BEST AVAILABLE COPY

HARDEE POWER PARTNERS LIMITED

RECEIVED
MAR ~~ 2005
DIVISION OF AIR
RESOURCE MANAGEMENT

Invenergy

RECEIVED
APR 01 2005
BUREAU OF AIR REGULATION

Via Federal Express

March 28, 2005

Via Federal Express 7910 1981 6378

Mr. Howard Rhodes
FDEP
Division of Air Resources
Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Via Federal Express 7922 3992 9617

Mr. Joel Smolen
FDEP
Southwest District Office
3804 Coconut Palm Drive
Tampa, FL 33619-8218

Re: Hardee Power Partners Limited
Hardee Power Station
Conditions of Certification PA 89-25
Title V Air Operations Permit No. 0490015-005-AV
2004 Annual Average Capacity Factor Report

Pursuant to Special Condition A.22 of Title V Air Operations Permit No. 0490015-005-AV and Condition II.A.1 of Conditions of Certification PA 89-25, Hardee Power Partners Limited hereby submits the enclosed report providing calculations of the 2004 annual average capacity factor and cumulative lifetime average capacity factor for Hardee Power Station Units 1A, 1B, 2A, and the Steam Turbine.

Please feel free to contact Frank Sarduy at (813) 319-1244 if you have any questions regarding this information.

Sincerely,

Ralph E Randall

Ralph E. Randall
Plant Manager

Attachment

6695 North County Road 663, Bowling Green, FL 33834-6817
Phone (863) 375-4711 Fax (863) 375-2092

ANNUAL CUMULATIVE LIFETIME CAPACITY FACTOR
FOR HARDEE POWER STATION UNITS 1A, 1B, ST, 2A
FOR THE CALENDAR YEAR 2004

	UNIT	2004 ANNUAL		CUMULATIVE LIFETIME	
UNIT	CAPABILITY (MW)	MWH	CAPACITY FACTOR	MWH	CAPACITY FACTOR
CT 1A	86	145,476	19.31%	2,671,898	29.56%
CT 1B	86	147,373	19.56%	2,713,714	30.02%
Steam Turbine	81	147,029	20.72%	2,706,722	31.79%
Total CC	**253**	439,878	**19.85%**	8,092,334	**30.43%**
CT 2A	87	17,213	2.26%	732,317	8.01%
Total	**340**	457,091	**15.35%**	**8,824,651**	**24.69%**

Note: Commercial operation began January 1, 1993.

Special Conditions

A.22. On or before April 1 of each year, the Permittee shall submit to DARM and the Department's Southwest District Office an annual report for the previous year showing:

a. The annual average capacity factor (CF) for each individual generating unit;
b. The cumulative lifetime average CF for each individual generating unit;
c. The annual average CF for the Hardee Power Station; and,
d. The cumulative lifetime average CF for the Hardee Power Station.

The annual average CF shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in a year. Cumulative lifetime average CF shall be calculated by dividing the cumulative total of megawatt hours output of generation by the product of the official combined cycle megawatt rating and the cumulative period of hours since commercial operation.
[PSD-FL-140]

A.23. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each CT.
[PSD-FL-140]

A.24. Should any annual report demonstrate that the cumulative lifetime CF for the Hardee Power Station exceeds 60% at any time, the Permittee shall install SCR or another technology of equal or greater NO_x reduction capability. In no event shall any such SCR or equivalent NO_x control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 60% cumulative average CF.
[PSD-FL-140]

A.25. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type and model, output capacity, anticipated hours of operation, and the air emissions of the unit.
[PSD-FL-140]

In the folder labeled as follows there are documents, listed below, which were not reproduced in this electronic file. That folder can be found in one of the file drawers labeled <u>Supplementary Documents Drawer</u>. Folders in that drawer are arranged alphabetically, then by permit number.

Folder Name: Tampa Electric Company

Permit(s) Numbered:

PSD	FL	-	140

Period during which document was received:		Detailed Description
APPLICATION 26 SEP 1990	1.	3.5" DISKETTE WITH FILES AS REFERENCED IN A LETTER RECEIVED ON 26 SEPTEMBER 1990.

Syed —
send to
file.

~~AL for File~~
~~CCAIR~~

TECO POWER SERVICES
HARDEE POWER
PARTNERS

RECEIVED
MAR 29 1999
DIVISION OF AIR
RESOURCES MANAGEMENT

March 26, 1999

Via Certified Mail - P 705 269 413
Howard Rhodes
Florida Department of
Environmental Protection
Division of Air Resource
Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Via Certified Mail - P 705 369 414
Richard D. Garrity, Ph.D.
Florida Department of
Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RECEIVED
MAR 30 1999
BUREAU OF
AIR REGULATION

RE: Hardee Power Station
Conditions of Certification PA 89-25
Permit PSD-FL-140
Annual Average Capacity Factor and
Cumulative Lifetime Average Capacity Factor

Gentlemen:

Pursuant to Permit PSD-FL-140, Specific Condition 1 and Condition II.A.1 of Conditions of Certification PA 89-25, Hardee Power Partners hereby submits the enclosed report providing calculations of the 1998 annual average capacity factor and cumulative lifetime average capacity factor for the Hardee Power Station. This is the sixth annual capacity factor report to be submitted since commercial operation for the Hardee Power Station began on January 1, 1993.

If you need any additional information, please contact me at (813) 228-1381 or Paul Carpinone at (813) 228-4858.

Sincerely,

A. J. Jennings
for John T. Duff
Director of Operations

JTD/gdb

Enclosure

cc: Hamilton S. Oven, FDEP - Tallahassee

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
FAX (813) 228-1308
HTTP://WWW.TECOPOWERSERVICES.COM

ANNUAL CUMULATIVE LIFETIME CAPACITY FACTOR
FOR THE HARDEE POWER STATION
FOR THE CALENDAR YEAR 1998

UNIT	UNIT CAPABILITY (MW)	1998 ANNUAL		CUMULATIVE LIFETIME	
		MWH	CAPACITY FACTOR	MWH	CAPACITY FACTOR
CT 1A	86	264,528	35.11%	1,032,217	22.84%
CT 1B	86	274,285	36.41%	1,035,561	22.91%
Steam Turbine	81	272,263	38.37%	997,184	23.42%
Total CC	**253**	811,076	**36.60%**	**3,064,962**	**23.05%**
CT 2A	87	117,408	15.41%	230,140	5.03%
Total HPS	**340**	928,484	**31.17%**	**3,295,102**	**18.44%**

Note: Commercial operation began January 1, 1993.

03/25/98

```
  Change fac |  Emission unit |  Add record |  Query all EU |  Return |  eXit
                                   Emission Unit
                                                                        ARMINV50
      POINT AIRS ID 0490015  STATUS  A    OFFICE SWD   SW: TAMPA
  SITE NAME HARDEE POWER STATION               COUNTY  HARDEE
 OWNER/COMP HARDEE POWER PARTNERS,LTD

 EU ID | Stat | Description

  001  |   A  | Combustion Turbine 1A with HRSG
  002  |   A  | Combustion Turbine 1B with HRSG
  003  |   A  | Simple cycle Combustion Turbine 2A
  004  |   A  | 4.4 Million gallon #2 fuel oil tank
  005  |   C  | Unit 2B - 75 MW gas turbine

Press [ENTER] to Select this Emission Unit
Count: *5                                                              <Replace>
```

Appendix H-1, Permit History

Hardee Power Partners, Ltd.
Hardee Power Station

FINAL Permit No. 0490015-001-AV

Permit History

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date	Revised Date
001	CT-1A	PSD-FL-140/PA 89-25	02/24/92			
002	CT-1B	PSD-FL-140/PA 89-25	02/24/92			
003	CT-2A	PSD-FL-140/PA 89-25	02/24/92			
Seminole Electric Cooperative, Inc.		PA-89-25SA	08/16/95			

Notes:

{Rule 62-213.420(1)(b)2., F.A.C., allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective}

```
  Affected E.U. |  Return |  eXit
 ______________________________ Facility PPS/PSD ____________________________
 ___________________________________________________________________ARMINV07
|     POINT AIRS ID 0490015  STATUS  A    OFFICE SWD   SW: TAMPA
|  SITE NAME HARDEE POWER STATION             COUNTY   HARDEE
| OWNER/COMP HARDEE POWER PARTNERS,LTD
|____________________________________________________________________________
| PPS/PSD No  | Dt Issued   | Date Comp   | Description
|_____________|_____________|_____________|__________________________________
| PPS PA8925  | 24-FEB-1992 |             |
| PSD FL- 140 | 24-FEB-1992 |             |
|             |             |             |
|             |             |             |
|             |             |             |
|             |             |             |
|             |             |             |
|             |             |             |
|_____________|_____________|_____________|__________________________________
 Enter PPS/PSD Number with first three letter as PSD or PPS
 Count: *2                                                          <Replace>
```

TECO POWER SERVICES

HARDEE POWER PARTNERS

Clair

RECEIVED

APR 07 1998

DIVISION OF AIR
RESOURCES MANAGEMENT

March 25, 1998

Via Certified Mail - P 240 442 304
Howard Rhodes
Florida Department of
Environmental Protection
Division of Air Resource
Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Via Certified Mail - P 240 442 305
Richard D. Garrity, Ph.D.
Florida Department of
Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RE: Hardee Power Station
Conditions of Certification PA 89-25
Permit PSD-FL-140
Annual Average Capacity Factor and
Cumulative Lifetime Average Capacity Factor

Gentlemen:

Pursuant to Permit PSD-FL-140, Specific Condition 1 and Condition II.A.1 of Conditions of Certification PA 89-25, Hardee Power Partners hereby submits the enclosed report providing calculations of the 1997 annual average capacity factor and cumulative lifetime average capacity factor for the Hardee Power Station. This is the fifth annual capacity factor report to be submitted since commercial operation for the Hardee Power Station began on January 1, 1993.

If you need any additional information, please contact me at (813) 228-1381 or Paul Carpinone at (813) 228-4858.

Sincerely,

John T. Duff
Director of Operations

JTD/gdb

cc: J. Arif, BAR

Enclosure

cc: Hamilton S. Oven, FDEP - Tallahassee

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
FAX (813) 228-1308
HTTP://WWW.TECOENERGY.COM

ANNUAL CUMULATIVE LIFETIME CAPACITY FACTOR
FOR THE HARDEE POWER STATION
FOR THE CALENDAR YEAR 1997

UNIT	UNIT NET CAPABILITY (MW)	1997 ANNUAL NET MWH	1997 ANNUAL CAPACITY FACTOR	CUMULATIVE LIFETIME NET MWH	CUMULATIVE LIFETIME CAPACITY FACTOR
CT 1A	86	163,380	21.69%	767,624	20.38%
CT 1B	86	154,648	20.53%	761,211	20.21%
Steam Turbine	82	115,708	16.11%	717,845	19.99%
Total CC	**254**	**433,736**	**19.49%**	**2,246,680**	**20.19%**
CT 2A	86	25,805	3.43%	112,547	2.99%
Total HPS	**340**	**459,541**	**15.43%**	**2,359,227**	**15.84%**

Note: Commercial operation began January 1, 1993.

03/25/98

John
AL
C/AIR

HPP
HARDEE POWER PARTNERS LIMITED

Via Certified Mail - P 880 005 912

September 13, 1996

RECEIVED
SEP 17 1996
DIVISION OF AIR
RESOURCES MANAGEMENT

Howard Rhodes
Florida Department of
Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Hardee Power station
Conditions of Certification PA 89-25 - FDEP Permit No. PSD-FL-140
Annual Average Capacity Factor and
Cumulative Lifetime Average Capacity Factor
Change of Assigned Agent

Dear Mr. Rhodes:

This letter will act as notification that John T. Duff, Director Operations for Hardee Power Station, will become the assigned agent and assume the responsibilities associated with this position, including signing future environmental reports.

Michael Schuyler, the current assigned agent, is assuming other responsibilities within TECO Power Services.

If you have questions regarding this information, please call John Duff at (813) 228-1381 or Paul Carpinone at (813) 228-4858.

Sincerely,

George D. Jennings
Vice President

cc: Richard D. Garrity, FDEP - Tampa (Certified No. P 880 005 913)
L. N. Curtin

P.O. Box 111 ◦ Tampa, Florida 33601-0111 ◦ 813 / 228-1330 ◦ FAX 813 / 228-1308

HPP
HARDEE POWER PARTNERS LIMITED

CLAIR

March 26, 1996

Via Certified Mail - P 880 005 850	**Via Certified Mail - P 880 005 851**

Howard Rhodes
Florida Department of
Environmental Protection
Division of Air Resource
Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Richard D. Garrity, Ph.D.
Florida Department of
Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RE: Hardee Power Station
Conditions of Certification PA 89-25
Permit PSD-FL-140
Annual Average Capacity Factor and
Cumulative Lifetime Average Capacity Factor

Gentlemen:

Pursuant to Permit PSD-FL-140, Specific Condition 1 and Condition II.A.1 of Conditions of Certification PA 89-25, Hardee Power Partners hereby submits the enclosed report providing calculations of the 1995 annual average capacity factor and cumulative lifetime average capacity factor for the Hardee Power Station. This is the third annual capacity factor report to be submitted since commercial operation for the Hardee Power Station began on January 1, 1993.

If you need any additional information, please contact me at (813) 228-4493 or Paul Carpinone at (813) 228-4858.

Sincerely,

M.R. Schuyler
Michael R. Schuyler
Director, Project Services

MRS/gdb

Enclosure

cc: Hamilton S. Oven, FDEP - Tal.

RECEIVED
APR 01 1996
DIVISION OF AIR
RESOURCES MANAGEMENT

ANNUAL CUMULATIVE LIFETIME CAPACITY FACTOR
FOR THE HARDEE POWER STATION
FOR THE CALENDAR YEAR 1995

UNIT	UNIT NET CAPABILITY (MW)	1995 ANNUAL NET MWH	1995 ANNUAL CAPACITY FACTOR	CUMULATIVE LIFETIME NET MWH	CUMULATIVE LIFETIME CAPACITY FACTOR
CT 1A	86	207,092	27.49%	334,617	22.21%
CT 1B	86	212,706	28.23%	341,136	22.64%
Steam Turbine	82	222,741	31.01%	325,999	22.69%
Total CC	**254**	**642,539**	**14.25%**	**1,001,752**	**22.51%**
CT 2A	86	31,208	0.20%	52,543	3.49%
Total HPS	**340**	**673,747**	**10.69%**	**1,054,295**	**17.70%**

Note: Commercial operation began January 1, 1993.

03/29/95

BEST AVAILABLE COPY

HPP
HARDEE POWER PARTNERS LIMITED

Clair/Phu
~~Marty~~
File

RECEIVED
OCT 12 199
Division of Air
Resources Management

Via Express Mail

October 9, 1995

RECEIVED
OCT 12 1995
BUREAU OF
AIR REGULATION

Richard Garrity, Ph.D.
Florida Department of Environmental
Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RE: Hardee Power Partners
Hardee Power Station
Annual Compliance Test Notification
Conditions of Certification PA 89-25

Dear Dr. Garrity:

Pursuant to Condition II.A.15 of the Conditions of Certification for Hardee Power Station, please be advised that the annual compliance test will begin on Tuesday, October 24, 1995. In accordance with this condition, after the required testing is completed, a written report of the test results will be submitted to the Department within 45 days of test completion. We will notify you if there are any changes in our testing schedule.

If you need further information concerning this, please call me at (813) 228-4858.

Sincerely,

Paul L. Carpinone

Paul L. Carpinone
Project Services Manager

PLC/gdb

cc: H. Rhodes, FDEP - Tallahassee
H. Oven, FDEP - Tallahassee

P.O. Box 111 · Tampa, Florida 33601-0111 · 813 / 228-1330 · FAX 813 / 228-1308

HPP
HARDEE POWER PARTNERS LIMITED

RECEIVED
DEC 5 199/
Division of Air
Resources Management

Clair/Larry

HOWARD
12/6

Yi, please
update APIS;
forward to Clair

This is done.
yh
12/9

December 1, 1994

Via Certified Mail - P 278 134 196
Howard Rhodes
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Via Certified Mail - P 278 134 197
Dr. Richard Garrity, Ph.D.
Florida Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RE: Hardee Power Station
Conditions of Certification PA 89-25
Permit PSD-FL-140
Change of Assigned Agent

Gentlemen:

This letter will act as notification that Michael R. Schuyler will become the assigned agent and assume the responsibilities associated with this position, including signing future reports.

Gordon Gillette, the current assigned agent, has been promoted to vice president of Tampa Electric Company. Mr. Schuyler is assuming his position and responsibilities.

If you have any questions regarding this information, please call Michael Schuyler at 228-4493 or Paul Carpinone at 228-4858.

Sincerely,

George Jennings

George D. Jennings
Vice President

/gdb
cc: B. [illegible]
[illegible]

P.O. Box 111 · Tampa, Florida 33601-0111 · 813 / 228-1330 FAX 813 / 228-1308

BEST AVAILABLE COPY

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. ~~Clair Fancy~~

2. Patty

3. [illegible]

4. _____

5. _____

PLEASE PREPARE REPLY FOR:

_____ SECRETARY'S SIGNATURE

_____ DIV/DIST DIR SIGNATURE

_____ MY SIGNATURE

_____ YOUR SIGNATURE

_____ DUE DATE _____

ACTION/DISPOSITION

_____ DISCUSS WITH ME

_____ COMMENTS/ADVISE

_____ REVIEW AND RETURN

_____ SET UP MEETING

_____ FOR YOUR INFORMATION

_____ HANDLE APPROPRIATELY

_____ INITIAL AND FORWARD

_____ SHARE WITH STAFF

_____ FOR YOUR FILES

COMMENTS:

FROM: Yi

DATE: 12/9

PHONE: _____

DEP 15-026 (12/93)

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 27, 1994

Mr. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, Florida 33601-0111

Re: Hardee Power Station, PA 89-25

Dear Mr. Gillette:

The Department of Environmental Protection approved the use of either EPA Reference Method 5 or 17 for particulate testing when firing oil by my letter dated July 15, 1994. That letter also allowed the use of Method 17 when the stack temperature is less than 320° F. Particulate matter sampling is only required when firing oil. Particulate matter need not be tested when the units are operating solely on natural gas. This approval is granted pursuant to Condition II.A. 8. and to make the conditions of certification consistent with the modification of PSD Permit PSD-FL-140(A) as approved by the Division of Air Resources on September 22, 1994.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Section

cc: Clair Fancy, BAR
Bill Thomas, SWD

--ATTENTION MAIL ROOM--

PLEASE ROUTE THIS DOCUMENT TO:

Clair Fancy
Name of Individual/Office Bureau of Air Regulation

5505
Mail Station Number

RECEIVED

SEP 28 1994

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 22, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, Florida 33601-0111

Re: Hardee Power Station
Amendment to PSD-FL-140(A)

Dear Mr. Gillette:

The Department received your request for an amendment of the subject permit. The permit is amended as shown:

<u>Permit No. PSD-FL-140(A)</u>

<u>Specific Condition 8.a.</u>

FROM:

a. 5 for PM (I,A).

