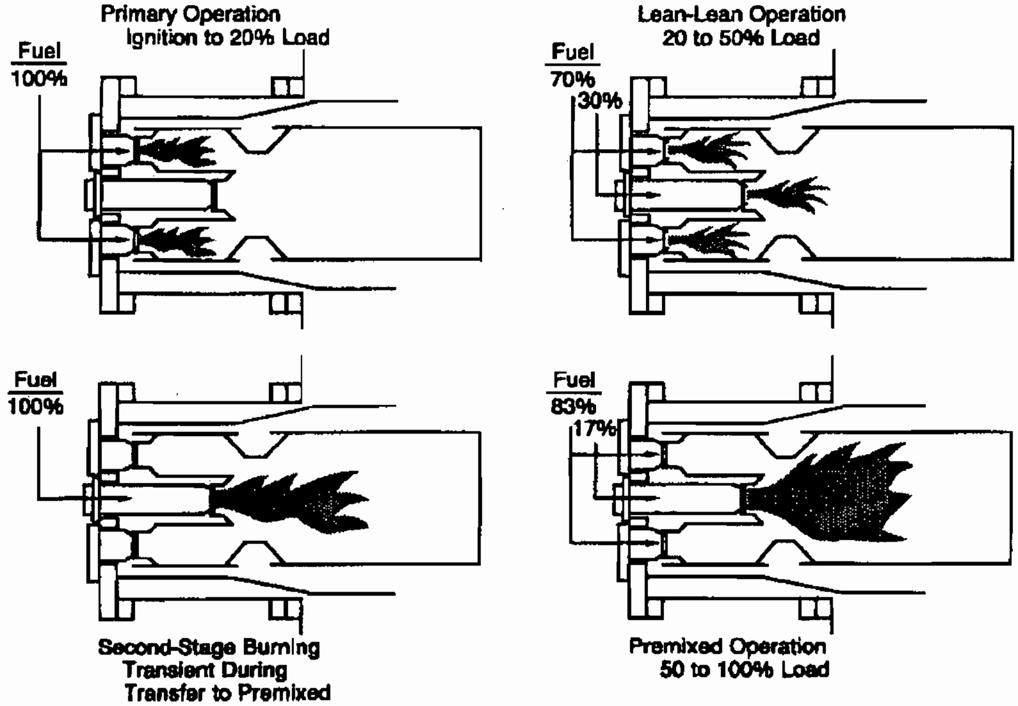
[19] Monthly Report. Florida DEP Bureau of Air Regulation. June, 1998.

[20] Telecon. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

[21] Telecon. Gianazza, N.B., JEA, and Linero, A.A., Florida DEP. Proposed NO_X limits at Brandy Branch Project.

[22] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

[23] Letter. Linero, A. A., FDEP to Forry, J. and Chalfin, J. General Electric. NO_X emissions control while firing fuel oil in Simple Cycle Units. October 12, 1999.



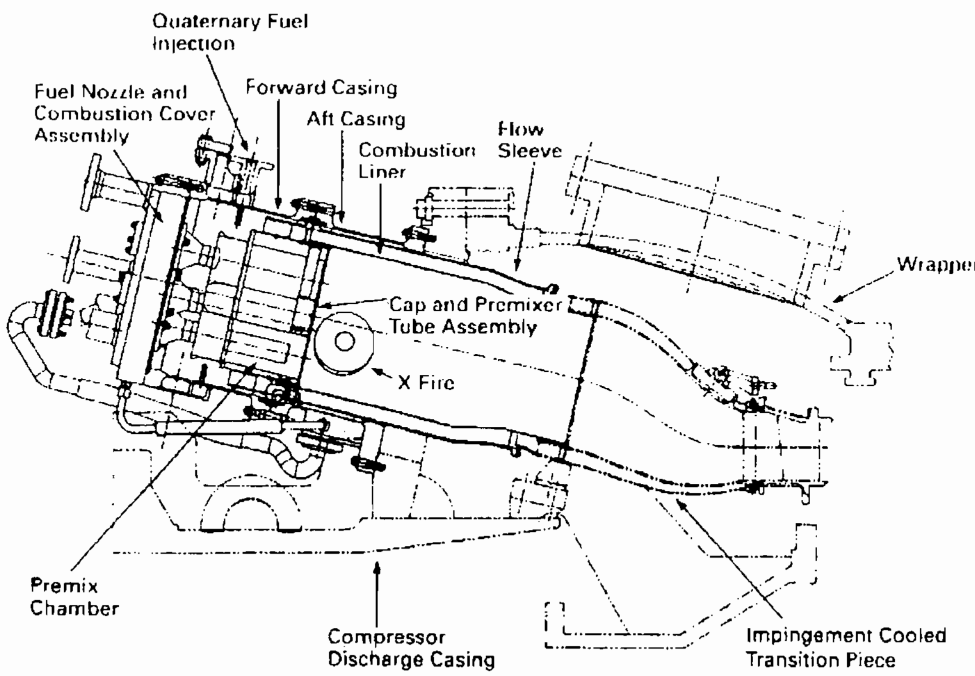


Figure 1 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

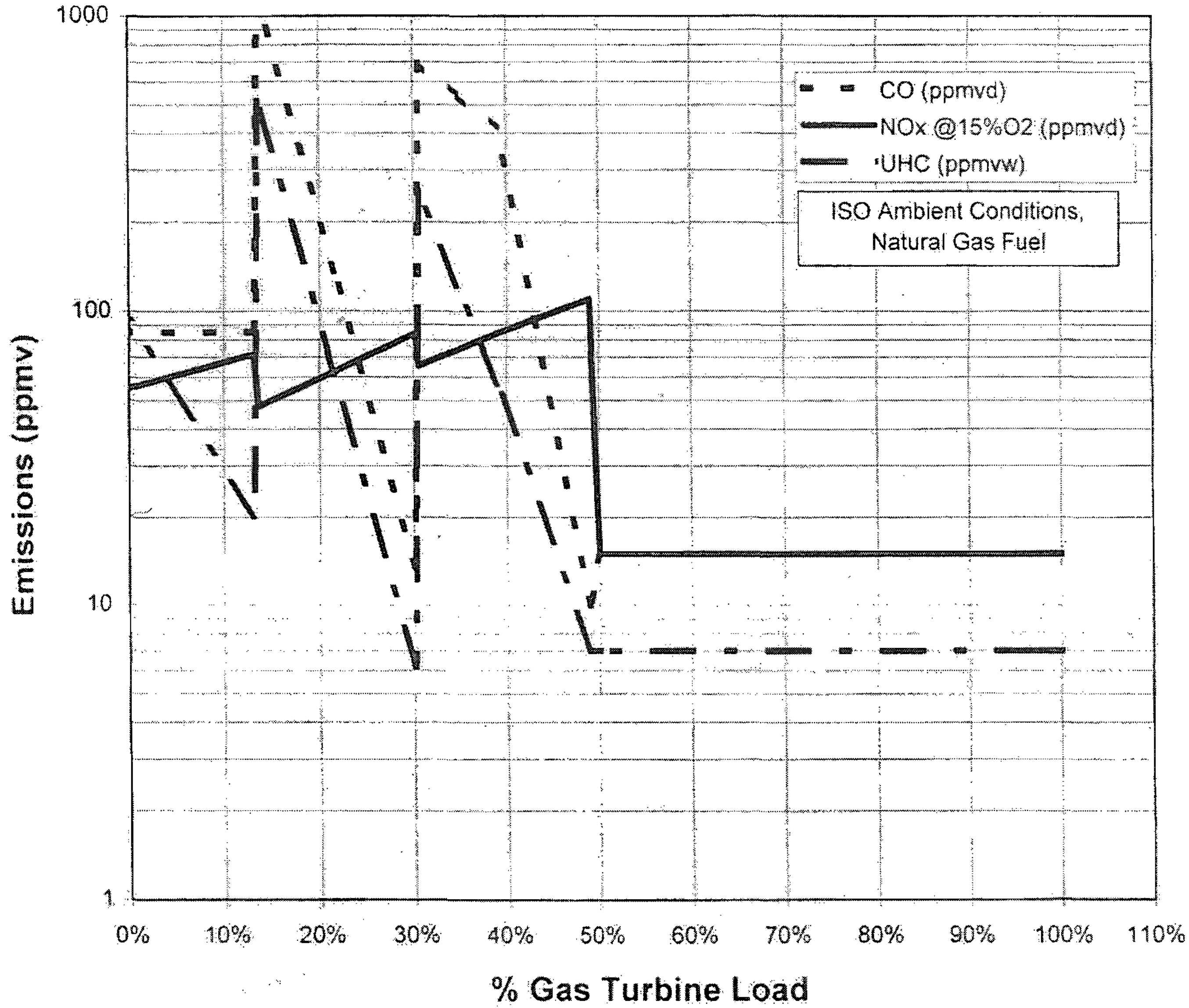


Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

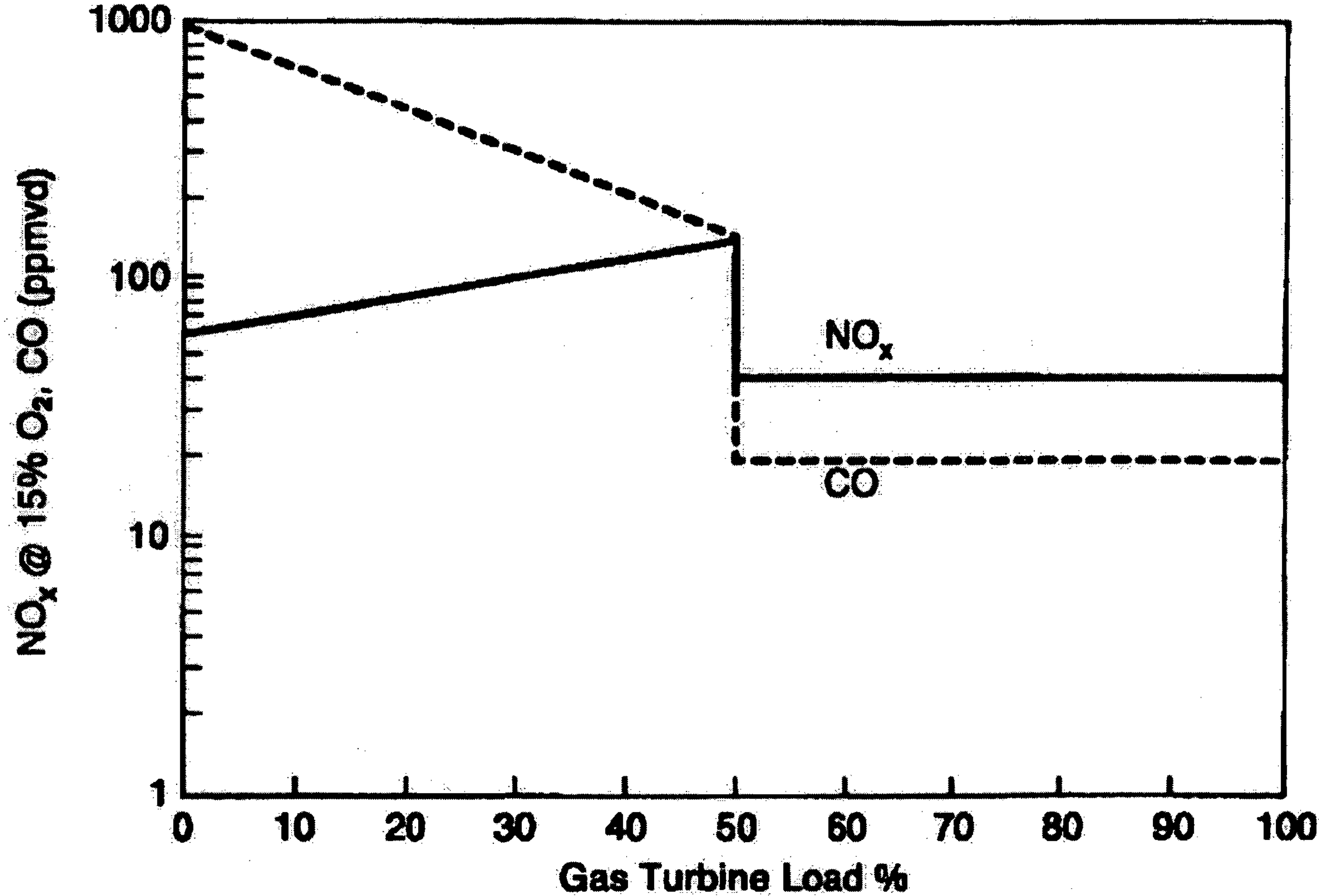


Figure 3 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

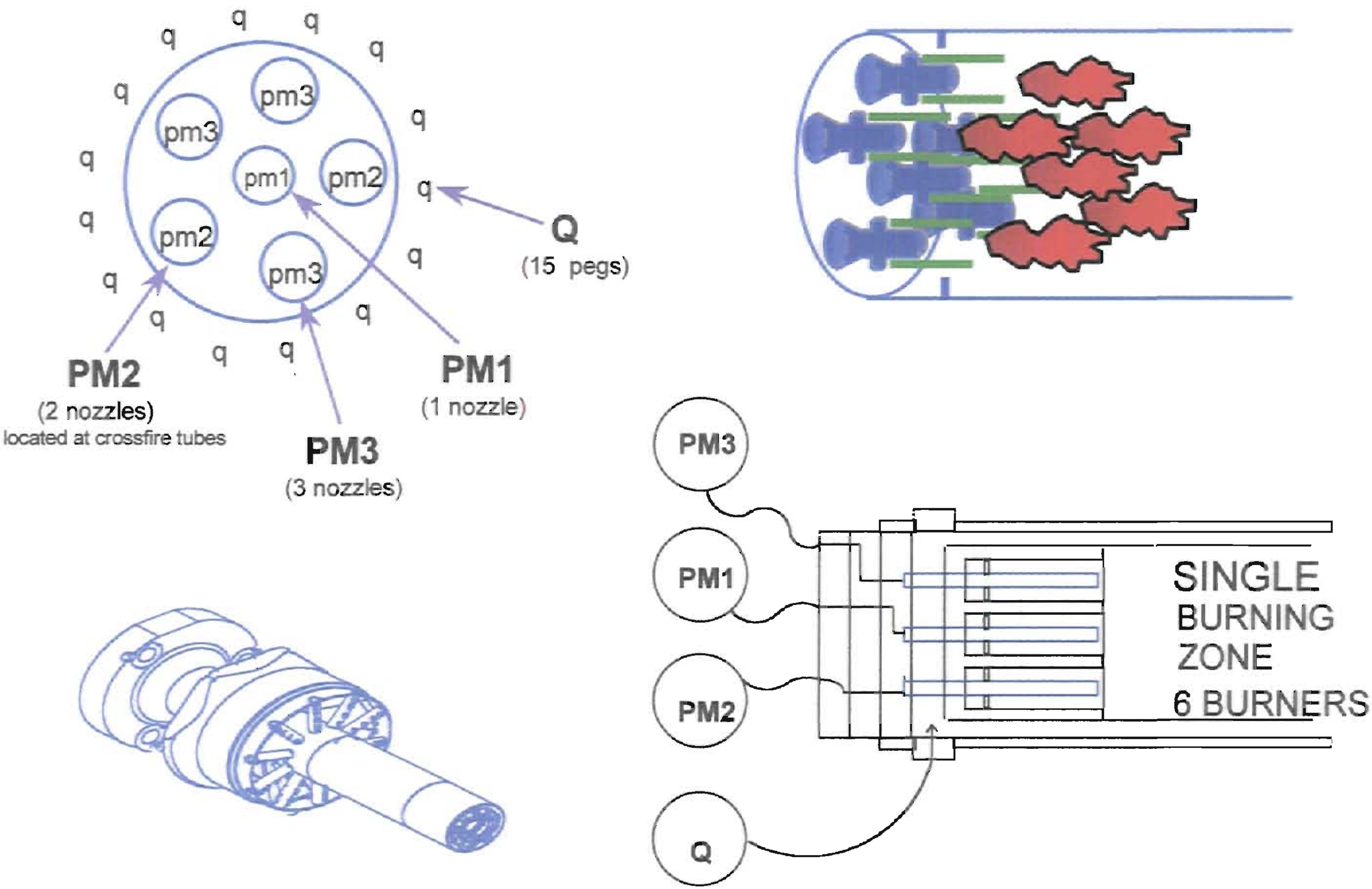


Figure 4 - DLN2.6 Fuel Nozzle Arrangement

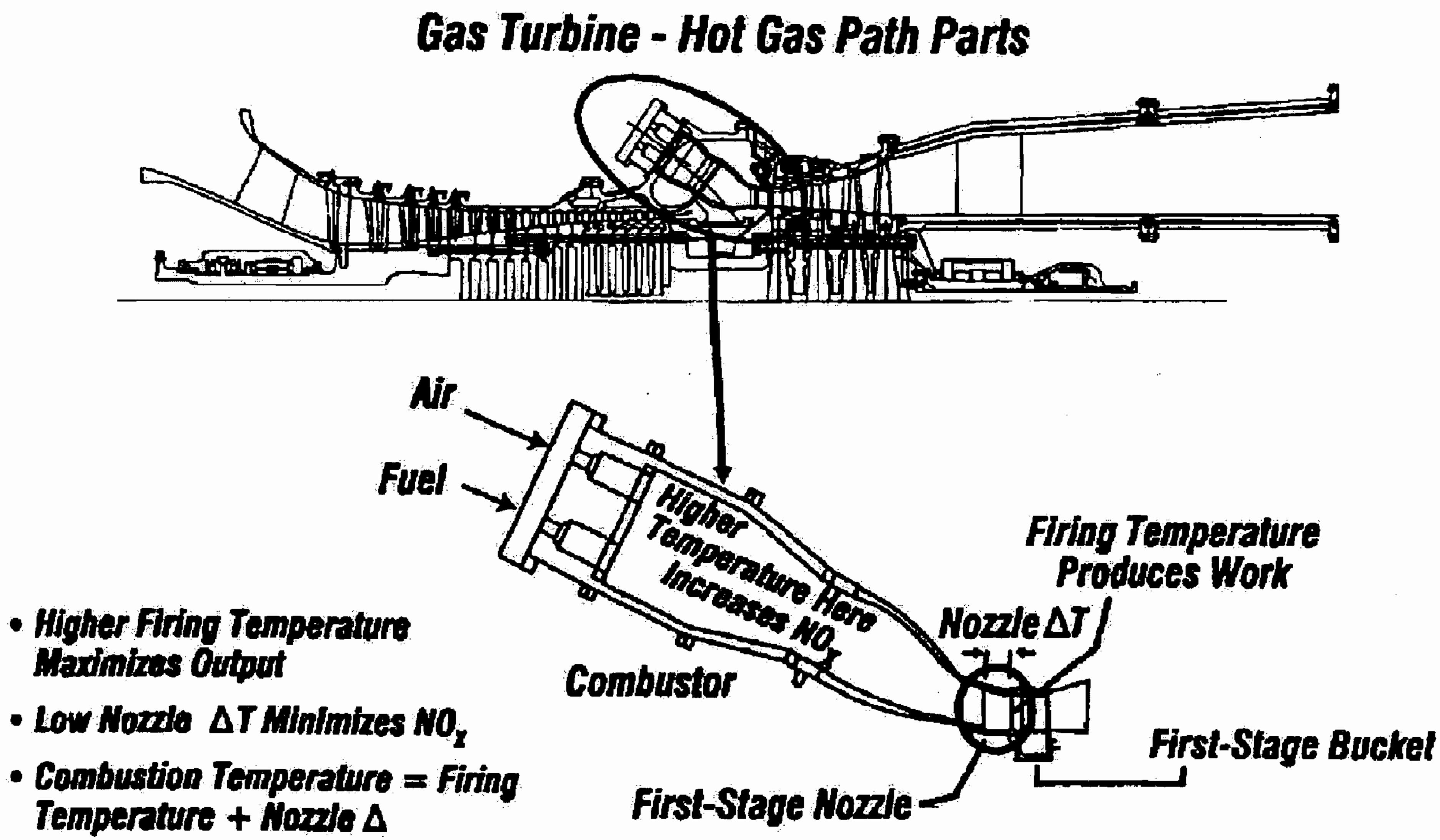


Figure 5 – Relation Between Flame Temperature and Firing Temperature

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Case-by-Case Maximum Achievable Control Technology (X)
c) Determination of Prevention of Significant Deterioration (X); and
d) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

P.E. Certification Statement

Reliant Energy Osceola, L.L.C.
Osceola Power Project
Osceola County

DEP File No.: 0970071-001-AC (PSD-FL-273)
Facility ID No.: 0970071

Project: Air Construction Permit

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, and subject to the proposed permit conditions, provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

Chris Carlson and I conducted this review.

(Seal)

Michael P. Halpin, P.E.
Registration Number: 31970

11/3/99
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Memorandum

Florida Department of
Environmental Protection

TO: Clair Fancy

THRU: Al Linero *aaf 11/2*

FROM: Michael P. Halpin

DATE: November 3, 1999

SUBJECT: Reliant Energy Osceola, L.L.C.
Three 170 MW Simple Cycle Combustion Turbines
DEP File No. 0970071-001-AC (PSD-FL-273)

Attached is the public notice package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW combustion turbines and one 3 million-gallon fuel oil storage tank at the planned Osceola Power Project.

Nitrogen Oxides (NO_X) emissions from the gas turbines will be controlled by Dry Low NO_X (DLN-2.6). The applicant proposed an NO_X emission limit of 10.5 ppmvd @15% O_2. We are requiring compliance on a continuous (24-hour average) basis. The use of fuel oil will be allowed up to 750 hours per year per unit, although the applicant originally sought approval for up to 2000 hours per year per unit. The NO_X and fuel oil hours are equal to the values in the recently issued TECO and JEA permits. For reference, Oleander and IPS Vandolah (IPSAPC) were allowed 9 ppmvd NO_X on gas, but up to 1000 hours per year per unit of oil operation.

NO_X emissions will be controlled to 42 ppm during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

Recent simple cycle emission limits in Region IV (outside of Florida) have typically been at 15 ppm for simple cycle "F Class" units. In fact, North Carolina recently issued a draft BACT to Dynegy for six dual-fuel Westinghouse "F Class" units with limits of 25 ppm and well over 1000 hours of fuel oil usage. The Dynegy Westinghouse units must meet 15 ppm by early 2002.

Apparently IPSAPC and Oleander feel more confident that they can maintain the guaranteed "new and clean" emission limit of 9 ppmvd for the GE units whereas Reliant, along with JEA and TECO do not have the same confidence. The added risk to IPSAPC and Oleander comes at a cost. The reduced oil firing hours help to even things out between the different companies, NO_X limits, and hours of fuel oil operation.

I recommend your approval of the attached Intent to Issue.

AAL/mph

Attachments

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Christopher Allen
Reliant Energy Osceola
PO Box 4455
Houston, TX
77210-4455

4a. Article Number
Z 031 392 003

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery NOV 12 1999

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Geo

PS Fo... Receipt

Thank you for using Return Receipt Service.

Z 031 392 003

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Christopher Allen	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 097071-001-AC PSD-FI-273	11-9-99

PS Form **3800**, April 1995

Department of
Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

November 8, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregg Worley, Chief
Preconstruction/HAP Section
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
Reliant Energy Osceola
PSD-FL-273

Dear Mr. Worley:

Enclosed are two copies of the Department's Intent to Issue package for the Reliant Energy Osceola Power Project in Osceola County. It will be a natural gas and oil-fired simple cycle facility consisting of three nominal 170-megawatt (MW) simple cycle combustion turbine-electrical generators.

Please provide your comments on the Draft BACT determination and Draft Permit. The project is not subject to the Florida's Power Plant Siting procedure because it will generate no electricity from steam.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which has a maximum SO_2 emission rate of 0.0006 lb/MMBtu (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 0.003 % sulfur. Fuel oil with a 0.05% sulfur content will be used as a backup. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 45 and 46 and read as follows:

45. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 2 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

46. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

Please comment on Specific Conditions 41 and 42 which allow the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions, as well as Specific Condition 43 which allows the use of CEMS in lieu of measuring the water to fuel ratio. Typically NO_X emissions will be less than 10.5 ppmvd @15% O_2 (natural gas) which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedule and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Mike Halpin at 850/921-9530.

Sincerely,

MHalpin for AAL

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

Enclosures

592

1000

FedEx USA Airbill FedEx Tracking Number 808307934580

Form I.D. No. 0210 **Recipient's Copy**

SDA11

1 From

Date 07-30-99 [redacted]

Sender's Name Jason Goodwin Phone (713) 945-7167

Company HOUSTON LIGHTING & POWER

Address 12301 KURLAND DR

Dept./Floor/Suite/Room

City HOUSTON State TX ZIP 77034

2 Your Internal Billing Reference Information 102431;532010

3 To

Recipient's Name Mr. Al Linero, P.E. Phone ( )

New Source Review Section

Company Florida Department of Environmental Protection

Check here if residence (Extra charge applies for FedEx Express Saver)

Address 2600 Blair Stone Road

(To "HOLD" at FedEx location, print FedEx address here) Dept./Floor/Suite/Room

City Tallahassee State FL ZIP 32399-2400

For HOLD at FedEx Location check here For Saturday Delivery check here (Extra Charge. Not available at all locations)

- [ ] Hold Weekday (Not available with FedEx First Overnight)
- [ ] Hold Saturday (Not available at all locations) (Available for FedEx Priority Overnight and FedEx 2Day only)
- [ ] Saturday Delivery (Available for FedEx Priority Overnight and FedEx 2Day only)
- [ ] NEW Sunday Delivery (Available for FedEx Priority Overnight only)

8 0 8 3 0 7 9 3 4 5 8 0

4a Express Package Service *Packages under 150 lbs.* Delivery commitment may be later in some areas.

- [x] FedEx Priority Overnight (Next business morning)
- [ ] FedEx Standard Overnight (Next business afternoon)
- [ ] FedEx First Overnight (Earliest next business morning delivery to select locations) (Higher rates apply)
- [ ] FedEx 2Day (Second business day)
- [ ] FedEx Express Saver (Third business day)

FedEx Letter Rate not available. Minimum charge: One pound rate.

4b Express Freight Service *Packages over 150 lbs.* Delivery commitment may be later in some areas.

- [ ] FedEx Overnight Freight (Next business day)
- [ ] FedEx 2Day Freight (Second business day)
- [ ] FedEx Express Saver Freight (Up to 3 business days)

(Call for delivery schedule. See back for detailed descriptions of freight services.)

5 Packaging

- [ ] FedEx Letter
- [ ] FedEx Pak
- [ ] FedEx Box
- [ ] FedEx Tube
- [x] Other Pkg.

Declared value limit $500

6 Special Handling

Does this shipment contain dangerous goods?* (One box must be checked)

- [ ] No
- [ ] Yes (As per attached Shipper's Declaration)
- [ ] Yes (Shipper's Declaration not required)
- [ ] Dry Ice — Dry Ice, 9, UN 1845 ______ x ______ kg.
- [ ] Cargo Aircraft Only

*Dangerous Goods cannot be shipped in FedEx packaging.

7 Payment

Bill to:

- [x] Sender (Account No. in Section 1 will be billed)
- [ ] Recipient
- [ ] Third Party
- [ ] Credit Card
- [ ] Cash/Check

(Enter FedEx Account No. or Credit Card No. below) Obtain Recipient FedEx Account No.

[redacted]

Total Packages	Total Weight	Total Declared Value*	Total Charges
1	50	$ .00	$

*When declaring a value higher than $100 per shipment, you pay an additional charge. See SERVICE CONDITIONS, DECLARED VALUE, AND LIMIT OF LIABILITY section for further information.

Credit Card Auth.

8 Release Signature

Your signature authorizes Federal Express to deliver this shipment without obtaining a signature and agrees to indemnify and hold harmless Federal Express from any resulting claims.

321

Questions?
Call 1·800·Go·FedEx® (800)463-3339

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007120675 4

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 031 392 004

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
11-12-99

5. Received By: *(Print Name)* Bruce Hobbs

6. Signature: *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 031 392 004

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to	Gregg Worley
Street & Number	EPA
Post Office, State, & ZIP Code	Atlanta GA
Postage	$
Certified Fee	
Special Delivery Fee	Reliant
Restricted Delivery Fee	Energy
Return Receipt Showing to Whom & Date Delivered	Osceola
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	11-9-99

0970071-001-AC
PSD-FL-273

PS Form **3800**, April 1995

Reliant Energy

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OCT 29 1999

BUREAU OF AIR REGULATION

October 28, 1999

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

Subject: Submittal of Revised Ambient Air Quality Analysis
Reliant Energy Osceola

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. recently submitted a Prevention of Significant Deterioration (PSD) Air Permit Application for the Osceola Power Project, to be located near Holopaw, Florida. As we discussed by telephone recently, the air quality impact analysis (AQIA) for Osceola has been modified to account for changes made to the proposed site layout. These changes include: addition of a small natural gas-fired pipeline heater; the reduction of proposed oil-firing hours to 750 hours/year/unit; and the movement of the plant island approximately 1,500 feet south of the original location.

The enclosed report discusses the results of the revised AQIA, and the enclosed compact disk includes the electronic files used in the revised analysis. The results of this revised analysis are consistent with the original analysis and indicate that emissions from the proposed Osceola facility will not exceed the applicable PSD significant impact levels for any regulated pollutant.

Please contact me at 713-945-7167 if you have any questions concerning this permit application.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Revised Model Trans.doc
Encl.

c: Al Linero – Florida DEP – Tallahassee, FL

cc: C. Carlson
L. Kozlov
NPS
EPA

Reliant Energy Osceola, L.L.C.

Revised Air Dispersion Modeling Analysis

Recent changes to the proposed Reliant Energy Osceola facility have prompted additional air dispersion modeling to be performed for the proposed facility. These changes include modifications in the locations of on-site structures, fencelines and fenceline receptors, as well as the addition of a 9.8 MBtu/hr natural gas fired fuel-gas heater. The changes, and their associated impacts were assessed with the Industrial Source Complex (ISCST3) air dispersion model. The methodology of this air dispersion modeling, including specific air dispersion model defaults, terrain, and meteorological data, remain unchanged from the air dispersion modeling submitted in the original Construction Permit Application of July 30, 1999.