TO:

a. 5 **or 17** for PM (I,A, **for oil only**).

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the applicant of the amendment request/application and the parties listed below must be filed within 14 days of receipt of this amendment. Petitions filed by other persons must be filed within 14 days of the amendment issuance or within 14 days of their receipt of this amendment, whichever occurs first. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information:

(a) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the amendment request/application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this amendment in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

This letter amendment shall become an attachment to this permit, No. PSD-FL-140(A), and shall become a part of the permit.

Sincerely,

Howard L Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/SA/bjb

cc: B. Thomas, SW District
T. Davis, ECT
J. Harper, EPA
J. Bunyak, NPS

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this AMENDMENT and all copies were mailed by certified mail before the close of business on 9/23/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to 120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J Hayes — 9/23/94
Clerk — Date

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, FL 33601-0111

4a. Article Number
Z 751 859 982

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

7. Date of Delivery SEP 28 1994

5. Signature (Addressee) R. Clark

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

6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

Z 751 859 982

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to
Mr. Gordon L. Gillette

Street and No.
P. O. Box 111

P.O., State and ZIP Code
Tampa, FL 33601-0111

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date

Mailed: 9-23-94
Permit: PSD-FL-140(A)

PS Form **3800**, March 1993

Florida Department of
Environmental Protection

Memorandum

TO: Howard Rhodes

John Brown

FROM: John Brown

DATE: September 21, 1994

SUBJECT: Hardee Power Station
Amendment to PSD-FL-140(A)

Attached for your approval and signature is the PSD permit amendment as requested by Hardee Power Station for their combined cycle electrical power plant in Hardee County, Florida.

The conditions of certification were modified by Buck Oven at an earlier date. This amendment to the PSD permit will conform with the changes to the conditions of certification.

I recommend your approval and signature.

JB/SA/bjb

Attachment

BEST AVAILABLE COPY

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

June 7, 1994

Mr. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, Florida 33601-0111

Re: Hardee Power Station, PA 89-25, PSD-FL-140

Dear Mr. Gillette:

I have reviewed your letter of June 3, 1994, requesting modification of Condition II.A.8.a. to include Method 17. Condition II.A.8. contains the sentence, "Other DER approved methods may be used for compliance testing after prior DER approval." A letter of approval from the Department can be provided to authorize use of this method.

If you wish the department to proceed with a formal modification of the Condtions of Certification, then you must file the $10,000.00 modification fee as required by the statute and rule. Any unexpended funds remaining after the department's review will be returned to you.

The Division of Air Resources Management may proceed to modify the PSD permit as they see fit.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Richard Donelan
Clair Fancy
Robert Soich
Larry Curtin

RECEIVED

JUN 07 199

Bureau of
Air Regulation

Department of Environmental [redacted] Protection

Routing and Transmittal Slip

To: (Name, Office, Location)

1. ~~Clair Fancy~~ Patty

2. ~~MS 5505~~

3.

4.

Remarks: FYI

Please return to me for file

Thanks
Patty

From

Date 6-7-94

Phone 7-0472

HPP
HARDEE POWER PARTNERS LIMITED

RECEIVED

JUN 07 1994

Bureau of
Air Regulation

June 3, 1994

Via Certified Mail
P 278 132 733

Hamilton S. Oven
Siting Coordinator
Florida Department of
Environmental Protection
Marjory Stoneman Douglas Bldg.
3900 Commonwealth Boulevard
Suite 953A
Tallahassee, FL 32399-3000

Via Certified Mail
P 278 132 734

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulations
Florida Department of
Environmental Protection
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, FL 32399=2400

Re: Hardee Power Station
Conditions of Certification PA 89-25
PSD Permit PSD-FL-140
Compliance Testing for Air Emissions

Gentlemen:

As you know, the combustion turbines at Hardee Power Station (HPS) are capable of being fired on natural gas or oil. HPS uses natural gas as the primary fuel and distillate oil as a backup fuel. The Conditions of Certification and PSD-FL-140 permit were issued for the HPS on November 27, 1991 and January 4, 1991, respectively. Both the Conditions of Certification and PSD permit require that EPA reference method number 5 be used for particulate testing. Since the combustion turbine units burn primarily natural gas and only a limited amount of oil (less than 400 hours during the 12 months preceding the most recent test), testing on oil for particulates and other constituents was not required for the most recent tests completed in October 1993. Therefore, method 17 was used rather than method 5. Hardee Power Partners has discussed this methodology with several of the Department's district personnel in the air and enforcement branches and they have suggested we modify both the Conditions of Certification and the permit to best address the Department's overall requirements. A copy of that correspondence is enclosed.

Based on these discussions, we request that the Conditions of Certification be modified to reflect that for particulate testing on oil, either method 5 or 17 can be used and that no particulate testing be required on natural gas. We propose that Condition II.A.8.a. be changed to read as follows:

" a. 5 or 17 for PM (I, A, for oil only)"

It is our understanding that once this change has been accomplished, the situation described in the April 8, 1994 letter (enclosed) will be resolved and, in accordance with DEP rules, particulate testing will not be required for any of our facilities that do not burn liquid or solid fuel for a total of more than 400 hours in a federal fiscal year.

We understand that the Department has authority under the Conditions of Certification to approve this change. We also request that the PSD permit be changed to parallel the change to the Conditions of Certification. Please let us know if additional information is required.

Thank you for your cooperation.

Sincerely,

Gordon L. Gillette
Director, Project Services

GLG/gdb

Enclosure

cc: Mr. Robert Soich, Air Compliance (FDEP)
L. N. Curtin, Holland & Knight
M. Harley
P. Lewis
B. Thomas, SW Dist.,
J. Harper, EPA

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619
813-744-6100

Virginia B. Wetherell
Secretary

RECEIVED
APR 14 1994
TECO Power Services

April 8,1994

Paul L. Carpinone, P.E.
Hardee Power Partners Limited
P.O. Box 111
Tampa, Fl. 33601-0111

RE: December 1993 Hardee Power Particulate Compliance Test.

Dear Mr. Carpinone:

Hardee Power Partners performed a compliance test on units CT-1A and CT-1B on October 21st and 22nd 1993. Permit # PSD-FL-140 requires that EPA reference method 5 be used for particulate testing. Hardee Power used EPA reference method 17.

The proper method was not performed per the permit. The DEP does not allow sources to deviate from the permit prescribed methods unless an alternate sampling procedure request (ASP) received prior approval.

After discussion with Mr. Bill Thomas, P. E., Southwest District Air Program Administrator, and Mr. Donald Garrepy, District Enforcement Coordinator, it was determined that enforcement action was not warranted because of the following:

Testing must be done once every federal fiscal year starting on October 1st. This test was performed in October, Hardee Power still has until Sept. 30th. of 1994 to perform their method 5 test. Hardee Power Partners can amend their permit in the meantime, so that they only have to test for particulate when oil is burned for 400 hrs. or more. This would reflect what is in the state regulations and alleviate the need for particulate testing under the current plant operating conditions where only natural gas is burned.

Method 17 uses an in-stack filter. The Stack temperatures were around 240-250 F and velocities were not extreme. Method 5 Requires an out of stack filter temperature of 248 F + or - 25 F. There should be no difference in sample capture of particulate. 17-297.340 (1), (e) states that a particulate test is not required for any fuel burning source that, in a federal fiscal year, does not burn liquid and/ or solid fuel, other than startup, for a total of more than 400 hours. Only natural gas was burned.

Mike Harley (DEP Tall. Source Sampling and Compliance) stated that they should only have to perform a particulate test if they burned oil for 400 hrs. or more for the federal fiscal year. He feels the permit should have reflected the rules and now needs to be amended. Mr. Harely did say that they have to honor the current permit conditions in the meantime.

The Southwest District requests that Hardee Power Partners Limited apply to the DEP for a permit amendment of permit # PSD-FL-140. The permit should be amended to reflect 17-297.340 (1), (e) FAC and all testing requirements, as prescribed by the amended permit, should be strictly followed. If incorrect test methods are used in the future, enforcement action may be warranted.

The method 17 test will be accepted as an annual compliance test for this year only contingent on the amendment of permit # PSD-FL-140 reflecting the conditions of 17-297.340 (1), (e) FAC.

Sincerely,

Robert Soich

Robert Soich, Air Compliance

HPP
HARDEE POWER PARTNERS LIMITED

Via Federal Express

August 20, 1992

RECEIVED
AUG 20 1992
Division of Air
Resources Management

Mr. Howard Rhodes
Director
Division of Air Resource Management
Florida Department of Environmental
 Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Hardee Power Partners
Hardee Power Station
Initial Compliance Test Notification
Conditions of Certification PA 89-25

Dear Mr. Rhodes:

Pursuant to Condition II.A.15 of the Conditions of Certification for Hardee Power Station, please be advised that the initial sampling test will begin in approximately 30 days. In accordance with this condition, after the required sampling is completed, a written report of the test results will be submitted to the Department within 45 days of test completion. We will notify you if there are any changes in our testing schedule.

If you need further information concerning this, please call me at (813) 228-4492 or Paul Carpinone, Senior Environmental Coordinator, at (813) 228-4858.

Sincerely,

Gordon L. Gillette
Director, Project Services

PLC/gdb

P.O. Box 111 · Tampa, Florida 33601-0111 813 / 228-1330 FAX 813 / 228-1308

BEST AVAILABLE COPY

FEDERAL EXPRESS

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

2721284473

AIRBILL
PACKAGE
TRACKING NUMBER
2721284473

RECIPIENT'S COPY

1 [redacted]

Date 8/20/92
~~8/18/92~~

From (Your Name) Please Print: Gordon Gillette
Your Phone Number (Very Important): (813) [illegible]
Company: TECO POWER SERVICES CORP
Department/Floor No.: P7
Street Address: 702 N FRANKLIN ST
City: Tampa
State: FL
ZIP Required: 336[illegible]

2 To (Recipient's Name) Please Print: Howard Rhodes
Recipient's Phone Number (Very Important): ( )
Company: FDER - Division of Air Resource Mgmt.
Department/Floor No.:
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.): Twin Towers Bldg., 2600 Blair Stone Rd.
City: Tallahassee
State: FL
ZIP Required: 32399-2400

YOUR INTERNAL BILLING REFERENCE INFORMATION (optional) (First 24 characters will appear on invoice.)
T1130180003

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City
State
ZIP Required

3 PAYMENT
1 ☒ Bill Sender
2 ☐ Bill Recipient's FedEx Acct. No.
3 ☐ Bill 3rd Party FedEx Acct. No.
4 ☐ Bill Credit Card
5 ☐ Cash/Check
[redacted]

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)
11 ☐ YOUR PACKAGING
16 ☒ FEDEX LETTER*
12 ☐ FEDEX PAK*
13 ☐ FEDEX BOX
14 ☐ FEDEX TUBE

Standard Overnight (Delivery by next business afternoon. No Saturday delivery†)
51 ☐ YOUR PACKAGING
56 ☐ FEDEX LETTER*
52 ☐ FEDEX PAK*
53 ☐ FEDEX BOX
54 ☐ FEDEX TUBE

Economy Two-Day (Delivery by second business day †)
30 ☐ ECONOMY

Government Overnight (Restricted for authorized users only)
46 ☐ GOV'T LETTER
41 ☐ GOV'T PACKAGE

Freight Service (for packages over 150 lbs.)
70 ☐ OVERNIGHT FREIGHT** (Confirmed reservation required)
80 ☐ TWO-DAY FREIGHT**

† Delivery commitment may be later in some areas.
*Declared Value Limit $500.
**Call for delivery schedule.

5 DELIVERY AND SPECIAL HANDLING (Check services required)
1 ☐ HOLD FOR PICK-UP (Fill in Box H)
2 ☒ DELIVER WEEKDAY
3 ☐ DELIVER SATURDAY (Extra charge) (Not available to all locations)
4 ☐ DANGEROUS GOODS (Extra charge)
5 ☐
6 ☐ DRY ICE .... Lbs.
7 ☐ OTHER SPECIAL SERVICE
8 ☐
9 ☐ SATURDAY PICK-UP (Extra charge)
10 ☐
☐
12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

6
PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE
Total	Total	Total

DIM SHIPMENT (Chargeable Weight)
☐ lbs.
L x W x H

Received At
1 ☐ Regular Stop
2 ☐ On-Call Stop
3 ☐ Drop Box
4 ☐ B.S.C.
5 ☐ Station

Emp. No.
Date
☐ Cash Received
☐ Return Shipment
☐ Third Party
☐ Chg. To Del.
☐ Chg. To Hold
Street Address
City
State
Zip
Received By:
X
Date/Time Received
FedEx Employee Number

7 Release Signature:

RECEIVED
AUG 20 1992
Division of Air Resources Management

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 2/92
PART #137204 FXEM 6/92
FORMAT #126
126
© 1991-92 FEDEX
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HARDEE POWER PARTNERS LIMITED

Hand Delivered

August 20, 1992

Richard Garrity, Ph.D.
Florida Department of Environmental
 Regulation
Southwest District Office
4520 Oak Fair Boulevard
Tampa, FL 33610-7347

Re: Hardee Power Partners
Hardee Power Station
Initial Compliance Test Notification
Conditions of Certification PA 89-25

Dear Dr. Garrity:

Pursuant to Condition II.A.15 of the Conditions of Certification for Hardee Power Station, please be advised that the initial sampling test will begin in approximately 30 days. In accordance with this condition, after the required sampling is completed, a written report of the test results will be submitted to the Department within 45 days of test completion. We will notify you if there are any changes in our testing schedule.

If you need further information concerning this, please call me at (813) 228-4492 or Paul Carpinone, Senior Environmental Coordinator, at (813) 228-4858.

Sincerely,

Gordon L. Gillette
Director, Project Services

PLC/gdb

cc: H. C. Oven, FDER-Tallahassee
H. Rhodes, FDER-Tallahassee

P.O. Box 111 • Tampa, Florida 33601-0111 • 813 / 228-1330 • FAX 813 / 228-1308

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

February 26, 1992

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. G. D. Jennings, Jr.
Vice President
Hardee Power Partners, Limited
A Florida Limited Partnership
702 N. Franklin Street
Tampa, FL 33602

Dear Mr. Jennings:

RE: Hardee Power Station
PSD-FL-140

Please find enclosed the above referenced revised permit. It replaces the one issued on January 7, 1991. If you have any questions, please call Mr. Richard Donelan at (904)488-9730 or write to me at the above address.

Sincerely,

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

CHF/pa

Enclosure

cc: B. Thomas, SW District
J. Harper, EPA
C. Shaver, NPS
R. Donelan, OGC
B. Oven, Siting Office
L. Curtin, Esq.

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete itams 3, and 4a & b.
- 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 Fee will provide you the signature of the person delivered to and the date of delivery.

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. G.D. Jennings, Jr., V.P.
Hardee Power Partners, Ltd.
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number
P 617 884 148

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

7. Date of Delivery
MAR - 2 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-068 **DOMESTIC RETURN RECEIPT**

P 617 884 148

Certified Mail Receipt

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to G. D. Jennings	
Street & No. Hardee Power Part. Ltd	
P.O., State & ZIP Code Tampa Fl 33602	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date 2/26/92 PSD-FL-140	

PS Form **3800**, June 1990

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Carol M. Browner

FROM: Steve Smallwood

DATE: January 31, 199~~1~~2

SUBJ: Approval of Permit No. PSD-FL-140
TECO Power Services Corporation - Hardee Power Station

Attached for your approval and signature is a permit prepared by the Bureau of Air Regulation for the above mentioned company to construct a combined cycle power plant directly associated facilities with an ultimate capacity of 660 MW (nominal net). The permit is being reissued based on a court order in which the First District Court of Appeal has directed the Department to issue a permit which conforms to the conditions of the Power Plant Siting Certification. It is expected that EPA will be upset over this reissuance since the original PSD permit contained several conditions which were more stringent than those contained in the site certification.

I recommend your approval and signature.

SS/BA/plm

Attachments

Revised
Final Determination

TECO Power Services Corporation
Hardee Power Station
Hardee/Polk County
Tampa, Florida

Permit No. PSD-FL-140

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

January 31, 1991 ← Actually
Jan 31, 1992

Revised Final Determination

On January 7, 1991, TECO Power Services was issued a federally enforceable PSD permit authorizing construction of the Hardee Power Station, a 660 MW combined cycle power plant which had been certified under the Florida Electrical Power Plant Siting Act on November 27, 1991. Certain federally enforceable conditions of the PSD permit differed from conditions contained in the State certification.

Following an appeal by TECO Power Services Corporation, on December 20, 1991, the Florida First District Court of Appeal entered an order which invalidated the federally enforceable PSD permit issued by the Department because its conditions did not exactly correspond to the conditions included in the State certification. The court directed the Department to issue a PSD permit which conforms to the conditions of the State certification without regard to the federal enforceability of the conditions at issue.

In accordance with the court's order, the Department is issuing this revised permit. The Department recognizes that Specific Conditions 1 and 2 of the permit are not considered to be federally enforceable by EPA.

The Department intends to obtain an appropriate modification to the State certification as soon as possible to eliminate conflicting conditions found therein, as authorized by the court's order. The Department will then reissue its January 7, 1991, final permit to establish all federally enforceable conditions necessary for construction of this source in accordance with the State Implementation Plan for Florida.