Due to recent engineering changes to the proposed project, the facility was relocated approximately 1,500 feet south of the originally proposed site, near the southeast corner of the property. Figure 1 illustrates the revised nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures, including the addition of the fuel-gas heater. It may be noted that this site arrangement is also rotated approximately 15-degrees to the left compared to the original site arrangement. The fuel gas heater is located in the northwest corner of the proposed site. Although the enclosed plot plan indicates the presence of six combustion turbines, the proposed Osceola facility will include only the three units located on the east side of the facility. All air quality impact analyses and other representations have been based on these three units only.

Performance and emissions data for the fuel gas heater were developed from similar projects and include low-NO_X burners to minimize emissions from this source. Stack parameters and emission rates for this fuel-gas heater are included in Table 1. Potential-to-emit calculations for the fuel-gas heater are included in Table 2. Emissions data for the proposed CTs was modified to reflect a change from the originally proposed 2,000 hours per CT per year of fuel oil firing to the currently proposed 750 hours per CT per year. This change was considered in evaluating annualized emissions and resulting impacts. Short-term emissions data was not changed from the original evaluation.

All sources, including the additional fuel gas heater, and operating scenarios modeled in the originally submitted air dispersion modeling analysis were again modeled in this new arrangement. Maximum model predicted concentrations for each pollutant and applicable averaging period are presented in Table 3. This table also provides the PSD Class II significant impact levels and required preconstruction monitoring levels. As the table indicates, the Project's maximum predicted concentrations for all pollutants from all sources and modeled operating scenarios are still less than the PSD Class II Significant Impact Level (SIL) for each pollutant and applicable averaging period. These results are similar to those found in the original air dispersion modeling analysis, where the maximum predicted modeled impacts also were less than the PSD SIL for all pollutants and applicable averaging periods. The changes to the proposed project will have an insignificant impact on the environment, and under the PSD program, no further air quality impact analyses are required. In addition, because the revised maximum predicted concentrations are all less than the PSD SILs for each pollutant and applicable averaging period, and are not significantly greater than the original predicted maximum concentrations, the originally submitted Additional Impacts Analysis and Class I Area Impact Analysis were not updated. Therefore, the original analysis and conclusions are valid.

A copy of the revised input (*.DAT) files and the output (*.LST) files from this updated analysis are included as an attachment.

Table 1
Stack Parameters and Pollutant Emissions for the Fuel Gas Heater*

Operating Scenario/Fuel	ISCST3 Source ID	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
						NO_x	SO_2	CO	PM/PM_{10}
Natural Gas Fuel Gas Heater	FUELHEAT	4.57	0.51	4.57	505	0.046	0.035	0.093	0.006

*Representative of a 9.8 MBtu/hr gas heater.

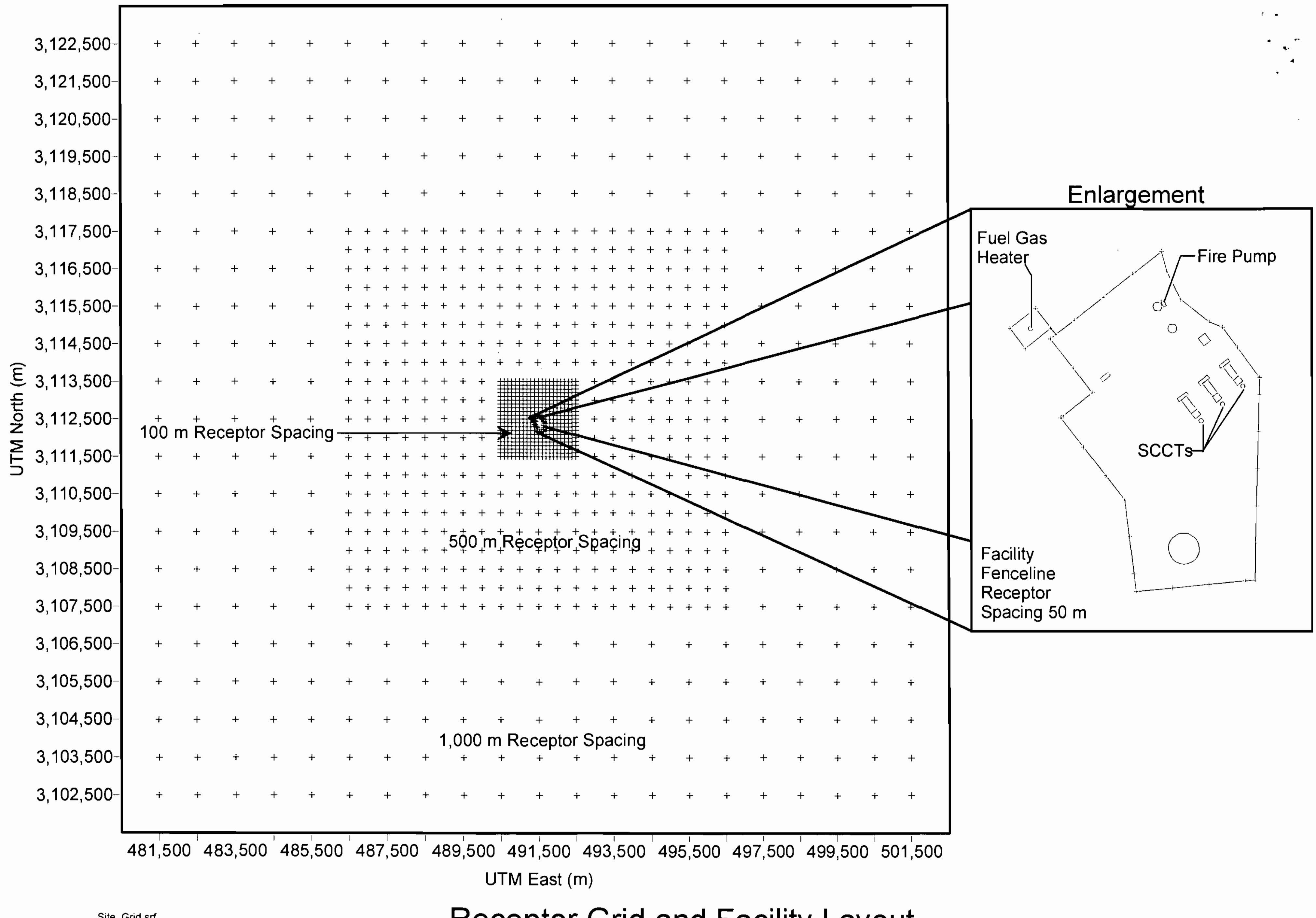
Table 2 Pollutant Emissions for the Fuel Gas Heater							
NO_x		SO_2		CO		PM/PM_{10}	
lb/hr	ton/yr*	lb/hr	ton/yr*	lb/hr	ton/yr*	lb/hr	ton/yr*
0.365	1.60	0.278	1.22	0.738	2.23	0.048	0.21

*8760 hours of operation per year

Table 3
Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimus Monitoring Levels

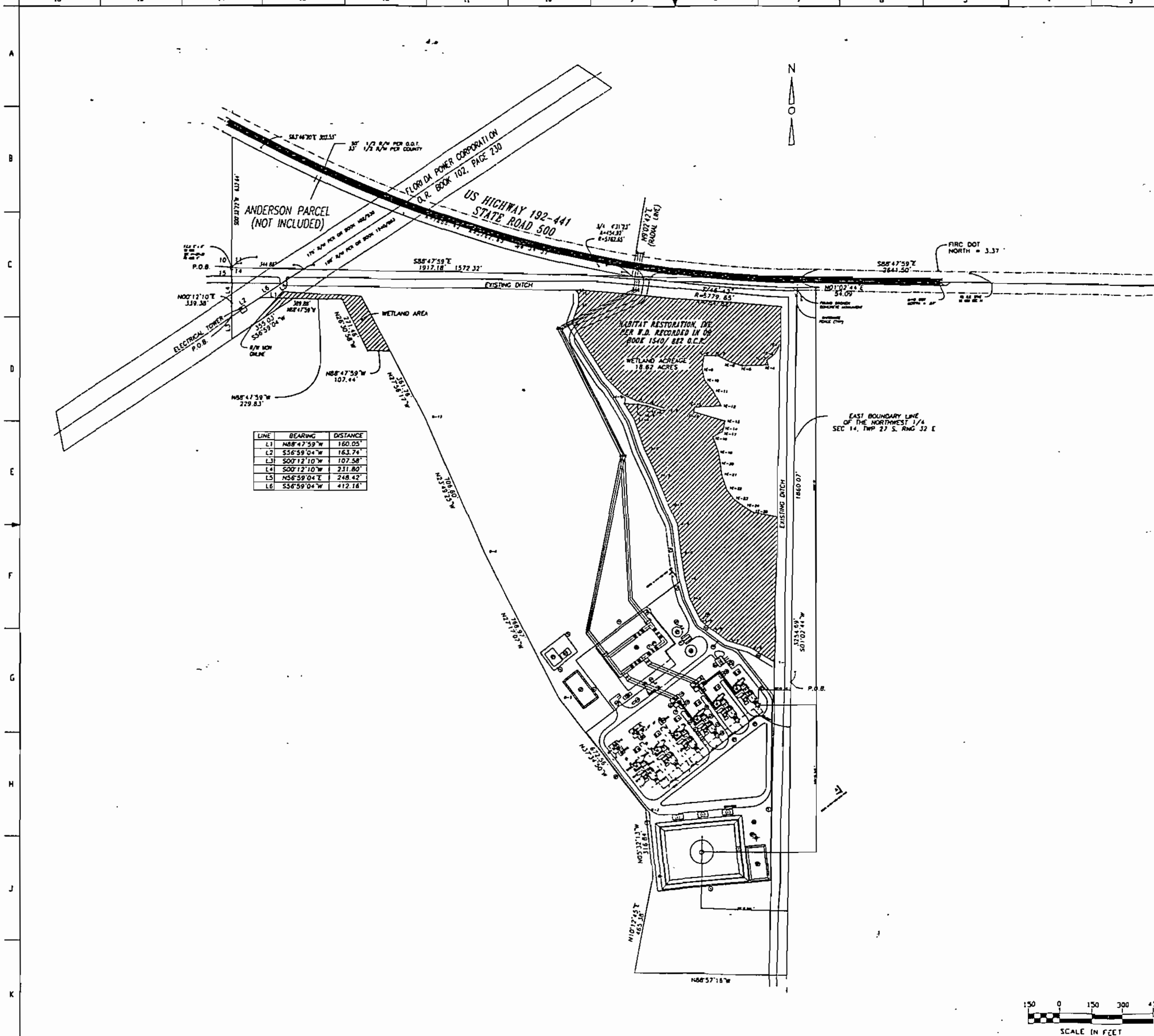
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimus Monitoring Level
NOx	Annual	0.69	1	14
SO2	Annual	0.33	1	-
	3-Hour	11.70	25	-
	24-Hour	4.64	5	13
CO	1-Hour	44.89	2,000	-
	8-Hour	20.36	500	575
PM/PM10	Annual	0.06	1	-
	24-Hour	1.99	5	10

Figure 1
Receptor Locations and Facility Layout



Receptor Grid and Facility Layout

Figure 1



LINE	BEARING	DISTANCE
L1	N88°47'59"W	160.05'
L2	S56°59'04"W	163.74'
L3	S00°12'10"W	107.58'
L4	S00°12'10"W	231.80'
L5	N56°59'04"E	248.42'
L6	S56°59'04"W	412.16'

NOTES:

LEGEND:

1. FUEL OIL STORAGE TANK
2. FUEL OIL OFF-LOADING
3. FUEL OIL CONTAINMENT BERM
4. 230KV CIRCUIT BREAKER
5. PERIMETER FENCE
6. COOLING MODULE
7. WATER TREATMENT TRAILER PARKING
8. EMPLOYEE PARKING
9. FIREWALL
10. DEMINERALIZED WATER STORAGE TANK
11. ELECTRICAL EQUIPMENT, OFFICE AND PARTS STORAGE
12. STEP-UP TRANSFORMER
13. COMBUSTION GAS TURBINE GENERATOR
14. COMBUSTION GAS TURBINE
15. FIRE / RAW WATER TANK
16. FIREWATER PUMPS
17. STORMWATER BASIN
18. SWITCHYARD CONTROL BUILDING
19. 230KV DISC. SWITCH
20. GENERATOR BREAKER
21. CT ELECTRICAL PACKAGE
22. SWITCHYARD
23. GAS METERING STATION
24. GAS HEATER AND SCRUBBER
25. ROAD
26. LAYDOWN AREA
27. ENTRANCE ROAD
28. PROPERTY BOUNDARY
29. ACCESSORY MODULE
30. WETLAND BOUNDARY
31. 25' BUFFER
32. HYDROGEN TUBE TRAILER PARKING
33. HYDROGEN VALVE MANIFOLD
34. CO2 STORAGE
35. AUXILIARY TRANSFORMER
36. WATER WELL No. 1
37. WATER WELL No. 2
38. CT AIR INLET FILTER
39. NOT USED
40. OILY/WATER SEPARATOR
41. CT STACK
42. GATE

REV	DESCRIPTION
C	MOVED ENTRANCE ROAD AND RELOCATED TRANS. LINES
B	ADDED 10A TO STACK & OIL TANK, RELOCATED TRANS. LINE
A	ISSUED FOR REVIEW

VJB

PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.

Reliant Energy. OSCEOLA PROJECT

OSCEOLA COUNTY, FLORIDA
SIMPLE CYCLE PLANT

SITE PLAN

1" = 150'

OSCE-1-SK-110-002-001 C

Reliant Energy

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OCT 07 1999

BUREAU OF AIR REGULATION

October 6, 1999

Mr. Michael P. Halpin, P.E.
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Subject: Response to Request for Additional Information
Reliant Energy Osceola, L.L.C. – PSD Permit Application

Dear Mr. Halpin:

On August 30, 1999, Reliant Energy Osceola, L.L.C. (Reliant Energy) received your letter requesting additional information in support of an air permit application that was submitted to the Florida Department of Environmental Protection (DEP) on July 30, 1999. This permit application was submitted for the Reliant Energy Osceola project, a three-unit simple-cycle combustion turbine electric generating facility that is proposed to be constructed near Holopaw, Florida. In response to your request, Reliant Energy is providing the following information under seal of a Florida registered professional engineer.

BACT for NO_x Emissions

As noted in the August 25, 1999 Request for Information, DEP requested cost information on obtaining a guaranteed NO_x emission rate of 9 ppm for the proposed F-class combustion turbines (CTs) while firing natural gas. In addition, a letter from the U.S. Department of the Interior to DEP dated September 15, 1999 suggests that other simple-cycle combustion turbine facilities have been issued permits that limit NO_x emissions to 9 ppm, and that Reliant Energy Osceola should meet the same limit. Reliant Energy's proposed CTs have a vendor guarantee from General Electric for NO_x emissions at 9 ppm between 60 and 100 percent of base load. However, it is important to note that this guarantee must be demonstrated by a single test (e.g. the "new and clean" test) conducted during the initial commissioning of the CTs, and there is no guarantee that NO_x emissions will remain below the 9 ppm level at all times over the operational lifetime of the units. Consequently, Reliant Energy has proposed a NO_x emission limit of 10.5 ppm to provide a margin for compliance that should allow for operational variability that may result in NO_x emissions in excess of the 9 ppm level.

Delivery of Fuel Oil

Although Reliant Energy plans to construct a pipeline that will deliver natural gas fuel to the proposed Osceola facility, there will be no fuel oil pipeline constructed to deliver fuel oil. In fact, there are no fuel oil transmission pipelines in the vicinity of the proposed Osceola site, and this option is not practically available. Fuel oil that will be delivered to the Osceola facility will be delivered via tank trucks with an estimated delivery schedule of one truck every 12 minutes on average during periods that the units are firing fuel oil. However, this estimate assumes that all three units will be firing fuel oil at the same time and does not include consideration of the on-site oil storage capacity. Furthermore, Reliant Energy intends to fire natural gas in lieu of fuel oil when available and economically attractive.

Justification of Proposed Hours of Fuel Oil Firing

As mentioned in the original permit application, Reliant Energy has proposed fuel oil firing at the Osceola facility of up to 2,000 hours/year per unit to provide assurance that a dependable and economical supply of fuel is available at the site. Natural gas is the preferred fuel when available and economically attractive. However, given the possibility of interruption of the natural gas supply in Florida, such as through supply curtailments or limited availability due to high demand, a realistic potential exists for the need to fire fuel oil on an extended basis. Fuel supply is a critical issue when considering the nature of the Osceola facility, which is designed to provide electrical power during periods of peak demand.

Reliant Energy has provided an analysis below demonstrating that, based on fuel cost and emission reductions, the proposed 2,000 hours/year per unit of oil firing is justified. The result of this analysis is expressed as a cost of reduction per ton of NO_x emissions reduced ($/ton). Recent pricing data for natural gas and transportation grade No. 2 fuel oil shows that fuel oil is more expensive than natural gas when compared on the basis of "delivered" cost, which includes the cost of the fuel and transportation costs. This cost differential, which was obtained from data taken during the 1994 through 1999 period (Attachment A), indicates a differential delivered cost of 1.33 $/mmBtu for fuel oil over natural gas.

However, natural gas becomes significantly more expensive than oil when the cost of "firming," or guaranteeing, the ability to transport gas to the facility is factored into the analysis. This cost is determined by dividing 0.80 $/mcf, which is the cost of firming gas transmission capacity from Florida Gas Transmission, by the effective capacity factor of one generating unit and the heat content of the gas. As a clarification, the cost of firming the transportation costs is adjusted to reflect the capacity factor of the plant because the overall cost basis of 0.80 $/mcf is assessed as a "take-or-pay" contract – the facility would be required to pay for the firm transportation cost of the gas regardless of whether gas is fired. On the basis of firming gas transmission costs for the 2,000 hours/year of operation in question and a natural gas heat content of 1,040 Btu/scf, the cost of firming the natural gas supply for Osceola would be 3.37 $/mmBtu. The overall cost differential associated with firing natural gas in lieu of fuel oil can be calculated by calculating the total cost of firm transportation over the 2,000 hour period and subtracting the differential cost savings of firing fuel oil instead of natural gas for the same period. A summary of calculations also is provided under Attachment A.

NO_x emissions during periods of natural gas firing are significantly less than during operation of the units on fuel oil. Emissions of NO_x during natural gas firing will be limited to 10.5 ppm, while the NO_x emission limit while firing fuel oil is 42 ppm. Given the 2,000 hour period of proposed oil firing and assuming an ambient temperature of 59 °F, operation of the combustion turbines while firing natural gas would result in per-unit emissions of 68.9 tons/year, and fuel oil firing over the same period would result in 314.6 tons/year of NO_x. The differential emissions reduction of 245.7 tons/year per unit, combined with the differential annual cost of $5,447,246 per year per unit, results in an additional cost of $22,170 per ton when natural gas is fired in lieu of fuel oil. Considering the high cost associated with substitution of natural gas for fuel oil over the proposed 2,000 hour period, Reliant Energy submits that the effective cost per ton of NO_x emissions reduced supports the proposed number of up to 2,000 hours/year per unit on fuel oil.

Moreover, the FGT pipeline is currently fully subscribed, meaning that there is no transmission capacity available on the pipeline. Natural gas transmission capacity for this facility must be acquired through the capacity released market, which includes segments of gas transmission capacity that have been relinquished by customers that have firm transmission capacity under contract. Reliant Energy will be required to purchase available relinquished capacity to satisfy the needs of the Osceola facility, the cost of which is approximately equal to the cost required to purchase available firm transmission capacity directly from the pipeline. In addition, the Osceola facility will be competing with other nearby peaking facilities that will use natural gas fuel, such as the Oleander facility in Brevard County and a facility proposed by Dynegy to be located in eastern Osceola County, for the same opportunities to acquire relinquished gas transmission capacity. Given this additional fuel supply constraint, fuel oil-firing capability becomes even more critical for the Reliant Energy Osceola facility.

Reliant Energy believes that the proposed 2,000 hours/year of fuel oil firing requested is reasonable. As demonstrated by the air quality impact analysis, the proposed amount of fuel oil firing will not result in ambient impacts in excess of the significant impact levels for the National Ambient Air Quality Standards (NAAQS). Also, the Osceola facility has been demonstrated to meet the requirements of best available control technology for simple-cycle combustion turbines that fire natural gas and fuel oil. Furthermore, the proposed number of fuel oil-firing hours also is consistent with a recently issued air permit to the Oleander Power Project, L.P. in which up to 5,000 hours per year of fuel oil firing was authorized for the facility. Given the information discussed above, Reliant Energy believes that considerations of fuel supply reliability and cost support our request for up to 2,000 hours/year per unit of operation while firing fuel oil.

Guarantee of Emission Control for SCR on Fuel Oil

Reliant Energy reviewed all available information during the preparation of the Best Available Control Technology (BACT) analysis that was submitted with the original permit application. This included conversations with several equipment vendors, including Mr. Fred Booth at Engelhard Corporation, as well as a review of the BACT/RACT/LAER clearinghouse for available information on existing simple-cycle combustion turbine installations firing oil and equipped with SCR. The Cambalache Plant in Puerto Rico, which is the facility noted in the Engelhard proposal that you referred to, was the only facility identified as having this configuration.

Mr. Booth was contacted concerning the performance of the facility but was unable to provide us with information on the long-term performance of the SCR components. In an attempt to obtain additional information, we also contacted Mr. Harish Patel at U.S. EPA Region 2 headquarters in New York (212-637-4046) who was able to provide the following information:

- The Cambalache facility was permitted for a NO_X emission rate of 10 ppm with ammonia slip at 10 ppm. Water injection is being used in conjunction with SCR to control NO_x emissions, and the facility is experiencing problems meeting their permit emission limit.

- Because of the high exhaust temperatures on the simple cycle turbines, a zeolite catalyst is required for the SCR at this facility. The zeolite catalyst has not performed as well in actual field conditions as it did in the laboratory.

- The facility is now increasing the amount of ammonia injected into the SCR system to minimize NO_X emissions. Although this approach results in decreased NO_X emissions, it also results in increased emissions of ammonia slip. Continued increasing use of ammonia is only a short-term solution because the ammonia delivery system is limited in the amount of ammonia that can be injected into their system.

- After several months of operation, the NO_X emission rate is increasing despite efforts to control NO_x emissions. The current NO_X emissions rate is approximately 20 to 25 ppm, and ammonia slip emissions also have increased to about 30 to 40 ppm.

- When the water injection/SCR system first went into operation, NO_X emissions were at approximately 10 ppm. However, NO_x emissions are expected to increase steadily to approximately 42 ppm due to increasingly ineffective performance by the SCR catalyst. This is equivalent to the emissions rate resulting from water injection only.

In our review of the recently submitted Engelhard cost proposal, we also noted that proposal indicates that the system design basis specifies "limited" oil firing. This is language typical of a facility using this fuel for emergency backup fuel only. Moreover, the performance warranty appears to reflect 9,000 hours of operation on gas firing only as oil firing is limited/emergency use only. In addition, the proposed cost of the installed system appears to be very high when considering the limited Scope of Supply. These caveats indicate that the performance specifications provided in the referenced proposal for a high-temperature SCR system are inconsistent with the proposed Osceola facility.

Reliant Energy reasserts that the conclusion reached in our original BACT analysis is valid. Experience with SCR on simple-cycle combustion turbine applications is very limited and results are poor. There is little to no successful operating experience with these systems when firing fuel oil, and the overall economics and long-term system performance data are unfavorable. In addition, the potential for additional negative environmental impacts from increased emissions of particulate matter (PM_{10}) resulting from increased oxidation of SO_2 to SO_3, as well as from the formation of ammonium bisulfate, indicate that this technology is not appropriate for the proposed Osceola facility. Based on these factors, Reliant Energy believes that the use of dry low-NO_x combustion technology for gas firing and water injection for oil firing represents BACT for NO_x emissions from the proposed facility.

Start-up Emission Rates

Reliant Energy has provided emission vs. load tables under Attachment B that indicate NO_x emissions during partial load operation. General Electric has stated that the approximate elapsed time required for the Frame 7FA combustion turbine to reach synchronization with the electric grid and full load is 6 minutes 45 seconds and 12 minutes, respectively, from initial firing of the turbine. Also, depending on ambient temperature, the 7FA turbine is able to achieve compliance with the NO_x emissions guarantee of 9 ppm after approximately 8 minutes of operation. It is important to note that periods of excess emissions are inherent to dry low-NO_x combustors as their operation requires a transitional period of operation from primary mode, through lean-lean mode, and finally to the premix mode seen in normal operation.

Because unit efficiency is much lower and emissions are much higher during these periods when compared with normal operation, it is the interests of Reliant Energy to minimize operation of the

CTs in startup or shutdown modes. These periods of partial load operation are minimized to the extent possible due to the low efficiency of operation that is experienced at low loads. Also, the nature of this generating facility requires the combustion turbine units to achieve full load with very short notice, which also serves to minimize the amount of time spent with the units operating at low loads. Furthermore, other emission control technologies and methods, such as selective catalytic reduction, also would not be effective because there is insufficient time for the catalyst material to reach the proper temperature required for conversion of NO_x emissions. Even if SCR systems were installed on the proposed units, the higher NO_x emissions experienced during start-up would still occur because of the low catalyst temperature. Accordingly, Reliant Energy believes that the excess emissions that are experienced during partial load operation are reasonable and that the current emissions control scheme of dry low-NO_x combustion for gas firing and water injection for oil firing represents BACT.

Submittal of New Source Information and Revised Modeling Analysis

Although not discussed in the original July 30 permit application submittal, Reliant Energy plans to construct a small natural gas-fired heater at the Osceola project site. This heater will be constructed adjacent to the facility's natural gas supply pipeline and is intended to remove moisture from the gas through heating, and the pipeline heater will have a heat input capacity of no more than 9.8 mmBtu/hour. Reliant Energy is in the process of performing an air quality impact analysis on the proposed Osceola facility that includes emissions from the pipeline heater, the results of which will be forwarded to DEP upon completion of the analysis. Initial results from the modeling analysis indicate that the new configuration of the facility, including the pipeline heater, will not result in ambient impacts in excess of the applicable significant impact levels for any pollutant analyzed.

Please contact me at 713-945-7167 if you have any questions or require additional information.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Response to RAI.doc
Attachments

c: Al Linero – Florida DEP – Tallahassee, FL
Joe Welborn – Seminole Electric Cooperative – Tampa, FL*
(* - w/ attachments)

cc: CD
EPA
NPS
File

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D. Dean Schultz | October 5, 1999
Signature | Date

(seal) DONALD DEAN SCHULTZ CERTIFICATE NO. 30304 STATE OF FLORIDA REGISTERED ENGINEER

* Attach any exception to certification statement.

Attachment A

Assumptions:

Cost of firm transportation:	0.80 \$/mcf
Heat content of natural gas:	1,040 Btu/scf
Annual operation on fuel oil:	2,000 hours/year
Unit generating capacity @ 59°F while firing:	
- natural gas:	171,200 kW
- fuel oil:	181,800 kW
Unit heat rate @ 59°F while firing:	
- natural gas:	10,389 Btu/kWh
- fuel oil:	11,056 Btu/kWh
Delivered fuel cost:	
- natural gas:	2.60 \$/mmBtu
- fuel oil:	3.93 \$/mmBtu

Calculations:

Natural gas firm transportation cost (per unit of fuel):

= (0.80 \$/mcf)(1 mcf/1,000 cf)(1 cf/1,040 Btu)(10^6 Btu/1 mmBtu)
= 0.77 \$/mmBtu

= (0.77 \$/mmBtu)/(2,000 hours/8,760 hours)
= 3.37 \$/mmBtu

Natural gas total transportation cost (per year per unit):

= (2,000 hours/year)(171,200 kW)(10,389 Btu/kWh)(1 mmBtu /10^6 Btu)
= 3,557,194 mmBtu/year

= (3.37 \$/mmBtu)(3,557,194 mmBtu/year)
= \$ 11,996,992 per year

Natural gas fuel cost (per year per unit):

= (2,000 hours/year)(171,200 kW)(10,389 Btu/kWh)(1 mmBtu /10^6 Btu)
= 3,557,194 mmBtu/year

= (2.60 \$/mmBtu)(3,557,194 mmBtu/year)
= \$ 9,248,703 per year

Total natural gas fuel cost (per year per unit):

= (\$ 9,248,703 per year)+(\$ 11,996,992 per year)
= \$ 21,245,695 per year

Total fuel oil cost (per year per unit):

= (2,000 hours/year)(181,800 kW)(11,056 Btu/kWh)(1 mmBtu /10^6 Btu)
= 4,019,962 mmBtu/year

= (3.93 $/mmBtu)(4,019,962 mmBtu/year)
= $ 15,798,449 per year

Total net fuel cost (per year per unit):

= ($ 21,245,695) – ($15,798,449)
= **$ 5,447,246 per year**

Assumptions:

Annual operation on fuel oil:	2,000 hours/year
Unit heat input rate @ 59°F while firing:	
- natural gas:	1,779 mmBtu/hour
- fuel oil:	1,930 mmBtu/hour
NO_x emission rate while firing:	
- natural gas:	0.0387 lb/mmBtu (10.5 ppm @ 15% O_2)
- fuel oil:	0.163 lb/mmBtu (42 ppm @ 15% O_2)

Calculations:

NO_x emissions while firing natural gas:

= (0.0387 lb/mmBtu)(1,779 mmBtu/hour)(2,000 hours/year)(1 ton/2,000 lb)
= 68.85 tons/year

NO_x emissions while firing fuel oil:

= (0.163 lb/mmBtu)(1,779 mmBtu/hour)(2,000 hours/year)(1 ton/2,000 lb)
= 314.6 tons/year

Differential NO_x emissions:

= (314.6 tons/year) – (68.85 tons/year)
= **245.7 tons/year**

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

September 15, 1999

Re: PSD-FL-273

RECEIVED

SEP 21 1999

BUREAU OF AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Reliant Energy, Osceola

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for the Osceola Power Project (Osceola), a 510 MW power production facility in Osceola County, Florida. The facility would be located 155 km southeast of Chassahowitzka Wilderness, a Class I area administered by the Fish and Wildlife Service.