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

PERMITTEE:
TECO Power Services Corporation
c/o Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

Permit Number: PSD-FL-140
County: Hardee/Polk
Latitude/Longitude: 22°38'02"N
81°38'02"W
Project: Hardee Power Station

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the construction of a combined cycle power plant and directly associated facilities with an ultimate capacity of 660 MW (nominal net) to be constructed in 3 phases. Phase 1-A will consist of a nominal 220 MW combined cycle unit and a 75 MW stand-alone combustion turbine. Phase 1-B will add 145 MW of generating capacity through the addition of a combustion turbine, two HRSG's and one steam electric generator, resulting in two 220 MW combined cycle units. Phase 2 will consist of a third 220 MW unit to be added at an unspecified future date. The combustion turbines will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbines will use natural gas as the primary fuel and distillate oil as the backup fuel.

Nitrogen oxides will be controlled by water injection unless the cumulative lifetime average capacity factor exceeds 60 percent. Should any annual report demonstrate that the cumulative lifetime average capacity factor exceeds 60 percent at any time, the Permittee shall install SCR or another technology of equal or greater NO_x reduction capability. The power plant site certification number for this project is PA 89-25.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Power Plant Site Certification Package PA 89-25 and its associated attachments, dated June 14, 1990.
2. Letter from EPA dated December 21, 1990.
3. DER's Final Determination dated January 4, 1991.
4. First District Court of Appeal Court Order dated December 20, 1991.
5. DER's Revised Final Determination dated January 22, 1991.

GENERAL CONDITIONS:

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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 of 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.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement 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.

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.

GENERAL CONDITIONS:

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.

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 any 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.

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.

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

GENERAL CONDITIONS:

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.

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.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, 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.

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

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT)
- (x) Determination of Prevention of Significant Deterioration (PSD)
- (x) Compliance with New Source Performance Standards (NSPS)

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 for this permit. These materials shall be retained at least three years from the date of the sample, measurement,

GENERAL CONDITIONS:

report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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.

SPECIFIC CONDITIONS:

1. On or before April 1 of each year, the Permittee shall submit to the Division of Air Resources Management and the Air Section of the Southwest District Office an annual report for the previous calendar year showing:

(a) The annual average capacity factor for each individual generating unit;
(b) The cumulative lifetime average capacity factor for each individual generating unit;
(c) The annual average capacity factor for the Hardee Power Station; and,
(d) The cumulative lifetime average capacity factor for the Hardee Power Station.

The annual average capacity factor shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in a year. Cumulative lifetime average capacity factor shall be calculated by dividing the cumulative total of megawatt hours output of generation by the product of the official combined cycle megawatt rating and the cumulative period of hours since commercial operation.

SPECIFIC CONDITIONS:

2. The Permittee shall install duct module(s) suitable for later installation of SCR equipment when constructing any combined cycle generating unit at the Hardee Power Station. Should any annual report demonstrate that the cumulative lifetime average capacity factor for the Hardee Power Station exceeds 60% at any time, the Permittee shall install SCR or another technology of equal or greater NO_x reduction capability. In no event shall any such SCR or equivalent NO_x control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 60% cumulative lifetime average capacity factor.

3. Only natural gas or No. 2 fuel oil shall be fired in the turbine.

4. The maximum heat input to each CT shall neither exceed 1268.4 MMBtu/hr while firing natural gas, nor 1312.3 MMBtu/hr while firing fuel oil (@ 32°F). Each CT's fuel consumption shall be continuously measured and recorded.

5. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following:

Pollutant	Fuel	Concentration	Emission Limitations lbs/hr/CT
NO_x	Gas	42 ppmvd @ 15% O_2	215.9
	Oil	65 ppmvd @ 15% O_2	383.8
VOC	Gas	2 ppmvd	3.6
	Oil	5 ppmvd	10.3
CO	Gas	10 ppmvd	31.3
	Oil	26 ppmvd	93.4
PM/PM_{10}	Gas	--	5.0
	Oil	--	10.0
SO_2	Gas	--	35.8
	Oil	0.3% S Oil	734.4

SPECIFIC CONDITIONS:

6. The following allowable emissions, most determined by BACT, are tabulated for PSD and inventory purposes:

Pollutant	Fuel	Concentration	Maximum Allowable Emission (@ 32°F) lbs/hr/CT
H_2SO_4 Acid Mist	Gas	---	1.6
	Oil	---	22.0 (avg)/33.7 (max)
Mercury	Gas	---	0.0144
	Oil	---	0.0039
Fluoride	Oil	---	0.0427
Beryllium	Oil	---	0.0333

NOTE: Sulfur dioxide emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

7. Visible emissions shall neither exceed 10% opacity while burning natural gas, nor 20% opacity while burning distillate oil.

8. Initial (I) compliance tests shall be performed using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1988, version of 40 CFR 60 Appendix A:

a. 5 for PM (I,A).
b. 8 for sulfuric acid mist (I, for oil only).
c. 9 for VE (I,A).
d. 10 for CO (I,A).
e. 20 for NO_x (I,A).
f. 25A for VOC (I,A).
g. 104 for Beryllium (I, for distillate oil only). A fuel analysis for Be using either Method 7090 or 7091, and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846, is also acceptable.
h. ASTM D 2880-71 for sulfur content of distillate oil (I,A).
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DER).

SPECIFIC CONDITIONS:

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. The average annual sulfur content of the No. 2 fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the No. 2 fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing all oil shipments for sulfur content using ASTM D 2880-71, and testing for nitrogen content.

10. For all generating units, water injection shall be utilized for NO_x control. The water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored for all units.

11. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each turbine. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

12. The project shall comply with all the applicable requirements of Chapter 17-2, Florida Administrative Code (F.A.C.) and the July 1, 1988, version of 40 CFR 60 Subpart GG, Gas Turbines.

13. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to DER's Bureau of Air Regulation.

14. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type/model, output capacity, anticipated hours of operation, and air emissions of the unit.

15. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days prior notice of the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southwest District office. Written reports of the tests shall be submitted to the Southwest District office within 45 days of test completion.

16. If construction does not commence on the first three units within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DER a review and, if necessary, a

SPECIFIC CONDITIONS:

modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2). Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988, version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office. Annual reports shall be submitted to the District office in accordance with F.A.C. Rule 17-2.700(7).

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NO_x emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Southwest District office and the Bureau of Air Regulation.

19. Stack sampling facilities shall be provided for both the bypass stack (CT) and the main stack (HRSG).

20. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

Issued this 24th day
of February, 1992

**STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION**

Carol M. Browner, Secretary

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

August 9, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. E. Ludwig, President
TECO Power Services Corporation
Post Office Box 111
Tampa, Florida 33601

Dear Mr. Ludwing:

Re: Transfer of Construction Permit PSD-FL-140
Hardee Power Station

The Department is in receipt of your Application for Transfer of Permit requesting the permit to construct the referenced air pollution source be transferred from TECO Power Services Corporation to Hardee Power Partners, Limited. This request is acceptable and our records for construction permit No. PSD-FL-140 have been changed to show that the new owner/operator is:

Mr. G. D. Jennings, Jr., Vice President
Hardee Power Partners, Limited,
a Florida Limited Partnership
702 N. Franklin Street
Tampa, Florida 33602

Hardee Power Partners, Limited will be responsible for the operation of the referenced facility. A copy of this letter must be filed with the referenced construction permit and shall become a part of that permit.

Sincerely,

Howard L Rhodes
for Carol M. Browner
Secretary

CMB/plm

Attachment: Application for Transfer of Permit

c: G. D. Jennings, Jr.
Jewell Harper, EPA
W. C. Thomas, SW Dist.
Larry Curtin
Richard Donelan, OGC

BEST AVAILABLE COPY

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION FOR TRANSFER OF PERMIT

Permit No. PSD-FL140 Date Issued January 7, 1991 Date Expires ______

NOTIFICATION OF SALE OR LEGAL TRANSFER

Source Name: Hardee Power Station County: Polk/Hardee
Source Location: Polk and Hardee County, Florida City: ______
Permittee Name: TECO Power Serviees Corporation Title: ______
Mailing Address: P.O. Box 111, Tampa, FL 33601

The undersigned hereby notifies the department of the sale or legal transfer of this pollution source. He further agrees to assign his rights as permittee to the applicant in the event the department agrees to the transfer of permit.

Sworn to and subscribed before me at Tampa, Florida
County of Hillsborough
this 6th day of June 1991.
Jan Hoffman
Notary Public
My Commission Expires: 6/18/91

Signature of Permittee
President
Title
Date: 6/6/91

REQUEST FOR TRANSFER OF PERMIT

Source Name: Hardee Power Station
Applicant Name: Hardee Power Partners, Limited, a Florida limited partnership Title: ______
Mailing Address: 702 North Franklin St.
Tampa, FL 33602 Telephone: (813) 228-1301
area

Project Engineer: Name: Kevin E. Fleming
Mailing Address: 702 North Franklin St.
Tampa, FL 33602 Telephone: (813) 228-1301
area

The undersigned hereby notifies the department of his having acquired title to this pollution source. He further states that he has examined the application and documents submitted by the current permittee the basis on which Permit No. ______ was issued by the department, and states that they accurately and completely describe the permitted activity or project. He further states that he is familiar with the permit, agrees to comply with its terms and conditions, and agrees to assume the rights and liabilities contained therein. He also agrees to promptly notify the department of any future change in ownership of, or responsibility for, the permitted activity or project.

Sworn to and subscribed before me at Tampa, Florida
County of Hillsborough
this 6th day of June 1991.
Jan Hoffman
Notary Public
My Commission Expires: 6/18/91

J. D. Jennings, Jr.
Signature of Applicant*
Vice President, Operations & Development
Title
Date: 6/6/91

*Attach letter of authorization if other than owner or corporate officer.

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

COMMISSION
PHYLLIS BUSANSKY
JOE CHILLURA
PAM IORIO
SYLVIA KIMBELL
JAN KAMINIS PLATT
JAMES D. SELVEY
ED TURANCHIK

FAX (813) 272-5157

ROGER P. STEWART
EXECUTIVE DIRECTOR
ADMINISTRATIVE OFFICES
AND
WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960

AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530

WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788

ECOSYSTEMS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

RECEIVED
DEC 2 1991
Division of Air
Resources Management

November 26, 1991

Ms. Cindy Phillips
Division of Air Resources Management
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Standardized Specific Conditions for SIC Group 4911

Dear Ms. Phillips:

Enclosed are copies of the process description and the specific conditions for each of the sources requested (see attached list). Some of the permits are basically identical and these are noted on the attached list.

We would like to submit permit AO29-203001 (TECO/Hookers Point Unit 1 or any of the TECO Hookers Point Units) and permit AO29-171912 (TECO/Big Bend Unit 2) as EPC/HC's concept of what an ideal permit should contain.

Sincerely,

Darrel Graziani
Chief, Air Permitting Section

bm

Attachment

cc: J. Harry Kerns, P.E., FDER SW-District

4911.SIC

APIS NO.	FACILITY	SOURCE	PERMIT NO.
40HIL29003801	TECO/HOOKERS POINT	UNIT 1 ✓ enclosed	203001
40HIL29003802	TECO/HOOKERS POINT	UNIT 2 similar to unit 1	125686
40HIL29003803	TECO/HOOKERS POINT	UNIT 3 ✓ enclosed	125687
40HIL29003804	TECO/HOOKERS POINT	UNIT 4 similar to unit 3	125689
40HIL29003805	TECO/HOOKERS POINT	UNIT 5 similar to unit 2	125690
40HIL29003806	TECO/HOOKERS POINT	UNIT 6 ✓ enclosed	125691
40HIL29003901	TECO/BIG BEND	UNIT 1 ✓ enclosed	140721
40HIL29003902	TECO/BIG BEND	UNIT 2 ✓ enclosed	171912
40HIL29003903	TECO/BIG BEND	UNIT 3 ✓ enclosed	179911
~~40HIL29003904~~	~~TECO/BIG BEND~~	~~UNIT 4~~	~~PA79-12, PSD-40-~~
40HIL29003905	TECO/BIG BEND	TURBINE 2 ✓ enclosed	174596
40HIL29003906	TECO/BIG BEND	TURBINE 3 ✓ enclosed	174611
40HIL29003907	TECO/BIG BEND	TURBINE 1 ✓ enclosed	160257
40HIL29004001	TECO/GANNON	UNIT 1 ✓ enclosed	125315
40HIL29004002	TECO/GANNON	UNIT 2 ✓ enclosed	189206
40HIL29004003	TECO/GANNON	UNIT 3 ✓ enclosed	172179
40HIL29004004-19	TECO/GANNON	UNIT 4 E & W ✓ enclosed	160269
40HIL29004005	TECO/GANNON	UNIT 5 ✓ enclosed	125993
40HIL29004006	TECO/GANNON	UNIT 6 ✓ enclosed	125992
40HIL29004007	TECO/GANNON	TURBINE ✓ enclosed	160272

For Routing To Other Than The Addressee

To: ______________________ Location: ______________________
To: ______________________ Location: ______________________
To: ______________________ Location: ______________________
From: ______________________ Date: ______________________

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: District Air Program Administrators and Local Air Program Administrators

FROM: Clair Fancy, Chief, Bureau of Air Regulation

SUBJECT: Standardized Specific Conditions for SIC Group 4911

DATE: November 13, 1991

When the Department receives delegation from EPA to implement the Title V operating permit program, all proposed major source operation source permits will be submitted to EPA for review through the Bureau of Air Regulation (BAR). To facilitate BAR's and EPA's review of these proposed permits and to ensure statewide consistency, the specific conditions for similar sources should be as standardized as possible. (Realistically each source may still have one or two specific conditions that apply uniquely to it and will have to be added to the end of the standardized list.)

The Florida Electric Power Coordinating Group (FCG) is currently lobbying to have the statutes revised to mandate that BAR process all FCG members' operation permits here in Tallahassee under the Title V program. They want to ensure statewide consistency in electric power plant permits. This is a valid concern, but BAR believes the District and Local Program offices are capable of processing these operation permits and can ensure statewide consistency by means of standardized specific conditions.

To accomplish this goal of standardized specific conditions we must first evaluate the specific conditions that are listed in existing operation permits. As Standard Industrial Classification (SIC) code group 4911 (electric services) is a major source of pollution in the state, and as the FCG has voiced concerns about statewide consistency, BAR will start by evaluating specific conditions in existing operation permits for electric services. In order to do so, BAR needs to obtain copies of the specific conditions and process descriptions from the operation permits for the sources on the attached list. This list was compiled by pulling sources from APIS with SIC code 4911 and SCC range 1-01-001-01 to 2-01-002-02.

By January 31, 1992 please submit to BAR (attn. Cindy Phillips) the following:

1. Copies of the process description (as shown on first page of permit) and the specific conditions for each of the sources on

the attached list. If some of the permits on the list are basically identical, only one of them needs to be submitted. If you don't have time to check to see whether they are identical or not, just send them all and we will sort them out here.

2. If you want to develop your own concept of what an ideal permit should look like for any of the SIC 4911 source types, please submit it.

BAR is actively encouraging District and Local Program participation in this project and will circulate draft versions for comment as they are developed. We have also told the FCG that they are welcome to make format suggestions.

This project will not be easy but the end product will be well worth the effort.

CHF/CLP

4911.CLP

APIS NO.	FACILITY	SOURCE	PERMIT NO.
10PCY03001401	GULF POWER/LANSING	UNIT 1	134885
10PCY03001402	GULF POWER/LANSING	UNIT 2	134887
10PCY03001403	GULF POWER/LANSING	PEAKING TURBINES	166927
10PCY23000301	FPC/PORT ST. JOE	GAS TURBINE	144681
10PCY32001401	GULF POWER/SHOLZ	UNIT 1	134888
10PCY32001402	GULF POWER/SHOLZ	UNIT 2	134889
10PEN17004501-03	GULF POWER/CRIST	UNITS 1-3	166928
10PEN17004504	GULF POWER/CRIST	UNIT 4	134882
10PEN17004505	GULF POWER/CRIST	UNIT 5	134883
10PEN17004506	GULF POWER/CRIST	UNIT 6	171809
10PEN17004507	GULF POWER/CRIST	UNIT 7	171806
10TLH33000101	LFC/MONTICELLO	UNIT 1	186821
10TLH37000301	COTE/HOPKINS	UNIT 1	159965
10TLH37000302-03	COTE/HOPKINS	TURBINES 1 & 2	159963
10TLH37000304	COTE/HOPKINS	UNIT 2	PA74-03
10TLH65000101-02	COTE/PURDOM	UNITS 1 & 2	159968
10TLH65000103-04	COTE/PURDOM	UNITS 3 & 4	159969
10TLH65000105	COTE/PURDOM	UNIT 5	159970
10TLH65000106	COTE/PURDOM	UNIT 6	159971
10TLH65000107	COTE/PURDOM	UNIT 7	159972
10TLH65000108-09	COTE/PURDOM	PEAKING UNITS 1 & 2	159966
APIS NO.	FACILITY	SOURCE	PERMIT NO.
30ORG48001401	FPC/RIO PINAR	PEAKING UNIT	180356
30ORL05000601	FPL/CANAVERAL	UNIT 1	132054
30ORL05000602	FPL/CANAVERAL	UNIT 2	163421
30ORL05000801-03	OUC/INDIAN RIVER	UNITS 1-3	183384
30ORL31002901	VERO BEACH	UNIT 1	184320
30ORL31002902	VERO BEACH	UNIT 2	146711
30ORL31002903	VERO BEACH	UNIT 3	142513
30ORL31002904	VERO BEACH	UNIT 4	146712
30ORL48010901-03	REEDY CREEK/EPCOT	UNITS 1-3	144040
30ORL48013701	OUC/STANTON	UNIT 1	PA81-14, PSD 84
30ORL49001401-06	FPC/OSCEOLA	PEAKING UNITS 1-6	176549
30ORL64000404	NEW SMYRNA BEACH	PEAKING UNIT 7	180656
30ORL64000901	FPL/SANFORD	UNIT 3	131230
30ORL64000902	FPL/SANFORD	UNIT 4	132055
30ORL64000903	FPL/SANFORD	UNIT 5	132060
30ORL64002002-06	FPC/TURNER	UNITS 2, 3A, 3B, 4A, 4B	185095
30ORL64002801-02	FPC/DEBARY	OIL HEATERS 1 & 2	125826
30ORL64002803-14	FPC/DEBARY	TURBINES 1-6 A&B	129252