The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your Department require Osceola to meet lower limits than proposed for nitrogen oxides emissions.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely yours,

Sam D. Hamilton

Sam D. Hamilton
Regional Director

Enclosures

cc: M. Halpin, BAR
C. Holladay, BAR
EPA
CD
J. Goodwin, P.E.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

August 25, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James M. Goodwin, P.E.
Reliant Energy Wholesale Group
12301 Kurland, P.O. Box 4455
Houston, TX 77034

Re: Request for Additional Information
DEP File No. 0970071-001-AC (PSD-FL-273)
Osceola Power Project - Three 170 MW Combustion Turbines

Dear Mr. Goodwin:

On August 3, the Department received your application and complete fee for an air construction/operation permit for three 170-MW dual fuel, proposed 'F' class combustion turbines for the Osceola Power Project in Osceola County. The application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. A recent BACT determination of General Electric simple cycle CT's for the Oleander Project resulted in NO_X emissions of 9 ppm while firing natural gas. Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that application.
2. How will the liquid fuel be delivered to the site, e.g. pipeline or trucks? If by truck, please estimate the average number of daily deliveries.
3. Please re-examine the requested 2000 hours per CT per year usage of 0.05% sulfur No. 2 fuel oil. Provide the Department with a cost evaluation of utilizing differing (superior) types of liquid fuels so as to minimize associated pollutant emissions. The Department will consider fuel quality and quantity in making its determination of BACT.
4. SCR information recently supplied to the Department by Engelhard Corporation differs from Osceola's BACT submittal. Specifically, Engelhard indicates that they will guarantee performance on a GE 7FA machine firing oil in simple cycle mode, as well as only 5 ppm ammonia slip (versus 10 ppm) and 2.5" of pressure drop (versus 3.15"). The Department intends to analyze the use of SCR during oil firing as part of its BACT Determination and suggests that the applicant consider revising the related submittal.
5. Provide the worst case start-up and shutdown emissions characteristics for the units under consideration including start-up curves and duration of excess emissions. The Department plans to address excess emissions in its BACT determination.

We are awaiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530. Matters regarding review of the modeling should be directed to Cleveland Holladay (meteorologist) at 850/921-8986.

Sincerely,

AA Linero 8/25

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
Len Kozlov, DEP-CD
Donald Schultz, P.E., Black & Veatch

Reliant Energy

RECEIVED

OCT 26 1999

BUREAU OF AIR REGULATION

October 20, 1999

Mr. Michael P. Halpin, P.E.
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Subject: Reliant Energy Osceola, L.L.C. – PSD Permit Application
Revision to Proposed Hours of Operation on Fuel Oil

Dear Mr. Halpin:

On October 6, 1999, Reliant Energy Osceola, L.L.C. (Reliant Energy) submitted information to the Florida Department of Environmental Protection (DEP) in response to a request for information that was received by Reliant Energy on August 30, 1999. Included in this response was a justification for the proposed operational limit of 2,000 hours per year per unit while firing fuel oil. Since this letter was submitted to FDEP, Reliant Energy has chosen to revise its proposal for the number of fuel oil firing hours at Osceola. As we discussed in a telephone conversation on October 19, Reliant Energy is now proposing to revise the operational limit for each combustion turbine unit to no more than 3,000 hours per year in total and no more than 750 hours per year of operation on fuel oil. The proposed emission limits for NO_x while firing natural gas and fuel oil remain at 10.5 ppm and 42 ppm, respectively.

Reliant Energy is currently in the process of preparing a revised air quality impact analysis that includes the revisions discussed above. As mentioned in our October 6 response to FDEP, Reliant Energy plans to construct a small natural gas-fired heater at the Osceola project site. This heater will be constructed adjacent to the facility's natural gas supply pipeline and is intended to remove moisture from the gas through heating, and the pipeline heater will have a heat input capacity of no more than 9.8 mmBtu/hour. The results of this revised air quality impact analysis, which includes emissions from the pipeline heater, will be forwarded to FDEP upon completion of the analysis. Initial results from the modeling analysis indicate that the new configuration of the facility, including the pipeline heater, will not result in ambient impacts in excess of the applicable significant impact levels for any pollutant analyzed.

Please contact me at 713-945-7167 if you have any questions or require additional information.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Revised Oil Hours.doc

c: Al Linero – Florida DEP – Tallahassee, FL

cc: L. Kozlov, CD
NPS
EPA

Price Comparison of Natural Gas to No. 2 Oil Delivered to Florida

	GAS	NO. 2 OIL	+ NO. 2 OIL HIGHER THAN GAS ( ) NO. 2 OIL LESS THAN GAS
Jan-94	2.506	3.583	1.077
Feb-94	2.608	3.602	0.994
Mar-94	2.359	3.313	0.954
Apr-94	2.361	3.450	1.089
May-94	2.187	3.528	1.341
Jun-94	2.330	3.629	1.299
Jul-94	2.225	3.698	1.472
Aug-94	1.944	3.661	1.717
Sep-94	1.867	3.567	1.700
Oct-94	1.972	3.588	1.616
Nov-94	2.031	3.671	1.640
Dec-94	1.945	3.562	1.617
Jan-95	1.677	3.534	1.857
Feb-95	1.688	3.523	1.835
Mar-95	1.784	3.391	1.607
Apr-95	1.908	3.689	1.781
May-95	1.960	3.782	1.822
Jun-95	1.884	3.548	1.664
Jul-95	1.745	3.464	1.719
Aug-95	1.808	3.653	1.846
Sep-95	1.928	3.716	1.788
Oct-95	2.040	3.608	1.568
Nov-95	2.225	3.816	1.591
Dec-95	2.706	4.101	1.395
Jan-96	2.753	3.944	1.191
Feb-96	2.708	4.126	1.418
Mar-96	2.603	4.260	1.656
Apr-96	2.561	4.411	1.851
May-96	2.537	4.099	1.562
Jun-96	2.795	3.835	1.040
Jul-96	2.800	4.111	1.312
Aug-96	2.300	4.452	2.152
Sep-96	2.183	4.950	2.767
Oct-96	2.731	5.252	2.521
Nov-96	3.319	5.093	1.775
Dec-96	3.912	5.072	1.161

Florida Gas Transmission Co.	06880	1998	11	36371000	30	1,212,367	1,410,000	197,633	86.0%
Florida Gas Transmission Co.	06880	1998	12	37522000	31	1,210,387	1,410,000	199,613	85.8%
Florida Gas Transmission Co.	06880	1999	1	35904000	31	1,158,194	1,410,000	251,806	82.1%
Florida Gas Transmission Co.	06880	1999	2	32820000	28	1,172,143	1,410,000	237,857	83.1%
Florida Gas Transmission Co.	06880	1999	3	40772000	31	1,315,226	1,410,000	94,774	93.3%
					30				
					31				
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					31				
					30				
					31				
					30				
					31				

Attachment B

Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	94.	94.	94.	94.	94.	94.	94.	94.	94.	94.
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel Temperature	Deg F	130	130	130	130	130	130	130	130	130	130
Output	kW	148,800.	74,400.	67,000.	59,500.	52,100.	44,600.	37,200.	29,800.	14,900.	0.
Heat Rate (LHV)	Btu/kWh	9,720.	12,940.	13,610.	14,430.	15,420.	16,610.	18,310.	20,900.	34,990.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,446.3	962.7	911.9	858.6	803.4	740.8	681.1	622.8	521.4	387.6
Exhaust Flow X 10^3	lb/h	3235.	2287.	2201.	2112.	2049.	2047.	2046.	2044.	2041.	2039.
Exhaust Temp.	Deg F.	1151.	1200.	1200.	1200.	1182.	1124.	1068.	1014.	909.	811.
Exhaust Heat (LHV) X 10^6	Btu/h	885.7	672.1	648.0	622.0	593.8	558.7	526.1	494.8	447.0	N/A

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	84.	79.	72.	63.	69.	59.	69.	62.
NOx AS NO2	lb/h	54.	35.	308.	272.	231.	186.	187.	146.	138.	97.
CO	ppmvd	9.	9.	490.	530.	612.	810.	44.	154.	102.	102.
CO	lb/h	26.	19.	971.	1010.	1134.	1500.	82.	289.	192.	193.
UHC	ppmvw	7.	7.	64.	80.	123.	277.	20.	70.	26.	77.
UHC	lb/h	13.	9.	79.	96.	142.	320.	23.	80.	30.	88.
VOC	ppmvw	1.4	1.4	12.8	16.	24.6	55.4	4.	14.	5.2	15.4
VOC	lb/h	2.6	1.8	15.8	19.2	28.4	64.	4.6	16.	6.	17.6
Particulates	lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.88	0.88	0.87	0.89	0.88	0.89	0.89	0.90	0.90
Nitrogen	73.39	73.60	73.65	73.70	73.79	73.98	74.17	74.35	74.69	75.02
Oxygen	12.21	12.83	12.97	13.12	13.39	13.93	14.46	14.98	15.99	16.95
Carbon Dioxide	3.77	3.49	3.42	3.36	3.23	2.99	2.74	2.51	2.05	1.62
Water	9.76	9.21	9.08	8.95	8.70	8.22	7.74	7.28	6.38	5.52

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	44
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 5 . 1 Opt: N 72411298
SANDERJO 9/14/99 13:29 ReliantOsceola.dat

Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	73.	73.	73.	73.	73.	73.	73.	73.	73.	73.
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel Temperature	Deg F	130	130	130	130	130	130	130	130	130	130
Output	kW	162,200.	81,100.	73,000.	64,900.	56,800.	48,700.	40,500.	32,400.	16,200.	0.
Heat Rate (LHV)	Btu/kWh	9,480.	12,510.	13,140.	13,910.	14,800.	15,900.	17,460.	19,850.	32,120.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,537.7	1,014.6	959.2	902.8	840.6	774.3	707.1	643.1	520.3	391.7
Exhaust Flow X 10^3	lb/h	3412.	2347.	2255.	2161.	2104.	2102.	2100.	2098.	2094.	2090.
Exhaust Temp.	Deg F.	1131.	1200.	1200.	1200.	1174.	1113.	1054.	997.	888.	785.
Exhaust Heat (LHV) X 10^6	Btu/h	928.1	699.4	673.4	646.4	613.8	577.2	540.1	505.7	441.7	N/A

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	88.	80.	69.	76.	64.	73.	65.
NOx AS NO2	lb/h	57.	37.	35.	318.	269.	213.	214.	164.	150.	103.
CO	ppmvd	9.	9.	9.	498.	593.	797.	44.	165.	102.	102.
CO	lb/h	28.	19.	18.	973.	1132.	1521.	84.	317.	198.	199.
UHC	ppmvw	7.	7.	7.	67.	112.	264.	20.	74.	29.	89.
UHC	lb/h	14.	9.	9.	82.	133.	312.	24.	87.	34.	105.
VOC	ppmvw	1.4	1.4	1.4	13.4	22.4	52.8	4.	14.8	5.8	17.8
VOC	lb/h	2.8	1.8	1.8	16.4	26.6	62.4	4.8	17.4	6.8	21.
Particulates	lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.89	0.88	0.89	0.90	0.90	0.90	0.90	0.91
Nitrogen	73.90	74.07	74.12	74.18	74.29	74.49	74.69	74.88	75.25	75.60
Oxygen	12.27	12.76	12.90	13.05	13.39	13.96	14.52	15.07	16.13	17.14
Carbon Dioxide	3.81	3.59	3.52	3.45	3.30	3.04	2.79	2.54	2.06	1.60
Water	9.14	8.70	8.57	8.44	8.13	7.62	7.11	6.62	5.67	4.76

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 5 . 1 Opt: N 72411298
SANDERJO 9/14/99 13:22 ReliantOsceola.dat

Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel Temperature	Deg F	130	130	130	130	130	130	130	130	130	130
Output	kW	187,000.	93,500.	84,200.	74,800.	65,500.	56,100.	46,800.	37,400.	18,700.	0.
Heat Rate (LHV)	Btu/kWh	9,140.	11,880.	12,470.	13,160.	13,870.	14,850.	16,250.	18,390.	29,420.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,709.2	1,110.8	1,050.	984.4	908.5	833.1	760.5	687.8	550.2	407.4
Exhaust Flow X 10^3	lb/h	3791.	2486.	2368.	2270.	2267.	2265.	2262.	2260.	2255.	2251.
Exhaust Temp.	Deg F.	1071.	1174.	1185.	1181.	1117.	1054.	994.	934.	823.	719.
Exhaust Heat (LHV) X 10^6	Btu/h	1008.8	750.1	723.0	691.6	649.8	608.9	570.3	531.9	462.1	N/A

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.	90.	101.	84.	71.	79.	70.
NOx AS NO2	lb/h	63.	40.	38.	36.	327.	336.	254.	194.	171.	115.
CO	ppmvd	9.	9.	9.	9.	643.	18.	73.	295.	102.	102.
CO	lb/h	31.	20.	19.	19.	1335.	37.	152.	619.	215.	216.
UHC	ppmvw	7.	7.	7.	7.	142.	8.	33.	132.	39.	129.
UHC	lb/h	15.	10.	9.	9.	180.	10.	42.	167.	49.	162.
VOC	ppmvw	1.4	1.4	1.4	1.4	28.4	1.6	6.6	26.4	7.8	25.8
VOC	lb/h	3.	2.	1.8	1.8	36.	2.	8.4	33.4	9.8	32.4
Particulates	lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.90	0.90	0.89	0.91	0.91	0.92	0.91	0.91
Nitrogen	74.97	75.06	75.08	75.15	75.37	75.58	75.78	75.99	76.38	76.75
Oxygen	12.51	12.75	12.83	13.02	13.63	14.22	14.81	15.38	16.49	17.54
Carbon Dioxide	3.83	3.72	3.69	3.60	3.33	3.06	2.79	2.53	2.03	1.56
Water	7.79	7.58	7.51	7.33	6.78	6.24	5.71	5.19	4.20	3.25

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 5 . 1 Opt: N 72411298
SANDERJO 9/14/99 13:18 ReliantOsceola.dat

Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	94.	94.	94.	94.	94.	94.	94.	94.	94.	94.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80	80	80	80	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Output	kW	161,700.	80,900.	72,800.	64,700.	56,600.	48,500.	40,400.	32,300.	16,200.	0.
Heat Rate (LHV)	Btu/kWh	10,230.	13,310.	13,950.	14,740.	15,670.	16,760.	17,790.	20,220.	32,610.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,654.2	1,076.8	1,015.6	953.7	886.9	812.9	718.7	653.1	528.3	390.3
Exhaust Flow X 10^3	lb/h	3359.	2344.	2255.	2163.	2095.	2086.	2052.	2050.	2046.	2042.
Exhaust Temp.	Deg F.	1139.	1200.	1200.	1200.	1183.	1129.	1106.	1044.	928.	819.
Exhaust Heat (LHV) X 10^6	Btu/h	935.2	705.8	679.2	651.8	620.5	583.3	551.6	515.6	449.4	N/A
Water Flow	lb/h	102,750.	51,710.	46,890.	42,100.	36,670.	30,160.	0.	0.	0.	0.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.	42.	127.	108.	79.	64.
NOx AS NO2	lb/h	292.	186.	175.	164.	152.	139.	372.	286.	168.	104.
CO	ppmvd	20.	38.	45.	53.	71.	125.	161.	262.	432.	708.
CO	lb/h	59.	80.	89.	101.	132.	234.	303.	495.	820.	1349.
UHC	ppmvw	7.	7.	8.	8.	10.	14.	16.	24.	53.	113.
UHC	lb/h	13.	9.	10.	10.	12.	16.	19.	28.	60.	129.
VOC	ppmvw	3.5	3.5	4.	4.	5.	7.	8.	12.	26.5	56.5
VOC	lb/h	6.5	4.5	5.	5.	6.	8.	9.5	14.	30.	64.5
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.87	0.87	0.86	0.87	0.87	0.90	0.90	0.89	0.90
Nitrogen	70.63	71.80	71.99	72.19	72.49	72.99	74.89	75.02	75.26	75.48
Oxygen	10.88	11.86	12.06	12.28	12.65	13.32	14.42	14.98	16.05	17.06
Carbon Dioxide	5.59	5.13	5.03	4.92	4.72	4.35	3.94	3.58	2.89	2.23
Water	12.06	10.35	10.06	9.76	9.28	8.48	5.85	5.53	4.91	4.33

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	44
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	73.	73.	73.	73.	73.	73.	73.	73.	73.	73.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80	80	80	80	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Output	kW	175,900.	88,000.	79,200.	70,400.	61,600.	52,800.	44,000.	35,200.	17,600.	0.
Heat Rate (LHV)	Btu/kWh	10,040.	12,950.	13,550.	14,280.	15,100.	16,110.	17,000.	19,240.	30,740.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,766.	1,139.6	1,073.2	1,005.3	930.2	850.6	748.	677.2	541.	394.7
Exhaust Flow X 10^3	lb/h	3550.	2402.	2308.	2211.	2156.	2146.	2107.	2104.	2099.	2094.
Exhaust Temp.	Deg F.	1117.	1200.	1200.	1200.	1171.	1115.	1092.	1028.	906.	793.
Exhaust Heat (LHV) X 10^6	Btu/h	983.1	735.5	706.8	676.8	641.0	601.6	567.7	529.1	457.0	N/A
Water Flow	lb/h	114,710.	58,740.	53,260.	47,810.	41,160.	33,840.	0.	0.	0.	0.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.	42.	138.	117.	84.	67.
NOx AS NO2	lb/h	312.	197.	185.	173.	160.	146.	420.	321.	183.	110.
CO	ppmvd	20.	34.	40.	47.	69.	124.	159.	265.	448.	756.
CO	lb/h	62.	72.	81.	92.	133.	240.	309.	515.	877.	1480.
UHC	ppmvw	7.	7.	7.	8.	10.	14.	16.	24.	56.	125.
UHC	lb/h	14.	9.	9.	10.	12.	17.	19.	29.	65.	145.
VOC	ppmvw	3.5	3.5	3.5	4.	5.	7.	8.	12.	28.	62.5
VOC	lb/h	7.	4.5	4.5	5.	6.	8.5	9.5	14.5	32.5	72.5
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87	0.87	0.87	0.87	0.90	0.91	0.91	0.93
Nitrogen	70.92	71.98	72.19	72.40	72.80	73.34	75.43	75.56	75.82	76.05
Oxygen	10.87	11.66	11.88	12.10	12.59	13.30	14.48	15.06	16.19	17.25
Carbon Dioxide	5.65	5.31	5.19	5.08	4.82	4.43	4.00	3.62	2.89	2.20
Water	11.71	10.20	9.88	9.55	8.93	8.06	5.19	4.85	4.20	3.58

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Reliant Energy/Osceola Project

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	50%	45%	40%	35%	30%	25%	20%	10%	FSNL
Ambient Temp.	Deg F.	19.	19.	19.	19.	19.	19.	19.	19.	19.	19.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	80	80	80	80	80	80	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Output	kW	196,400.	98,200.	88,400.	78,600.	68,700.	58,900.	49,100.	39,300.	19,600.	0.
Heat Rate (LHV)	Btu/kWh	9,830.	12,530.	13,120.	13,710.	14,380.	15,310.	16,090.	18,170.	28,870.	0.
Heat Cons. (LHV) X 10^6	Btu/h	1,930.6	1,230.4	1,159.8	1,077.6	987.9	901.8	790.	714.1	565.9	410.7
Exhaust Flow X 10^3	lb/h	3948.	2511.	2391.	2338.	2325.	2313.	2269.	2266.	2260.	2255.
Exhaust Temp.	Deg F.	1047.	1174.	1185.	1155.	1099.	1044.	1021.	957.	837.	727.
Exhaust Heat (LHV) X 10^6	Btu/h	1058.9	779.2	750.1	712.3	668.3	626.7	591.0	550.8	474.2	N/A
Water Flow	lb/h	130,080.	69,100.	63,360.	55,230.	46,340.	38,210.	0.	0.	0.	0.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.	42.	150.	127.	91.	72.
NOx AS NO2	lb/h	341.	213.	200.	185.	170.	155.	482.	368.	208.	123.
CO	ppmvd	20.	34.	37.	54.	98.	178.	228.	304.	520.	884.
CO	lb/h	70.	76.	78.	114.	205.	374.	482.	644.	1106.	1879.
UHC	ppmvw	7.	7.	7.	9.	12.	17.	20.	30.	70.	159.
UHC	lb/h	16.	10.	9.	11.	16.	22.	25.	38.	88.	198.
VOC	ppmvw	3.5	3.5	3.5	4.5	6.	8.5	10.	15.	35.	79.5
VOC	lb/h	8.	5.	4.5	5.5	8.	11.	12.5	19.	44.	99.
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.87	0.86	0.88	0.89	0.90	0.91	0.92	0.92	0.91
Nitrogen	71.89	72.58	72.73	73.18	73.77	74.33	76.56	76.70	76.95	77.20
Oxygen	11.24	11.54	11.67	12.18	12.92	13.63	14.87	15.45	16.58	17.65
Carbon Dioxide	5.58	5.50	5.44	5.16	4.77	4.38	3.94	3.56	2.83	2.14
Water	10.44	9.52	9.30	8.60	7.66	6.77	3.72	3.37	2.72	2.10

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Jan-97	3.319	4.953	1.634
Feb-97	2.311	4.427	2.116
Mar-97	2.151	4.033	1.882
Apr-97	2.256	4.019	1.763
May-97	2.489	4.104	1.615
Jun-97	2.412	3.872	1.460
Jul-97	2.383	3.928	1.545
Aug-97	2.716	4.022	1.305
Sep-97	3.123	3.964	0.841
Oct-97	3.494	4.282	0.788
Nov-97	3.291	4.131	0.840
Dec-97	2.649	3.717	1.068
Jan-98	2.355	3.439	1.084
Feb-98	2.511	3.310	0.800
Mar-98	2.504	3.122	0.618
Apr-98	2.724	3.195	0.471
May-98	2.405	3.070	0.666
Jun-98	2.419	2.917	0.498
Jul-98	2.411	2.821	0.410
Aug-98	2.106	2.649	0.543
Sep-98	2.279	3.080	0.801
Oct-98	2.464	2.992	0.528
Nov-98	2.560	2.652	0.092
Dec-98	2.176	2.355	0.179
Jan-99	2.080	2.476	0.396
Feb-99	2.013	2.282	0.269
Mar-99	2.051	2.850	0.799
Apr-99	2.406	3.173	0.767
May-99	2.526	3.097	0.571
Jun-99	2.596	3.222	0.625

Pipeline Co Name	Pipeline Co ID	Year	Month	Trans: Quantity MDth	Days	Dth/d	Capacity	Avail	LF
Florida Gas Transmission Co.	06880	1996	1	37236000	31	1,201,161	1,410,000	208,839	85.2%
Florida Gas Transmission Co.	06880	1996	2	31451000	28	1,123,250	1,410,000	286,750	79.7%
Florida Gas Transmission Co.	06880	1996	3	34377000	31	1,108,935	1,410,000	301,065	78.6%
Florida Gas Transmission Co.	06880	1996	4	38143000	30	1,271,433	1,410,000	138,567	90.2%
Florida Gas Transmission Co.	06880	1996	5	47231000	31	1,523,581	1,410,000	-113,581	108.1%
Florida Gas Transmission Co.	06880	1996	6	41394000	30	1,379,800	1,410,000	30,200	97.9%
Florida Gas Transmission Co.	06880	1996	7	43846000	31	1,414,387	1,410,000	-4,387	100.3%
Florida Gas Transmission Co.	06880	1996	8	47123000	31	1,520,097	1,410,000	-110,097	107.8%
Florida Gas Transmission Co.	06880	1996	9	46517000	30	1,550,567	1,410,000	-140,567	110.0%
Florida Gas Transmission Co.	06880	1996	10	42568000	31	1,373,161	1,410,000	36,839	97.4%
Florida Gas Transmission Co.	06880	1996	11	34557000	30	1,151,900	1,410,000	258,100	81.7%
Florida Gas Transmission Co.	06880	1996	12	30559000	31	985,774	1,410,000	424,226	69.9%
Florida Gas Transmission Co.	06880	1997	1	30530000	31	984,839	1,410,000	425,161	69.8%
Florida Gas Transmission Co.	06880	1997	2	33931000	28	1,211,821	1,410,000	198,179	85.9%
Florida Gas Transmission Co.	06880	1997	3	45104000	31	1,454,968	1,410,000	-44,968	103.2%
Florida Gas Transmission Co.	06880	1997	4	44382000	30	1,479,400	1,410,000	-69,400	104.9%
Florida Gas Transmission Co.	06880	1997	5	45194000	31	1,457,871	1,410,000	-47,871	103.4%
Florida Gas Transmission Co.	06880	1997	6	45462000	30	1,515,400	1,410,000	-105,400	107.5%
Florida Gas Transmission Co.	06880	1997	7	49512000	31	1,597,161	1,410,000	-187,161	113.3%
Florida Gas Transmission Co.	06880	1997	8	44734000	31	1,443,032	1,410,000	-33,032	102.3%
Florida Gas Transmission Co.	06880	1997	9	40331000	30	1,344,367	1,410,000	65,633	95.3%
Florida Gas Transmission Co.	06880	1997	10	36259000	31	1,169,645	1,410,000	240,355	83.0%
Florida Gas Transmission Co.	06880	1997	11	35265000	30	1,175,500	1,410,000	234,500	83.4%
Florida Gas Transmission Co.	06880	1997	12	39296000	31	1,267,613	1,410,000	142,387	89.9%
Florida Gas Transmission Co.	06880	1998	1	37046000	31	1,195,032	1,410,000	214,968	84.8%
Florida Gas Transmission Co.	06880	1998	2	32217000	28	1,150,607	1,410,000	259,393	81.6%
Florida Gas Transmission Co.	06880	1998	3	37139000	31	1,198,032	1,410,000	211,968	85.0%
Florida Gas Transmission Co.	06880	1998	4	32639000	30	1,087,967	1,410,000	322,033	77.2%
Florida Gas Transmission Co.	06880	1998	5	41418000	31	1,336,065	1,410,000	73,935	94.8%
Florida Gas Transmission Co.	06880	1998	6	47818000	30	1,593,933	1,410,000	-183,933	113.0%
Florida Gas Transmission Co.	06880	1998	7	47774000	31	1,541,097	1,410,000	-131,097	109.3%
Florida Gas Transmission Co.	06880	1998	8	44600000	31	1,438,710	1,410,000	-28,710	102.0%
Florida Gas Transmission Co.	06880	1998	9	42900000	30	1,430,000	1,410,000	-20,000	101.4%
Florida Gas Transmission Co.	06880	1998	10	45582000	31	1,470,387	1,410,000	-60,387	104.3%

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
James M. Goodwin, PE
Reliant Energy W. G.
PO Box 4455
Houston, TX 77034

4a. Article Number
Z 333 618 129

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
AUG 30 1999

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 129

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to James Goodwin	
Street & Number Reliant Energy	
Post Office, State, & ZIP Code Osceola	
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Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
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PS Form **3800**, April 1995

Technical Review of Prevention of Significant Deterioration Permit Application
For the Construction of a 510 MW Power Production Facility
Osceola Power Project
Osceola County, Florida
PSD-FL-273

by

Air Quality Branch, Fish and Wildlife Service – Denver
August 31, 1999

Reliant Energy Osceola, L.L.C. (Osceola) proposes to construct a 510 MW power production facility, composed of three 170 MW General Electric GE PG7241 (FA) simple cycle gas/oil turbines. The facility would be located in Osceola County, Florida, 155 km southeast of Chassahowitzka Wilderness, a Class I area administered by the U.S. Fish and Wildlife Service (FWS).

This project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM-10), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	1,074
SO_2	297
SAM	46
PM-10	129
CO	246

Best Available Control Technology (BACT) Analysis

Only NO_x emissions are of concern from a control technology standpoint for this type of application because NO_x emissions are highly dependent upon the combustor type and any add-on controls. Emissions of other pollutants depend primarily on good combustion techniques. (Although CO emissions will also be controlled, they have no effect beyond the immediate vicinity.)

Osceola has proposed to meet NO_x limits of 10.5 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen by use of Dry Low-NO_x (DLN) combustors while burning natural gas. When burning oil, Osceola proposes to limit NO_x to 42 ppm through the use of water injection.