4911.SIC

APIS NO.	FACILITY	SOURCE	PERMIT NO.
31DVL16004501	JEA/NORTHSIDE	UNIT 1	194743
31DVL16004502	JEA/NORTHSIDE	UNIT 2	178094
31DVL16004503	HEA/NORTHSIDE	UNIT 3	130950
31DVL16004506-09	JEA/NORTHSIDE	TURBINES 3-6	173886
31DVL16004513	JEA/NORTHSIDE	AUX. BOILER B	158401
31DVL16004514	JEA/NORTHSIDE	AUX. BOILER A	183584
31DVL16004601	JEA/SOUTHSIDE	UNIT 1	59259
31DVL16004602	JEA/SOUTHSIDE	UNIT 2	59260
31DVL16004603	JEA/SOUTHSIDE	UNIT 3	59261
31DVL16004604	JEA/SOUTHSIDE	UNIT 4	180744
31DVL16004605	JEA/SOUTHSIDE	UNIT 5	59262
31DVL16004610	JEA/SOUTHSIDE	AUX. BOILER	196794
31DVL16004703-06	JEA/KENNEDY	TURBINES 3-6	173880
31DVL16004708	JEA/KENNEDY	UNIT 9	59264
31DVL16004709	JEA/KENNEDY	UNIT 10	58584
31DVL16004713	JEA/KENNEDY	AUX. BOILER	183586
31DVL16023601,3,4	RING POWER CORP/PHILLIPS	GENERATORS 1-3	139233
31DVL16024001	1ST UNION BANK OF FL	(4) GENERATORS	184210
31DVL16026501-02	RING POWER CORP/SUNBEAM	GENERATORS	134475
APIS NO.	FACILITY	SOURCE	PERMIT NO.
31GVL40001101	LFC/MADISON	BOILER	179441
31JAX01000501-03	GAINESVILLE REG./KELLY	TURBINES 1-3	158797
31JAX01000506	GAINESVILLE REG./KELLY	UNIT 6	195854
31JAX01000507	GAINESVILLE REG./KELLY	UNIT 7	143846
31JAX01000508	GAINESVILLE REG./KELLY	UNIT 8	147240
31JAX01000601	GAINES. REG./DEERHAVEN	TURBINE 1	26657
31JAX01000602	GAINES. REG./DEERHAVEN	TURBINE 2	199846
31JAX01000603	GAINES. REG./DEERHAVEN	UNIT 1	147239
31JAX01000605	GAINES. REG./DEERHAVEN	UNIT 2	PA74-04
31JAX04000201-07	CITY OF STARKE	(7) GENERATORS	174353
31JAX16000101,2,4	JEA/ST. JOHN'S	UNITS 1&2, AUX. BOIL.	PA81-13
31JAX54001401-02	FPL/PUTNAM	(2) GENERATORS	PA74-01
31JAX54001602	FPL/PALATKA	UNIT 2	168027
31JAX54002501-02	SEMINOLE/PALATKA	UNITS 1 & 2	PA78-10
31JAX61000301-02	FPC/SUWANNEE	UNITS 1 & 2	189582
31JAX61000304-06	FPC/SUWANNEE	PEAKING UNITS 1,2,3	189579, PSD14
31JAX61000303	FPC/SUWANNEE	UNIT 3	189581

APIS NO.	FACILITY	SOURCE	PERMIT NO.
40HIL29003801	TECO/HOOKERS POINT	UNIT 1	203001
40HIL29003802	TECO/HOOKERS POINT	UNIT 2	125686
40HIL29003803	TECO/HOOKERS POINT	UNIT 3	125687
40HIL29003804	TECO/HOOKERS POINT	UNIT 4	125689
40HIL29003805	TECO/HOOKERS POINT	UNIT 5	125690
40HIL29003806	TECO/HOOKERS POINT	UNIT 6	125691
40HIL29003901	TECO/BIG BEND	UNIT 1	140721
40HIL29003902	TECO/BIG BEND	UNIT 2	171912
40HIL29003903	TECO/BIG BEND	UNIT 3	179911
40HIL29003904	TECO/BIG BEND	UNIT 4	PA79-12,PSD 40
40HIL29003905	TECO/BIG BEND	TURBINE 2	174596
40HIL29003906	TECO/BIG BEND	TURBINE 3	174611
40HIL29003907	TECO/BIG BEND	TURBINE 1	160257
40HIL29004001	TECO/GANNON	UNIT 1	125315
40HIL29004002	TECO/GANNON	UNIT	189206
40HIL29004003	TECO/GANNON	UNIT 3	172179
40HIL29004004-19	TECO/GANNON	UNIT 4 E & W	160269
40HIL29004005	TECO/GANNON	UNIT 5	125993
40HIL29004006	TECO/GANNON	UNIT 6	125992
40HIL29004007	TECO/GANNON	TURBINE	160272
APIS NO.	FACILITY	SOURCE	PERMIT NO.
40PNL52001101	FPC/BARTOW	UNIT 1	149126
40PNL52001102	FPC/BARTOW	UNIT 2	137121
40PNL52001103	FPC/BARTOW	UNIT 3	137123
40PNL52001104	FPC/BARTOW	PIPELINE HEATER	159575
40PNL52001105	FPC/BARTOW	PEAKING UNIT 1	167173
40PNL52001106	FPC/BARTOW	PEAKING UNIT 2	167174
40PNL52001107	FPC/BARTOW	PEAKING UNIT 3	167175
40PNL52001108	FPC/BARTOW	PEAKING UNIT 4	167172
40PNL52001201	FPC/HIGGINS	UNIT 1	137124
40PNL52001202	FPC/HIGGINS	UNIT 2	137125
40PNL52001203	FPC/HIGGINS	UNIT 3	137126
40PNL52001204	FPC/HIGGINS	PEAKING UNIT 1	137555
40PNL52001205	FPC/HIGGINS	PEAKING UNIT 2	137556
40PNL52001206	FPC/HIGGINS	PEAKING UNIT 3	137557
40PNL52001207	FPC/HIGGINS	PEAKING UNIT 4	137554
40PNL52001301	FPC/BAYBORO	PEAKING UNIT 1	167163
40PNL52001302	FPC/BAYBORO	PEAKING UNIT 2	167164
40PNL52001303	FPC/BAYBORO	PEAKING UNIT 3	167165
40PNL52001304	FPC/BAYBORO	PEAKING UNIT 4	167166

4911.SIC

APIS NO.	FACILITY	SOURCE	PERMIT NO.
40MAN41001001	FPL/MANATEE	UNIT 1	127329
40MAN41001002	FPL/MANATEE	UNIT 2	140480
40TPA09000401	FPC/CRYSTAL RIVER	BOILER	169341,PSD 7
40TPA09000402	FPC/CRYSTAL RIVER	BOILER	191820,PSD 7
40TPA09000403	FPC/CRYSTAL RIVER	UNIT 5	PA77-09
40TPA09000404	FPC/CRYSTAL RIVER	UNIT 4	PA77-09
40TPA25000901	CITY OF WAUCHULA	PEAKING UNIT 1	154883
40TPA25000902	CITY OF WAUCHULA	PEAKING UNIT 2	154882
40TPA25000903	CITY OF WAUCHULA	PEAKING UNIT 3	154881
40TPA25000904	CITY OF WAUCHULA	PEAKING UNIT 4	154880
40TPA25000905	CITY OF WAUCHULA	PEAKING UNIT 5	154879
40TPA51001701	FPC/ANCLOTE	UNIT 1	160331
40TPA51001702	FPC/ANCLOTE	UNIT 2	94924
40TPA53000301	CITY OF LAKELAND/LARSON	UNIT 4	175869
40TPA53000302	CITY OF LAKELAND/LARSON	UNIT 5	175868
40TPA53000303	CITY OF LAKELAND/LARSON	UNIT 6	175871
40TPA53000304	CITY OF LAKELAND/LARSON	UNIT 7	175870
40TPA53000305-07	CITY OF LAKELAND/LARSON	PEAKING UNITS 1,2,3	150455
40TPA53000401	LAKELAND/MCINTOSH	UNIT 1	157652, PSD 8
40TPA53000402-03	LAKELAND/MCINTOSH	PEAKING UNITS 2 & 3	158429
40TPA53000404	LAKELAND/MCINTOSH	PEAKING UNIT 1	158431
40TPA53000405	LAKELAND/MCINTOSH	UNIT 2	174090
40TPA53000406	LAKELAND/MCINTOSH	UNIT 3	PA74-06
APIS NO.	FACILITY	SOURCE	PERMIT NO.
50BRO06003601	FPL/PORT EVERGLADES	UNIT 1	143214
50BRO06003602	FPL/PORT EVERGLADES	UNIT 2	143215
50BRO06003603	FPL/PORT EVERGLADES	UNIT 3	143217
50BRO06003604	FPL/PORT EVERGLADES	UNIT 4	143212
50BRO06003605-16	FPL/PORT EVERGLADES	GENERATORS 1-12	148762
50DAD13000103-04	FPL/CUTLER RIDGE	GENERATORS	71894
50DAD13000301	FPL/TURKEY POINT	UNIT 1	155467
50DAD13000302	FPL/TURKEY POINT	UNIT 2	155471
50DAD13001308-18	HOMESTEAD CITY UTILITIES	GENERATORS	147940
50DAD13047001	S.FL.COGEN ASSOC./DADE CO.	TURBINE	127283
50PMB50004203	FPL/RIVIERA	UNIT 3	128936
50PMB50004203	FPL/RIVIERA	UNIT4	128937
50WPB43000101	FPL/MARTIN	UNIT 1	170568
50WPB43000102	FPL/MARTIN	UNIT 2	170567
50WPB56000303	FT. PIERCE UTILITIES/KING	TURBINE	175955
50WPB56000304	FT. PIERCE UTILITIES/KING	UNIT 6	113534
50WPB56000307	FT. PIERCE UTILITIES/KING	UNIT 7	112679
50WPB56000308	FT. PIERCE UTILITIES/KING	UNIT 8	112678

4911.SIC

APIS NO.	FACILITY	SOURCE	PERMIT NO.
52FTM28000303-04	FPC/AVON PARK	PEAKING UNITS 1& 2	202500
52FTM28000401	TECO/SEBRING	BOILER	139806
52FTM28001801	TECO/SEBRING AIRPORT	GENERATOR 1	154204
52FTM28001802	TECO/SEBRING AIRPORT	GENERATOR 2	154205
52FTM28002801	SEBRING UTILITIES	GENERATOR 2	125885
52FTM28002802	SEBRING UTILITIES	GENERATOR 3	125886
52FTM28002803	SEBRING UTILITIES	GENERATOR 4	125888
52FTM28002804	SEBRING UTILITIES	GENERATOR 6	125889
52FTM28002805	SEBRING UTILITIES	GENERATOR 7	125890
52FTM28002806	SEBRING UTILITIES	GENERATOR 8	125891
52FTM28002807	SEBRING UTILITIES	GENERATOR 9	125893
52FTM36000201	FPL/FT. MYERS	UNIT 1	143155
52FTM36000202	FPL/FT. MYERS	UNIT 2	143156
52FTM36000203	FPL/FT. MYERS	PEAKING UNITS 1-12	145172
52FTM36001301	FPL/BOCA GRANDE	BOILER	188595
52FTM44000206	KEY WEST/TRUMBO	GENERATOR	147179
52FTM44000301	KEY WEST/STOCK ISLAND	TURBINE	162684
52FTM44000302-04	KEY WEST/STOCK ISLAND	PEAKING UNITS 1,2,3	175804
52FTM44000401,2,6,7	FL. KYS. EL. COOP/MARATHON	GENERATORS	167945
52FTM44000403	FL. KYS. EL. COOP/MARATHON	GENERATOR 3	147446
52FTM44000404	FL. KYS. EL. COOP/MARATHON	GENERATOR 4	147447
52FTM44000405	FL. KYS. EL. COOP/MARATHON	GENERATOR 5	147448
52FTM44001301-02	CITY ELEC SYSTEM/CUDJOE	GENERATORS 2 & 3	175803

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

August 9, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. E. Ludwig, President
TECO Power Services Corporation
Post Office Box 111
Tampa, Florida 33601

Dear Mr. Ludwing:

Re: Transfer of Construction Permit PSD-FL-140
Hardee Power Station

The Department is in receipt of your Application for Transfer of Permit requesting the permit to construct the referenced air pollution source be transferred from TECO Power Services Corporation to Hardee Power Partners, Limited. This request is acceptable and our records for construction permit No. PSD-FL-140 have been changed to show that the new owner/operator is:

Mr. G. D. Jennings, Jr., Vice President
Hardee Power Partners, Limited,
a Florida Limited Partnership
702 N. Franklin Street
Tampa, Florida 33602

Hardee Power Partners, Limited will be responsible for the operation of the referenced facility. A copy of this letter must be filed with the referenced construction permit and shall become a part of that permit.

Sincerely,

Howard L Rhodes

for Carol M. Browner
Secretary

CMB/plm

Attachment: Application for Transfer of Permit

c: G. D. Jennings, Jr.
Jewell Harper, EPA
W. C. Thomas, SW Dist.
Larry Curtin
Richard Donelan, OGC

Recycled Paper

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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 next to the article number.

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. R. E. Ludwig, President
TECO Power Services Corporation
Post Office Box 111
Tampa, FL 33601

4a. Article Number
P 832 538 672

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

7. Date of Delivery
AUG 15 1991

RECEIVED
AUG 19 1991
Division of Air Resources Management

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 832 538 672

Certified Mail Receipt

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to
Mr. R. E. Ludwig, TECO Power Services

Street & No.
P. O. Box 111

P.O., State & ZIP Code
Tampa, FL 33601

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$

Postmark or Date
Mailed: 8-12-91
Permit: PSD-FL-140

PS Form **3800**, June 1990

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION FOR TRANSFER OF PERMIT

Permit No. PSD-FL140 Date Issued January 7, 1991 Date Expires

NOTIFICATION OF SALE OR LEGAL TRANSFER

Source Name: Hardee Power Station County: Polk/Hardee
Source Location: Polk and Hardee County, Florida City:
Permittee Name: TECO Power Serviees Corporation Title:
Mailing Address: P.O. Box 111, Tampa, FL 33601

The undersigned hereby notifies the department of the sale or legal transfer of this pollution source. He further agrees to assign his rights as permittee to the applicant in the event the department agrees to the transfer of permit.

Sworn to and subscribed before me at Tampa, Florida
County of Hillsborough
this 6th day of June 1991
Jan Hoffman
Notary Public
My Commission Expires: 6/18/91

Signature of Permittee
President
Title
Date: 6/6/91

REQUEST FOR TRANSFER OF PERMIT

Source Name: Hardee Power Station
Applicant Name: Hardee Power Partners, Limited, a Florida limited partnership Title:
Mailing Address: 702 North Franklin St.
Tampa, FL 33602 Telephone: (813) 228-1301
area

Project Engineer: Name: Kevin E. Fleming
Mailing Address: 702 North Franklin St.
Tampa, FL 33602 Telephone: (813) 228-1301
area

The undersigned hereby notifies the department of his having acquired title to this pollution source. He further states that he has examined the application and documents submitted by the current permittee the basis on which Permit No. ______ was issued by the department, and states that they accurately and completely describe the permitted activity or project. He further states that he is familiar with the permit, agrees to comply with its terms and conditions, and agrees to assume the rights and liabilities contained therein. He also agrees to promptly notify the department of any future change in ownership of, or responsibility for, the permitted activity or project.

Sworn to and subscribed before me at Tampa, Florida
County of Hillsborough
this 6th day of June 1991
Jan Hoffman
Notary Public
My Commission Expires: 6/18/91

J. D. Jennings Jr.
Signature of Applicant*
Vice President, Operations & Development
Title
Date: 6/6/91

*Attach letter of authorization if other than owner or corporate officer.

DER Form 17-1.201(1) Effective November 30, 1982

For Routing To Other Than The Addressee

To: ______________________ Location: ______________
To: ______________________ Location: ______________
To: ______________________ Location: ______________
From: ____________________ Date: ________________

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Howard Rhodes

FROM: Clair Fancy

DATE: August 9, 1991

SUBJ: Hardee Power Station, PSD-FL-140
Transfer of Permit

Attached for your approval and signature is a letter that will transfer the permit for the above referenced facility to Hardee Power Partners, Limited. Although this permit is currently under appeal, the Office of General Counsel has no objections to the transfer.

I recommend your signature.

CHF/kt

attachment

BEST AVAILABLE COPY

HOLLAND & KNIGHT
Law Offices
FAX COVER PAGE

Bradenton, FL 34206
(813) 747-5550
Fax: (813) 748-6945

Ft. Lauderdale, FL 33302
(305) 525-1000
Fax: (305) 463-2030

Lakeland, FL 33802
(813) 682-1161
Fax: (813) 688-1186

Miami, FL 33101
(305) 374-8500
Fax: (305) 374-1164

Orlando, FL 32802
(407) 425-8500
Fax: (407) 423-3397

Tallahassee, FL 32302
(904) 224-7000
Fax: (904) 222-8185

Tampa, FL 33601
(813) 227-8500
Fax: (813) 229-0134

Jacksonville, FL 32202
(904) 353-2000
Fax: (904) 358-1872

Washington, DC 20006
(202) 955-5550
Fax: (202) 955-5564

REPLY TO: P.O. Drawer 810
TALLAHASSEE, FL 32302

TO: Clair Fancy

FROM: LAWRENCE N. C[illegible]

CITY: ______________________

MESSAGE: ____

____

____

URGENCY OF FAX: *SUPER RUSH (Immediate)* ☒ *RUSH (Within 1 hour)* ☐

EMPLOYEE NAME: *RHONDA TIDWELL* *LOCATION:* *TALLAHASSEE* *Ext:* *5677*

Client Initial	*Number*	*Matter*	*Area Code*	*Fax #*	*Time*	*Zone*
T	*15359*	*42*		*922-6979*		
Atty. #	*No. of Pages (Inc. Cover)*	*Other Amt.*	*Area Code*	*Telephone #*	*Date (00/00/00)*	
96	*9*				*8/8/91*	

fax lnc:311

LAW OFFICES
HOLLAND & KNIGHT

[illegible] Manatee [illegible] West
P.O. Box [illegible]
Bradenton, Florida 34206
(813) 747-5550
Fax (813) 746-6846

One East Broward Blvd.
P.O. Box 14070
Fort Lauderdale, Florida 33302
(305) 525-1000
Fax (305) [illegible]

50 Independent Square
P.O. Box 52687
Jacksonville, Florida 32201
(904) 353-2000
Fax (904) 358-1872

92 Lake Wire Drive
P.O. Box 32092
Lakeland, Florida 33802
(813) 682-1161
Fax (813) 688-1186

1200 Brickell Avenue
P.O. Box 015441
Miami, Florida 33101
(305) 374-8500
Fax (305) 374-1164

[illegible] North [illegible] Avenue
P.O. Box [illegible]
Orlando, Florida 32802
(407) 425-8500
Fax (407) 425-3321

315 South Calhoun Street
[illegible]
Tallahassee, Florida 32302
(904) 224-7000
Fax (904) 224-8832

400 North Ashley
P.O. Box 1288
Tampa, Florida 33601
(813) 227-8500
Fax (813) 229-0134

Cable Address
HGK [illegible]
Telex 80 3283 Miami

888 Seventeenth Street, N.W.
Suite 900
Washington, D.C. 20006
(202) 955-5550
Fax (202) 955-5564

Please Reply To: Tallahassee

July 1, 1991

VIA HAND DELIVERY

Mr. Steve Smallwood, P.E.
Director, Division of Air
Resources Management
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Re: Request for Additional Information re: Transfer of PSD Construction Permit PSD-FL140

Dear Mr. Smallwood:

This is in response to your letter of June 20, 1991, concerning the referenced permit transfer application. By way of background, Hardee Power Partners, Limited is an entity that was formed for the purpose of undertaking power generation projects. The entity is owned by TECO Power Services, which is wholly owned by TECO Energy, Inc. TECO Energy, Inc. is also the parent corporation of Tampa Electric Company.

With respect to your four areas of inquiry, we submit the following:

1. R. E. Ludwig is President of TECO Power Services Corporation. G. D. Jennings, Jr., is Vice President of Hardee Power Partners, Limited. Mr. Jennings also is an officer of TECO Power Services Corporation.

2. The Hardee Power Station is the first project to be undertaken by Hardee Power Partners, Limited. General Electric has been retained to construct the project on a turnkey basis. An experienced project management team will supervise the activities of the construction contractors that were identified during the certification process. The

contractors' personnel are aware of the requirements of the Conditions of Certification, the PSD permit, and the NPDES permit, and are contractually bound to comply with those terms. The project management team from Hardee Power Partners, Limited will supervise the construction activities to ensure that compliance occurs. During the operation phase, experienced personnel will be responsible for the operation of the Hardee Power Station, again in accordance with the testimony provided in the site certification proceedings. The operations will be under the supervision of Charles Black, Vice President of Engineering and Construction, who is familiar with the operation of air pollution sources and particularly electrical power plants. W. T. Whale has been hired as the General Manager for the facility. Mr. Whale has over eleven years of experience operating electrical generating facilities.

3. The approximately $250,000,000 facility will be financed with a mix of debt and equity. During the construction period, expenditures will be financed solely through debt. After completion of the construction, the construction debt will be funded partly by the sale of long-term debt securities and partly with equity capital. The asset financing will be provided by a syndicate of commercial banks and the financing is scheduled to close in July. Interim funding has been provided by TECO Energy. Nearly $80,000,000 has been expended on the project to date. For your information, the Florida Public Service Commission has reviewed the assignments of rights and obligations to Hardee Power Partners, Limited and has approved the transaction. A copy of the Commission's action is enclosed for your review.

4. As stated above, the transaction has been structured in a manner that will enable the facility to be financed on a project basis. This requires that the permits be transferred to Hardee Power Partners, Limited. Hardee Power Powers is contractually bound to comply with the conditions of the permits, as reflected in the assignment agreement that previously was submitted to the Department. Of course, to the extent that those conditions are modified as a result of the pending appeal in case no. 91-300, Hardee Power Partners expects to receive the benefit of those modifications. If the appeal is unsuccessful, Hardee Power Partners will abide by the conditions as stated in the permit currently in effect. As we discussed during the certification phase, the design has been modified to accommodate the installation of the SCR technology should it become necessary in the future.

It is my understanding based upon conversations with you that there has been some concern in the legal department that the transfer of the PSD permit may somehow disadvantage the Department in the appeal. This will confirm that Hardee Power Partners, Limited, to the extent it becomes the permittee under the PSD permit, seeks only to succeed to the rights and obligations of TECO Power Services under the permit and the appeal. We do not intend to utilize the transaction as a way to gain any advantage over the Department in the appeal, and we do not wish to be disadvantaged in the appeal as a result of the transaction. As stated above, to the extent the appeal is successful, we would expect that the PSD permit would be modified to reflect that the SCR technology would have to be installed when the capacity factor exceeds a cumulative lifetime average of 60%, as is currently reflected in the Conditions of Certification. If the appeal is unsuccessful, we would expect the Conditions of Certification to be modified to reflect that SCR technology would have to be installed when the capacity factor exceeds 25%. In either case, as reflected above, the facility has been designed to accommodate the installation of the technology within the time frame specified in the Conditions of Certification and the permit.

With respect to the issue of ultimate enforcement, we would point out that Tampa Electric Company and Seminole Electric Cooperative, Inc., remain permittees under the Conditions of Certification that has been issued. Despite the fact that the PSD permit is issued in the name of the Hardee Power Partners, Limited, upon the transfer, the Conditions of Certification, we assume, will be made consistent with that PSD permit. As noted above, Hardee Power Partners, Limited, is wholly owned by TECO Energy, Inc. We do not believe that enforceability is an issue.

I hope that this satisfies the concerns as expressed in your letter. Please let me know if additional information is required.

Sincerely,

HOLLAND & KNIGHT

Lawrence N. Curtin

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LNC/rt
Enclosure
15359-42 ltr62791:311

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Notification of changes to power sales contracts by Tampa Electric Company, Seminole Electric Cooperative, Inc. and Hardee Power I, Inc. formerly known as TECO Power Services Corporation	DOCKET NO. 910633-EU ORDER NO. 24692-A ISSUED: 6/28/91

The following commissioners participated in the disposition of this matter:

THOMAS M. BEARD, Chairman
J. TERRY DEASON
BETTY EASLEY
GERALD L. GUNTER
MICHAEL McK. WILSON

AMENDATORY ORDER

Order No. 24692 Order Accepting Notification of Changes to Power Sales Agreements was improvidently issued as a Notice of Proposed Agency Action on June 21, 1991. That Order is amended by the substitution of the following Order:

ORDER ACCEPTING NOTIFICATION OF CHANGES TO POWER SALES AGREEMENTS AND ASSIGNMENT OF INTEREST

BY THE COMMISSION:

Order No. 22335, Final Order on Need Determination, issued December 22, 1989, requires Tampa Electric Company, Seminole Electric Cooperative, Inc. and TECO Power Services, Inc. to notify this Commission of any changes to the power sales agreements so that appropriate action may be taken.

On April 23, 1991 the parties notified this Commission of amendments to the power sales agreements and the assignment by TECO Power Services, Inc. of its rights and obligations under the agreements to Hardee Power Partners, Ltd.

On December 21, 1990, TECO Power Services filed an application pursuant to Section 203 of the Federal Power Act to transfer the power service agreements to Hardee Power Partners Limited and revise the revenue credit provisions of the Rate Schedules.

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The Federal Energy Regulatory Commission (FERC) has reviewed and accepted the rates contained in the power sales agreements. TECO Power Services states that the transfer of the power sales agreements to Hardee Power will not affect the rates, terms, or conditions of the agreement.

In the FERC's previous Order Granting Intervention, Denying Rehearing and Accepting Proposed Agreements, issued on November 19, 1990 in FERC Docket No. ER90-164-001, the Commission directed TECO Power Services to revise the revenue credit provisions of these rate schedules.

The revenue credit provisions of these rate schedules originally had provided that the revenues from sales to other utilities would be divided among the parties as follows:

> Power Services, 15%; Tampa Electric Company (Tampa Electric), 35%; and Seminole Electric Cooperative, Inc. (Seminole), 50%.

In conformity with the FERC's November 19th order, Power Services revised its Rate Schedules FERC Nos. 1 and 2, respectively, to allocate such revenues as follows:

> Tampa Electric, 40%, and Seminole, 60%.

The effect of the above changes from the standpoint of Tampa Electric's Customers is a beneficial one in that Tampa Electric's share of revenues from certain sales to other utilities has been increased from 35% to 40%. Seminole's share has also increased and the 15% share originally allocated to Power Services has been eliminated.

In addition to the revisions to the revenue allocation called for in the FERC Order, which were made in the Second Amendments to the Agreements, some other changes were made to the contracts to correct minor errors, none of which were substantive in nature.

In Order No. 498002, Docket No. EC 91-3-000 the FERC concluded that the proposed transfer of the power sales agreements to the Partnership will be consistent with the public interest. Additionally, a condition of the FERC order states...

> "The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, services, accounts, valuation, estimates, determinations of cost or any other matter whatsoever now pending or which may

BEST AVAILABLE COPY

> come before this Commission or any other regulatory body in the future."

We accept notification of the changes to the power sales agreements pursuant to the requirement of Order No. 22335. We accept notification of the assignment by TECO Power Services, Inc. of its interests to Hardee Power Partners, Ltd pursuant to the requirement of Order No 22335.

Based on the foregoing it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company, Seminole Electric Cooperative, Inc. and TECO Power Services Corporation have complied with the requirement of Order No. 22335 and notified the Commission of changes to the power sales contracts, including the assignment and assumption agreement between TECO Power Services, Inc. and Hardee Power Partners, Ltd. and the revenue credit provisions of the rate schedules. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission, this 28th day of JUNE, 1991.

Steve Tribble
STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

R V E

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

For Routing To Other Than The Addressee

To: ____________ Location: ____________
To: ____________ Location: ____________
To: ____________ Location: ____________
From: ____________ Date: ____________

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Steve Smallwood, P.E.
Director, Division of Air Resources Management

FROM: Richard T. Donelan, Jr.
Assistant General Counsel RTD

DATE: July 18, 1991

SUBJECT: Hardee Power Station Permit Transfer

I am responding to your memorandum dated July 11, 1991. I apologize if my memo to you of July 3, 1991, has generated any confusion as to the Hardee matter.

Larry Curtin has told me, allegedly based on conversations with you, that you do not have any substantive problem allowing the transfer of the permit as requested. If this is your policy determination, then the permit should be transferred without further ado.

Curtin has also told me, and it is also reflected in his letter responding to the July 1 completeness questions, that you have raised with him the OGC's concerns as to impact of the transfer on the pending appeal. I would appreciate it if you did not discuss issues like this with opposing counsel in cases of mine. There is no impact on the appeal, which is fully briefed. However, any conversations between you and I as to legal strategy or tactics relative to active permit challenge cases should remain confidential at all times in accordance with the Godfather's first rule: "Never tell anyone outside of the family what you are thinking." I apparently did not make this point effectively in my July 3 memo.

The point of my brief memo was to indicate that there was no legal impediment to the transfer of the Hardee Power Station PSD permit. There is only this policy question: whether the Department should facilitate TECO's Hardee Power Station financing scheme by transferring the PSD permit to another TECO entity when we know that the company does not want to apply SCR NO_x controls and is currently suing us to escape the EPA-dictated SCR requirements of the permit in question.

RTD/kjr

cc: Carol Forthman, Esquire
Buck Oven, P.E.
Clair Fancy, P.E.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor
Carol M. Browner, Secretary

June 20, 1991

Lawrence N. Curtin, Esquire
Holland & Knight
P.O. Drawer 810
Tallahassee, Florida 32302

Re: Request for Additional Information re: Transfer of
PSD Construction Permit PSD-FL140

Dear Mr. Curtin:

This letter acknowledges the Department's receipt on June 11, 1991, of DER Form 17-1.201(1), Application for Transfer of Permit, submitted on behalf of TECO Power Services Corporation and Hardee Power Partners Limited, seeking transfer of Permit Number PSD-FL140, issued January 7, 1991, to TECO Power Services Corporation. Pursuant to Rule 17-4.120(3), F.A.C., this letter is official notification to TECO Power Services Corporation and Hardee Power Partners Limited that additional information is necessary for an adequate review of this transfer request. Information is required regarding the following four areas:

1. Please clarify the corporate authority of the signatories to the Form 1.201(1). Is R.E. Ludwig President of TECO Power Services Corporation? Is G.D. Jennings, Jr., Vice President of Hardee Power Partners Limited?

2. Does Hardee Power Partners Limited currently own or operate any electric power generating facilities? Has Hardee Power Partners Limited ever been responsible for the construction and operation of a major air pollution source? If the answer to either of these questions is no, please identify the person or legal entity on whom Hardee Power Partners Limited intends to rely to ensure that Hardee Power Station is constructed and operated in compliance with the terms of the permit.

3. On what source of funds will Hardee Power Partners Limited rely to fund construction of the Hardee Power Station in accordance with the terms of the permit? Pursuant to Rule 17-4.110, F.A.C., please submit proof of financial responsibility on the part of Hardee Power Partners Limited to fulfill the permit conditions.

4. Currently pending before the First District Court of Appeal is TECO Power Services Corporation's appeal of the construction permit in question. <u>TECO Power Services Corp. v. Dept. of Environmental Regulation</u>, First DCA Case Number 91-300. In order to determine whether Hardee Power Partners Limited can provide reasonable assurance that it will fulfill the conditions of PSD-FL140, it is necessary for an authorized agent of Hardee Power Partners Limited to state in writing whether Hardee Power Partners intends to abide by the conditions of the permit as issued, including conditions related to the utilization when appropriate of NO_x control measures such as selective catalytic reduction (SCR). Please provide such a statement.

Please submit your responses, if any, to the questions contained in this letter as soon as practicable. Pursuant to Rule 17-4.120(3), F.A.C., the Department will take no further action on the transfer request until the requested additional information is received and reviewed.

Please communicate with me or Richard Donelan if there are any questions regarding this request for additional information.

Sincerely,

Steve Smallwood, P.E.
Director
Division of Air Resources
Management

SS/rdk

cc: Richard Donelan, Esquire, OGC

LAW OFFICES

HOLLAND & KNIGHT

1401 Manatee Avenue West
P. O. Box 241
Bradenton, Florida 34206
(813) 747-5550
Fax (813) 748-6945

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Fax (305) 463-2030

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Fax (904) 358-1872

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1200 Brickell Avenue
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(305) 374-8500
Fax (305) 374-1164

800 North Magnolia Avenue
P. O. Box 1526
Orlando, Florida 32802
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Fax (407) 423-3397

Barnett Bank Bldg.
P. O. Drawer 810
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(904) 224-7000
Fax (904) 224-8832

400 North Ashley
P. O. Box 1288
Tampa, Florida 33601
(813) 227-8500
Fax (813) 229-0134

Cable Address
H&K Mia
Telex 52-2233 Miami

888 Seventeenth Street, N. W.
Suite 900
Washington, D. C. 20006
(202) 955-5550
Fax (202) 955-5564

PLEASE REPLY TO:

Tallahassee
June 11, 1991

RECEIVED
JUN 11 1991
Dept. of Environmental Reg.
Office of General Counsel

<u>VIA HAND DELIVERY</u>

Richard Donelan, Esquire
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Hardee Power Station

Dear Richard:

Enclosed for processing is the application for transfer of the Hardee Power Station PSD permit. The transfer would be from TECO Power Services Corporation to Hardee Power Partners, Limited, a Florida limited partnership. As we have discussed, the financing transaction is scheduled to close in the very near future and we would appreciate any consideration you can give us in expediting this transfer.

Although the permit is currently in effect, there is an appeal pending in the Florida First District Court of Appeal, as you know. After the transfer is completed, Hardee Power Partners, Limited, will be responsible for complying with all terms and conditions of the permit as currently in effect. However, we will continue to pursue the appeal and any future modifications that may result from that, and the request for the transfer is subject to the appeal.

Thank you for your assistance in this matter.

Sincerely,

HOLLAND & KNIGHT

Larry

Lawrence N. Curtin

LNC/rt
15359-42 ltr61191:311

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Bob Martinez, Governor   Dale Twachtmann, Secretary   John Shearer, Assistant Secretary

January 7, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jerry L. Williams
Director, Environmental
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

Dear Mr. Williams:

Re: TECO/Seminole Electric
Hardee Power Station, PSD-FL-140

Please find enclosed the above referenced permit. You have the right to petition for an administrative hearing pursuant to Section 120.57, Florida Statutes, within 14 days of receipt of this permit or file a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, within 30 days from the date this permit is filed with the Clerk of the Department. Further, you may request a public hearing. Such request must be submitted within 30 days of receipt of this permit.

If you have any questions, please call Barry Andrews at 904-488-1344 or write to me at the above address.

Sincerely,

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

CHF/plm

Enclosure

c: Jewell A. Harper, EPA
William C. Thomas, SW District
Larry Curtin, Holland & Knight

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Mr. Jerry L. Williams
Tampa Electric Co.
P.O. Box 111
Tampa, Fl 33601-0111

4. Article Number
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U.S.G.P.O. 1989-234-555

PS Form 3800, June 1985

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this notice of permit and all copies were mailed before the close of buisness on 1-7-91.

FILING AND ACKNOWLEDGEMENT FILED, on this date, pursuant to §120.52(9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Dober 1-7-91

Clerk Date

Final Determination

TECO/Seminole Electric - Hardee Power Station
Hardee/Polk County, Florida

Permit No. PSD-FL-140

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

January 4, 1991

Final Determination

TECO Power Services Corporation's PSD permit application (part of the Power Plant Siting application), has been reviewed by the Division of Air Resources Management. Comments received from EPA Region IV dated December 21, 1990 (see attachment 2) are addressed below.

Modeling/Monitoring

The EPA has questioned the use of Hillsborough County urban ozone data to represent background conditions in Hardee County. While it is true that, in many areas, the maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is unlikely that such high concentrations will occur at the Hardee County site (approximately 60 km from Tampa). High ozone values in Florida typically occur under conditions of a large-scale high pressure system and a weak surface pressure gradient. This allows the land-sea breeze to dominate the local wind flow pattern. The daytime onshore flow pattern and its nighttime return flow makes it very unlikely that high readings of ozone would be found in Hardee County. The Tampa monitoring site with the highest, second-highest value (Site No. 1800-081, 1989 second-highest value of 0.103 ppm) would be expected to provide a conservative estimate for the actual background concentration at the Hardee County site. Furthermore, during the period 1988 through 1990 there are no monitors in Hillsborough County or any other nearby county that indicate a violation of the ozone standard. Therefore, the Department has concluded that onsite preconstruction monitoring for ozone is not needed.