While we agree with the control technologies proposed by Osceola, we also believe that it can better utilize these technologies to achieve lower NO_x emissions. For example, table 1.d (enclosed) indicates that emissions in the 9-ppm range are readily achievable and feasible on the overwhelming majority of newer simple-cycle units with DLN. For example, a permit issued recently by the Virginia department of Environmental Quality for identical GE PG7241 (FA) simple cycle combustion turbines in Fauquier County, Virginia limited NO_x emissions to 9 ppm as a one-hour average.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Table 1.a Gas Turbine Limits from RBLC

	Project Description									Permit	NOx Emission Limits			
											Dry Lox-NOx Comb.		SCR	
	Simple	Combined	Peak	Turbine	Duct		Power			Issue	Gas	Oil	Gas	Oil
Facility Name	Cycle	Cycle	Base	Type	Burner	MW	mmBtu/hr	HP	Permit #	Date	(ppm)	(ppm)	(ppm)	(ppm)
Alabama Power Company		Y			Y	100	353	10566	AL-0115	Dec-97	15.0			
American Cogen Tech.										Sep-85			17.0	
Arrowhead Cogen										Dec-89			9.0	
Auburndale Power Part.						356	1214	36298	FL-0080	Dec-92	15.0	25.0		
Baf Energy										Jul-87			9.0	
Baltimore Gas & Electric						140	495	14792	MD-0019		15.0			
Bear Island Paper		Y			Y	139	474	14172	VA-0190	Oct-92			9.0	15.0
Berkshire, MA		Y				272							3.5	9.0
Bermuda Hundred										Mar-92			9.0	15.0
Blue Mtn. Pwr.					Y	153	541	16166	PA-0148	Jul-96	Y	Y	4.0	8.4
Brooklyn Navy Yard Cogen		Y				240	848	25358	NY-0044	Jun-95			3.5	10.0
Cimarron Chemical						0			CO-0020	Mar-91				
Cogen Technologies										Jun-87			9.6	
Doswell Ltd.										May-90			9.0	
Ecoelectrica		Y				461	1629	48709	PR-0004	Oct-96			7.0	9.0
Fleetwood Cogeneration					Y	105	360	10764	PA-0099	Apr-94			15.0	
Florida Power–Polk		Y					1510		FL-0082	Feb-94	12.0	42.0		
Formosa Plastics		Y				132	450	13455	LA-0093	Mar-97	9.0			
Formosa Plastics		Y				132	450	13455	LA-0089	Mar-95	9.0			
Gainesville Regional Utilities	Y					74	262	7819	FL-0092	Apr-95	15.0			
Goal Line						113	386	11541	CA-0544	Nov-92			5.0	
Gordonsville Energy					Y	445	1520	45433	VA-0189	Sep-92			9.0	
Granite Road Limited						135	461	13781	CA-0441	May-92			3.5	
Grays Ferry		Y			Y	337	1150	34384	PA-0098	Nov-92	9.0			
Hermiston Generating		Y				497	1696	50709	OR-0011	Apr-94			4.5	
Kalamazoo Power						529	1806	53995	MI-0206	Dec-91	15.0			
Kamine/Besicorp						190	650	19434	NY-0049	Nov-92	9.0		9.0	
Kamine/Besicorp						191	653	19524	NY-0048	Nov-92	9.0		9.0	
Kingsburg Energy					Y	35	122	3645	CA-0347	Sep-89			6.0	
Kissimmee Utility Authority						255	869	25982	FL-0078	Apr-93	15.0			
Lakewood Cogen										Apr-91			9.0	
Lakewood Cogeneration						56	190	5681	NJ-0013	Apr-91			9.0	
Las Vegas Cogen										Oct-90			10.0	
Linden Cogeneration		Y				165	583	17434	NJ-0011	Aug-91				
Lordsburg						100	353	10566	NM-0031	Jun-97	15.0			
Lsp-Cottage Grove						577	1970	58901	MN-0022	Mar-95			4.5	
Mid-Ga. Cogen						116	410	12257	GA-0063	Apr-96			9.0	20.0
Milagro, Williams Field Ser.						10983	37500	1121220	NM-0024					
Narragansett Electric					Y	398	1360	40663	RI-0010	Jun-96			9.0	
Newark Bay Cogen						171	585	17491	NJ-0009	Nov-90			8.3	
Newark Bay Cogen						181	617	18448	NJ-0017	Jun-93			8.3	16.0
Ocean State Power										Dec-88			9.0	
Ols Energy										Jan-86			9.0	
Orange Cogen						108	368	11012	FL-0068	Dec-93	15.0			
Panda-Kathleen		Y				75	265	7925	FL-0102	Jun-95	15.0			
Pasny/Holtsville		Y				336	1146	34264	NY-0047	Sep-92	9.0			
Pawtucket Power										Jan-89			9.0	
Pedricktown Cogen						293	1000	29899	NJ-0010	Feb-90			9.0	

Table 1.a Gas Turbine Limits from RBLC

	Project Description					Power				Permit	NOx Emission Limits			
											Dry Lox-NOx Comb.		SCR	
Facility Name/Location	Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	MW	mmBtu/hr	HP	Permit #	Issue Date	Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Phoenix Power Part.						0				May-93	22.0			
Pilgrim Energy Center					Y	410	1400	41859	NY-0075	Apr-95			4.5	
Portland General Elec.						504	1720	51427	OR-0010	May-94			4.5	
Puerto Rico Electric Power	Y					248	876	26204	PR-0002	Jul-95			10.0	42.0
Richmond Power Enterprise										Dec-89			8.2	
Saguaro Power Company						35	122	3645	NV-0015	Jun-91			9.0	
Saranac Energy Company					Y	329	1123	33577	NY-0046	Jul-92			9.0	
Selkirk Cogen					Y	344	1173	35072	NY-0045	Jun-92			9.0	
Seminole Fertilizer										Mar-91			9.0	
Seminole Fertilizer Corp						26	92	2747	FL-0059	Mar-91			9.0	
Seminole Hardee Unit 3		Y				2 x 244	981	29331	FL-0104	Jan-96	15.0		12.0	
Sithe/Independence		Y				625	2133	63775		Nov-92			4.5	
So. Cal. Gas										Oct-91			8.0	
Southern CA Gas						0			CA-0418	Oct-91			8.0	
Southern CA Gas						54	184	5500	CA-0463	Oct-91			8.0	
Sumas Energy										Jun-91			8.0	
Sumas Energy										Dec-90			9.0	
Sumas Energy Inc						88	311	9298	WA-0027	Dec-92			6.0	
Sunlaw										Jun-85			9.0	
SW PSCo						100	353	10566	NM-0028	Nov-96	15.0			
SW PSCo						100	353	10566	NM-0029	Feb-97	?			
Talahassee		Y				260					12.0	42.0		
Tenaska WA Partners		Y			Y	1	2	55	WA-0275	May-92			7.0	
Tiger Bay						473	1615	48281	FL-0072	May-92	15.0			
Union Oil										Mar-86			2.5	
Unocal						0			CA-0613	Jul-89			9.0	
Western Power Sys.										Mar-86			9.0	
Willamette Ind.										Apr-85			15.0	

Table 1.b Permits Pending or Not Yet in RBLC

											NOx Emission Limits			
	Project Description									Permit	Dry Lox-NOx Comb.		SCR	
	Simple	Combined	Peak	Turbine	Duct	Power				Issue	Gas	Oil	Gas	Oil
Facility Name/Location	Cycle	Cycle	Base	Type	Burner	MW	mmBtu/hr	HP	Permit #	Date	(ppm)	(ppm)	(ppm)	(ppm)
AES--Red Oak		Y		GE 7241 (FA)		3 x186	3 x 1748		NJ					
Alabama Pwr--Theodore		Y			Y	210			AL				3.5	
Androscoggin Energy		Y			Y	3 x 50	3 x 619		ME				6.0	42.0
ARCO Watson Project						45			CA	Oct-97			5.0	
Black Hills Pwr-Niel Simpson #2	Y		Peak	GE LM6000 aero		2 x 40			WY		25.0			
Black Hills Power--Rapid City	Y		Peak	aeroderivative		3x40			SD		25.0			
Bridgeport Energy Project													6.0	
Brush	Y		Peak			2 x 25			CO		42 (1)			
Calpine--South Point		Y			Y	500			AZ		Y		3.0	
Casco Bay Energy		Y				520	1838	54943	ME				5.0	
Cogen Tech. Linden Venture		Y				581	1983	59275	NJ				3.5	
Col. Springs--Nixon	Y		Peak	GE Frame 6		2 x 33			CO		25.0			
Desert Basin Gen		Y					2 x 1940		AZ				4.5	
Dighton, MA									MA				3.5	
Duke Energy--New Smyrna		Y		GE PG7241FA		2 x 165			FL		12.0			
Enron (LAER)									CA				2.5	
FPC--Hines		Y		W 501Frame		2 x 165			FL				6.0	
FPC--Polk		Y				2x235			FL					
Ft. Lupton	Y		Peak			4 x 40			CO		22 (1)			
Frontera Power		Y				330			TX		15.0			
Griffith Energy		Y			Y	650			AZ				3.0	
HDPP (LAER)									CA				3.0	
Hermiston Generating		Y							CA	Dec-95			4.5	
High Desert Power		Y							CA		9.0		2.5	
Intercession City	Y					3x			FL		9.0	42.0		
JEA--Brandy Branch	Y			GE PG7241 (FA)		3x170			FL		12.0	42.0		
Kissimmee Utility--Cane Is. #1	Y					40			FL		15.0			
Kissimmee Utility--Cane Is. #3		Y		GE Frame 7A	Y	167			FL		12.0	42.0	6.0	15.0
Lakeland McIntosh CCT		Y				350			FL				7.5	15.0
Lakeland McIntosh SCT	Y					250	883	26415	FL		9.0	42.0		
Lake Worth Gen.		Y		GE Frame 7FA		170			FL		9.0			
LaPoloma Generating		Y				262 x 4			CA				3.0	
Manchief Elec Gen	Y		Base			142 x 2			CO		25/15			
Mississippi Pwr--Daniels		Y				170			MI		Y		3.5	
Northwest Regional Power		Y		GE Frame 7FA		4 x 210	1530	45746	WA		9.0			
Oleander Power	Y		Peak	GE Frame 7A		5 x 190			FL		9.0	42.0		
Orange Generation--Bartow		Y				2 x 41			FL		15.0			
PSCoNM--Afton	Y			GE Frame 7		140	1470		NM		15.0			
Rotterdam, N.Y.									NY				4.5	
Sacramento Power						115			CA	Dec-94			3.0	
Sumas		Y				2 x 350			WA		9.0		4.5	
Sutter						170					Y		3.5	
TECO--Hardee	Y		Peak	GE PG7241 (FA)		2 x 165	2x1947		FL		9.0	42.0		
Tampa Electric--Polk County	Y		Peak	GE PG7241 (FA)		2 x 165	2x1947		FL		10.5	42.0		
TVA--Gallatin	Y					4 x 85			TN		15.0			
TVA--Johnsonville	Y					4 x 85			TN		15.0			
TX-NM Pwr--Lordsburg		Y		aero		2 x 40			NM		15.0	25.0		
Theodore Co-Gen		Y			Y								3.5	
Three Mountain Power		Y				500			CA				2.5	
Va Power--Faquier Co	Y		Peak	GE PG7241 (FA)		5 x 150	5x1910		VA	Jun-99	9.0	42.0		
Tiverton, RI									RI				3.5	

(1) does not use dry low-NOx combustor technology

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

August 4, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, CO 80225

Re: Reliant Energy Osceola, L.L.C. – Osceola Power Project PSD-FL-273

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above-mentioned project. It consists of a new facility to be located in Osceola County, near Holopaw. The new units are proposed to be three nominal 170 MW GE combustion turbines and a fuel oil storage tank.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at (850) 922-6979. If you have any questions, please contact Mike Halpin at (850) 921-9530.

Sincerely,

AA Lin 8/4

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/mph

Enclosures

cc: Mike Halpin, BAR

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

August 4, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Reliant Energy Osceola, L.L.C. – Osceola Power Project PSD-FL-273

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above-mentioned project. It is a new facility planned to be in Osceola County, near Holopaw. This facility will be comprised of three nominal 170 MW GE Frame 7FA combustion turbines operating in simple cycle mode with one fuel oil storage tank. The proposed project requests that the CT's be fired for up to 3000 hours with pipeline quality natural gas, of which up to 2000 hours may be fired with 0.05% sulfur (No.2) oil.

The applicant proposes NO_X emissions at 10.5 ppmvd on natural gas and 42 ppmvd on fuel oil with annual emissions as per the table below:

Pollutant	Proposed Facility emissions (TPY)
NO_X	1074
SO_2	297
CO	246
PM/PM_{10}	129
VOC	26.7

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact Mike Halpin at (850) 921-9530.

Sincerely,

A. A. Linero 8/4

A. A. Linero, P.E.Administrator
New Source Review Section

AAL/mph

Enclosures

cc: Mike Halpin, BAR

Reliant Energy

August 13, 1999

Mr. Michael P. Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

0970071-001-AC
PSD-FL-273

Dear Mr. Halpin:

Reliant Energy Osceola, L.L.C. recently submitted a Prevention of Significant Deterioration Air Permit Application for the Osceola Power Project, to be located near Holopaw, Florida. At your request, we have enclosed three additional copies to facilitate the review of our permit application.

If you have any questions concerning this permit application, please do not hesitate to contact me at 713-945-7167.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Osceola Permit Trans v2.doc
Encl.

Reliant Energy

0970071-001-AC
PSD-FL-273

July 30, 1999

Mr. Al Linero, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

RECEIVED
AUG 03 1999
BUREAU OF AIR REGULATION

Dear Mr. Linero:

Reliant Energy Osceola, L.L.C. is pleased to submit the enclosed Prevention of Significant Deterioration Air Permit Application for the Osceola Power Project. Please find four copies of the permit application enclosed with this letter, as well as a check for $7,500 for processing the permit application. A complete set of computer diskettes containing the air permit application (ELSA) and a CD ROM containing the air dispersion modeling files also are included with this submittal.

If you have any questions concerning this permit application, please do not hesitate to contact me at 713-945-7167.

Sincerely,

Jason M. Goodwin, P.E.
Senior Engineer, Air Resources Division
Environmental Department
Wholesale Group

JMG:\Power Projects\Osceola\Osceola Permit Trans.doc
Encl.

c: Mike Halpin, P.E. – Division of Air Resources Management, FDEP – Tallahassee, FL
Joe Welborn, P.E. – Seminole Electric Cooperative – Tampa, FL*
(* - w/ encl.)

cc: Central Dist.
EPA
NPS
C. Holladay
File

RELIANT ENERGY POWER GENERATION, INC.

REFERENCE NUMBER	DATE	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
072799	07/27/1999	1700001136	$7,500.00	0.00	$7,500.00

CHECK NUMBER	DATE	VENDOR NUMBER	VENDOR NAME	TOTAL AMOUNT
1000712	07/28/1999	0000141932	FLORIDA DEPARTMENT OF ENVIRONMENTAL	$7,500.00

Direct any inquiries to: Accounts Payable, RELIANT ENERGY Power Generation, Inc., P.O. Box 286, Houston, TX 77001-0286 (713) 207-8818
Refer to above check number and voucher number when inquiring about your payment

0055

Reliant Energy

RELIANT ENERGY POWER GENERATION, INC.
HOUSTON, TEXAS

52-153
112

Vendor Number: 0000141932 **Date:** 07/28/1999 **Check Number:** 1000712

PAY *Seven thousand five hundred and 00/100 Dollars*

TO THE ORDER OF

Pay Exactly
********$7,500.00

FLORIDA DEPARTMENT OF ENVIRONMENTAL
PROTECTION
2600 BLAIR STONE RD
TALLAHASSEE FL 32399-2400

BANK BOSTON, MAINE, N.A.
SOUTH PORTLAND, MAINE

AUTHORIZED SIGNATURE
VOID WITHOUT SIGNATURE
VOID AFTER NINETY DAYS.

[redacted]

Reliant Energy Osceola, L.L.C.
Osceola Power Project

Construction Permit Application
July 1999

BLACK & VEATCH

Rec'd 8/3/99
0970071-001-AC
PSD-FL-273

PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION FOR THE OSCEOLA POWER PROJECT

SUBMITTED BY
Reliant Energy Osceola, L.L.C.

PREPARED BY
Black & Veatch

July 1999
Project No. 63812

Table of Contents

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1.0 Introduction

Reliant Energy Osceola, L.L.C. proposes to develop a new electrical power generating project in Osceola County (herein after referred to as the Project) near Holopaw, Florida. The proposed Project will be composed of three simple cycle combustion turbines (SCCT) rated at a nominal 170 MW each, firing natural gas and No. 2 distillate fuel oil. New support facilities for the Project will include water and wastewater treatment facilities, water storage tanks, a storm water detention pond, a switchyard and electrical interconnections to an existing nearby substation, and a fuel oil storage tank.

This report is technical support document for the Prevention of Significant Deterioration (PSD) Air Permit Application. The following sections contain a project characterization, Best Available Control Technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project and includes a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The Project is located in a rural part of northern Osceola County, Florida. Figure 2-1 shows the general location of the Project which is approximately 1 mile northwest of Holopaw. The nearest Federal PSD Class I Area is the Chassahowitzka National Wilderness Area located approximately 155 km northwest of the Project. The topography of the area is generally unpronounced and relatively flat.

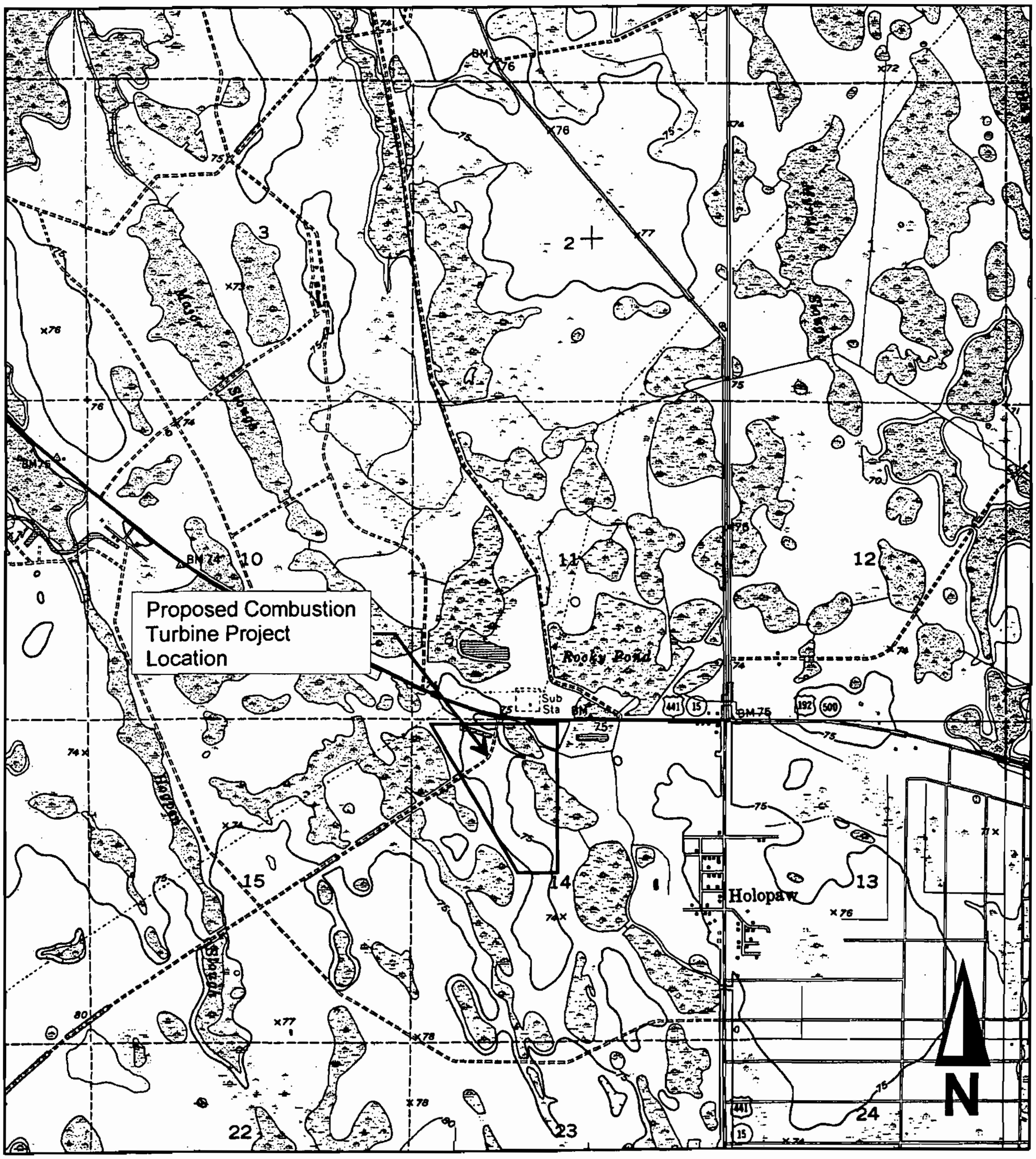
2.2 Project Description

The Project will be composed of three SCCTs. The SCCT proposed for the Project is a General Electric Frame 7FA simple cycle combustion turbine (Model PG7241FA) firing natural gas and No. 2 distillate fuel. The energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as they expand through the turbine section of each SCCT. The rotating mechanical energy will be converted into electrical energy via a shaft on the SCCT that is connected to an electrical generator. The remaining combustion gases will be exhausted to the atmosphere through an exhaust stack.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- Three SCCTs firing natural gas and No. 2 distillate fuel.
- One No. 2 distillate fuel oil storage tank of approximately 3,000,000 gallons capacity.
- A diesel-fired emergency fire water pump.



Base Map: 7.5' Quadrangle
Holopaw, Florida

Reliant Energy Osceola, L.L.C. Proposed
Combustion Turbine Project Location

Figure 2-1

2.3.1 SCCT Emissions

Performance data for the SCCTs, based on vendor data from GE at design loads of 60, 80, and 100 percent while firing natural gas and distillate fuel at ambient air temperatures of 19°F, 59°F, and 94°F, are provided in Attachment 1. Ambient temperature data were selected based on meteorological data representing winter seasonal site temperatures, which correspond to maximum heat input and power generation, average annual site temperatures representative of the average heat input rate, and summer seasonal site temperatures that correspond to the lowest heat input rate. The maximum pound per hour emission rates considering all ambient temperatures and partial load operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.3.2 No. 2 Distillate Fuel Oil Storage Tank

The fuel oil storage tank is estimated to have a capacity of 3,000,000 gallons. Emissions of VOCs from the fuel oil storage tank were estimated at less than 1.0 tpy.

2.4 Maximum Project Potential to Emit

The proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. The potential to emit was calculated from the maximum hourly emission rate for each pollutant at an ambient temperature of 59°F (average annual) considering 60 to 100 percent load simple cycle operation, 3,000 hours per year per CT. This total includes up to 2,000 hours of distillate fuel oil firing (0.05 % sulfur) with the balance of the firing on natural gas. The Project's potential to emit for each pollutant is summarized in Table 2-2. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 3.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs; the PSD program outlined in 40 CFR 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

Table 2-1 Project Maximum Emission Rates (lb/h)*		
Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NOx	73.5	343.0
SO2	1.1	104.3
CO	36.2	70.0
PM/PM10	18.0	34.0
VOC	3.0	8.0

*Maximum pound per hour emission rates for the SCCTs considering worst-case ambient temperature and partial load operation for natural gas and distillate fuel oil firing.

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NOx	1,074.0[a]	40	**yes**
SO_2	296.8[a,b]	40	**yes**
CO	245.7[a]	100	**yes**
PM/PM_{10}	129.0[a,c]	25/15	**yes**
VOC	26.7[a,e]	40	no
Sulfuric Acid Mist	45.5[a,d]	7	**yes**
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	Negl.	10	no
Vinyl Chloride	Negl.	1	no
Total Fluorides	Negl.	3	no
Mercury	Negl.	0.1	no
Beryllium	Negl.	0.0004	no
Lead	Negl.	0.6	no

[a]Based on maximum lb/h emission rate at 59°F conditions for all loads and operating scenarios; assuming 1,000 and 2,000 hours per year of natural gas and distillate fuel oil firing, respectively.
[b]Based on 0.05% sulfur distillate fuel oil, 0.2 gr/100 scf sulfur natural gas, and assuming 100 percent conversion to SO_2.
[c]Assumes front and back half PM/PM_{10} emissions.
[d]Conservatively assuming a 10 percent conversion of SO2 to H2SO4 and a molecular ratio of 1.53 from SO2 to H2SO4.
[e]VOC PTE is based on potential emissions from the Project's combustion sources only.
Note: PTE calculations are provided in a spreadsheet included in Attachment 3.

2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS) while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Osceola Power Project is not one of the 28 major source categories but does has a PTE greater than 250 tpy for at least one regulated pollutant. Additionally, the estimated emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project, exceed the PSD significant emissions levels of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, and PM/ PM_{10}, and SAM are subject to PSD review as a new major source. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the total project's impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

A best available control technology (BACT) analysis for proposed Project has been included as an Attachment to this document.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants having a PTE greater than the PSD significant emission rate (i.e., NO_x, SO_2, CO, and PM/PM_{10}). (SAM emissions are discussed in the BACT, Section 3.0, but were not assessed in the application). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as an air dispersion modeling protocol previously submitted to the FDEP (Attached).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA-approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing each SCCT unit's proposed operating load range (i.e., 60, 80, and 100 percent loads) with a worst-case set of stack parameters and pollutant emission rates conservatively selected from vendor performance data to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping."

The worst-case representative stack parameters and emission rates for each load, fuel type, and ambient temperature considered in the analysis are presented in Table 4-1. A spreadsheet used in determining the load based representative emissions and stack parameters from the vendor performance data is included in Attachment 3.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the proposed Project's location, it was concluded that over 50 percent of the area surrounding the Project is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. EPA's <u>Guideline for Determination of Good Engineering Practice Stack Height</u> guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for each SCCT is 41.55 m (136.3 ft).

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

Table 4-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis

Operating Scenario/Fuel	ISCST3 Source ID[a]	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
						NO_x	SO_2	CO	PM/PM_{10}[d]
SCCT Natural Gas and Distillate Fuel Oil	SWCBF	22.86	5.49	36.52	840.37	43.22	13.15	8.82	4.28
SCCT Annualized[b]	Annual	22.86	5.49	48.13	857.59	10.30	2.85	2.36	1.24
Diesel Fire Pump[d]	SFP	7.32	0.15	60.02	615.93	N/A	0.004	0.013	0.004
	AFP	7.32	0.15	60.02	615.93	0.009	0.0006	N/A	0.0006

[a]S or A refer to short-term or annualized emission rate; WC refers to worst case conditions; BF refers to both fuels (natural gas and distillate fuel oil).
[b]Annualized emission rate based on 1,000 hours of natural gas firing and 2,000 hours of distillate fuel oil firing.
[c]Assumes front and back half PM/PM_{10} Emissions.
[d]Assumes the diesel fire pump operates 52 hours per year for testing purposes.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1 km, 250 m spacing from 1 to 3 km, 500 m spacing from 3 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing of 50 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

4.2.6 Meteorological Data

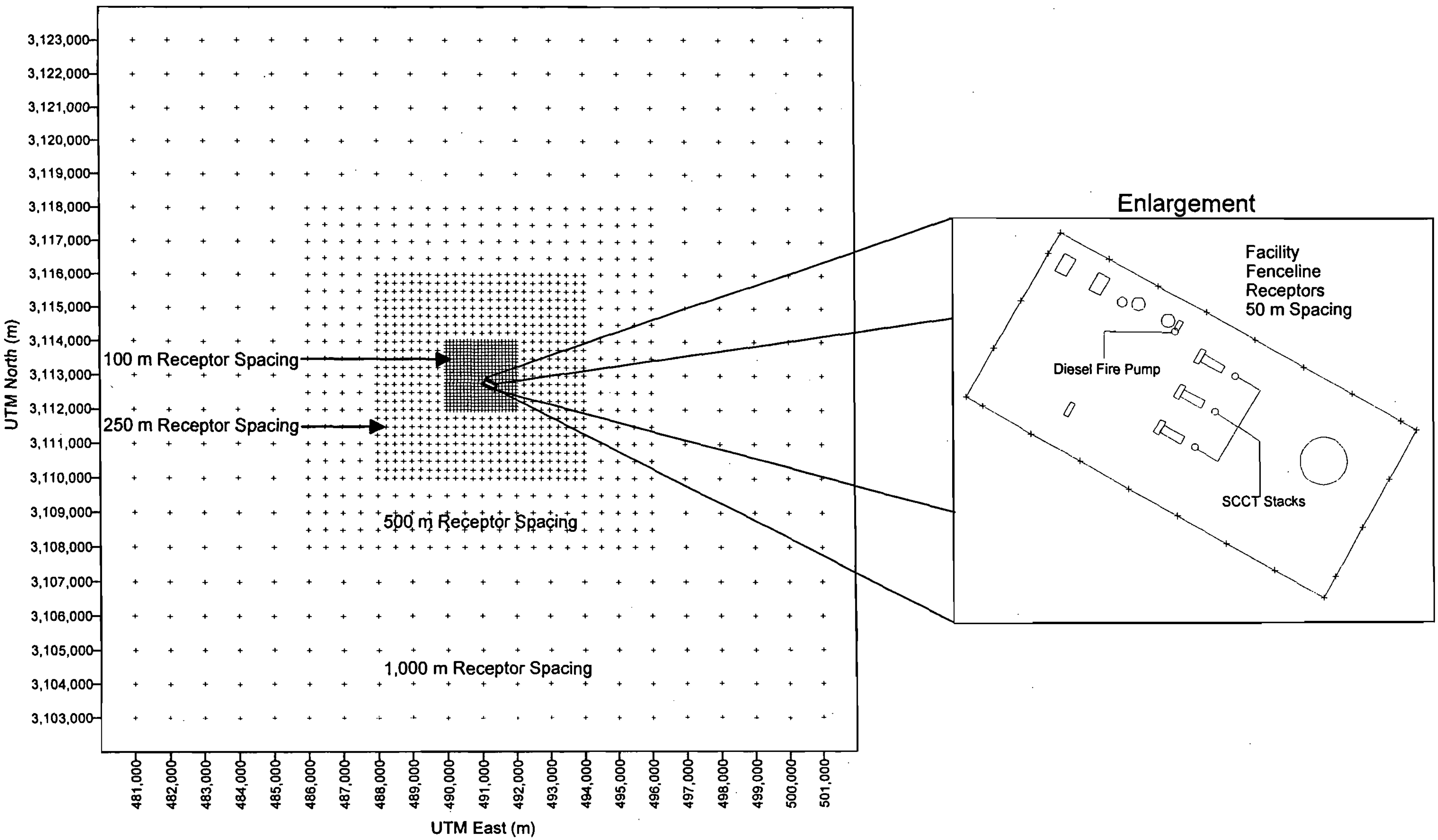
The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, Florida and Waycross, Georgia, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, CO, and PM/PM_{10}. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, SO_2, CO, and PM/PM_{10} for each applicable averaging period. Tables 4-2 through 4-5 present the results for the 5 year refined modeling period (1984-1988) for each pollutant and applicable averaging period.