BACT Analysis

Based on EPA's comments the Department has revised the BACT determination to exempt the gas/oil fired turbines from being equipped with selective catalytic reduction (SCR) emissions control technology for nitrogen oxides only if all of the turbines are collectively operated at a capacity factor of 25% or less, based on a twelve month rolling average. The permit has been modified such that if the 25 percent 12 month rolling average facility capacity factor be exceeded, the permittee shall within 30 months install SCR or another technology of equal or greater NOx reduction capability. Specific Conditions 1 and 2 of the Preliminary Determination will be amended to include these changes.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Bob Martinez, Governor
Dale Twachtmann, Secretary
John Shearer, Assistant Secretary

PERMITTEE:
TECO Power Services Corporation
c/o Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111

Permit Number: PSD-FL-140
County: Hardee/Polk
Latitude/Longitude: 22° 38' 02"N
81° 38' 02"E
Project: Hardee Power Station

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the construction of a combined cycle power plant and directly associated facilities with an ultimate capacity of 660 MW (nominal net) to be constructed in 3 phases. Phase 1-A will consist of a nominal 220 MW combined cycle unit and a 75 MW stand-alone combustion turbine. Phase 1-B will add 145 MW of generating capacity through the addition of a combustion turbine, two HRSG's and one steam electric generator, resulting in two 220 MW combined cycle units. Phase 2 will consist of a third 220 MW unit to be added at an unspecified future date. The combustion turbines will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbines will use natural gas as the primary fuel and distillate oil as the backup fuel.

Nitrogen oxides will be controlled by water injection unless the combined capacity of all the turbines (both combined cycle and simple cycle) exceeds 25 percent of the facility's capacity. Should any quarterly report demonstrate that the combined capacity of all the turbines (both combined cycle and simple cycle) exceeds 25 percent of the facility's capacity at any time, the Permittee shall install SCR or another technology of equal or greater NOx reduction capability. The power plant site certification number for this project is PA 89-25.

Construction shall be in accordance with the attached permit application and additional information except as other wise noted in the Specific Conditions.

Attachments are as follows:

1. Power plant site certification package PA 89-25 and its associated attachments, dated June 14, 1990.
2. Letter from EPA dated December 21, 1990.

3. DER's Final Determination dated January 4, 1991.

GENERAL CONDITIONS:

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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 of 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.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement 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.

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.

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.

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 any 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.

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.

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.

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.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, 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.

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

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT)
- (x) Determination of Prevention of Significant Deterioration (PSD)
- (x) Compliance with New Source Performance Standards

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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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.

SPECIFIC CONDITIONS:

1. Beginning with the fifth quarter of operation, the Permittee shall submit to the Bureau of Air Regulation and the Air Section, Southwest District Office, a quarterly report for the previous quarter showing:

(a) The 12 month rolling average capacity factor for each individual generating unit; and

(b) The 12 month rolling average capacity factor for the Hardee Power Station.

The 12 month rolling average capacity factor shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in the 12 month period.

2. The Permittee shall install duct module(s) suitable for later installation of SCR equipment when constructing any combined cycle generating unit at the Hardee Power Station. Should any quarterly report demonstrate that the 12 month rolling average capacity factor for the Hardee Power Station exceeds 25 percent at any time, the Permittee shall install SCR or another technology of equal or greater NOx reduction capability. In no event shall any such SCR or equivalent NOx control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 25 percent 12 month rolling average capacity factor.

3. Only natural gas or No. 2 fuel oil shall be fired in the turbine.

4. The maximum heat input to each CT shall neither exceed 1268.4 MMBtu/hr while firing natural gas, nor 1312.3 MMBtu/hr while firing fuel oil (@ 32°F). Each CT's fuel consumption shall be continuously measured and recorded.

5. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following:

Pollutant	Fuel	Emission Limitations	
		concentration	lb/hr/CT
NOx	Gas	42 ppmvd @ 15% O_2	215.9
	Oil	65 ppmvd "	383.8
VOC	Gas	2 ppmvd	3.6
	Oil	5 ppmvd	10.3
CO	Gas	10 ppmvd	31.3
	Oil	26 ppmvd	93.4
PM/PM_{10}	Gas	--	5.0
	Oil	--	10.0
SO_2	Gas	--	35.8
	Oil	0.3% S oil	734.4

6. The following allowable emissions, most determined by BACT, are tabulated for PSD and allowable inventory purposes:

Pollutant	Fuel	Maximum Allowable Emission (@ 32°F)	
		concentration	lb/hr/CT
H_2SO_4 Acid Mist	Gas	---	1.6
	Oil	---	22.0 (avg)/33.7 (max)
Mercury	Gas	---	0.0144
	Oil	---	0.0039
Fluoride	Oil	---	0.0427
Beryllium	Oil	---	0.0333

NOTE: Sulfur dioxide emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

7. Visible emissions shall neither exceed 10% opacity while burning natural gas, nor 20% opacity while burning distillate oil.

8. Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1988 version of 40 CFR 60 Appendix A:

a. 5 for PM (I,A)
b. 8 for sulfuric acid mist (I, for oil only)
c. 9 for VE (I,A)
d. 10 for CO (I,A)
e. 20 for NOx (I,A)
f. 25A for VOC (I,A)
g. 104 for Beryllium (I, for distillate oil only) A fuel analysis for Be using either Method 7090 or 7091, and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846, is also acceptable.
h. ASTM D 2880-71 for sulfur content of distillate oil (I,A)
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DER)

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. The average annual sulfur content of the No. 2 fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the No. 2 fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing all oil shipments for sulfur content using ASTM D 2880-71, and testing for nitrogen content.

10. For all generating units, water injection shall be utilized for NOx control. The water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored for all units.

11. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each turbine. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

12. The project shall comply with all the applicable requirements of Chapter 17-2, Florida Administrative Code (F.A.C.) and the July 1, 1988, version of 40 CFR 60 Subpart GG, Gas Turbines.

13. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to DER's Bureau of Air Regulation.

14. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type/model, output capacity, anticipated hours of operation, and air emissions of the unit.

15. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days prior notice of the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southwest District Office. Written reports of the tests shall be submitted to the Southwest District office within 45 days of test completion.

16. If construction does not commence on the first three units within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2). Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988 version 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office. Annual reports shall be submitted to the District office in accordance with F.A.C. Rule 17-2.700(7).

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Southwest District office and the Bureau of Air Regulation.

19. Stack sampling facilities shall be provided for both the bypass stack (CT) and the main stack (HRSG).

SPECIFIC CONDITIONS:

modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2). Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988, version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office. Annual reports shall be submitted to the District office in accordance with F.A.C. Rule 17-2.700(7).

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NO_x emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Southwest District office and the Bureau of Air Regulation.

19. Stack sampling facilities shall be provided for both the bypass stack (CT) and the main stack (HRSG).

20. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

Issued this 24th day
of February, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M Browner
Carol M. Browner, Secretary

wrong last page
for this 1991 permit
where is actual
final page?

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

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DEC 21 1990

Mr. Steve Smallwood, P.E., Director
Air Resources Management Division
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: TECO Power Services Corp. Hardee Power Station (PSD-FL-140)

Dear Mr. Smallwood:

This is to acknowledge receipt of the revised preliminary determination for the above referenced facility by letter dated December 5, 1990. We have reviewed the package as submitted and have significant comments as outlined in the following paragraphs. The issues raised in this letter are sufficient to preclude the issuance of a construction permit to TECO Power Services Corp. In order to prevent additional action by EPA, we strongly advise that you not issue this construction permit until the following issues are resolved.

MODELING/MONITORING

As noted in our comments on the permit application dated August 11, 1989, and in our comments on the preliminary determination of August 2, 1990, we indicated that preconstruction monitoring based on regional monitors was acceptable if such monitors could be found to be representative. As you know, the requirement for preconstruction monitoring under PSD regulations is not discretionary. A source may be exempted from preconstruction monitoring only if its impacts are predicted to be de minimis as defined in PSD regulations. Once the predicted impacts are determined to be greater than de minimis, a reviewing agency may allow the use of representative data in place of on-site monitoring. Such decision is made on a case-by-case basis and is not discretionary; the basis for such decision must conform to the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration."

For SO_2, the monitors located north of the site fall into the representative category and we will accept one of those monitors as fulfilling the PSD requirement for SO_2.

For ozone however, we believe the Tampa monitoring site is the most representative site based on the prevailing winds and distance to the Hardee County site. Also, since maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is possible that the background levels at the site are higher than at sites that are not downwind of the Tampa area. The purpose of PSD monitoring is to quantify the background levels in the impact area. Therefore, we do not concur that the identified monitoring sites are representative and we recommend actual preconstruction monitoring at the Hardee site or use of data from the Tampa monitoring site.

BACT ANALYSIS

In light of Region IV's previous comments on the application and preliminary determination for this source along with the permitting history for combustion turbines both in the Region and nationwide, Region IV cannot condone the BACT determination presented in the revised preliminary determination. The applicant has continually based the rejection of SCR as a NO_x control on the fact that the projected use of the facility is 25% of capacity, thereby rendering the application of SCR to be technically infeasible (when firing in the simple cycle mode) and economically unreasonable (when firing in the combined cycle mode). This is consistent with recent BACT determinations in Florida and Region IV; however, the sources in previous cases (Key West, Panda Energy, and South Carolina Electric and Gas) each accepted permit limits on hours of operation to roughly 25% of capacity.

The NESCAUM Stationary Source Committee published a recommendation in June of 1990 concerning the permitting of simple cycle turbines. This recommendation stated: "Historically, simple cycle gas turbines used in peaking service have operated, on the average, less than fifteen hundred hours per year. However, actual hours of operation in any given year can vary substantially and could easily exceed fifteen hundred hours per year." 1500 hours per year is roughly 18% of full capacity (8760 hours per year). The recommendation suggested that regulatory agencies limit the hours of operation of "peaking units" and proposed emission guidelines for sources which included limiting the hours of operation to 2500 hours per year (28.5%).

Correspondence from the applicant indicates that in addition to the predicted capacity utilization of 25%, a maximum capacity utilization of 55% is expected. In other words, the applicant proposes to utilize the facility in a cycling manner, going from peak load to mid-range to base load according to need. The August 2, 1990, preliminary determination is consistent with recent BACT determinations in that it proposed to limit the hours of operation of the source to 25% with the condition that if this capacity would be exceeded, the source would install SCR. However, the December 5, 1990, preliminary determination proposes to allow the source to operate at 60% lifetime capacity before having to install SCR. It is not acceptable to limit capacity on a 60% lifetime average such that the source could operate at 20% capacity one year and 100% capacity the next year and still not be required to apply SCR. In essence, the revised preliminary determination allows the source to operate as a base load unit without requiring add-on controls or even dry low-NO_x combustors. Furthermore, a lifetime average is not an enforceable entity.

The August 2, 1990 BACT determination for TECO required the use of wet injection and limited the hours of operation of the combined cycle units to 2190 hours per year. This is equivalent to 25% of capacity which is typical of a "peaking" unit. The simple cycle turbine of Phase IA, however, was not limited on hours of operation. In addition, the combined cycle units have the capacity to use by-pass vents and thus function as simple cycle units. It would appear, then, that the combined cycle units could operate continuously provided the hours of operation in the combined phase did not exceed 2190.

If the units are "peaking" units as the applicant previously claimed, then the combined capacity of all the units (both combined cycle and simple cycle) should be limited to 25% of facility capacity. This is in keeping with the precedent set with Key West and facilities in North and South Carolina. Otherwise, the BACT analysis would indicate the need for add-on NO_x controls.

In addition, the burner design should be evaluated for BACT. The applicant proposes to use General Electric Frame 7EA turbines. General Electric manufactures a "quiet combustor" which achieves NO_x levels of 25 ppm using wet injection when firing natural gas. Other burner designs are available which are capable of achieving equal or better emission levels with and without wet injection. For example, the South Bay Power Plant in Chula Vista, CA, has recently proposed a 140 MW combined cycle turbine with emission limits of 9 ppm NO_x and 8 ppm CO firing natural gas, using steam injection. The technology proposed is currently in practice at the Delmarva Power and Light, Hay Road Station, Delaware. NO_x emissions at this facility have been tested at lower than 25 ppm.

In any case, it does not seem appropriate to allow a simple cycle "peaking" unit to operate 8760 hours per year without a lower emission rate. Also, clarification should be given as to whether the combined cycle units will be allowed to operate in simple cycle mode.

The applicant has continually pointed to the firing of fuel oil as another drawback to implementing the use of SCR; however, as seen in publications such as the "White Paper Selective Catalytic Reduction Controls to Abate NO_x Emissions" by the Industrial Gas Cleaning Institute (November, 1989), SCR manufacturers are confident with performance on "high sulfur" fuels, and especially low sulfur distillate fuels such as proposed by the applicant.

As with the Key West permit, the permit for TECO should contain provisions to require the facility reevaluate BACT, with SCR as a minimum, in the event that the 25% capacity factor is exceeded or the source wishes to operate as other than a peaking unit. The determination made by DER staff in the August 2, 1990, document is justified and consistent with previous BACT determinations.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please do not hesitate to contact me at (404) 347-3043.

Sincerely yours,

Richard D. Green, Deputy/for

Winston A. Smith, Director
Air, Pesticides, and Toxics
Management Division

cc: TECO Hardee
B. Andrews
B. Oven
C. Fancy
B. Thomas, SW Dist
M. Zinn

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY - REGION IV
AIR, PESTICIDES AND TOXICS MANAGEMENT DIVISION
345 Courtland Street, N.E.
Atlanta, Georgia 30365
Fax Number: FTS 257-5207 or (404) 347-5207

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(preparer must number all pages)

TO: Clair Fancy ~~[illegible]~~ Oven PHONE:

ADDRESS: FAX NO. (904) 922-6979

FROM: Winston Smith PHONE: 347-~~[illegible]~~ 3043

If the following pages are received poorly, please call Angela
at FTS 257- 2904 or (404) 347- 2904

SPECIAL INSTRUCTIONS FOR RECEIVER:

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Bob Martinez, Governor | Dale Twachtmann, Secretary | John Shearer, Assistant Secretary

December 13, 1990

RECEIVED
DEC 20 1990
[illegible]

Mr. Jerry Williams
Director, Environmental
Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Re: Federal PSD Permit-Hardy Power Project

Dr. Mr. Williams:

As we discussed earlier this week, the Department plans to take final action on the federal PSD permit for the Hardy Power Project on or around December 27th. A copy of the proposed permits was mailed to EPA earlier this month for their review and comment. A thirty day public comment period required for federal PSD permits was satisfied by the notice for the site certification hearing.

The term "simultaneous" in the siting act does not mean literally simultaneously; that should be read to mean, as soon as possible after the site certification decision. EPA does not recognize the site certification as a substitute for the federal PSD permit, and therefore requires the Department as EPA's [illegible] issue a seperate PSD permit based on the results of the [illegible] certification hearing.

Our delegation agreement also calls for us to give them a reasonable time to review the proposed permit after the siting hearing has taken place. It has been customary to allow EPA thirty days to review the proposed permit before we take final action on it. In this case we have advised EPA that we need them to make an expedited review in order that we may take final action before the end of this month. It is my understanding that they are agreeable to doing that.

Should you have any additional questions on this matter, please give me a call.

Sincerely,

STEVE SMALLWOOD, P.E.
Director
Division of Air Resources
Management

SSm/tp

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Bob Martinez, Governor   Dale Twachtmann, Secretary   John Shearer, Assistant Secretary

December 17, 1990

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Ms. Harper:

RE: TECO/Seminole Electric, Hardee Power Station
PSD-FL-140

In accordance with a recent telephone conversation with Mr. Greg Worley, please find the enclosed correspondences that are not in your files for the above referenced project. The correspondence being sent is listed in chronological order as follows:

TECO letter dated April 4, 1990
TECO letter dated May 4, 1990
TECO letter dated May 18, 1990
Internal Memorandum dated June 5, 1990
TECO letter dated July 17, 1990
TECO letter dated July 18, 1990
TECO letter dated July 25, 1990
Internal Memorandum dated August 10, 1990
TECO letter dated September 26, 1990
TECO letter dated December 7, 1990

If you have questions regarding any of these correspondences, please contact Barry Andrews at (904)488-1344.

Sincerely,

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

CHF/BA/pa

Enclosures

● **SENDER:** Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.
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3. Article Addressed to:
Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

4. Article Number
P 256 395 044

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X Charles Davis

6. Signature — Agent
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P 256 395 044

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TAMPA ELECTRIC
A TECO ENERGY COMPANY

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Mr. Steve Smallwood
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Hardee Power Station

Dear Steve:

On behalf of the Hardee Power Station applicants, I would again like to thank you, Buck, Clair, Barry and the Department for your support in getting the facility approved by the Governor and Cabinet on November 27, 1990. As we discussed after the Governor and Cabinet meeting, due to contractual obligations, it is critical that construction begin on the Hardee Power Station project in early 1991. The remaining authorization required from the state is the PSD permit issued by your office.

We received today the PSD materials that were transmitted by Clair Fancy to EPA for review. We understand that the normal procedure is to provide EPA with 30 days in which to comment on the material prior to issuance of the permit. Obviously, if the 30 day period is adhered to in this case, we will not have the PSD permit in calendar 1990 and this will cause us to be behind schedule with the construction. We believe under the circumstances that the normal 30 day period can be substantially shortened, and we are requesting your assistance in accomplishing this. We will take whatever steps are required to assist in expediting the matter and will be available at your request to meet with either you or EPA to review any of the matters relating to the BACT determination of the PSD permit.

It would be useful if we could meet to discuss this in the near future. I will contact you to determine whether such a meeting can take place the week of December 10, 1990.

Thank you for your cooperation.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

JLW/ams/AA033.DOC

cc: Mr. Buck Oven, FDER
Mr. Clair Fancy, FDER
Mr. Barry Andrews, FDER
Mr. John Shearer, FDER

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Bob Martinez, Governor Dale Twachtmann, Secretary John Shearer, Assistant Secretary

December 5, 1990

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Ms. Harper:

Re: TECO/Seminole Electric - Hardee Power Station
Federal Number: PSD-FL-140

Enclosed for your review and comment is a copy of the Technical Evaluation and Preliminary Determination for the above referenced project. Please submit any comments or questions to Tom Rogers or Barry Andrews at the above address or call them at 904-488-1344 at your earliest convenience.