4.3.1 Comparison to PSD SILs and Pre-Construction Monitoring Requirements

Table 4-6 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the pre-construction monitoring requirements. As the Table indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for



Receptor and Emission Source Locations

Figure 4-1

Table 4-2
ISCST3 Model Predicted Maximum Concentration of SO_2

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
Annual	1987	0.03	1	491,211.5	3,112,867.0
	1988	0.03	1	491,211.5	3,112,867.0
	1989	0.03	1	491,211.5	3,112,867.0
	1990	0.03	1	491,211.5	3,112,867.0
	1991	0.03	1	491,211.5	3,112,867.0
24-Hour*	1987	1.51	5	491,211.5	3,112,867.0
	1988	1.27	5	491,211.5	3,112,867.0
	1989	1.54	5	491,211.5	3,112,867.0
	1990	1.53	5	491,211.5	3,112,867.0
	1991	1.50	5	491,211.5	3,112,867.0
3-Hour*	1987	5.92	25	491,211.5	3,112,867.0
	1988	4.88	25	491,211.5	3,112,867.0
	1989	5.47	25	491,211.5	3,112,867.0
	1990	4.84	25	491,211.5	3,112,867.0
	1991	4.96	25	491,211.5	3,112,867.0

* Values in table represent highest 2nd highest concentration.

Table 4-3
ISCST3 Model Predicted Maximum Concentration of PM/PM_{10}

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location	
				East (m)	North (m)
Annual	1987	0.03	1	491,211.5	3,112,867.0
	1988	0.03	1	491,211.5	3,112,867.0
	1989	0.03	1	491,211.5	3,112,867.0
	1990	0.03	1	491,211.5	3,112,867.0
	1991	0.03	1	491,211.5	3,112,867.0
24-Hour*	1987	1.51	5	491,211.5	3,112,867.0
	1988	1.27	5	491,211.5	3,112,867.0
	1989	1.53	5	491,211.5	3,112,867.0
	1990	1.52	5	491,211.5	3,112,867.0
	1991	1.50	5	491,211.5	3,112,867.0

* Values in table represent highest 2nd highest concentration.

Table 4-4
ISCST3 Model Predicted Maximum Concentration of NO_x

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
Annual	1987	0.39	1	491,211.5	3,112,867.0
	1988	0.38	1	491,211.5	3,112,867.0
	1989	0.51	1	491,211.5	3,112,867.0
	1990	0.41	1	491,211.5	3,112,867.0
	1991	0.52	1	491,211.5	3,112,867.0

Table 4-5
ISCST3 Model Predicted Maximum Concentration of CO

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
8-Hour*	1987	8.80	500	491,211.5	3,112,867.0
	1988	8.99	500	491,211.5	3,112,867.0
	1989	9.01	500	491,211.5	3,112,867.0
	1990	11.61	500	491,211.5	3,112,867.0
	1991	9.97	500	491,211.5	3,112,867.0
1-Hour*	1987	32.65	2,000	491,211.5	3,112,867.0
	1988	31.25	2,000	491,211.5	3,112,867.0
	1989	32.64	2,000	491,211.5	3,112,867.0
	1990	30.46	2,000	491,211.5	3,112,867.0
	1991	31.79	2,000	491,211.5	3,112,867.0

* Values in table represent highest 2nd highest concentration.

Table 4-6 Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimis Monitoring Levels				
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimis Monitoring Level
NO_x	Annual	0.52	1	14
SO_2	Annual	0.03	1	-
	3-Hour	5.92	25	-
	24-Hour	1.54	5	13
CO	1-Hour	32.65	2,000	-
	8-Hour	11.61	500	575
PM/PM_{10}	Annual	0.03	1	-
	24-Hour	1.53	5	10

each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

5.0 Additional and Class I Area Impact Analyses

The following sections discuss the Project's impacts on commercial, residential, and industrial growth, vegetation and soils, visibility, and nearby Class I areas.

5.1 Commercial, Residential, and Industrial Growth

The proposed Project is a new electrical power generating station to be constructed near Holopaw within Osceola County. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area considering that the generated electric power will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality impacts. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. The net number of new, permanent jobs that will be created by the Project is estimated to be six. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the proposed facility will be very small, compared to the overall population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the project's impacts on soils and vegetation will be minimal.

The NAAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, ambient concentrations of NO_2, SO_2, CO, and PM/PM_{10} below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants that triggered an additional impact analysis include NO_x, SO_2, CO, and PM/PM_{10}. The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The modeling impacts discussed in Section 4.0

showed that the NO_x, SO_2, CO, and PM/PM_{10} impacts are below the NAAQS. The impacts also are less than the much lower significant impact level thresholds. Because the Project's emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Project is located more than 150 km southeast of the Chassahowitzka National Wilderness Area (NWA), a Federal PSD Class I Area. The area is designated as mandatory Class I area, under the jurisdiction of the Fish and Wildlife Service as their Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and visibility/regional haze.

5.3.1 Class I Air Quality Impact Analysis and Results

Air dispersion modeling was performed to determine the Project's maximum predicted impact at the Class I area. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the NWA. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 4.0, were also used in the Class I air quality impact analyses.

Tables 5-1 through 5-4 presents the results of the Class I areas air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results in Table 5-4 indicate, the maximum predicted concentrations of all pollutants are less than the applicable Class I SILs for both annual and short-term averaging periods. Therefore, further analysis is not required.

Table 5-1
ISCST3 Model Predicted Maximum Concentrations of SO_2 at Chassahowitzka National Wilderness Area

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL[1] ($\mu g/m^3$)
Annual	1987	0.002	2	0.08
	1988	0.002	2	0.08
	1989	0.002	2	0.08
	1990	0.002	2	0.08
	1991	0.002	2	0.08
24-Hour*	1987	0.13	5	0.20
	1988	0.17	5	0.20
	1989	0.18	5	0.20
	1990	0.14	5	0.20
	1991	0.14	5	0.20
3-Hour*	1987	0.69	25	1.00
	1988	0.69	25	1.00
	1989	0.95	25	1.00
	1990	0.80	25	1.00
	1991	0.66	25	1.00

* Values in table represent highest 2^{nd} highest concentration.
[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-2
ISCST3 Model Predicted Maximum Concentrations of PM/PM_{10} Chassahowitzka National Wilderness Area

Averaging Period	Year	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)	Class I SIL[1] (μg/m^3)
Annual	1987	0.001	4	0.16
	1988	0.001	4	0.16
	1989	0.001	4	0.16
	1990	0.001	4	0.16
	1991	0.001	4	0.16
24-Hour*	1987	0.13	8	0.32
	1988	0.17	8	0.32
	1989	0.18	8	0.32
	1990	0.14	8	0.32
	1991	0.14	8	0.32

* Values in table represent highest 2nd highest concentration.
[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-3
ISCST3 Model Predicted Maximum Concentrations of NO_x at Chassahowitzka National Wilderness Area

Averaging Period	Year	Maximum Predicted Conc. (µg/m³)	Class I Increment (µg/m³)	Class I SIL[1] (µg/m³)
Annual	1987	0.01	2.5	0.10
	1988	0.01	2.5	0.10
	1989	0.01	2.5	0.10
	1990	0.01	2.5	0.10
	1991	0.01	2.5	0.10

[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-4
Comparison of Maximum Predicted Impacts with the PSD Class I Significant Impact Levels at Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Level
SO_2	Annual	0.00	0.08
	24-Hour	0.18	0.20
	3-Hour	0.95	1.00
PM/PM_{10}	Annual	0.00	0.16
	24-Hour	0.18	0.32
NO_x	Annual	0.01	0.10

5.4 Visibility/Regional Haze Analysis

The Project is located more than 150 km southeast of the Chassahowitzka National Wilderness Area (NWA), the nearest Class I Area. Because of this great distance, and because the proposed Project will consist of highly efficient combustion turbines operating as peaking units and utilizing Best Available Control Technology to minimize emissions to the environment, a detailed visibility/regional haze analysis is not proposed.

Attachments

Attachment 1
(Turbine Vendor Data)

Reliant Energy/Osceola

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	80%	60%	BASE	BASE	80%	60%	BASE
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Evap. Cooler Status		Off	Off	Off	On	Off	Off	Off	On
Evap. Cooler Effectiveness	%				85				85
Fuel Type		Methane	Methane	Methane	Methane	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	130	130	130	130	80	80	80	80
Liquid Fuel H/C Ratio						1.8	1.8	1.8	1.8
Output	kW	171,200.	136,900.	102,700.	174,200.	181,800.	145,500.	109,100.	184,800.
Heat Rate (LHV)	Btu/kWh	9,350.	9,910.	11,280.	9,310.	9,950.	10,560.	11,910.	9,910.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.7	1,356.7	1,158.5	1,621.8	1,808.9	1,536.5	1,299.4	1,831.4
Exhaust Flow X 10^3	lb/h	3534.	2985.	2602.	3576.	3679.	2959.	2604.	3721.
Exhaust Temp.	Deg F.	1119.	1145.	1180.	1111.	1090.	1175.	1200.	1084.
Exhaust Heat (LHV) X 10^6	Btu/h	958.2	839.8	764.9	968.3	999.4	884.9	801.7	1011.8
Water Flow	lb/h	0.	0.	0.	0.	120,130.	96,430.	74,930.	119,510.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.	42.	42.	42.	42.
NOx AS NO2	lb/h	59.	50.	42.	60.	319.	269.	226.	323.
CO	ppmvd	9.	9.	9.	9.	20.	20.	24.	20.
CO	lb/h	29.	24.	21.	29.	65.	52.	56.	65.
UHC	ppmvw	7.	7.	7.	7.	7.	7.	7.	7.
UHC	lb/h	14.	12.	10.	14.	15.	12.	10.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4	3.5	3.5	3.5	3.5
VOC	lb/h	2.8	2.4	2.	2.8	7.5	6.	5.	7.5
Particulates	lb/h	9.0	9.0	9.0	9.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.89	0.89	0.89	0.86	0.84	0.85	0.85
Nitrogen	74.36	74.37	74.45	74.19	71.35	71.26	71.81	71.25
Oxygen	12.33	12.37	12.61	12.28	11.06	10.65	11.17	11.04
Carbon Dioxide	3.84	3.82	3.71	3.84	5.60	5.87	5.61	5.60
Water	8.58	8.55	8.34	8.81	11.14	11.38	10.56	11.27

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Reliant Energy/Escondido Power

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	80%	60%	BASE	83%	63%
Ambient Temp.	Deg F.	19.	19.	19.	19.	19.	19.
Fuel Type		Methane	Methane	Methane	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	21,515	18,300	18,300	18,300
Fuel Temperature	Deg F	130	130	130	80	80	80
Liquid Fuel H/C Ratio					1.8	1.8	1.8
Output	kW	187,000.	149,600.	112,200.	197,000.	157,600.	118,200.
Heat Rate (LHV)	Btu/kWh	9,140.	9,640.	10,930.	9,860.	10,400.	11,720.
Heat Cons. (LHV) X 10^6	Btu/h	1,709.2	1,442.1	1,226.3	1,942.4	1,639.5	1,385.2
Exhaust Flow X 10^3	lb/h	3791.	3118.	2707.	3951.	3059.	2657.
Exhaust Temp.	Deg F.	1071.	1116.	1153.	1053.	1163.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	1008.8	879.0	798.1	1064.5	931.4	843.7
Water Flow	lb/h	0.	0.	0.	131,670.	107,720.	84,490.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	42.	42.	42.
NOx AS NO2	lb/h	63.	53.	45.	343.	288.	241.
CO	ppmvd	9.	9.	9.	20.	20.	21.
CO	lb/h	31.	25.	22.	70.	54.	48.
UHC	ppmvw	7.	7.	7.	7.	7.	7.
UHC	lb/h	15.	12.	11.	16.	12.	10.
VOC	ppmvw	1.4	1.4	1.4	3.5	3.5	3.5
VOC	lb/h	3.	2.4	2.2	8.	6.	5.
Particulates	lb/h	9.0	9.0	9.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.90	0.88	0.87	0.86	0.86
Nitrogen	74.97	74.92	75.01	71.83	71.44	71.93
Oxygen	12.51	12.37	12.61	11.17	10.41	10.83
Carbon Dioxide	3.83	3.89	3.79	5.61	6.07	5.86
Water	7.79	7.92	7.71	10.53	11.23	10.52

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Reliant Energy/Escondido Power

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	94.	94.	94.	94.
Evap. Cooler Status		On	Off	On	Off
Evap. Cooler Effectiveness	%	85		85	
Fuel Type		Methane	Methane	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	18,300	18,300
Fuel Temperature	Deg F	130	130	80	130
Liquid Fuel H/C Ratio				1.8	1.8
Output	kW	158,600.	148,800.	168,300.	158,900.
Heat Rate (LHV)	Btu/kWh	9,570.	9,720.	10,090.	10,240.
Heat Cons. (LHV) X 10^6	Btu/h	1,517.8	1,446.3	1,698.1	1,627.1
Exhaust Flow X 10^3	lb/h	3353.	3235.	3474.	3354.
Exhaust Temp.	Deg F.	1137.	1151.	1115.	1128.
Exhaust Heat (LHV) X 10^6	Btu/h	921.2	885.7	958.1	921.8
Water Flow	lb/h	0.	0.	100,430.	99,680.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	42.	42.
NOx AS NO2	lb/h	56.	54.	300.	287.
CO	ppmvd	9.	9.	20.	20.
CO	lb/h	27.	26.	61.	59.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	13.	13.	14.	13.
VOC	ppmvw	1.4	1.4	3.5	3.5
VOC	lb/h	2.6	2.6	7.	6.5
Particulates	lb/h	9.0	9.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.87	0.85	0.85
Nitrogen	72.96	73.39	70.47	70.76
Oxygen	12.02	12.21	10.91	11.04
Carbon Dioxide	3.80	3.77	5.54	5.50
Water	10.35	9.76	12.24	11.85

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	44
Application		
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

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Attachment 2

(Emission Calculation Spreadsheet)

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Reliant Energy Osceola, L.L.C.
Osceola Power Project
Enveloped Stack Parameters

Last Revised: 7/23/99
Date Printed: 7/28/99 3:48 PM

Special Comments:

Load	100 Percent (Base) (NG)			Representative	
Turbine	PG7241(FA) - GE			100 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	163.05	157.91	151.95	151.95 ft/s	46.33 m/s
Exit Temperature (F)	1071.00	1111.00	1137.00	1071.00 F	850.37 K
Emissions (lb/h)					
NOx	73.50	70.00	65.33	73.50 lb/h	9.26 g/s
CO	36.20	33.80	31.50	36.20 lb/h	4.56 g/s
SO2	1.14	1.08	1.01	1.14 lb/h	0.14 g/s
PM[1]	18.00	18.00	18.00	18.00 lb/h	2.27 g/s

Load	80 Percent (NG)			Representative	
Turbine	PG7241(FA) - GE			80 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	138.11	134.55		134.55 ft/s	41.02 m/s
Exit Temperature (F)	1116.00	1145.00		1116.00 F	875.37 K
Emissions (lb/h)					
NOx	61.83	58.33		61.83 lb/h	7.79 g/s
CO	29.20	28.00		29.20 lb/h	3.68 g/s
SO2	0.96	0.90		0.96 lb/h	0.12 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for NG Across 3 Load	
119.79 ft/s	36.52 m/s
1071.00 F	850.37 K
73.50 lb/h	9.26 g/s
36.20 lb/h	4.56 g/s
1.14 lb/h	0.14 g/s
18.00 lb/h	2.27 g/s

Load	60 Percent (NG)			Representative	
Turbine	PG7241(FA) - GE			60 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	122.67	119.79		119.79 ft/s	36.52 m/s
Exit Temperature (F)	1153.00	1180.00		1153.00 F	895.93 K
Emissions (lb/h)					
NOx	52.50	49.00		52.50 lb/h	6.61 g/s
CO	25.70	24.50		25.70 lb/h	3.24 g/s
SO2	0.82	0.77		0.82 lb/h	0.10 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for both NG and FO Across 3 Loads	
119.79 ft/s	36.52 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	[illegible]
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load	100 Percent (Base) (FO)			Representative	
Turbine	PG7241(FA) - GE			100 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	168.22	161.59	155.03	155.03 ft/s	47.27 m/s
Exit Temperature (F)	1053.00	1084.00	1115.00	1053.00 F	840.37 K
Emissions (lb/h)					
NOx	343.00	323.00	300.00	343.00 lb/h	43.22 g/s
CO	70.00	65.00	61.00	70.00 lb/h	8.82 g/s
SO2	104.38	98.41	91.25	104.38 lb/h	13.15 g/s
PM[1]	34.00	34.00	34.00	34.00 lb/h	4.28 g/s

Load	80 Percent (FO)			Representative	
Turbine	PG7241(FA) - GE			80 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	139.85	136.01		136.01 ft/s	41.47 m/s
Exit Temperature (F)	1163.00	1175.00		1163.00 F	901.48 K
Emissions (lb/h)					
NOx	288.00	269.00		288.00 lb/h	36.29 g/s
CO	54.00	52.00		54.00 lb/h	6.80 g/s
SO2	88.10	82.57		88.10 lb/h	11.10 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

Representative Worst-Case Stack for FO Across 3 Loads	
121.26 ft/s	36.97 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	8.82 g/s
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load	60 Percent (FO)			Representative	
Turbine	PG7241(FA) - GE			60 Percent Load	
Ambient Temperature (F)	19	59	94		
Exit Velocity (ft/s)	124.01	121.26		121.26 ft/s	36.97 m/s
Exit Temperature (F)	1200.00	1200.00		1200.00 F	922.04 K
Emissions (lb/h)					
NOx	241.00	226.00		241.00 lb/h	30.37 g/s
CO	48.00	56.00		56.00 lb/h	7.06 g/s
SO2	74.44	69.83		74.44 lb/h	9.38 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

[1] PM emissions are front and back half

Attachment 3
(Best Available Control Technology)

Best Available Control Technology Analysis

The Reliant Energy Osceola, L.L.C.
Osceloa Power Project

Prepared for: Reliant Energy Osceola, L.L.C.

Prepared by: Black & Veatch

Executive Summary

A best available control technology (BACT) analysis was performed for three (3) new General Electric 7FA combustion turbines to be installed at Reliant Energy's Osceola Power Project. The combustion turbines are to be operated as simple cycle combustion turbines (SCCT), i.e., without heat recovery steam generators, to allow for fast response to changing system load demands. The following was evaluated to be BACT for the subsequent emissions parameters for each SCCT.

<u>Nitrogen oxides (NO_x) emissions</u> -- BACT was determined to be the use of dry low NO_x burners during natural gas firing and water injection for fuel oil firing to achieve the following emission limits.

- Burning natural gas at unit loads between 60 percent and 100 percent of normal capacity, an emission limit of 10.5 ppmvd (referenced to 15 percent O_2).
- Burning fuel oil at load between 60 and 100 percent of normal capacity, an emission limit of 42 ppmvd (referenced to 15 percent O_2).

<u>Carbon monoxide (CO) emissions</u>--Good combustion controls to achieve a CO emission limit of 10.5 ppmvd during natural gas firing or 20 ppmvd during fuel oil firing.

<u>Particulate emissions</u>--Good combustion controls.

<u>Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)</u>--Good combustion controls using natural gas, and fuel oil with less than 0.05 percent sulfur.

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1.0 Introduction

The 1977 Clean Air Act established revised conditions for the approval of pre-construction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the act emitted in significant amounts from new major sources or modifications. The new significant sources proposed for this project consist of three combustion turbines subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

2.0 BACT Analysis Basis

This section describes the basis of this BACT analysis. Information is provided on such issues as the project description, BACT methodology and approach used, and the parameters and factors used in developing the analysis are identified.

2.1 Project Description

The Osceola Power Project will consist of the installation of three General Electric 7FA combustion turbine electric generating units. Each combustion turbine unit will consist of one turbine and one generator operating as simple cycle combustion turbines (SCCT). The output rating for each of the new units will be nominally 170 MW net while firing gas. Total plant output will be nominally 510 MW.

The combustion turbines will fire natural gas and No. 2 fuel oil. The proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. This is equivalent to a per unit operation of 3,000 hours per year, with up to 2,000 hours per CT per year of fuel oil firing (up to 6,000 hours total). The balance of the facility's operation would consist of firing natural gas.

2.2 BACT Methodology

As defined in the air permit application, operation of the Project will result in an increase in the potential to emit emissions of NO_x, CO, PM/PM_{10}, and SO_2/Sulfuric Acid Mist (SAM); in excess of the major modification PSD threshold levels set for these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15,

1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under Lowest Achievable Emission Rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, 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.

Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

2.3 Economic Basis

Table 2-1 lists the economic criteria used in the analysis of BACT alternatives.

Table 2-1
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	15
Real Interest Rate, percent	10
Economic Life years	20
Labor Cost, $/man-hr	50
Aqueous Ammonia Cost, $/ton (1999)	375
Energy Cost, $/kWhr (1999)	0.044
Catalyst Life, years	3

3.0 BACT Analysis Basis

The BACT analysis for the SCCT units is based on certain regulatory requirements and project assumptions.

The following is a summary of the requirements and assumptions for which this BACT analysis is based:

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal NSPS for combustion turbines with heat input greater than 10 MBtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for SO_2 and NO_x emissions only. No NSPS criteria have been established for limiting CO, VOC, and PM/PM_{10} emissions. The following flue gas emission limits are established by NSPS for Subpart GG units:

  NO_x: 75 ppmvd at 15 percent O_2, corrected for fuel nitrogen content and turbine heat rate.
- The combustion turbine will have the following emission rates at 100% load and 59 °F:

	Natural gas	Fuel Oil
NO_x, ppmvd @ 15% O_2:	10.5	42
CO, ppmvd:	10.5	20
PM/PM_{10}, lb/hr:	18	34
SO_2, lb/hr	0.97	92.2
VOC, lb/hr	2.8	7.5

As mentioned previously, the proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. This is equivalent to a per unit operation of 3,000 hours per year, with up to 2,000 hours per CT per year of fuel oil firing (up to 6,000 hours total). The balance of the facility's operation would consist of firing natural gas. For the purposes of this analysis, worst-case annual operation and emissions were evaluated. This is equivalent of 1,000 hours per year of natural gas firing and 2,000 hours per year of fuel oil firing per CT.

4.0 NO_x BACT

The objective of this analysis is to determine BACT for NO_x emissions from the combustion turbines. Unless otherwise noted the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents (CAPCOA, 1985-1992; USEPA, 1990 to present) indicates that the most stringent NO_x emissions limit for a natural gas fired CT is 3.0 ppmvd for the Sacramento Power Authority located in California. The emissions from that unit are controlled through the use of standard combustors and selective catalytic reduction (SCR). This unit is a combined cycle combustion turbine (CCCT) as compared to the simple cycle combustion turbine proposed for the Project. It should be noted that this combustion turbine is located in a non-attainment area for ozone, with NO_x regulated as a non-attainment pollutant. Thus, this emission level represents LAER for CCCT.

For SCCT units, the strictest emission limit identified during the review is 5 ppm. This limit has been set for three different projects in California. These projects are the Southern California Gas Wheeler Ridge Gas plant located in the San Joaquin Valley, the Carson Energy Project in metropolitan Sacramento, and the Sacramento Power Authority (Proctor and Gamble Plant) in metropolitan Sacramento.

It should also be noted that recently the South Coast Management District in California has officially declared new LAER limits for NO_x. This designation is limited to only specific application of CCCT projects and is not considered applicable to this Project as will be discussed.

Review of previous State of Florida DEP permits indicates that combustion turbine permits approved in the last 4 years have NO_x emission limits that vary from 15 to 9 ppmvd. The Oleander Power Project was recently granted a permit (Air Permit No. PSD-FL-258) during 1999 which limits NO_x emissions to 9 ppmvd when firing natural gas. Review of the permit conditions indicate that most of the NO_X generated by this facility will occur as a result of the fuel oil firing (at 42 ppmvd). Tampa Electric Company recently submitted a permit application for similar CTs that limit NO_x emissions to 10.5 ppmvd when firing natural gas, and 42 ppmvd during fuel oil firing. The primary fuel proposed for the Osceola Power Project will be based on economics and availability of the fuel.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. Emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame zone is required to achieve stable combustion.

Nitrogen oxides control methods can be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The different types of emission controls reviewed by this BACT analysis are noted below.

- In Combustor Type Control:
  - Water/Steam Injection
  - Dry Low NO_x Burners
  - Xonon
- Post Combustion Type Control:
  - SNCR
  - SCR
  - SCONOX

4.2.1 Water or Steam Injection

NO_x emissions from the combustion turbines can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. However, there is a point at which the amount of water injected into the combustion turbine seriously degrades its reliability and operational life. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions that are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls except for certain cases such as oil firing. The use of water injection will be considered for operations when firing oil.

4.2.2 Dry Low NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called dry low NO_x burners, because when firing fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state of the art for NO_x controls in combustion turbine.

DLN combustion turbine burner designs are available that use improved air/fuel mixing and reduced flame temperatures to limit thermal NO_x formation. DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage, while the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required, which results in low NO_x emissions.

Also, as with the standard combustor with water injection, the dry low NO_x burners can also be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures can result in higher CO and VOC emissions if proper combustion control is not maintained. However, due to increased combustion efficiency associated with improved air/fuel mixing, emissions of CO and VOC also can be reduced through the proper use and control of DLN combustors.

4.2.3 XONON

Another form of in-combustor control is Xonon. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2700 °F at full power rating, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of carbon monoxide and unburned hydrocarbons when compared with conventional combustors. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce hot gases, which are used to drive the turbine. This technology is being commercialized by several joint ventures that Catlaytica has with turbine manufacturers. To date, commercial applications of this technology for utility size CTs, such as those proposed for this Project, have not been developed.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. This technology operates by injecting an ammonia or urea reagent into the exhaust gas, where it reacts with the NO_X to form water and molecular nitrogen. Reaction temperatures in the range of 1500 to 1900 °F, along with adequate reaction time at this temperature range, are required for this technology to be effective. However, the exhaust temperature at the exit of a combustion turbine, which ranges from 1,000 to over 1200 °F for the GE 7FA units, is too low for any consideration of this technology. SNCR is therefore not a viable control feasible option for this project

4.2.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CCCT projects for the past several years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. Ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, where the chemical conversion of NO_X to water and nitrogen takes place. The use of SCR results in small levels of ammonia emissions (ammonia slip) resulting from unreacted ammonia reagent passing through the catalyst bed and out the stack. Ammonia slip will increase over time as the catalyst degrades, ultimately requiring replacement of the catalyst.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas as it passes through the catalyst. Vanadia/titania catalysts have been used on the vast majority of SCR system installations (greater than 95 percent). The flue gas temperature range for optimum SCR operation using a conventional vanadia/titania catalyst is approximately 600 to 750 °F. At temperatures above 800 °F permanent damage to the vanadia/titania catalyst occurs. For the simple cycle turbines proposed for the Project, the flue gas temperature will typically range from 1050 to 1200 °F, which is well above the necessary reaction temperature window necessary for SCR operation. Accordingly, a vanadia/titania catalyst can not be installed at a simple cycle facility, and will not be evaluated further for this project.

However, a catalyst material developed from crystalline aluminasilicate compounds, known as zeolite, has been developed which has had mixed success in limited applications. This zeolite catalyst can operate effectively at temperatures of up to 1125 °F. Due to the high flue gas exit temperatures (up to 1200 °F) of the GE 7FA, the use of a zeolite catalyst would require special precautions and equipment additions. As previously indicated, the maximum operating temperature of the zeolite catalyst is 1125 °F. To prevent damage to the catalyst at these higher temperatures, a dilution air system and fan must be included for each unit to cool the flue gas below the maximum operating temperature of the catalyst. This BACT analysis will include a dilution air system in the evaluation of a zeolite catalyst based SCR.

Currently there is limited experience with the operation of zeolite catalysts in conjunction with units that fire sulfur bearing fuels, such as fuel oil. Operation of the SCR system on units that burn sulfur-bearing fuels can present a negative impact on the environmental performance of the combustion turbine through the formation of ammonia-sulfur salts. Reaction of excess ammonia that passes through the SCR with sulfur trioxide in the flue gas can form significant quantities of ammonia-sulfur salts, such as ammonium bisulfate. These compounds form when the flue gas cools upon leaving the stack, forming a fine particulate that significantly adds to the emission of PM_{10} from the unit. Increased PM_{10} emissions can lead to increased opacity from the unit, an increased contribution to regional haze, and additional health risks. Furthermore, an analysis of the SCR must consider reduced overall catalyst activity and higher catalyst deactivation rates due to sulfur poisoning of the catalyst encountered when firing fuel oil. In many cases, permitting authorities have recognized these negative impacts and provided permit exemptions for operating the SCR during fuel oil firing. Zeolite based catalysts are also significantly more expensive that vanadia/titania based catalysts used in combined cycle operation. The durability and effectiveness of zeolite catalysts in commercial SCR appliactions also has a limited operational history.

Because of the technical obstacles to effective use of SCR on simple cycle CTs firing fuel oil, this method of post-combustion control will be considered in this BACT analysis to control NO_x emissions when only firing natural gas.

4.2.6 SCONOX

A third, relatively new post-combustion technology is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO. Using this technology as a basis, the South Coast Management District recently declared LAER as 2.0 ppm of NO_x. However, because the $SCONO_x$ catalyst is sensitive to SO_2 and is required to operate in temperature range between 550 to 650 °F, this technology is not feasible for this Project because of the high exhaust temperatures and the use of fuel oil. Therefore, this method of post-combustion control will not be considered in this BACT analysis.

4.2.7 Technology Summary

The following control technologies will be evaluated in this NO_x BACT analysis and are ranked in order of relative control effectiveness:

- The addition of zeolite catalyst SCR systems to reduce outlet emissions from each combustion turbine to 5.0 and 42 ppmvd during natural gas and oil firing (LAER), respectively.

- In-combustor NO_x control consisting of dry low NO_x combustors to limit outlet emissions during natural gas firing to 10.5 ppmvd and water injection to limit outlet emissions to 42 ppmvd during fuel oil firing for all operating loads.

The NO_x emissions for a GE 7FA unit are summarized in Table 4-1. Note that NO_x emissions are provided for both 1,000 and 3,000 hours per year operation on natural gas, as well as 2,000 hours per year of fuel oil firing.

4.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenarios evaluated.

4.3.1 Economic Impacts

The use of an SCR would have a significant economic impact on the Project. An analysis of the economic impact is provided in this section. Since control of NOx emissions during fuel oil firing has been rejected based on technical noncompatability issues, the BACT costs presented in this analysis are based on the worst-case scenario of operating the combustion turbines at full load for 3,000 hours per year on natural gas.

4.3.1.1 Capital and Operating Costs

Table 4-2 presents the capital costs for installing an SCR system on the General Electric 7FA combustion turbines to achieve a NO_x outlet emission level of 5.0 ppmvd (LAER) during natural gas firing and 42 ppmvd (LAER) for oil firing. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection systems; catalytic reactor; and balance of plant equipment. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the catalyst material were based on zeolite catalysts.

Table 4-3 presents the annual operating costs and emission rates using SCR to achieve NO_x outlet emissions of 5.0 and 42 ppmvd while firing natural gas and fuel oil, respectively. Annual operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements will require periodic replacement as they become deactivated. Currently, zeolite catalyst manufacturers will guarantee a catalyst life of three years of equivalent operating hours. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.40 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with the NO_2. The heat rate penalty cost item reflects the cost due to the SCR back pressure losses. The additional back pressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annual cost estimate.

The use of an SCR system also increases the energy requirements of the Project. The SCR system requires vaporizers and blowers to both vaporize and dilute the aqueous ammonia reagent for injection. These costs are inversely proportional to the controlled NO_X emissions rate - as emission rates go down, energy costs go up. Maintenance costs consist of routine SCR system maintenance, and replacement materials are assumed to be two percent of the original cost for equipment. Labor is assumed to be equal to materials.

Total 1999 annual costs for the NO_x control system are calculated as the sum of 1999 operating costs plus capital recovery factor. The total annual cost per unit for a 5.0 (gas)/42.0 (oil) ppmvd NO_x outlet emission SCR system for the 7FA combustion turbines is estimated to be $1,568,000. This annual cost results in a cost effectiveness per ton of NO_x removed of approximately $28,509.

Table 4-1
Estimated NO_x Emissions
From Alternate Control Technologies Per General Electric 7FA

Fuel	Control Technology Alternatives	
	Dry Low NO_x Combustors (Gas) - Water Injection (Oil)	SCR System
Natural Gas		
ppmvd (at 15% O_2)	10.5	5
Tons per year[a] – 1,000 hours operation	35	16.67
Tons per year[b] – 3,000 hours operation	105	50
Fuel Oil		
Ppmvd (at 15% O_2)	42	42[d]
Tons per year[c]	376.83	376.83
BACT Analysis (Annual)[e]		
Tons per year	411.83	393.5

Notes:

[a] Annual emissions are based on 1,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[b] Annual emissions are based on 3,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[c] Annual emissions are based on 2,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[d] SCR will not operate during fuel oil firing. BACT assumes worst-case NO_X emissions result from 3,000 hours per year of natural gas firing.

[e] BACT analysis total emissions are based on 1,000 hours per year of natural gas firing and 2,000 hours per year of No. 2 fuel oil firing.

Table 4-2
NO_x Control Alternative Capital Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts and Ammonia Injection	2,124,000	NA	Scaled from previous projects.
Catalyst Reactor	697,000	NA	Estimated from previous project.
Control/Instrumentation	140,000	NA	Estimated; includes controls and monitoring equipment.
Dilution Air System	Included	NA	Included with catalyst cost.
Ammonia Storage	218,000	NA	Scaled from previous projects
Balance of Plant	1,081,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering.
Total Direct Capital Cost	4,260,000	Base	
Indirect Capital Costs			
Contingency	639,000	NA	15% of Direct Capital Cost
Engineering and Supervision	426,000	NA	10% of Direct Capital Cost
Construction & Field Expense	213,000	NA	5% of Direct Capital Cost
Construction Fee	426,000	NA	10% of Direct Capital Cost,
Start-up Assistance	85,000	NA	2% of Direct Capital Cost
Performance Test	58,000	NA	Estimated Cost
Total Indirect Capital Costs	1,847,000	Base	
Total Installed Cost	6,107,000	Base	

Table 4-3
NO_x Control Alternative Annual Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	139,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	20,000	NA	See text for background information on this item
Reagent Feed	23,000	NA	Assumes 1.4 stoichiometric ratio
Power Consumption	121,000	NA	Includes dilution air fan
Lost Power Generation	167,000	NA	Back pressure on combustion turbine
Annual Distribution Check	21,000	NA	Required for SCR
Total Direct Annual Cost	491,000	NA	
Indirect Annual Costs			
Overhead	8,000	NA	60% of O&M Labor
Administrative Charges	122,000	NA	2% of Total Installed Cost
Property Taxes	168,000	NA	2.75% of Total Installed Cost
Insurance	61,000	NA	1% of Total Installed Cost
Capital Recovery	718,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	1,077,000	NA	
Total Annual Cost	**1,568,000**	NA	
Annual Emissions, tpy	50	105	Emissions from Table 4-1 for 3,000 hrs of natural gas firing
Emissions Reduction, tpy	55	NA	Emissions calculated from Table 4-1
Total Cost Effectiveness, $/ton	**28,509**	NA	Total Annual Cost/Emissions Reduction

4.3.1.2 Energy Impacts

The use of an SCR system impacts the energy requirements of the Project through its need for equipment to vaporize and dilute the aqueous ammonia reagent for injection into the flue gas stream. In addition, an SCR system catalyst will increase the back pressure on each combustion turbine by approximately 3.15 inches water gauge (in. w.g.). This increase in back pressure will reduce the output of each combustion turbine by approximately 0.44 percent. Increased power consumption and lost power generation are included in the annual cost estimate.

4.3.1.3 Environmental Impacts

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes. With proper precautions, aqueous ammonia can be stored and used safely.

Some ammonia slip from the combustion turbine stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Also, the Ventura County California Air Pollution Control District recently set an ammonia slip emission limit of 10 ppmvd Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates more frequent catalyst replacement. A design value of 10 ppmvd is appropriate for a clean fuel facility such as this Project. With fresh catalyst ammonia slip emissions will be very low. However, as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and may be classified as hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

Another consideration is the potential for formation of SO_3 and ammonia salts. When firing fuel oil or other sulfur-bearing fuels, the SCR catalyst will oxidize approximately 2 to 3% of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600 °F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Regardless, ammonium sulfate, bisulfate salts and sulfuric acid mist generated by the SCR will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than 10 microns in diameter (PM_{10}).

4.4 Conclusions

SCR systems are representative of the LAER level of NO_x emissions reduction. Although SCR systems have been successfully used on numerous combined cycle combustion turbine applications, there are only a limited number of SCCT applications, and these have yielded mixed results at best. The fundamental obstacle to the use of these systems on a SCCT is the overall economics and the potential primary (SO_2 to SO_3 oxidation) and secondary (ammonium bisulfate deposits and increased PM_{10} emissions) environmental impacts when sulfur-bearing fuels are fired

The overall annual cost of the SCR required to meet a NO_x emission limit of 5.0 ppmvd (natural gas firing) and 42.0 ppmvd (fuel oil firing) and calculated at $28,509 per ton is excessive. Furthermore, SCR use may result in significant PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation, as well as associated ammonium bisulfate/sulfate and H_2SO_4 emissions. In addition, the potential for catalyst poisoning with sulfur bearing compounds during fuel oil firing severally affects the catalyst life on SCR systems. Therefore, based on energy, environmental, and economic impacts, the use of dry low NO_x combustors to meet an emissions limit of 10.5 ppmvd during natural gas firing, and water injection to meet an emission limit of 42 ppmvd during fuel oil firing, is recommended as BACT for the proposed General Electric 7FA combustion turbines at the Reliant Energy Osceola facility. The proposed limit is considered consistent with the range of emission limits allowed for other recent permits allowed in the U.S. and the State of Florida.

5.0 CO BACT

The objective of this analysis is to determine BACT for CO emissions from the combustion turbines.

5.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. These emissions are achieved by reducing CO emissions through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in an area designated as non-attainment areas for CO and ozone (VOC control required).

Recent applications in the State of Florida include the City of Tallahassee (25 ppm on gas and 90 ppm on oil), the FPC Hines project (25 ppm on gas and 30 ppm on oil), and the Tiger Bay project (15 ppm on gas and 30 ppm on oil).

5.2 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which can increase emissions of CO. CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures through steam/water injection or staged combustion, which is used to reduce combustor based NO_x formation, can be counterproductive with regard to CO emissions.

The only post-combustion CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst, which is not considered to be toxic. No reagent injection is necessary, and oxidizing catalysts are capable of reducing CO emissions by as much as 90 percent. Because the CO emission rate of the 7FA machine is already low at 10.5 ppmvd during natural gas firing, any additional emission reduction would be limited to approximately 1.8 ppmvd at 15% O_2 (83 percent removal) if a catalyst is used. Reductions of up to 88 percent (to 2.4 ppmvd at 15% O_2) can be expected during periods of fuel oil firing. CO emissions for the control technology are estimated in Table 5-1.

5.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenario's evaluated.

5.3.1 Economic Impacts

The use of oxidation catalyst has a significant negative economic impact to the Project. Analysis of the economic impacts is provided below. Because CO emissions are higher when firing fuel oil than when firing natural gas (20 ppmvd versus 10.5 ppmvd, respectively), typical worst-case annual emissions would arise from the firing of the maximum amount fuel oil, with the balance of the firing on natural gas. The CO BACT costs presented in this analysis, therefore, are based on operating the General Electric 7FA unit at full load for 2,000 hours per year on No. 2 fuel oil, and 1,000 hours per year on natural gas.

5.3.1.1 Capital Costs

Tables 5-2 presents the capital costs for installing an oxidation catalyst system on a General Electric 7FA. The capital costs for the systems includes the oxidation catalytic reactor and balance of plant equipment, and were based on budgetary quotations from equipment manufacturers and other engineering estimates.

5.3.1.2 Operating Costs

Table 5-3 presents the annual operating costs and emission rates using an oxidation catalyst to achieve 83 and 88% reduction of CO on a General Electric 7FA unit firing natural gas and fuel oil, respectively. CO stack emissions would be reduced to a maximum of 1.8 ppmvd at 15 percent O_2 during natural gas firing and 2.4 ppmvd during fuel oil firing. Annual operating costs for each system includes catalyst replacement, operating personnel, maintenance costs, and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers will guarantee a catalyst life of three years of equivalent operating hours for an oxidation catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

Total 1999 annual cost for the oxidation catalyst system is calculated as the sum of the 1999 annual operating costs plus capital recovery. The total annual operating cost for an oxidation catalyst is estimated to be \$892,000. This results in an incremental CO removal cost of \$12,888.

5.3.1.3 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the back pressure on the combustion turbine. The additional back pressure of 3.15 inches (w.g.) will reduce the CT output by approximately 0.44 percent. The cost of lost power revenue due to the back pressure is included in the economic analysis.

5.3.1.4 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions from sources firing fuel oil is that a significant percentage of the SO_2 in the flue gas will oxidize to SO_3. Higher operating temperatures result in a higher SO_2 to SO_3 oxidation potential. With the high exhaust temperatures seen on SCCT units, it is estimated that between 75 to 90% of the SO_2 in the flue gas will be oxidized to SO_3 by the CO oxidation catalyst. The SO_3 will then react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Because these units will fire fuel oil, formation of SO_3 and H_2SO_4 is a substantial concern. These emissions may significantly increase PM_{10} emissions from this facility. This additional particulate matter will predominately consist of matter less than 10 microns in diameter (PM_{10}).

5.4 Conclusions

Installation of an oxidation catalyst system designed to reduce CO emissions by up to 88 percent would add approximately \$892,000 to the annual operating capital cost of a GE 7FA. The resulting cost effectiveness on a per-ton of CO removed basis is \$12,888/ton, which is an excessively high cost for this pollutant. CO catalysts have not typically been applied to similar applications under BACT consideration, and the proposed CO emission rate of 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing represent emission levels equal to, or lower than other recent projects permitted by the State.

Table 5-1
Estimated CO Emissions From
Alternate Control Technologies Per GE 7FA Unit

Fuel	Control Technologies	
	Dry Low NO_x Combustors	Oxidation Catalyst
Natural Gas		
Ppmvd	10.5	1.8 (83% Reduction)
Tons per year[a]	43.5	8.7
Fuel Oil		
Ppmvd	20	2.4 (88% Reduction)
Tons per year[b]	195	23.4
BACT Basis (Annual)[c]		
Tons per year	79.5	10.3

Notes:

[a] Annual emissions based on 1,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[b] Annual emissions are based on 2,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[c] Annual emissions are based on firing natural gas for 1,000 hours and No. 2 fuel oil for 2,000 hours per year at full load rating with an ambient temperature of 59 °F.

Table 5-2 CO Reduction System Capital Cost Per GE 7FA			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Catalysts	712,000	NA	Scaled from previous vendors quotes
Catalyst Reactor	697,000	NA	Calculated based on catalyst size
Dilution Air System	281,500	NA	Estimated for entire fan system
Control/Instrumentation	40,000	NA	Estimated
Balance of Plant	260,000	NA	For: 15% For Foundations & Supports, Erection, Electrical Installation, Painting, Insulation, Vendor Engineering.
Total Direct Capital Cost	1,991,000	Base	
Indirect Capital Costs			
Contingency	299,000	NA	15% of Direct Capital Cost
Engineering and Supervision	100,000	NA	5% of Direct Capital Cost
Construction & Field Expense	40,000	NA	2% of Direct Capital Cost
Construction Fee	20,000	NA	1% of Direct Capital Cost
Start-up Assistance	20,000	NA	1% of Direct Capital Cost
Performance Test	10,000	NA	0.5% of Direct Capital Cost
Total Indirect Capital Costs	489,000	Base	
Total Installed Cost	**2,480,000**	Base	

Table 5-3

CO Reduction System Annual Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Table 5-1
Catalyst Replacement	89,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	38,000	NA	2% of Capitol Cost
Power Consumption	110,000	NA	Includes back pressure on combustion turbine and dilution air fan energy consumption
Lost Power Generation	198,000	NA	
Total Direct Annual Cost	435,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	23,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	50,000	NA	2% of Total Installed Cost
Property Taxes	68,000	NA	2.75% of Total Installed Cost
Insurance	25,000	NA	1% of Total Installed Cost
Capital Recovery	291,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	457,000	NA	
Total Annual Cost	**892,000**	NA	
Annual Emissions, tpy	10.3	79.5	Emissions taken from Table 5-1
Emissions Reduction, tpy	69.2	NA	Emissions calculated from Table 5-1
Total Cost Effectiveness, $/ton	**12,888**	NA	Total Annual Cost/Emissions Reduction

Therefore, based on economic, environmental and energy impacts, the proposed BACT for the control of CO emissions for this project is good combustion practices using advanced combustion control design. Emissions for the GE 7FA will be limited to 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

6.0 PM/PM_{10} Emissions Control

The emissions of particulate matter from the Project will be controlled by ensuring complete combustion of the fuel and by minimizing SO_2 to SO_3 oxidation. Natural gas, one of the fuels proposed for the proposed Project contains only trace quantities of non-combustible material. Also, the manufacturer's standard operating procedures include filtering the turbine air inlet air, which will contribute to lower emissions of particulate matter from these CTs.

The NSPS regulation for combustion turbines does not contain a particulate emission limit, and the BACT/LAER clearinghouse also does not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with recent determinations as referenced by the State of Florida, such as the FPL Fort Myers, Santa Rosa and Tallahassee projects, the use of combustion controls is considered BACT for particulate matter and is therefore proposed for this project. Particulate emissions (front half catch only) will be limited to 0.0055 lb/MBtu (9 lb/hr at full load) while firing natural gas and 0.0093 lb/MBtu (17 lb/hr at full load) while firing oil.

7.0 SO_2 BACT Analysis

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.05% sulfur. The selection of these fuels provide inherently low SO_2 emissions. No supplemental SO_2 emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies. In addition, other recent Florida projects have identified the use of natural gas and low sulfur fuel oil as BACT for SO_2. Therefore, the use of natural gas and low sulfur fuel oil is considered as BACT for this project.

8.0 Summary

The following is a summary of BACT for the combustion turbines and the associated emission rates.

- Nitrogen oxides (NO_x) emissions
  The use of dry low NO_x burners during natural gas firing to achieve an emission limit of 10.5 ppmvd at 15 % O_2.
  Water injection during fuel oil firing to achieve an emission limit of 42 ppmvd at 15% O_2.

- Carbon monoxide (CO) emissions
  Good combustion controls to achieve a CO emission limit of 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

- Particulate emissions
  Good combustion controls.

- Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)
  Good combustion controls.
  The use of natural gas and fuel oil with less than 0.05% sulfur.

Attachment 4
(Dispersion Modeling Protocol)

Ambient Air Quality Impact Analysis Workplan
For the
Reliant Energy Osceola, L.L.C.
Osceola Power Project

Prepared By
Black & Veatch

June 1999

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1.0 Introduction

Reliant Energy Osceola, L.L.C. proposes to install three (3) simple cycle combustion turbines (here-inafter referred to as the "project"), at a location near Holopaw, Florida. The combustion turbines will use fuel oil and natural gas as fuel. It is anticipated that the project will be a new major stationary source, thus, subject to the Prevention of Significant Deterioration (PSD) review program. This Ambient Air Quality Impact Analysis Workplan (Workplan) describes the air quality impact analysis methodology for obtaining a Construction Permit for the project. After the Florida Department of Environmental Protection (FDEP) review and approval, this Workplan will provide the basis of a mutually agreed upon procedure for the final ambient air quality impact analysis in support of the air construction permit application.

This Workplan describes site and source characteristics, determination of pollutants applicable to the air quality review, and the analytical procedures that will be used to conduct the ambient air quality impact analysis. The ambient air quality impact analysis includes a determination of compliance with the National Ambient Air Quality Standards (NAAQS), the Prevention of Significant Deterioration (PSD) increments, and an additional impact assessment.

2.0 Project Characterization

The following sections briefly characterize the combustion turbine project including a general description of the project, location, and emission units, as well as an overview of the local air quality status and New Source Review (NSR) applicability.

2.1 Project Description

Reliant Energy Osceola, L.L.C. proposes to install three combustion (170 MW each) that will fire fuel oil and natural gas. The project will supply additional power to the existing electric grid.

2.2 Project Location and Proximity to Mandatory Class I Areas

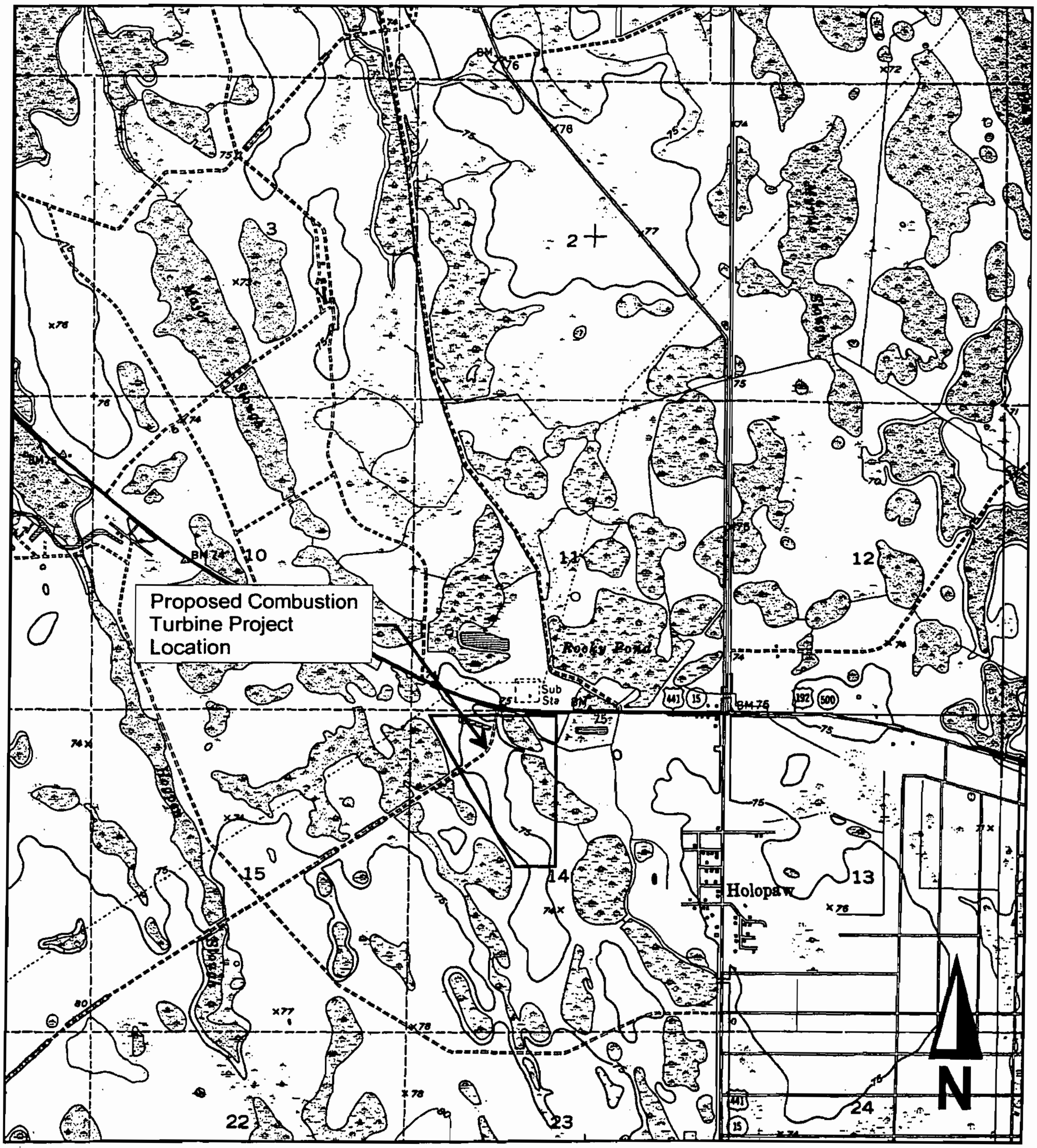
The project will be located near Holopaw, Florida within the county of Osceola. Specifically, the project will be located approximately 1 kilometer (km) northwest of Holopaw, Florida as shown in Figures 2-1. The nearest Mandatory Class I Area is Chassahowitzka Wilderness Area and is located more than 150 km west-northwest of the project site. Because of this extreme distance to the Class I area from the project site, an ambient air quality impact analysis and a regional haze analysis are not being proposed for this area.

2.3 Project Emissions

The project will consist of three simple cycle combustion turbines (SCCT). Representative manufacturer's data and engineering estimates will be used to characterize and quantify the potential to emit (PTE) of the project for determining PSD applicability and developing representative worst-case stack parameters and emission rates for the air dispersion modeling analysis as described in Section 3.0.

2.4 Local Air Quality Attainment/Nonattainment Status

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable NAAQS. Likewise, a given area is generally classified as nonattainment



Base Map: 7.5' Quadrangle
Holopaw, Florida

Reliant Energy Osceola, L.L.C. Proposed
Combustion Turbine Project Location

Figure 2-1

Reliant.srf

for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS. A review of the air quality status in the region reveals that the project site near Holopaw, Florida is in attainment or unclassifiable for all pollutants.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs; the PSD program outlined in 40 CFR 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. As noted in Section 2.4, the project will be located in an attainment area with respect to all pollutants. As such, the PSD program will apply to the project, which is assumed to be a new major stationary source.

2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable under Section 107 of the CAA for any criteria pollutant. The primary provisions of the PSD regulations require that new major stationary sources and major modifications to existing major stationary sources be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply BACT to minimize the project's emissions of air pollutants.

A new stationary source can be defined as a "major stationary source" if it is classified as any one of the listed major source categories which emits, or has the potential to emit, 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories. Because the project does not fall into one of the major source categories the 250 tpy threshold is applicable to the project. Because the project is likely to exceed the 250 tpy threshold for at least one regulated pollutant the project will be subject to PSD review. Once the project becomes applicable to PSD review, PSD applicability will then be determined on a pollutant by pollutant basis for the remaining pollutant by comparing the net emissions increase of each pollutant against the PSD significant emission rates (i.e., 40 tpy for NO_x, 40 tpy for SO_x, 25 tpy for TSP, 15 tpy for PM_{10}, 100 tpy for CO, and 40 tpy for VOCs). Each regulated pollutant with a PTE above the PSD significant emission rates will be subject to PSD review, including a BACT assessment, ambient air quality impact analysis, and an additional impact analysis.

3.0 Ambient Air Quality Impact Analysis

The following sections discuss the air dispersion modeling methodology and Ambient Air Quality Impact Analysis (AAQIA) that are proposed for those regulated pollutants which are determined to have a PTE greater than the PSD significant emission rate and thus subject to PSD review. The AAQIA will be conducted in accordance with USEPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon modeling methodology initiated by this Workplan.

3.1 Air Dispersion Modeling Methodology

The base elevation at the site location for the project is approximately 23 m (75 ft) above mean sea level (amsl). The site topography is essentially flat with no terrain elevation expected to exceed the proposed stack height of 60 to 90 feet above grade elevation. Since the terrain in the immediate vicinity of the project is flat. Site dispersion modeling receptors will be located in only simple terrain. As such, the Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model is proposed for the AAQIA.

The ISCST3 model is a USEPA approved, steady-state, straight-line gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. The ISCST3 air dispersion model will be used in a refined mode (based on the worst-case operating scenarios and five years of representative meteorological data) to determine the maximum predicted impact concentrations for the AAQIA. The refined ISCST3 modeling methodology is discussed below.

3.1.1 Model Input and Source Parameters

The AAQIA will be based on the worst-case combination of operating parameters. Manufacturer's data will be used as inputs in the ISCST3 air dispersion model to determine the maximum predicted ground level concentrations from the project based on various operating loads, equipment scenarios, and ambient operating temperatures. This will be accomplished by representing each combustion turbine with various operating loads in the air dispersion modeling. In a process referred to as "enveloping", each load analyzed will be represented with a set of stack parameters and pollutant emission rates that will be conservatively selected to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperatures, lowest exit velocity, and highest emission rate) over three ambient temperature ranges that include a representative minimum and maximum, and average annual ambient temperatures. Enveloping allows multiple operating scenarios to be conservatively considered in an AAQIA, while keeping the actual air dispersion modeling runs to a minimum.

3.1.2 Refined Modeling

The worst-case combination of representative operating loads for the combustion turbine will be used in the refined ISCST3 modeling for the PSD AAQIA. Actual sequential hourly meteorological data will be used to predict concentrations of each pollutant for each applicable averaging period.

3.1.3 GEP and Building Downwash Evaluation

The buildings and structures including the combustion turbine housings of the project will be analyzed to determine the potential to influence the plume dispersion from the combustion turbine stacks. The USEPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document will be followed in this evaluation. Structure dimensions and relative locations will be entered into the USEPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. This same program will also determine a good engineering practice (GEP) stack height for each of the combustion turbine stacks.

3.1.4 Model Options

The following standard USEPA default regulatory modeling options will be invoked in the ISCST3 model:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature

gradient values.
- Calm processing option.
- Terrain elevations will be incorporated.

3.1.5 Receptor Grids and Terrain Considerations

The air dispersion modeling receptor locations will be established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network is proposed that will extend 10 km from the center of the project. The rectangular grid network will consists of 100 m spacing out to 1 km, 250 m spacing from 1 to 3 km, 500 m spacing from 3 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing at 50 m intervals will be used along the property line. The receptor grid will be extended as necessary to ensure that the significant impact area is defined, and a 100 m fine grid will be used around the maximum receptor points. Terrain at all receptors will be modeled at the stack-base elevation.

3.1.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. The most recent five years (1987-1991) of surface data from Orlando, Florida and upper air meteorological data from the Tampa Bay International Airport available on the EPA's Support Center for Regulatory Air Models Bulletin Board System (SCRAM BBS) is proposed for this analysis. The meteorological data will be processed using the USEPA PCRAMMET program into a format suitable for the ISCST3 dispersion model.

3.1.7 Land Use Dispersion Coefficients

The USEPA's land use method will be used to determine whether rural or urban dispersion coefficients will be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site is classified as rural or urban using the Auer land use classification method. If rural land use types account for more than 50 percent of the land use area within the 3 km radius, then the rural dispersion coefficient option should be used. Otherwise, the urban coefficients are used.

Based on visual inspection of the USGS 7.5-minute topographic map of the proposed site location, it is conservatively concluded that over 50 percent of the area surrounding the proposed project are rural. Accordingly, the rural dispersion modeling option will be used.

3.2 Model Predicted Impacts

Based on the air dispersion modeling methodology outlined in the previous sections, the maximum model predicted ground-level concentrations for the worst-case operating scenario associated with the project will be determined for each regulated pollutant that is subject to PSD review and for which a significant impact level exists. From the modeling results, the significant impact area, preconstruction monitoring requirements, and the need for a NAAQS and PSD increment consumption analyses will be determined.

3.2.1 PSD Class II Significant Impact Area

The predicted inputs for all PSD significant pollutants will be compared to the applicable PSD Class II significant impact levels (SILs) identified in Table 3-1. If the model predicted maximum concentrations are less than the PSD significant impact levels for all pollutants and applicable averaging periods, then no further air dispersion modeling analyses will be performed. However, if the predicted impact of one or more pollutants and applicable averaging periods are greater than the PSD significant impact levels, then a significant impact area will be determined and interactive source modeling will be performed for those pollutants. In this event, additional agency consultation will be requested and an inventory of PSD increment consuming sources and all nearby sources for the NAAQS analysis will be obtained and included as interactive sources in the AAQIA.

3.2.2 Determination of Preconstruction Monitoring Requirements

Ambient air quality data will be compared with the PSD significant monitoring concentrations. If examination of existing air quality data in the area shows that the existing ambient pollutant concentrations for each criteria pollutant are less than the applicable significant monitoring concentrations, then an exemption from pre-application monitoring will be requested for that pollutant.