Sincerely,

Barry D. Andrews

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

CHF/BA/plm

Enclosure

cc: D. Thomas, SW Dist.
Holland & Knight

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NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTRUCT AND OPERATE AN ELECTRICAL POWER PLANT TO BE LOCATED NEAR WAUCHULA, FLORIDA

1. Application number PA 89-25 for certification to authorize construction and operation of an electrical power plant near Wauchula, Florida, associated transmission lines from the Hardee Power Station site to Tampa Electric Company's Pebbledale Substation, to Florida Power Corporation's Vandolah substation, and Lee County Cooperative's Lee substation, and a natural gas pipeline from the site to Florida Gas's pipeline near Polk City, is now pending before the Department of Environmental Regulation, pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S. Certification of this power plant would allow construction and operation of a new source of air pollution which would consume an increment or air quality resources. The department review has resulted in an assessment of the prevention of significant deterioration impacts and a determination of Best Available Control Technology necessary to control the emission of air pollutants from this source.

2. The proposed 1259 acre power plant site is located partly in the northwestern portion of Hardee County and partly in southwestern Polk County. The site is approximately seven and one-half miles west of Bowling Green and ten miles northwest of Wauchula. The unincorporated community of Fort Green Springs is located 2.5 miles to the south. The site will house combined cycle combustion turbines, heat recovery steam generators, electrical generators and a large cooling pond. The ultimate capacity of the site is proposed to be 660 megawatts. Associated linear facilities include three 230 kV transmission lines will connect the facility to existing Tampa Electric Company, Florida Power Corporation, and Florida Power and Light Company substations. Also, a natural gas pipeline will be constructed to the site from an existing gas pipeline north of Polk City.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application and the department's evaluation is available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Southwest District Office
4520 Live Oak Fair Boulevard
Tampa, Florida

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
South Florida District Office
2269 Bay Street
Ft. Myers, Florida

Bartow Public Library
315 E. Parker St.
Bartow, FL 33830

Lee County/Ft. Myers Public Library
2050 Lee St.
Ft. Myers, FL 33901

Desoto County Library
519 Hickory St.
Arcadia, FL 33821

Hardee County Library
315 N. 6th Ave. Suite 114
Wauchula, FL 33873

The business address of the co-applicants for the project are as follows:

Seminole Electric Cooperative, Inc.
1613 North Dale Mabry Highway
Tampa, Florida 33614

TECO Power Services Corporation
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings beginning on July 30, 1990, at 11:00 a.m., at the American Legion Post #2, 25 West Palmetto Street, Wauchula, Florida, on July 31, at 9:00 a.m., at the Hardee County Courthouse, County Commission Meeting Room, 412 West Orange Street, Wauchula, and on August 1, 9:00 a.m., American Legion Post #2, Wauchula, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. Need for the facility has been predetermined by the Public Service Commission at a separate hearing.

5. When appropriate, any person may be given an opportunity to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

6. Notices or petitions made prior to the hearing should be made in writing to:

Mr. Donald D. Conn
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

Copies of such submittals should be forwarded by mail to existing parties, including the Department of Environmental Regulation.

7. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S., or Chapter 17-103.020, F.A.C.

8. On June 30, 1989, TECO Power Services , Tampa Electric Company and Seminole Electric Cooperative, Inc. applied to the DER to construct the aforementioned power plant. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21, and Florida Administrative Code Chapter 17-2.04. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from DER Such permit can only be issued if the new construction has been determined by DER to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21 and 17-2.04, F.A.C. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-hr Average	3-hr Average
Particulate	4.7%	21.6%	
Sulfur Dioxide	41.5%	~~72.5%~~	82.8%
Nitrogen Dioxide	23.6%	--	--

The source is located more than 100 kilometers from the nearest Class I area.

Construction and operation of the source will not cause a violation of any ambient air quality standard nor will it cause an exceedance of any PSD increment.

9. This Public Notice is also provided in compliance with the Federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. Pursuant to Section 403.509 (2), F.S. Tampa Electric Company or Seminole Electric Cooperative, Inc. intends to use, connect to or cross over properties of the Florida Game and Fresh Water Fish Commission, Florida Department of Transportation and Trustees of the Internal Improvement Trust Fund.

11. Pursuant to Section 403.511 (2), F.S. Teco Power Services, and Seminole Electric Cooperative, Inc. seek a variance from Section 16C-16.0051, F.A.C., Department of Natural Resources for the purposes of constructing a cooling reservoir on mined lands subject to reclamation.

TABLE OF CONTENTS

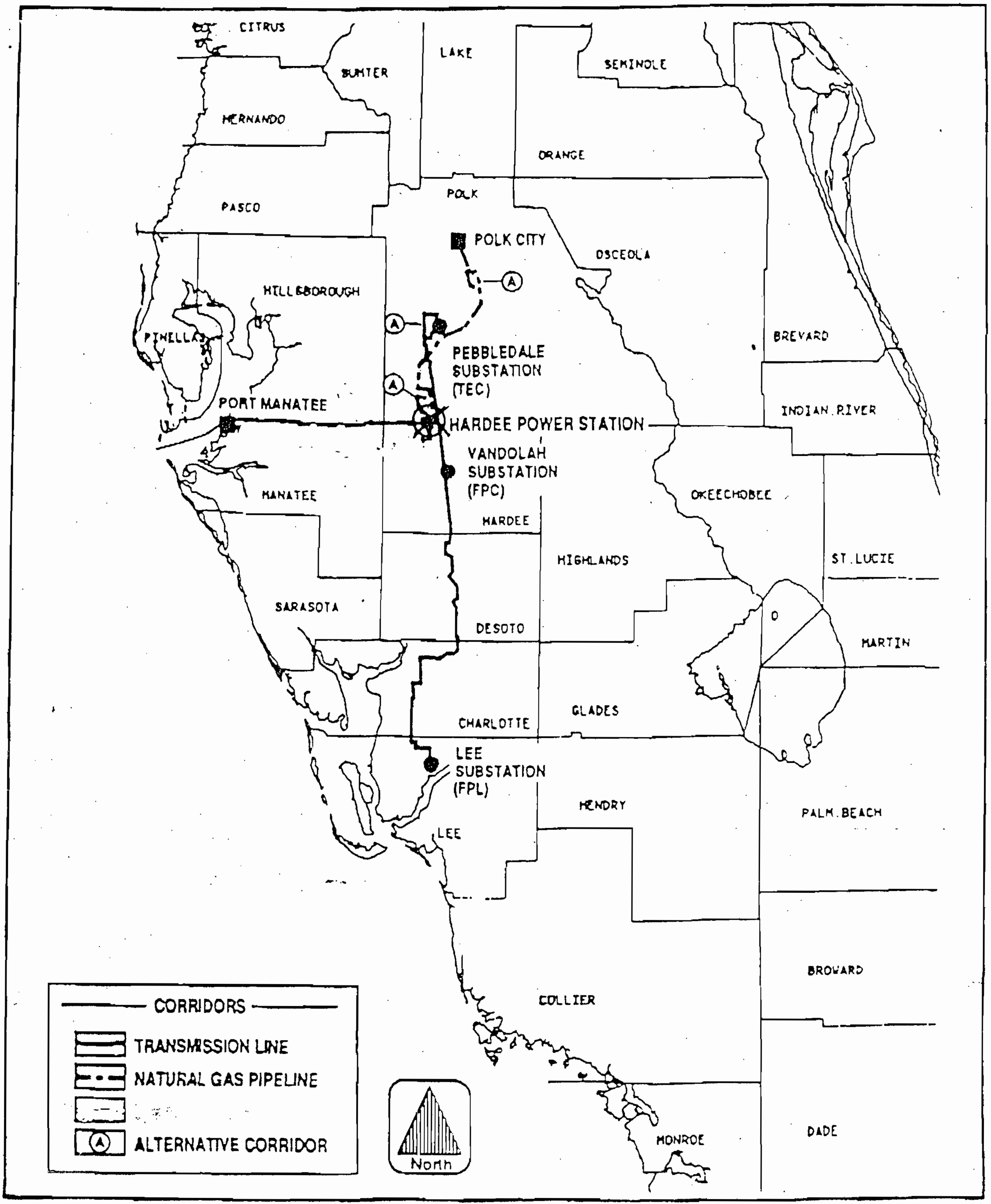
Technical Evaluation
and
Preliminary Determination

TECO/Seminole Electric - Hardee Power Station
Hardee/Polk County, Florida

Permit No. PSD-FL-140

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

August 10, 1990



HARDEE POWER STATION AND ASSOCIATED FACILITIES

TECO POWER SERVICES

TAMPA ELECTRIC COMPANY

SEMINOLE ELECTRIC
COOPERATIVE, INC.

State of Florida Department of Environmental Regulation
TECO Power Services/Seminole Electric Cooperative, Inc.
Tampa Electric Company
Hardee Power Station
Electric Power Plant Site Certification Review Case No. PA 89-25

I. SUMMARY

Facilities Overview

TECO Power Services, Inc, (TPS) Tampa Electric Company (TECO) in partnership with Seminole Electric Cooperative, Inc. (SECI) proposes to certify a power plant site that will ultimately house a 660 megawatt (MW), gas fired power plant. The first phase of the project will be a 295 MW combination of combustion turbines coupled with heat recovery steam generators. The generating plant will be constructed on property now owned by Agrico as part of their phosphate mining operations. The project is known as the Hardee Power Station. The generating units would be tied into the TECO, Florida Power Corporation (FPC) and Lee County Cooperative electric power networks via new transmission lines. Three 230 KV lines will be necessary to transmit the power from the plant to existing TECO, FPC, and Lee County Cooporative substations. Fuel delivery for the combustion turbines will be by natural gas pipeline from the Florida Gas Transmission System pipeline north of Polk City. A back up fuel supply of light oil will be trucked to the site.

Approximately 1300 acres of land would be required for the operation of the Hardee Station. This would be due to in part to the need for constructing a 570 acre cooling reservoir on mined over phosphate land. Land space is also being reserved in the event that coal gasification might become economically feasible in the future.

The Hardee Station will utilize a fresh water cooling reservoir with only emergency overflow discharge to Payne Creek during periods of high rainfall. Plant service water and cooling water would come from wells into the Floridian Aquifer. Rainfall will be a supplementary source of cooling water. Plant wastewaters would be pumped to wastewater treatment units with ultimate disposal to the cooling reservoir.

Air Impacts

Based on the proposed air pollutant control technologies, it is expected that the Hardee Power Station and associated facilities will use the best available control systems. Analysis of the predicted effects of plant emission indicates that no significant air quality impacts should occur.

Besides the biota already discussed in previous paragraphs, other species which are considered endangered or threatened at the site or transmission line corridors include the American alligator, the gopher tortoise, Florida gopher frog, the eastern indigo snake, wood stork, red cockaded woodpecker, and bald eagle.

The Florida Gopher Tortoise is a species of unique ecological value since Gopher Tortoise burrows provide a habitat for no less than 30 animal species, some of which can live nowhere else. Among these commensals inhabiting the dens are the Florida Gopher Frog (RARE), that emerges from these burrows only at night. No data is available on the number of these snakes living in gopher tortoise burrows at the HPS or corridors.

VI. FACILITY SPECIFIC CONCERNS

A. Air quality

1. Selected Fuel

The primary fuel for the HPS is natural gas. Light oil will be used as a backup fuel. Provisions are being made to leave room on site for a coal gasification unit as a future source of fuel.

2. Air Quality Impact Analysis

The proposed Hardee Power Station, located in northwest Hardee County, will emit in PSD-significant amounts nine pollutants. These pollutants include the criteria pollutants carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O3) (of which volatile organic compounds (VOC) are the regulated pollutant), particulate matter (PM and PM_{10}), and sulfur dioxide (SO_2), and the non-criteria pollutants beryllium (Be), mercury (Hg), and sulfuric acid mist.

The air quality impact analysis required by the PSD regulations for these pollutants include:

- An analysis of existing air quality;
- A PSD increment analysis (NO2, PM and SO2 only);
- An Ambient Air Quality Standards (AAQS) analysis;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality impacts; and
- A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The AAQS analysis depends on the air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department has reasonable assurance that the proposed sources at the Hardee Power Station, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any ambient air quality standard or PSD increment. A discussion of the modeling methodology and required analysis follows.

Modeling Methodology

For the screening modeling analysis, model results were calculated for a range of operating conditions for which the maximum ground-level impacts would be expected to occur. These operating conditions were based on either the facility's maximum emissions or on its minimum flow rate. The maximum predicted concentrations occurred when the minimum flow rate operating condition was modeled.

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the air quality impact analysis. This 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 and transformation. The ISCST 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 in each modeling scenario.

The modeling used a radial receptor grid with the center of the grid coinciding with the center of the proposed facility. Radials were spaced at 10 degree increments from 10 to 360 degrees. The grid for the near-field receptors consisted of 308 receptors located at distances of 600, 900, 1250, 2250, 2750, 3500, 4500, and 6000 meters. For the directions of 10 through 160 degrees, receptors at a downwind distance of 600 meters from the proposed facility were not included in the modeling analysis because these receptors are on plant property. The grid for the plant property consisted of 36 discrete receptors.

After the screening modeling was completed, refined short-term modeling was conducted using a receptor grid centered on the receptor which had the highest, second-highest short-term concentrations. The receptors were located at intervals of 100 meters between the distances considered in the screening phase along nine radials, at two degree increments, centered on the radial which produced the maximum concentration.
Meteorological data used in the modeling consisted of five years (1982-1986) of hourly surface data taken at Tampa, Florida. Mixing heights used in the modeling were based on upper air data from Ruskin (near Tampa), Florida.

Table 1 lists the significant and net emission rates for the proposed facility. Table 2 lists the stack parameters for the proposed facility for the operating condition that produced the highest ground-level concentrations. Table 2 also lists the SO2 emission rate which produced the maximum predicted ground-level SO2 concentrations. It should be noted that the modeled SO2 emissions were specific for each operating condition because the maximum predicted SO2 concentrations were relatively high when compared to PSD Class II increments. For the other pollutants, the emissions from Case 1, which had the highest emissions among the cases, were modeled for all four operating cases; therefore, the maximum impacts predicted for cases 2 through 4 are conservative (lower impacts would be predicted if the emissions associated with each case were modeled). The emission rates for the other modeled pollutants are presented in the original application.

Table 1. Significant and Net Emission Rates (Tons per Year)

Pollutant	Significant Emission Rate	Existing Emissions	Proposed Maximum Emissions	Net Emissions	Applicable Pollutant (Yes/No)
CO	100	0	2810	2810	Yes
NO2	40	0	8405	8405	Yes
SO2	40	0	16083	16083	Yes
PM	25	0	1250	1250	Yes
PM10	15	0	1250	1250	Yes
VOC	40	0	450	450	Yes
Lead	0.6	0	0.25	0.25	No
Be	0.0004	0	0.072	0.072	Yes
Hg	0.1	0	0.32	0.32	Yes
Fluoride	1.0	0	0.93	0.93	No
Sulfuric Acid Mst	7	0	738	738	Yes

Table 2. Stack Parameters for Proposed SO2 Sources.

Source	Emission Rate (g/s)	Height (m)	Exit Temp (K)	Exit Vel (m/s)	Diameter (m)
Facility	345	23	389	16.5	4.9

The Hardee facility was modeled as three identical units separated by 100 meters in a north-south line. The emission rate presented in Table 2 is the total emission of SO2 from the facility.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data exists and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The predicted ambient impact of the proposed facility for those pollutants subject to PSD review are listed in Table 3. Sulfuric acid mist is not listed because there is no de minimus level for this pollutant. However, an estimate of sulfuric acid mist ground-level concentrations can be obtained from modeling performed on SO2. Sulfuric acid mist is emitted at 738 TPY as compared to 16,083 TPY for SO2. The maximum predicted SO2 concentration is multiplied by this ratio (738/16083) to estimate the maximum ground-level concentration of sulfuric acid mist. A maximum 24- hour concentration of 2.9 ug/m3 is predicted for sulfuric acid mist. This value is much less than the acceptable ambient concentration of 4.76 ug/m3, as defined by the Department. Consequently, monitoring for this pollutant is not required.

The predicted maximum impact for CO, NO_2, PM, PM_{10}, Be, and Hg is less than their respective de minimus impact levels. Therefore, no additional monitoring is required for these pollutants.

The predicted maximum impact for SO_2 is greater than the appropriate de minimus value. The applicant obtained ambient SO_2 monitoring data from the Department for a monitoring station located about 25 km north-northwest of the proposed facility. Because this monitor is located in an urban area and/or in proximity of major sources, the observed concentrations are considered to be higher than those likely to occur at the proposed facility. A more detailed discussion about the monitoring data collected is presented in the section entitled "AAQS Analysis" of this report.

A preconstruction monitoring review is required for ozone concentrations because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY. The proposed facility is located in an ozone attainment area. The proposed site is in a rural area with minimal industrial development (i.e., lack of major VOC emission sources) within 15 km of the site. Consequently, the Department did not require preconstruction monitoring for ozone.

Table 3. Maximum Air Quality Impacts for Comparison to the Significant Impact and De Minimus Ambient Levels.

Pollutant	Avg. Time	Predicted Impact (ug/m3)	Sign. Impact Level (ug/m3)	De Minimus Level (ug/m3)
CO	1-hour	179	2000.0	N/A
	8-hour	38.0	500.0	575.0
NO2	Annual	4.6	1.0	14.0
PM	24-hour	7.5	5.0	10.0
	Annual	0.8	1.0	N/A
PM10	24-hour	7.5	5.0	10.0
	Annual	0.8	1.0	N/A
SO2	3-hour	424	25.0	N/A
	24-hour	62.5	5.0	13.0
	Annual	6.7	1.0	N/A
Be	24-hour	0.0004	N/A	0.0005
Hg	24-hour	0.0016	N/A	0.25
VOC	TPY	450 TPY	N/A	100 TPY

3. Prevention of Significant Deterioration

Pursuant to Chapter 17-2, F.A.C., and 40 CFR 52.21, the Hardee Power Project units are subject to a review for the Prevention of Significant Deterioration (PSD) of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. The Department of Environmental Regulation has reviewed the PSD analysis submitted by the applicants and has found that the construction of the facility is not expected to violate state PSD regulations as contained in Section 17-2.310, F.A.C.