Table 3-1 PSD Class II significant impact levels (SILs)		
SO_2	3-hour	25 $\mu g/m^3$
	24-hour	5 $\mu g/m^3$
	Annual	1 $\mu g/m^3$
PM	24-hour	5 $\mu g/m^3$
	Annual	1 $\mu g/m^3$
NO_x	Annual	1 $\mu g/m^3$
CO	1-hour	2000 $\mu g/m^3$
	8-hour	500 $\mu g/m^3$

If the existing air quality concentration for a given pollutant is equal to or greater than the applicable PSD significant monitoring concentration, then pre-application monitoring applicability will be determined by comparing the pollutant's maximum model predicted concentration from the project to the applicable PSD significant monitoring concentration. If the project's maximum model predicted concentration for that pollutant is less than the applicable PSD significant monitoring concentration, then an exemption from pre-application monitoring requirements will be requested for that pollutant.

In the event both the ambient air quality data and maximum model predicted impacts exceed the applicable PSD significant monitoring concentration for a given pollutant, then the existing ambient air quality monitoring network will be evaluated for representativeness of these data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for that pollutant.

3.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I or other relative designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Federal Land Manager (FLM) typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and regional haze/visibility. The nearest Class I area is more than 150 km from the proposed project location, so a Class I area impact analysis is not proposed.

3.4 Additional Impact Analysis

Federal PSD regulations require the preparation of an analysis of additional impacts due to construction and operation of a new major stationary source or major modification to an existing major source. The analysis considers impairment to visibility, soils, and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source.

3.4.1 Commercial, Residential, and Industrial Growth

Analysis is typically conducted to predict the amount of commercial, residential, and industrial growth may result from the operation of a proposed facility and the effect this growth may have on the ambient air quality. Because the project site will not be manned, the effects to ambient air quality due to growth associated with the project are expected to be insignificant.

3.4.2 Vegetation and Soils

An analysis will be performed to examine the project's predicted ambient air quality impacts on local soils and vegetation. The secondary NAAQS will serve as a basis for assessing the vegetation and soil impacts.

3.4.3 Visibility

Because the nearest Class I area is more than 150 km from the proposed project location, the effects on visibility from the project on the mandatory Class I areas will not be evaluated.

Reliant Energy Osceola, L.L.C.
Osceola Power Project

Construction Permit Application
July 1999

BLACK & VEATCH

I. Application Information

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Reliant Energy Osceola, L.L.C.	
2. Site Name : Reliant Energy Osceola	
3. Facility Identification Number :	[X] Unknown
4. Facility Location : Approximately 0.75 miles west of the intersection of U.S. 192 and U.S. 441 Street Address or Other Locator : City : Holopaw County : Osceola	Zip Code : 34771
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

   Name : J. Christopher Allen
   Title : Vice President

2. Owner or Authorized Representative or Responsible Official Mailing Address :

   Organization/Firm : Reliant Energy Osceola, L.L.C.
   Street Address : P.O. Box 4455
   City : Houston
   State : TX   Zip Code : 77210-4455

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

   Telephone : (713)207-7441   Fax : (713)207-0840

4. Owner/Authorized Representative or Responsible Official Statement :

   I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

   ______________________________   ____________________
   Signature   Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 170 MW Simple Cycle Combustion Turbine	NA
002	Unit 2 - 170 MW Simple Cycle Combustion Turbine	NA
003	Unit 3 - 170 MW Simple Cycle Combustion Turbine	NA
004	No. 2 Fuel Oil Storage Tank (3,000,000 gal)	NA

Purpose of Application and Category

Category I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

Category II : All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s) :

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one :

[X] Attached - Amount : $7500.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : Reliant Energy Osceola, L.L.C. proposes to construct three (3) 170 MW natural gas (NG) and No. 2 fuel (FO) fired simple cycle combustion turbines (SCCTs) at the new electrical generating facility located nea Holopaw, Florida. The proposed SCCTs will be used for peaking power.	
2. Projected or Actual Date of Commencement of Construction :	31-Dec-1999
3. Projected Date of Completion of Construction :	31-Dec-1999

Professional Engineer Certification

1. Professional Engineer Name : Registration Number :	Donald Schultz, P.E. 30304
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Corporation Street Address : 11401 Lamar Avenue City : Overland Park	 State : KS Zip Code : 66211
3. Professional Engineer Telephone Numbers : Telephone : (913)458-2028	 Fax : (913)458-2934

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✓] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

D V Schultz
Signature
(seal)

July 28, 1999
Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact : Name : Jason M. Goodwin, P.E. Title : Senior Engineer
2. Application Contact Mailing Address : Organization/Firm : Reliant Energy Wholesale Group Street Address : 12301 Kurland, P.O. Box 4455 City : Houston State : TX Zip Code : 77034
3. Application Contact Telephone Numbers : Telephone : (713)945-7167 Fax : (713)945-7598

Application Comment

II. Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

<table>
<tr><td colspan="4">1. Facility UTM Coordinates :
Zone : 17 East (km) : 491.36 North (km) : 3112.71</td></tr>
<tr><td colspan="4">2. Facility Latitude/Longitude :
Latitude (DD/MM/SS) : 28 5 17 Longitude (DD/MM/SS) : 28 8 29</td></tr>
<tr><td>3. Governmental Facility Code :
0</td><td>4. Facility Status Code :
C</td><td>5. Facility Major Group SIC Code :
49</td><td>6. Facility SIC(s) :
4911</td></tr>
<tr><td colspan="4">7. Facility Comment :</td></tr>
</table>

Facility Contact

<table>
<tr><td colspan="2">1. Name and Title of Facility Contact :

Jason M. Goodwin, P.E.
Senior Engineer</td></tr>
<tr><td colspan="2">2. Facility Contact Mailing Address :
Organization/Firm : Reliant Energy Wholesale Group
Street Address : 12301 Kurland
City : Houston State : TX Zip Code : 77034</td></tr>
<tr><td colspan="2">3. Facility Contact Telephone Numbers :
Telephone : (713)945-7167 Fax : (713)945-7598</td></tr>
</table>

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment :	

B. FACILITY REGULATIONS

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General - Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceeds the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment D for facility applicable requirements.

B. FACILITY REGULATIONS

List of Applicable Regulations

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100 - 300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
NOX	A
CO	A
VOC	B
SO2	A
PM	A
PM10	A
PB	B
SAM	A

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Attachment A
2. Facility Plot Plan :	Attachment B
3. Process Flow Diagram(s) :	Attachment C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	NA
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applic	Attachment D

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Requir

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

<u>Type of Emissions Unit Addressed in This Section</u>

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 1 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date : 31-Dec-1999
2. Long-term Reserve Shutdown Date :
3. Package Unit : Manufacturer : General Electric Model Number : PG7241(FA)
4. Generator Nameplate Rating : 170 MW
5. Incinerator Information : Dwell Temperature : Degrees Fahrenheit Dwell Time : Seconds Incinerator Afterburner Temperature : Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1942 mmBtu/hr
2. Maximum Incinerator Rate : lb/hr tons/day
3. Maximum Process or Throughput Rate :
4. Maximum Production Rate :
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : 24 hours/day 7 days/week

	52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General
Air emissions units must obtain an air construction permit prior to construction or modification.
Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 1		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.281 North (km) : 3112.785		
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 343.0000000 lb/hour	379.7500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 73.5 lb/h Fuel Oil = 343 lb/h Worst Casel Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 70.0000000 lb/hour 88.1000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor Units Reference Manufacturer's Data
7. Emissions Method Code : 0
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 36.2 lb/h Fuel Oil = 70.0 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
104.3800000 lb/hour 104.9500000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simply cycle operation:
Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf)
Fuel Oil = 104.38 lb/h (0.05% Sulfur)

Worst case hours of operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**	
2. Total Percent Efficiency of Control :	%
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference Manufacturer's Data	Units
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code :	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 15.9800000 lb/hour	16.0700000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 0.2 lb/h Fuel Oil = 15.98 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	343.00	lb/hour	343.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.		

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :			
2. Basis for Allowable Opacity : RULE			
3. Requested Allowable Opacity :			
	Normal Conditions :	20	%
	Exceptional Conditions :		%
	Maximum Period of Excess Opacity Allowed :		min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity			
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard			

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s): NOX
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
15.9800000 lb/hour 16.0700000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 0.2 lb/h
Fuel Oil = 15.98 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	343.00	lb/hour	343.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

<u>Allowable Emissions</u> 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO_2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

<u>Allowable Emissions</u> 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.		

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	
2. Basis for Allowable Opacity : RULE	
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity	
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	
11. Alterntive Modes of Operation (Emissions Trading) :	

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	31-Dec-1999	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : PG7241(FA)
4. Generator Nameplate Rating :	170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	1942 mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week

	52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General
Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 2		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.263	North (km) : 3112.753	
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
343.0000000 lb/hour 379.7500000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 73.5 lb/h
Fuel Oil = 343 lb/h

Worst Casel Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 70.0000000 lb/hour	88.1000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference Manufacturer's Data	Units
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 36.2 lb/h Fuel Oil = 70.0 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 104.3800000 lb/hour	104.9500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simply cycle operation: Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 104.38 lb/h (0.05% Sulfur) Worst case hours of operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
34.0000000 lb/hour 43.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code :	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Altemtive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 2 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 002 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 2

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 3 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 003 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

<u>Emissions Unit Control Equipment</u> 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	31-Dec-1999
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : PG7241(FA)
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1942	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : 24 hours/day	 7 days/week

	52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC). Rule 62-212.300 requires the following: (1) General Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase. (2) Permitting Requirements The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit. This facility is a Title V source. See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 3		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.245 North (km) : 3112.721		
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
343.0000000 lb/hour 379.7500000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 73.5 lb/h
Fuel Oil = 343 lb/h

Worst Casel Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 70.0000000 lb/hour	88.1000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 36.2 lb/h Fuel Oil = 70.0 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**		
2. Total Percent Efficiency of Control :	%	
3. Potential Emissions :	104.3800000 lb/hour	104.9500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions:	to	tons/year
6. Emissions Factor Reference Manufacturer's Data	Units	
7. Emissions Method Code : 0		
8. Calculations of Emissions : Highest hourly emissions for simply cycle operation: Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 104.38 lb/h (0.05% Sulfur) Worst case hours of operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr		
9. Pollutant Potential/Estimated Emissions Comment :		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
34.0000000 lb/hour 43.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
34.0000000 lb/hour 43.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code :

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
15.9800000 lb/hour 16.0700000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 0.2 lb/h
Fuel Oil = 15.98 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	42.00 ppm @ 15% O2
4. Equivalent Allowable Emissions :	343.00 lb/hour 343.00 tons/year
5. Method of Compliance :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.		

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	
4. Equivalent Allowable Emissions : 18.00 lb/hour 27.00 tons/year	
5. Method of Compliance :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.	

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	
11. Alterntive Modes of Operation (Emissions Trading) :	

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 4

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : No. 2 Fuel Oil Storage Tank (3,000,000 gal)		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (3,000,000 gallon capacity) is reported as an emission unit because it is subject to the reporting requirements of the New Source Performance Standards (NSPS) Subpart Kb. The tank is a vertical fixed roof design.		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Breathing Loss - No. 2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301020	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate : 3,000.00	5. Maximum Annual Rate : 3,000.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Losses - No. 2 Fuel Oil Throughput	
2. Source Classification Code (SCC) : 40301021	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate : 13.09	5. Maximum Annual Rate : 78,514.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1832 MBtu/h) / (0.14 MBtu/gal) = 13,086 gal/h (6,000 h/yr) x (13,086 gal/h) = 78,514,286 gal/yr (78,514,286 gal/yr) / (3,000,000 gal) = 26.17 turnovers/yr	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4
No. 2 Fuel Oil Storage Tank (3,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

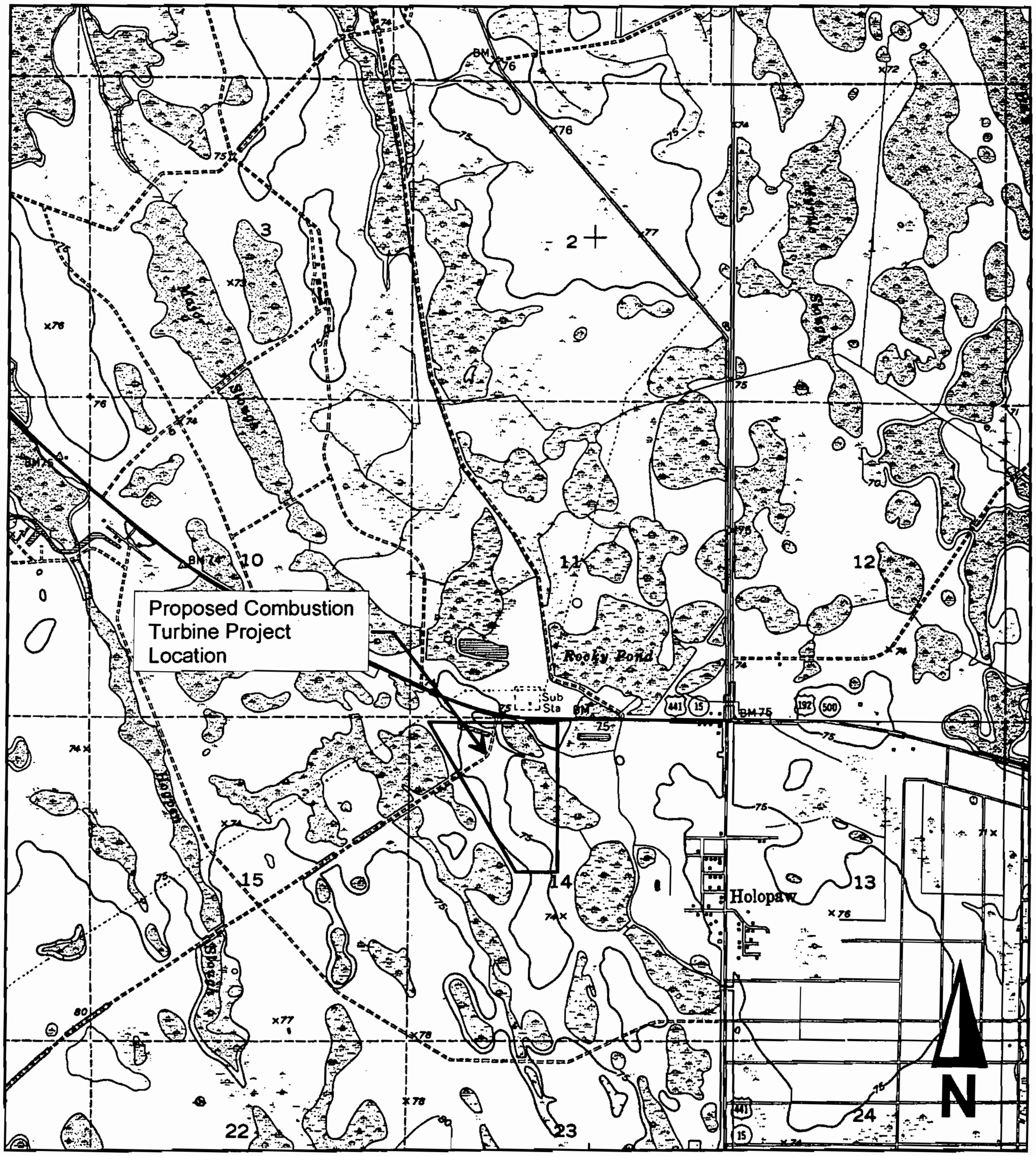
[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

Attachment A

Attachment A

Area Map Showing Facility Location



Base Map: 7.5' Quadrangle
Holopaw, Florida

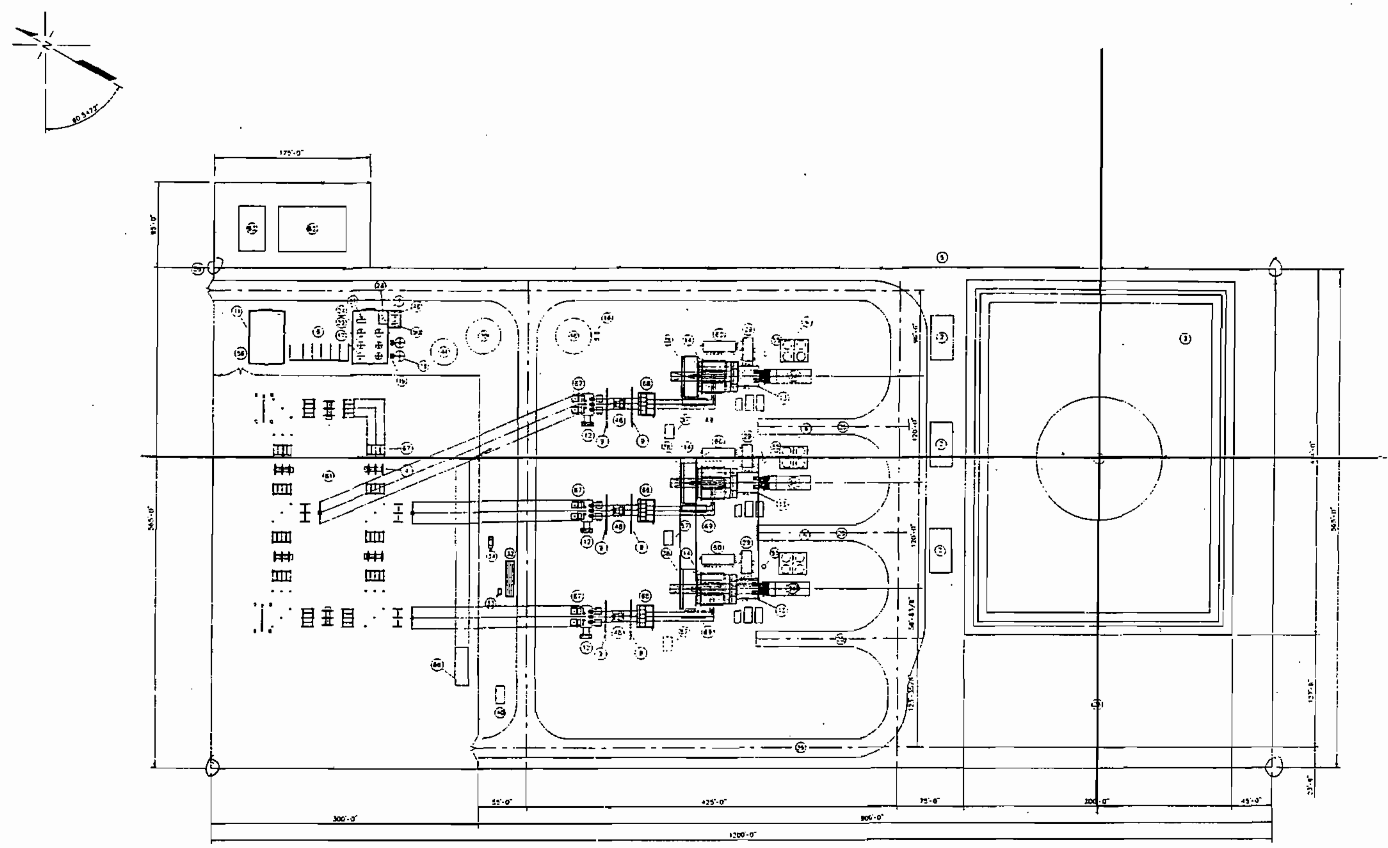
Reliant Energy Osceola, L.L.C. Proposed
Combustion Turbine Project Location

Figure 2-1

Attachment B

Attachment B

Facility Plot Plan



LEGEND:

1. FUEL OIL STORAGE TANK
2. FUEL OIL OFF-LOADING
3. FUEL OIL CONTAINMENT BERM
4. 230KV CIRCUIT BREAKER
5. PERIMETER FENCE
6. COOLING MODULE
7. PRE-ENGINEERED WATER TREATMENT BLDG
8. EMPLOYEE PARKING
9. FIREWALL
10. DEMINERALIZED WATER STORAGE TANK
11. ELECTRICAL EQUIPMENT, OFFICE, PARTS STORAGE
12. STEP-UP TRANSFORMER
13. COMBUSTION GAS TURBINE GENERATOR
14. COMBUSTION GAS TURBINE
15. FIRE / RAW WATER TANK
16. FIREWATER PUMPS
17. ACID CATION EXCHANGERS
18. DECARBONATOR
19. DECARBONATOR FORWARDING PUMPS
20. NOT USED
21. DEMINERALIZER CONTROL PANEL
22. ANION EXCHANGERS
23. NOT USED
24. MIXED BED EXCHANGERS
25. ROAD
26. LAYDOWN AREA
27. NOT USED
28. CHEMICAL FEED SKID
29. ACCESSORY MODULE
30. NOT USED
31. NOT USED
32. HYDROGEN TUBE TRAILER PARKING
33. HYDROGEN VALVE MANIFOLD
34. CO2 STORAGE
35. NOT USED
36. NOT USED
37. NOT USED
38. CT AIR INLET FILTER
39. NOT USED
40. OILY/WATER SEPARATOR
41. NEUTRALIZATION TANK
42. NOT USED
43. NOT USED
44. NOT USED
45. FUEL SKID
46. ACID TANK
47. NOT USED
48. AUXILIARY TRANSFORMER
49. ACID REGEN. SYSTEM
50. CAUSTIC TANK
51. CAUSTIC REGEN. SYSTEM
52. NOT USED
53. NOT USED
54. CT STACK
55. FUEL GAS FILTER SEPARATOR
56. GATE
57. MV SWITCHGEAR
58. NOT USED
59. NOT USED
60. CT ELECTRICAL PACKAGE
61. SWITHYARD
62. FUEL GAS SCRUBBER SKID
63. FUEL GAS METERING SKID
64. WATER WASH SKID
65. COMBUSTION TURBINE DRAIN TANK
66. SWITCHYARD CONTROL BUILDING
67. 230KV DISC. SWITCH
68. GENERATOR BREAKER
69. EXCITATION TRANSFORMER

NOT FOR EXTERNAL RELEASE
ISSUED FOR INTERNAL APPROVAL

BY ______________ DATE ________

BY ______________ DATE ________

PRELIMINARY

-50 -25 0 50 150 200 250 300
SCALE IN FEET

Reliant Energy. Wholesale Group

Escondido Project
Holopaw, Florida Site
Proposed Equipment Arrangement
3 & 3 Future -GE 7FAs Simple Cycle Installation

Drawn by : J.C Reyes Jr	06-18-99	Scale :	1"=50'-0"
Checked by		Filename	904EPM05.DWG
Approved by		904-EP-M-05	
Approved by			

Attachment C

Attachment C

Process Flow Diagrams
(See individual unit process flow diagrams, Attachments H, and P)

Attachment D

Attachment D

Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement
40 CFR 60.7, Notification and recordkeeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable.
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.
40 CFR 60.8 (e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.

Applicable Regulation	Applicable Requirement
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with permit conditions.
	Permits, or a copy thereof, shall be kept at the work site of the permitted activity.
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.
F.A.C. 62-4.210, Construction	No person shall construct any installation or facility which

Applicable Regulation	Applicable Requirement
Permits	will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.
F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A. C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA.
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollution Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting form malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit an operating permit application by June 15, 1996.
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in emission of air pollutants shall take actions as required in

Applicable Regulation	Applicable Requirement
	F.A.C. 62-273.400, 62-273.500, and 62-273.600.
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.
F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air emergency, operations will be restricted as prescribed under 62-273.600.
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment E

Attachment E

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

As a result of the construction of the simple cycle combustion turbines and the associated equipment at the project site minimal quantities of unconfined particulate matter (fugitive dust) may be released tot he atmosphere. These anticipated construction activities might be generally broken down into three phases as they relate to generating fugitive dust: debris removal, site preparation, and general construction. Because the equipment are being installed at new facility, JEA proposes to utilize watering to control fugitive dust. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder maintaining soil moisture content or establishing a crust which prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. For the construction phase of the project, it is proposed that water be applied as necessary during high wind conditions when fugitive dust is evident beyond the property boundary. The water will be applied using on or a combination of several methods listed above.

Attachment F

Attachment F

Supplemental Information for Construction Permit Application

Supplemental Information for Construction Permit Application

Please refer to the Prevention of Significant Deterioration Air Permit Application for the Osceola Power Project.

Attachment G

Attachment G

Unit Specific Applicable Requirements

170 MW Simple Cycle Combustion Turbine
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).
40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined and recorded daily.
	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334(c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.

Applicable Regulations	Applicable Requirement
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibrations, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5(f).
40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system (NO_x pollutant monitor and an O_2 or CO_2 diluent gas monitor) with automated DAHS which records NO_x concentration, O_2 or CO_2 concentration, and NO_x emission rate.
	The owner or operator shall measure CO_2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted

Applicable Regulations	Applicable Requirement
	according to the procedures in Appendix F of this subpart.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.
40 CFR 75.11, Specific provisions for monitoring SO_2	Gas and oiled fired units shall measure and record SO_2 emissions as specified in 40 CFR 75, Appendix D.
40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO_2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20(b) and (c).
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.
	The owner or operator using the optional SO_2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20(g).
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24(c) through (e), and repeat tests applicable to the "out-of-control" parameter.
40 CFR 75.30, SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.
40 CFR 75.51, SUBPART F	The owner or operator shall comply with the recordkeeping

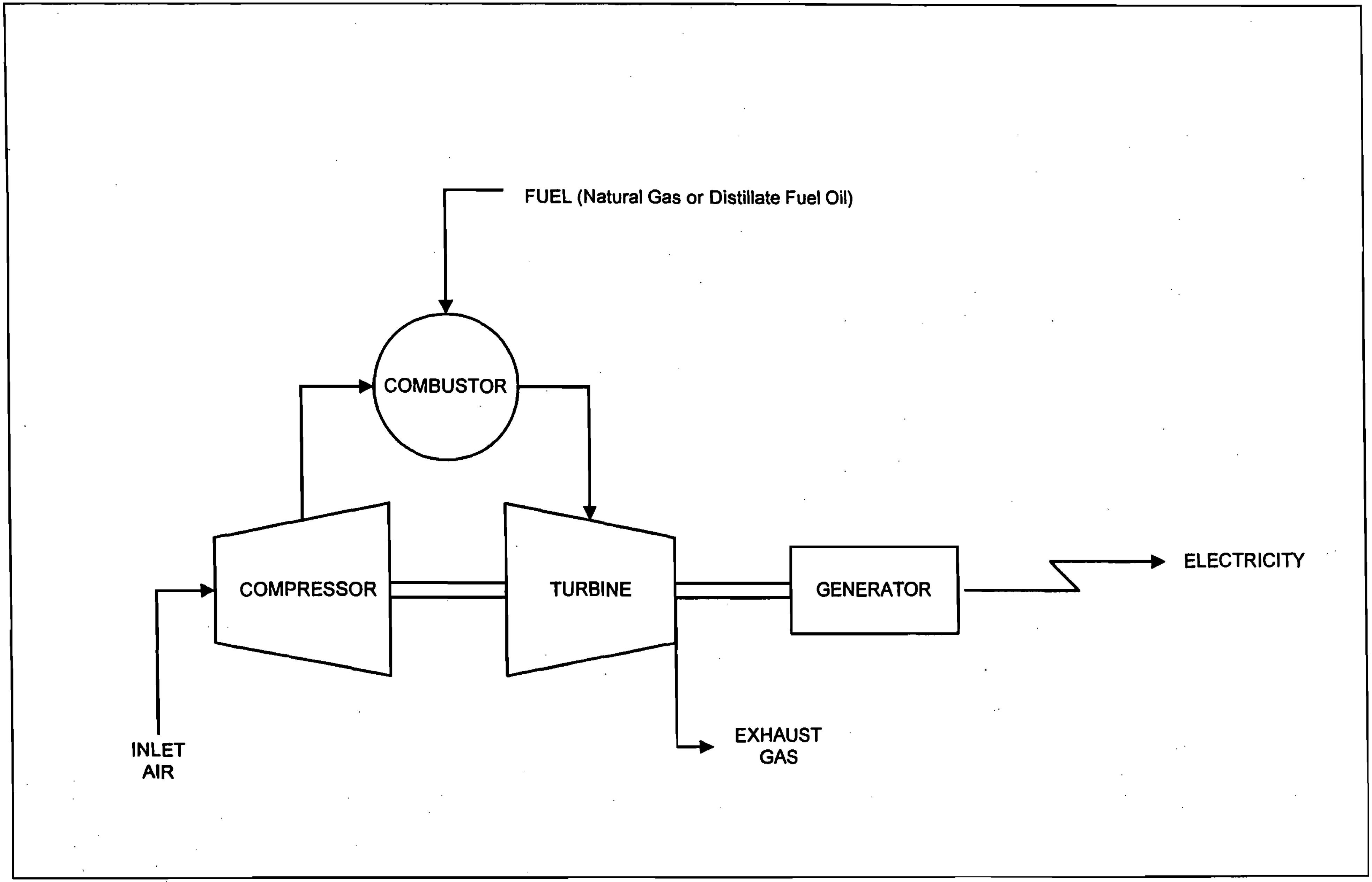
Applicable Regulations	Applicable Requirement
- Recordkeeping Requirements, General recordkeeping provisions for specific situations	requirements of 40 CFR 75.51(c)(1) through (3) when combusting natural gas and fuel oil.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52(a)(1) through (3) and 40 CFR 75.52(a)(5) through (7).
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO_2 emission records, the owner or operator shall record information as required in 40 CFR 75.55(c) in lieu of the provisions of 40 CFR 75.54(c).
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56(a)(1) through (3) and 40 CFR 75.56(a)(5) through (7).
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60(c) for any claims of confidential data.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this

Applicable Regulations	Applicable Requirement
	section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO_2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emissions rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment H

Attachment H

Process Flow Diagram



Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment I

Attachment I

Fuel Analysis or Specification

Fuel Analysis

Fuel is specified as pipeline quality sweet natural gas or No. 2 fuel oil containing no more than 0.05 percent sulfur.

Attachment J

Attachment J

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1.) Low NO_x Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. this two-stage process ensures good mixing of the air and fuel, and minimizes the amount of air required which results in low NO_x emissions.

2.) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

3.) Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Attachment K

Attachment K

Description of Stack Sampling Facilities

Stack Sampling Facilities

Vendors for these items have not yet been identified. A detailed description of the stack sampling facilities will be included with the operating permit application.

The stack sampling facilities will conform to F.A.C. Chapter 62-297.

TABLE OF CONTENTS
Chapter 62-297
Stationary Sources - Emissions Monitoring

Chapter 62-297
Stationary Sources - Emissions Monitoring

62-297.100 Purpose and Scope.

The Department of Environmental Protection adopts this chapter to establish test procedures that shall be used to determine the compliance of air pollutant emissions units with emission limiting standards specified in or established pursuant to any of the stationary source rules of the Department. Words and phrases used in this chapter, unless clearly indicated otherwise, are defined at Rule 62-210.200, F.A.C.
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(a); Formerly 17-297.100; Amended 11-23-94, 3-13-96.

62-297.200 Definitions. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.100; Amended 6-29-93; Formerly 17-297.200; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.310 General Compliance Test Requirements.

The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air.

(1) Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.

(2) Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined below. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

(a) Combustion Turbines. (Reserved)

(b) All Other Sources. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

(4) Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded Max. deviation between readings	Micrometer	+/-0.001" men of at least three readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(5) Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. inimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g). Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

(7) Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions

unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62- 210.300(4)(a)1. through 7., F.A.C.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

(8) Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(b); Formerly 17-297.310; Amended 11-23-94, 3-13-96, 10-28-97.

62-297.330 Applicable Test Procedures. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92, Formerly 17-297.330; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.340 Frequency of Compliance Tests. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(2); Formerly 17-297.340; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.345 Stack Sampling Facilities Provided by the Owner of an Emissions Unit. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(4), Formerly 17-297.345, Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.350 Determination of Process Variables. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(5), Formerly 17-297.350, Amended 11-23-94. Repealed 3-13-96.

62-297.400 EPA Methods Adopted by Reference. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(c), Formerly 17-297.400, Amended 11-23-94, Repealed 1-1-96.

62-297.401 Compliance Test Methods.

This rule adopts the test methods to be used where a compliance test is required by Department air pollution rule or air permit. The EPA test methods and quality assurance procedures listed in this rule and contained in 40 CFR Part 51, Appendix M, 40 CFR Part 60, Appendix A and F, 40 CFR Part 61, Appendix B and C and 40 CFR Part 63, Appendix A, are adopted and incorporated by reference in Rule 62-204.800, F.A.C. The EPA test methods that are adopted by reference in Rule 62-204.800, F.A.C., are adopted in their entirety except for those provisions referring to approval of alternative procedures by the Administrator. For purposes of this rule, such alternative procedures may only be approved by the Secretary or his or her designee in accordance with Rule 62-297.620, F.A.C.

(1)(a) EPA Method 1 -- Sample and Velocity Traverses for Stationary sources -- 40 CFR 60 Appendix A.

(b) EPA Method 1A -- Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts -- 40 CFR 60 Appendix A.

(2) EPA Method 2 -- Determination of Stack Gas Velocity and Volumetric Flow Rate -- 40 CFR 60 Appendix A.

(a) EPA Method 2A -- Direct Measurement of Gas Volume Through Pipes and Small Ducts -- 40 CFR 60 Appendix A.

(b) EPA Method 2B -- Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators -- 40 CFR 60 Appendix A.

(c) EPA Method 2C -- Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks and Ducts (Standard Pitot Tube) -- 40 CFR 60 Appendix A

(d) EPA Method 2D -- Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts -- 40 CFR 60 Appendix A.

(3) EPA Method 3 -- Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight -- 40 CFR 60 Appendix A.

(a) EPA Method 3A -- Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A

(b) (Reserved).

(4) EPA Method 4 -- Determination of Moisture Content in Stack Gases -- 40 CFR 60 Appendix A.

(5) EPA Method 5 -- Determination of Particulate Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 5A -- Determination of Particulate Emissions from the Asphalt Processing and Asphalt Roofing Industry -- 40 CFR 60 Appendix A.

(b) EPA Method 5B -- Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(c) Reserved.

(d) EPA Method 5D -- Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters -- 40 CFR 60 Appendix A.

(e) EPA Method 5E -- Determination of Particulate Emissions from the Wool Fiberglass Insulation Manufacturing Industry -- 40 CFR 60 Appendix A.

(f) EPA Method 5F -- Determination of Nonsulfate Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(g) EPA Method 5G -- Determination of Particulate Emissions from Wood Heaters from a Dilution Tunnel Sampling Location -- 40 CFR 60 Appendix A.

(h) EPA Method 5H -- Determination of Particulate Emissions from Wood Heaters from a Stack Location -- 40 CFR 60 Appendix A.

(6) EPA Method 6 -- Determination of Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 6A -- Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(b) EPA Method 6B -- Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(c) EPA Method 6C -- Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(7) EPA Method 7 -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 7A -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(b) EPA Method 7B -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry) -- 40 CFR 60 Appendix A.

(c) EPA Method 7C -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Colorimetric Method -- 40 CFR 60 Appendix A.

(d) EPA Method 7D -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(e) EPA Method 7E -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(8) EPA Method 8 -- Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(9)(a) EPA Method 9 -- Visual Determination of the Opacity of Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(b) Alternate Method 1 -- Determination of the Opacity of Emissions from Stationary Sources Remotely by Lidar -- 40 CFR 60 Appendix A.

(c) DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six- minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

(10) EPA Method 10 – Determination of Carbon Monoxide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 10A – Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries – 40 CFR 60 Appendix .

(b) EPA Method 10B – Determination of Carbon Monoxide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(11) EPA Method 11 – Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries – 40 CFR 60 Appendix A.

(12) EPA Method 12 – Determination of Inorganic Lead Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(13) EPA Methods 13A and 13B.

(a) EPA Method 13A – Determination of Total Fluoride Emissions from Stationary Sources – SPADNS — Zirconium Lake Method – 40 CFR 60 Appendix A.

(b) EPA Method 13B – Determination of Total Fluoride Emissions from Stationary Sources – Specific Ion Electrode Method – 40 CFR 60 Appendix A.

(14) EPA Method 14 – Determination of Fluoride Emissions from Potroom Roof Monitors of Primary Aluminum Plants – 40 CFR 60 Appendix A.

(15) EPA Method 15 – Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 15A – Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries – 40 CFR 60 Appendix A.

(16) EPA Method 16 – Semicontinuous Determination of Sulfur Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 16A – Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique) – 40 CFR 60 Appendix A.

(b) EPA Method 16B – Determination of Total Reduced Sulfur Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(17) EPA Method 17 – Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method) – 40 CFR 60 Appendix A.

(18) EPA Method 18 – Measurement of Gaseous Organic Compound Emissions by Gas Chromatography – 40 CFR 60 Appendix A.

(19) EPA Method 19 – Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates – 40 CFR 60 Appendix A.

(20) EPA Method 20 – Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines – 40 CFR 60 Appendix A.

(21) EPA Method 21 – Determination of Volatile Organic Compound Leaks – 40 CFR 60 Appendix A.

(22) EPA Method 22 – Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares – 40 CFR 60 Appendix A.

(23) EPA Method 23 – Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources – 40 CFR 60 Appendix A.

(24) EPA Method 24 – Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings – 40 CFR 60 Appendix A.

(a) EPA Method 24A – Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings – 40 CFR 60 Appendix A.

(b) No change.

(25) EPA Method 25 – Determination of Total Gaseous Nonmethane Organic Emissions as Carbon – 40 CFR 60 Appendix A.

(a) EPA Method 25A – Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer – 40 CFR 60 Appendix A.

(b) EPA Method 25B -- Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer -- 40 CFR 60 Appendix A.

(26) EPA Method 26 -- Determination of Hydrogen Chloride Emissions From Stationary Sources -- 40 CFR 60, Appendix A.

(a) EPA Method 26A -- Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources - Isokinetic Method -- 40 CFR 60, Appendix A

(27) EPA Method 27 -- Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test -- 40 CFR 60 Appendix A.

(28) EPA Method 28 -- Certification and Auditing of Wood Heaters -- 40 CFR 60 Appendix A.

(a) EPA Method 28A -- Measurement of Air to Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances -- 40 CFR 60 Appendix A.

(29) EPA Method 29 -- Determination of Metals Emission from Stationary Sources -- 40 CFR 60 Appendix A.

(30) Reserved.

(31) 40 CFR 60 Appendix F -- Quality Assurance Procedures -- .

(32) EPA Method 101 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Air Streams -- 40 CFR 61 Appendix B.

(a) EPA Method 101A -- Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators -- 40 CFR 61 Appendix B.

(33) EPA Method 102 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Hydrogen Streams -- 40 CFR 61 Appendix B.

(34) EPA Method 103 -- Beryllium Screening Method -- 40 CFR 61 Appendix B.

(35) EPA Method 104 -- Determination of Beryllium Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(36) EPA Method 105 -- Determination of Mercury in Wastewater Treatment Plant Sewage Sludges -- 40 CFR 61 Appendix B.

(37) EPA Method 106 -- Determination of Vinyl Chloride Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(38) EPA Method 107 -- Determination of Vinyl Chloride Content of Inprocess Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin, Slurry, Wet Cake, and Latex Samples -- 40 CFR 61 Appendix B.

(a) EPA Method 107A -- Determination of Vinyl Chloride Content of Solvents, Resin-Solvent Solution, Polyvinyl Chloride Resin, Resin Slurry, Wet Resin, and Latex Samples -- 40 CFR 61 Appendix B.

(39) EPA Method 108 -- Determination of Particulate and Gaseous Arsenic Emissions -- 40 CFR 61 Appendix B.

(a) EPA Method 108A -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(b) EPA Method 108B -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(c) EPA Method 108C -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(40) 40 CFR 61 Appendix C -- Quality Assurance Procedures.

(41) EPA Method 201 -- Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure) -- 40 CFR 51 Appendix M.

(a) EPA Method 201A -- Determination of PM_{10} Emissions (Constant Sampling Rate Procedure) -- 40 CFR 51 Appendix M.

(42) EPA Method 202 -- Determination of Condensible Particulate Emissions from Stationary Sources -- 40 CFR 51 Appendix M.

(43) EPA Method 301 -- Field Data Validation Protocol -- 40 CFR Part 63, Appendix A.

(44) EPA Method 303 -- Coke Oven Door Emissions -- 40 CFR Part 63, Appendix A.
Specific Authority 403.061 FS.
Law Implemented 403.021, 403.031, 403.061, 403.087 FS.
History Formerly 17-2.700(6)(b), Amended 10-14-92, 6-29-93; Formerly 17-297.401; Amended 11-23-94, 1-1-96, 3-13-96, 10-7-96.

62-297.411 DEP Method 1. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)1, Formerly 17-297.411, Amended 11-23-94, Repealed 1-1-96.

62-297.412 DEP Method 2 (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)2, Formerly 17-297.412, Repealed 1-1-96.

62-297.413 DEP Method 3. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)3, Formerly 17-297.413, Repealed 1-1-96.

62-297.414 DEP Method 4. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)4, Formerly 17-297.414, Repealed 1-1-96.

62-297.415 DEP Method 5. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.a, Formerly 17-297.415; Amended 11-23-94, Repealed 1-1-96.

62-297.416 DEP Method 5A. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.b, Formerly 17-297.416, Repealed 1-1-96.

62-297.417 DEP Method 6. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)6, Formerly 17-297.417, Amended 11-23-94, Repealed 1-1-96.

62-297.418 DEP Method 7. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)7, Formerly 17-297.418, Repealed 1-1-96.

62-297.419 DEP Method 8. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)8, Formerly 17-297.419, Repealed 1-1-96.

62-297.420 DEP Method 9. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)9, Formerly 17-297.420, Amended 11-23-94, Repealed 3-13-96.

62-297.421 DEP Method 10. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)10, Formerly 17-297.421, Repealed 1-1-96.

62-297.422 DEP Method 11. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 62-2.700(6)(a)11, Formerly 17-297.422, Repealed 1-1-96.

62-297.423 EPA Method 12. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)12, Formerly 17-297.423, Amended 11-23-94, 1-1-96.

62-297.424 DEP Method 13. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)13, Formerly 17-297.424, Repealed 1-1-96.

62-297.440 Supplementary Test Procedures.
The following test procedures are adopted by reference. Copies of these documents are available from the emissions units set forth below. Copies may also be inspected at the Department's Tallahassee Office.

(1) ASTM Methods. Standard Methods published by the American Society for Testing and Materials are available from the Society at 1916 Race Street, Philadelphia, Pennsylvania 19103.

(a) ASTM D 322-67, 1972. Standard Method of Test for Dilution of Gasoline Engine Crankcase Oils.

(b) ASTM D 396-76. Standard Specification for Fuel Oils, superceding ASTM D 396-69.

(c) ASTM D 2880-76. Standard Specification for Gas Turbine Fuel Oils, superceding ASTM D 2880-71.

(d) ASTM D 975-77. Standard Specification for Diesel Fuel Oils, superceding ASTM D 975-68.

(e) ASTM D 323-72. Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method).

(f) ASTM D 97-66. Standard Test Method for Pour Point of Petroleum Oils.

(g) ASTM D 4057-88. Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(h) ASTM D 129-91. Standard Test Method for Sulfur in Petroleum Products (General Bomb Method).

(i) ASTM D 2622-94. Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry.

(j) ASTM D 4294-90. Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy.

(2) EPA Reports -- EPA occasionally publishes test methods and emission control guidelines in a report format. These documents are available (unless otherwise stated) from the National Technical Information Services, 5286 Port Royal Road, Springfield, Virginia 22216, and may be inspected at the Department's Tallahassee Office.

(a) Petroleum Liquid Storage.

1. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA 450/2-78-047, p. 5-3.

2. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed- Roof Tanks, EPA 450/2-77-036, p. 6-2.

(b) Gasoline Bulk Terminals.

1. Vapor Control System Test.

a. VOC emissions from the vapor control system shall be determined by the method given in Appendix A of EPA 450/2-77-026, except that an adequate sampling time shall be at least six (6) hours of operation. For continuous vapor processing systems at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test. For intermittent vapor processing systems, at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test and at least two full cycles of operation of the vapor processing system shall occur. This test shall be performed prior to the date of compliance and annually thereafter. Test results records shall be maintained at the terminal until the subsequent annual test shall be made available to the Department upon request.

b. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA 450/2-77-026, Appendix A. Emission Test Procedure for Tank Truck Gasoline Loading Terminals.

2. Vapor Leak Detection.

a. During loading or unloading operations at bulk terminals, there shall be no reading greater than or equal to 100 percent of the lower explosive level (LEL), measured as propane at 1 in. (2.5 centimeters) around the perimeter of a potential leak source as detected by a combustible gas detector using the procedure described in Appendix B of EPA 450/2-78-051.

b. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA 450/2-78-051, Appendix B, Gasoline Vapor Leak Detection Procedures by Combustible Gas Detector.

(c) Gasoline Service Stations.

1. Design Criteria for Stage I Vapor Control: Gasoline Service Stations, USEPA, OAQPS, ESED, November, 1975.

2. [Reserved]

(d) Non-destructive Control Devices.

1. Measurement of Volatile Organic Compounds, EPA 450/2-78-041, Attachment 3, Alternate Test for Direct Measurement of Total Gaseous Organic Compounds Using a Flame Ionization Analyzer.

2. [Reserved]

(e) Perchloroethylene Dry Cleaning Systems.

1. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA 450/2-78-050, p. 6-3, Compliance Procedures, Liquid Leakage.

2. RACT Compliance Guidance for Carbon Absorbers on Perchloroethylene Dry Cleaners. Task No. 119, Contract No. 68-01-4147. EPA, DSSE, May, 1980, pp. 8-21, Appendices A and B.

(f) Cross Recovery Determination. When determining if a kraft recovery furnace is a straight kraft or cross recovery furnace the procedure in 40 CFR 60.285(d)(3) of Subpart BB shall be used.

(3) American Conference of Governmental Industrial Hygienists, Recommended Practices -- Industrial Ventilation: A Manual of Recommended Practice. Equipment Specifications published in the 16th Edition of the Industrial Ventilation Manual (or any subsequent versions approved by the Department) are available from the American Conference of Governmental Industrial Hygienists, Committee on Industrial Ventilation, P. O. Box 16153, Lansing, Michigan 48901, and may be inspected at the Department's Tallahassee Office.

(4) American Petroleum Institute (API) Recommended Practices -- These are available from the API, 2101 L Street, Northwest, Washington, D. C. 20037

(a) API Standard 650, Welded Steel Tanks for Oil Storage, Sixth Edition, Revision 1, May 15, 1978.

(b) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February, 1980.

(c) API 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, September 1, 1977.

(5) Technical Association of the Pulp and Paper Industry (TAPPI), Test Methods -- These are available from TAPPI, P. O. Box 105113, Atlanta, Georgia 30348.

(a) TAPPI Method T.624, Analysis of Soda and Sulfate White and Green Liquors.

(b) (Reserved).

(6) Sulphur Development Institute of Canada (SUDIC) Sampling and Testing Sulphur Forms -- These are available from SUDIC, Box 950, Bow Valley Square 1, 830, 202-6 Avenue S. W., Calgary, Alberta T2P 2W6.

(a) S1-77. Collection of a Gross Sample of Sulphur.

(b) S2-77. Sieve Analysis of Sulphur Forms, except paragraph 4.3 concerning wet sieving is not adopted.

(c) S3-77. Determination of Material Finer than No. 50 (300um) Sieve in Sulphur Forms by Washing.

(d) S5-77. Determination of Friability of Sulfur Forms.

(7) EPA VOC Capture Efficiency Test Procedures. Adopted by reference is an EPA memo dated April 16, 1990 entitled, "Guidelines for Developing a State Protocol for the Measurement of Capture Efficiency." A copy can be obtained by writing to: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(a) Procedure F.1 -- Fugitive VOC Emissions from Temporary Enclosures.

(b) Procedure F.2 -- Fugitive VOC Emissions from Building Enclosures.

(c) Procedure G.1 -- Captured VOC Emissions.

(d) Procedure G.2 -- Captured VOC Emissions (dilution technique).

(e) Procedure L -- VOC in Liquid Input Stream.

(f) Procedure T -- Criteria for and Verification of Permanent or Temporary Total Enclosure.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(c); Amended 6-29-93, Formerly 17-297.440, Amended 11-23-94, 1-1-96.

62-297.450 EPA VOC Capture Efficiency Test Procedures.

(1) Applicability. The requirements set forth in Rules 62-297.450(2) and (3), F.A.C., shall apply to all regulated VOC emitting emissions units employing a control system pursuant to Rules 62-296.501 through 62-296.516, F.A.C., and Rule 62-296.800, F.A.C., except as provided in Rules 62-297.450(1)(a) and (b), F.A.C.

(a) If an owner or operator installs a Permanent Total Enclosure that meets the specifications of Procedure T, and which directs all VOC to a control device, the capture efficiency is assumed to be 100 percent, and the facility owner or operator is exempted from the requirements described in Rule 62-297.450(2) , F.A.C. This does not exempt the owner or operator from conducting any required control device efficiency test.

(b) If the owner or operator of an affected activity, process, or emissions unit uses a nondestructive control device designed to collect and recover VOC (e.g. carbon adsorber), an explicit measurement of capture efficiency is not necessary if the owner or operator is able to equate solvent usage with solvent recovery on a 24-hour (daily) basis, rather than a 30-day weighted average, and can determine this within 72 hours following each 24-hour period, and one of the following two criteria is also met:

1. The solvent recovery system (i.e., capture and control system) is dedicated to a single activity, process line, or emissions unit (e.g., one process line venting to a carbon adsorber system), or

2. The solvent recovery system controls multiple activities, process lines, or emissions units and the owner or operator is able to demonstrate that the overall control (i.e., the total recovered solvent VOC divided by the sum of liquid VOC input to all activities, process lines, or emissions units venting of the control system) meets or exceeds the most stringent emission standard applicable for any activity, process line, or emissions unit venting to the control system.

(c) If the conditions given above in Rule 62-297.450(1)(b), F.A.C., are met, the overall emission reduction efficiency of the system can be determined by dividing the recovered liquid VOC by the input liquid VOC. The general procedure for this determination is given in 40 CFR 60.433, which is adopted by reference.

(2) Specific Requirements. The capture efficiency of a capture system shall be determined using one of the following EPA procedures, or an alternate capture efficiency test procedure if approved by the Department under the provisions of Rule 62-297.620, F.A.C.

(a) Gas/gas method using a Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = Gw/(Gw + Fw)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
Gw = mass of VOC captured and delivered to control device using a Temporary Total Enclosure

F_w = mass of fugitive VOC that escapes from a Temporary Total Enclosure

Procedure G.1 or Procedure G.2 is used to obtain G_w. Procedure F.1 is used to obtain F_w.

(b) Liquid/gas method using Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F = mass of fugitive VOC that escapes from a Temporary Total Enclosure

Procedure L is used to obtain L. Procedure F.1 is used to obtain F.

(c) Gas/gas method using the building or room in which the affected activity, process, or emissions unit is located as the enclosure and in which G and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room must be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = G/(G + F \text{ sub } B)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
G = mass of VOC captured and delivered to a control device
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure G.1 or Procedure G.2 is used to obtain G. Procedure F.2 is used to obtain F_B.

(d) Liquid/gas method using the building or room in which the affected activity, process, or emissions unit located as the enclosure and in which L and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room shall be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F_B)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure L is used to obtain L. Procedure F.2 is used to obtain F sub B.

(3) Sampling Requirements. A capture efficiency test shall consist of at least three sampling runs. Each run shall cover at least one complete production cycle, but shall be at least 3 hours long. The sampling time for each run need not exceed 8 hours, even if the production cycle has not been completed.

(4) Recordkeeping and Reporting.

(a) The owner or operator of an affected activity, process, or emissions unit shall submit to the Department a list of the procedures that will be used for the capture efficiency tests at the owner or operator's facility. A copy of the list shall be kept on file at the affected facility.

(b) Required test reports shall be submitted to the Department within forty-five (45) days of the test date. A copy of the results shall be kept on file at the facility.

(c) If any physical or operational change is made to a control system, the owner or operator of the affected facility shall notify the Department of the change within ten (10) working days after making such change. The Department shall require the owner or operator of the affected activity, process, or emissions unit to conduct a new capture efficiency test if the Department has reason to believe (based on engineering calculations or empirical evidence) that a physical or operational change made to the capture system has decreased the overall emissions reduction efficiency of the system.

(d) Notwithstanding the provisions of Rule 62-297.340(1), F.A.C., the owner or operator of an affected activity, process, or emissions unit shall notify the Department thirty (30) days prior to performing any capture efficiency and/or control efficiency tests.

(e) The owner or operator of an affected activity, process, or emissions unit using a Permanent Total Enclosure shall demonstrate that this enclosure meets the requirement given in Procedure T for a Permanent Total Enclosure during any required control device efficiency test.

(f) The owner or operator of an affected activity, process, or emissions unit using a Temporary Total Enclosure shall demonstrate that this enclosure meets the requirements given in Procedure T for a Temporary Total Enclosure during any required control device efficiency test.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(7); Amended 6-29-93, Formerly 17-297.450, Amended 11-23-94, 1-1-96.

62-297.500 Continuous Emission Monitoring Requirements. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92; 6-29-93; Formerly 17-297.500; Repealed 11-23-94.

62-297.520 EPA Continuous Monitor Performance Specifications.
This rule adopts the continuous monitor performance specifications to be used where required by Department air pollution rule or air permit. The EPA performance specifications listed in this rule and contained in 40 CFR 60, Appendix B, are adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(4) Performance Specification 4--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(5) Performance Specification 4A--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(6) Performance Specification 5--Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources.

(7) Performance Specification 6--Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources.

(8) Performance Specification 7--Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: New 6-29-93, Formerly 17-297.520, Amended 11-23-94, 3-13-96.

62-297.570 Test Reports. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(8), Formerly 17-297.570, Amended 11-23-94, Repealed 3-13-96.

62-297.620 Exceptions and Approval of Alternate Procedures and Requirements.

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.

Attachment L

Attachment L

Compliance Test Report

Compliance Test Report

A compliance test report will be included with the operating permit application after construction and initial testing has been completed.

Attachment M

Attachment M

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

As a normal start up is initiated, the date and time is documented when the turbine starts firing. Turbine start up continues with a normal warm up. The date and time is documented again when the generator breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NO_x emissions are controlled and stable, the date and time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Attachment N

Attachment N

Operation and Maintenance Plan

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by the construction permit.

Attachment O

Attachment O

Unit Specific Applicable Requirements

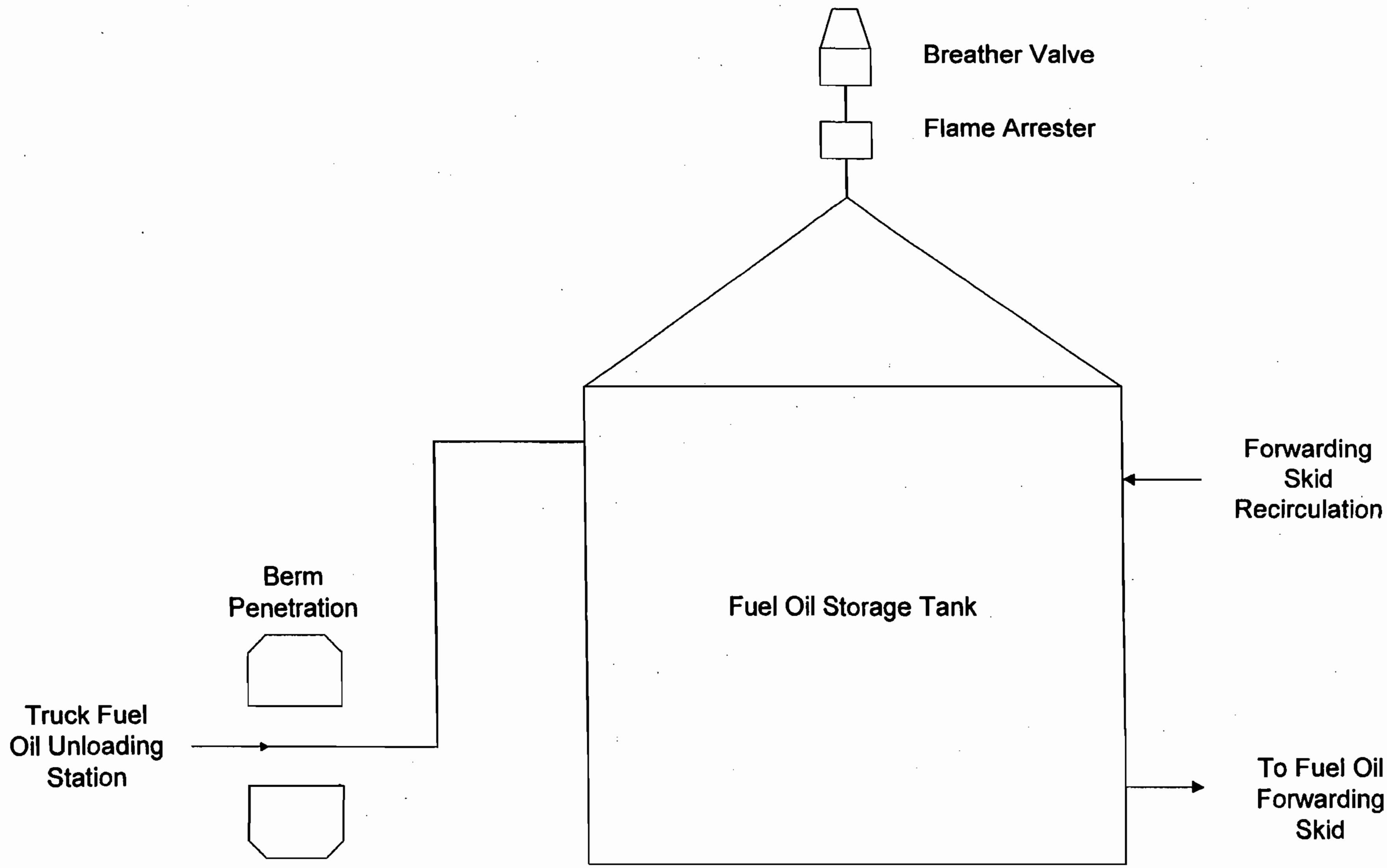
3,000,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of Operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment P

Attachment P

Process Flow Diagram



Breather Valve
Flame Arrester
Forwarding
Skid
Recirculation
Berm
Penetration
Fuel Oil Storage Tank
Truck Fuel
Oil Unloading
Station
To Fuel Oil
Forwarding
Skid

Attachment Q

Attachment Q

Emission Source Calculations

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	004
City:	Holopaw
State:	Florida
Company:	Reliant Energy Osceola, L.L.C.
Type of Tank:	Vertical Fixed Roof Tank
Description:	No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Tank Dimensions

Shell Height (ft):	32.00
Diameter (ft):	139.00
Liquid Height (ft):	28.00
Avg. Liquid Height (ft):	15.00
Volume (gallons):	3,000,000.00
Turnovers:	26.17
Net Throughput (gal/yr):	78,510,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	0.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Orlando, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	1,255.7299
Vapor Space Volume (cu ft):	402,646.0155
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9858
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	402,646.0155
Tank Diameter (ft):	139.0000
Vapor Space Outage (ft):	26.5341
Tank Shell Height (ft):	32.0000
Average Liquid Height (ft):	15.0000
Roof Outage (ft):	9.5341
Roof Outage (Dome Roof)	
Roof Outage (ft):	9.5341
Dome Radius (ft):	139.0000
Shell Radius (ft):	69.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance. (Shell):	0.1700
Tank Paint Solar Absorptance. (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft dey):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9858
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	26.5341

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Working Losses (lb):	2,494.6352
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	78,510,000.00
	00
Number of Turnovers:	26.1700
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	3,000,000.000
	0
Maximum Liquid Height (ft):	28.0000
Tank Diameter (ft):	139.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	3,750.3651

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	2,494.64	1,255.73	3,750.37