Additionally, the Preliminary Determination for the Hardee Power Project was completed in March of 1990. Federal regulations on PSD (40 CFR 52.21) require the following air quality impacts to be addressed:

a. National Ambient Air Quality Standards (AAQS)
b. PSD increment impact
c. Visibility, soils and vegetation impacts
d. Impacts due to growth caused by the proposed source
e. Class I area impacts
f. GEP stack height determination
g. Best Available Control Technology (BACT)

After their review, DER has made a preliminary determination that the the ambient air quality standards will not be violated and that the construction can be approved provided certain conditions are met.

AAQS Analysis

Given existing air quality in the area of the proposed facility, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS. The results of the AAQS analysis are summarized in Table 4.

Of the pollutants subject to review, only CO, NO_2, PM, PM_{10}, SO_2 and O_3 have an AAQS. Except for O_3, dispersion modeling was performed as detailed earlier for the proposed facility. The modeling results indicate that for CO the maximum predicted impacts were less than the significant impact levels defined in Rule 17- 2.100 (170), FAC. As such, no modeling of other sources was necessary for CO. The total CO impact was determined from the impact of proposed facility added to a background concentration of 21 ug/m3 (1-hour average) and 6 ug/m3 (8-hour average), the highest recorded values in Hillsborough County in 1988. These background estimates of the CO concentration are considered to be very conservative since the proposed facility's location is rural in nature and the monitored data were obtained from a heavily urbanized area. The total impact of the proposed impact, combined with this conservative background, is far below the respective AAQS's (Table 4).

For the remaining pollutants subject to review, the total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The "background" concentrations are taken from areas that are much more industrialized than the proposed facility's location. Therefore, these background values are considered to be conservative. The location of the monitors used to define the background concentrations are detailed in the original application.

Table 4. Ambient Air Quality Impact

Pollutant and Averaging Time		Maximum Impact of Proposed Project (ug/m3)	Predicted Total Impact (ug/m3)	Florida AAQS (ug/m3)
CO	(1-hour)	178.5	199.5	40000
	(8-hour)	38.0	44.0	10000
NO_2	(Annual)	6.2	51.2	100
SO_2	(3-hour)	424.0	691.0	1300
	(24-hour)	118.0	169.0	260
	(Annual)	19.3	30.3	60
PM_{10}	(24-hour)	21.2	112.2	150
	(Annual)	3.6	48.6	60

There is currently no acceptable method to model ozone. Consequently, the control of the VOC emissions are addressed in BACT review.

PSD Increment Impact Analysis

The proposed facility is located in a Class II area. This area is also designated as an attainment area for NO2, PM and SO2. Therefore, a PSD increment analysis is required to show compliance with the Class II NO2, PM and SO2 increments.

The PSD increment represents the amount that new sources in an area may increase ambient ground-level concentrations of a pollutant. At no time, however, can the increased loading of a pollutant cause or contribute to a violation of the ambient air quality standard.

Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. The modeling results indicate the maximum NO2 Class II increment consumed is 5.9 ug/m3, which is less than 25 percent of the allowable PSD NO2 increment of 25 ug/m3, annual average.

The modeling results indicate the maximum PM Class II increment consumed is 8 ug/m3 for a 24-hour average and 0.9 ug/m3 for an annual average. These predicted impacts are much below the allowable increment values of 37 and 19 ug/m3, respectively.

Modeling results indicate the maximum SO2 increment consumed is 424 ug/m3 for a three-hour average, 66 ug/m3 for a 24-hour average and 8.3 ug/m3 for an annual average. These predicted impacts are below the allowable increment values of 512, 91 and 20 ug/m3, respectively.

Impacts on Visibility, Soils and Vegetation

The maximum ground-level concentration predicted to occur for each pollutant as a result of the proposed project, including a background concentration, will be below the applicable AAQS including the national secondary standard developed to protect public welfare-related values. As such, this project is not expected to have a harmful impact on soils and vegetation.

A visibility analysis is not required since the proposed facility is not to located within 100 km of a Class I area.

Growth-Related Air Quality Impacts

The proposed facility is not expected to significantly change employment, population, housing or commercial/industrial development in the area to the extent that an air quality impact will result.

Class I Area Impacts

A Class I area increment analysis is not required because the facility is not located within 100 km of a designated Class I area.

GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The GEP stack height determination is dependent on the distance and orientation to the various buildings nearby the stack because the projected building width can change.

The applicant calculated the GEP heights for each proposed source based on the dimensions of nearby buildings. The greatest height for each of the sources was used for modeling purposes. The stack height used in the modeling was 22.9 meters, which is well below the GEP limit of 65 meters.

4. Best Available Control Technology

The applicant proposes to install a combined cycle power plant and directly associated facilities to be located on the border of Polk and Hardee County. The combined cycle facility will consist of combustion turbines, electric generators, and heat recovery steam generators (HRSG's).

Site certification is being sought for an ultimate capacity of 660 MW (nominal net); however, the facility will be constructed in 3 phases. Phase 1-A will consist of a nominal 220 MW combined cycle unit and a 75 MW stand-alone combustion turbine. Phase 1-B will add 145 MW of generating capacity through the addition of a combustion turbine, two HRSG's and one steam electric generator, resulting in two 220 MW combined cycle units. Phase 2 will consist of a third 220 MW unit to be added at an unspecified future date.

The combustion turbines will be capable of both combined cycle and simple cycle operation. It is anticipated that the combustion turbines will use natural gas as the primary fuel and distillate oil as the backup fuel. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and oil firing at 32°F to be as follows:

Pollutant	Maximum Potential Emissions (tons/yr)	PSD Significant Emission Rate (tons/yr)
NOx	8,405	40
SO_2	16,083	40
PM	1,250	25

Pollutant	Maximum Potential Emissions (tons/yr)	PSD Significant Emission Rate (tons/yr)
PM_{10}	1,250	15
CO	2,810	100
VOC	450	40
H_2SO_4	738	7
Fluorides	0.93	3
Be	0.072	0.0004
Hg	0.32	0.1
Pb	0.25	0.6

Florida Administrative Code Rule 17-2.500(2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

July 5, 1989

BACT Determination Requested by the Applicant

Pollutant	Determination
NOx	42 ppmvd @ 15% O_2 (natural gas firing) 65 ppmvd @ 15% O_2 (diesel oil firing)
SO_2	Firing of natural gas or No. 2 fuel oil with an annual average sulfur content of 0.3% and a maximum sulfur content of 0.5%
PM and PM_{10}	5 lbs/hr (natural gas firing) 10 lbs/hr (diesel oil firing)
CO	10 ppmvd @ 15% O_2 (natural gas firing) 26 ppmvd @ 15% O_2 (diesel oil firing)
VOC	2 ppmvd @ 15% O_2 (natural gas firing) 5 ppmvd @ 15% O_2 (diesel oil firing)
H_2SO_4	Firing of natural gas and No. 2 fuel oil
Be	Firing of natural gas and No. 2 fuel oil
Hg	Firing of natural gas and No. 2 fuel oil

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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:

(a) Any Environmental Protection Agency determination of Best Available Control Technology 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) 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 source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source 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.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SOx, NOx, HCl, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

Combustion Products

The Hardee Power Station's projected emissions of particulate matter, PM_{10}, beryllium, and mercury exceed the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission levels of 5 lbs/hr and 10 lbs/hr per turbine are consistant with previous BACT determinations for similar equipment firing natural gas and No. 2 fuel oil respectively. As this is the case, these emission limitations are reasonable as BACT for the Hardee Power Station.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium and mercury from turbines. BACT for heavy metals is typically represented by the level of particulate control. As this is the case, the emission factors of 5.0 and 10.0 lbs/hr per turbine for particulate matter/ PM_{10} when firing natural gas and No. 2 fuel oil, respectively, is judged to represent BACT for beryllium and mercury.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. A review of the BACT/LAER Clearinghouse indicates that combustion turbines of similar size have CO and VOC limitations similar to the proposed levels of 10 ppmvd and 2 ppmvd, respectively, for natural gas firing. The proposed levels of 26 ppmvd and 5 ppmvd for CO and VOC, respectively, are also judged to be reasonable for oil firing. As this is the case, these emission limitations are reasonable as BACT for the Hardee Power Station.

Acid Gases

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of natural gas and No. 2 fuel oil with an average sulfur content of 0.30% to control sulfur dioxide emissions. A review of the latest edition (1989) of the BACT/LAER Clearinghouse indicates that sulfur dioxide emissions from combustion turbines have been controlled by limiting fuel oil sulfur content to a range of 0.1 to 0.3%, with the average for the facilities listed being approximately 0.24 percent. As this is the case, the applicant's proposal appears to be reasonable and is judged to represent BACT

The applicant has stated that BACT for nitrogen oxides will be met by using wet (water or steam) injection necessary to limit emissions to 65 ppmvd or 42 ppmvd at 15% oxygen when burning No. 2 fuel oil or natural gas, respectively.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NOx emissions. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 100 percent capacity factor is $12,085,000. Taking into consideration the total levelized annual cost, a cost/benefit analysis of using SCR can now be developed. At 100% capacity factor, it is estimated that the maximum annual NOx emissions with wet injection from the Hardee facility would be 4,205 tons/year.

Assuming that SCR will reduce the NOx emissions by an additional 80%, the SCR would control a maximum of 3,364 tons of NOx annually for natural gas firing. When this reduction is taken into consideration with the total levelized annual cost of $12,085,000, the cost per ton of controlling NOx is $3,592. This cost ($3,592/ton) is representative of costs that have been previously justified as BACT and explains why SCR for combined cycle cogeneration facilities is becoming common as a BACT <u>not LAER</u> requirement for facilities being permitted today.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products Inc.), the following statement is made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are for commercial cogeneration purposes in which the main incentive is to generate power for sale to utility companies or private customers. As this is the case, these facilities want to operate as much as possible. The Hardee Power Station, however, is to be used initially for peaking and cycling purposes. The applicant has stated that the initial capacity factors for the Hardee Power Station are not expected to exceed a cumulative lifetime capacity factor of 60 percent. As this is the case, a SCR requirement for all modes of operation may not be justified.

For peaking units the cost of SCR can be much more expensive than units operating at high capacity factors on a cost per ton of nitrogen oxides controlled basis. This variability in cost is attributed to the fixed cost using SCR which is independent of hours of operation. Thus as hours of operation decrease, the cost to control nitrogen oxides increases.

The applicant has indicated that the cost of using SCR to control NOx emissions increases substantially as the capacity factor is decreased from 100 percent. It is estimated that the cost to control NOx would be as high as $9,063 per ton if the facility were to operate at a 25 percent capacity factor.

For fuel oil firing the applicant has proposed an emission limit of 65 ppm. A review of recent permitting activities in other states indicates that several turbines of the size proposed for the Hardee Power Facility are also being proposed with NOx emission guarantees of 65 ppm for oil firing. For fuel firing the applicant has indicated that the cost of using SCR to control NOx emissions would increase above that which is expected for natural gas firing only. This is due to the formation of ammonium salts.

For the SCR process, ammonium salts can be formed due to the reaction of sulfur in the fuel oil and the ammonia injected. The ammonium salts formed have a tendency to plug and corrode the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations. Assuming that SCR could not be operated for oil fired operation, the cost of NOx control would range from $4,398 to $11,815 per ton depending on the capacity factor with an 80-20 mix of natural gas and oil. The cost of using SCR for NOx control at various fuel mixtures and capacity factors is shown in Table 1.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal would be related to the use of SCR if required for NOx control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NOx control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Since the facility is being proposed as a peaking unit and SCR use is unlikely, these impacts do not pose a problem.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas and No. 2 fuel oil have been evaluated. Two of the toxic pollutants (mercury and beryllium) exceed PSD significant levels. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions with SCR the applicant has identified the following technical limitations:

1. SCR is not technically applicable to the simple cycle portion of the combined cycle configuration, i.e., the combustion turbine by-pass stack exhaust, and

2. Continuous operation of SCR using distillate oil has not been demonstrated; and therefore, technical, economic and environmental uncertainties would result.

TABLE 1
ECONOMIC ANALYSIS OF SCR FOR NOx

100% Natural Gas Firing

Capacity Factor	25	30	40	50	60	70	80	90	100
Total Annual Cost ($ X 1,000)	7,622	7,790	8,126	8,462	9,186	9,911	10,636	11,360	12,085
NOx Removal									
Ton/Year	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
$ /Ton	9,063	7,719	6,039	5,031	4,551	4,209	3,952	3,752	3,592

80% Natural Gas Firing/20% No. 2 Fuel Oil Firing

Capacity Factor	25	30	40	50	60	70	80	90	100
Total Annual Cost ($ X 1,000)	7,560	7,716	8,027	8,338	9,038	9,737	10,437	11,137	11,837
NOx Removal									
Ton/Year	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
$ /Ton	11,237	9,557	7,457	6,196	5,597	5,169	4,848	4,598	4,398

BACT Determination by DER

Based on the information presented by the applicant, the Department believes that the use of SCR is not justifiable providing that the facility operates as initially intended (not to exceed a cumulative lifetime capacity factor of 60 percent). Table 1 indicates that at this level of operation the cost of using SCR to control NOx emissions would be at least $4,551 per ton for natural gas firing and even more expensive if No. 2 fuel oil was used to supplement natural gas firing. This cost ($4,551 per ton) is judged to be excessive when compared to EPA's guidelines of $3,000 to $4,000 per ton for NOx removal. However, at operational levels above a capacity factor of 60 percent, SCR shall be installed and specific emission limitations will be established as BACT for both natural gas and oil firing. For this reason, the Hardee Facility shall provide space in the HRSG to accommodate SCR.

For simple cycle operation the use of SCR is not technically feasible, thus the use of wet injection would be appropriate for combined cycle units operating below the capacity factor limitation and for the stand alone turbine.

For sulfur dioxide BACT is represented by firing natural gas or No. 2 fuel oil with an average sulfur content not to exceed 0.30 percent. The emission limitations for PM, PM_{10}, CO and VOC's are based on previous BACT determinations for similar facilities, with the heavy metals beryllium and mercury being addressed through the particulate limitation and sulfuric acid mist being addressed through the sulfur dioxide limitation. The emission limits for the Hardee Power Station are thereby established as follows:

Pollutant	Emission Limit Natural Gas Firing	No. 2 Fuel Oil Firing
NOx *	42 ppmvd @ 15% O_2	65 ppmvd @ 15% O_2
SO_2	Natural gas as fuel	Sulfur content not to exceed 0.3%
PM & PM_{10}	5.0 lbs/hr per turbine	10.0 lbs/hr per turbine
CO	10 ppmvd	26 ppmvd
VOC	2 ppmvd	5 ppmvd
Sulfuric Acid Mist	Emissions limited by natural gas and No. 2 fuel oil firing	
Beryllium	Emissions limited by natural gas and No. 2 fuel oil firing	

Mercury	Emissions limited by natural gas and No. 2 fuel oil firing

*Nitrogen oxides emission limitation is based on limiting the cumulative lifetime capacity factor to 60 percent. If the applicant chooses to operate the facility in excess of this limitation, BACT will be re-evaluated for nitrogen oxides for both natural gas and oil firing.

Fugitive Dust

Fugitive dust during operation will be minimal due to movement of vehicles or mainteneance activities such as mowing.

5. Acid Rain

Rainfall acidity levels across Florida and other parts of the country have been ascribed in part to the air emissions from fossil fuel-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary man-made agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.0. It appears that after a certain amount of time, estimated to be on the order of 1-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric acid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes it's impacts, and numerous other questions relating to the conversion reactions. It is generally agreed that the entire cause-effect-control relationship is very complex.

One feature that will mitigate some of the impact of the project is that the fuels to be used will either have or be required to have a very low sulfur content prior to the plant going into operation. These units will thus have less impact than that of other units which do not employ those fuels. Oxides of nitrogen will be controlled. Such control will also help mitigate the rainfall acidification problem. In balancing the need for power with the environmental impacts from the operation of the plant, at this time, the required use of the low sulfur fuel and combustion design seems to be the most relevant and effective way of addressing the plant's contribution to rainfall acidification.

8/15/90

State of Florida Department of Environmental Regulation
TECO Power Services/Seminole Electric Cooperative, Inc.
Hardee Power Station
PA 89-25

CONDITIONS OF CERTIFICATION

TABLE OF CONTENTS

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

TECO POWER SERVICES/SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA ELECTRIC COMPANY
HARDEE POWER STATION
PA 89-25

CONDITIONS OF CERTIFICATION

I. GENERAL

A. Definitions

The meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, 372, and 253, Florida Statutes, and any regulation adopted pursuant thereto and the statutes and regulations of any agency. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the department. As used herein:

1. "Application" shall mean the Site Certification Application for the Hardee Power Station, as supplemented.

2. "CFRPC" shall mean the Central Florida Regional Planning Council.

3. "DER" shall mean the Florida Department of Environmental Regulation.

4. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

5. "DNR" shall mean the Florida Department of Natural Resources.

6. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement gas pipeline, transmission lines, or access facilities.

7. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

8. "GFWFC" shall mean the Florida Game and Freshwater Fish Commission.

9. "Lee transmission line" shall mean the corridor depicted in Attachment A .

10. "Linear facility" shall mean any one of the three transmission lines or the natural gas pipeline associated with the Hardee Power Station.

11. "M/C" shall mean mitigation/compensation.

12. "Pebbledale transmission line" shall mean the corridor depicted in Attachment B.

13. "Permittees" shall mean TECO Power Services Corporation (TPS), Tampa Electric Company (TEC), and Seminole Electric Cooperative, Inc. (SECI).

14. "Power plant" shall mean the electric power generating equipment and appurtenances to be constructed on a site in Hardee County and Polk County, as generally depicted in the Application.

15. "Project" shall mean the Hardee Power Station and all associated facilities, including: The power plant and related facilities; the cooling reservoir and related facilities; any off-site mitigation/compensation areas; and all of the linear facilities.

16. "ROW" shall mean the transmission line and natural gas pipeline rights-of-way to be selected by the Permittees within the certified corridors in accordance with the conditions of certification.

17. "SFWMD" shall mean the South Florida Water Management District.

18. "SWFRPC" shall mean the Southwest Florida Regional Planning Council.

19. "SWFWMD" shall mean the Southwest Florida Water Management District.

20. "USFWS" shall mean the United States Fish and Wildlife Service.

21. "Vandolah transmission line" shall mean the corridor depicted in Attachment C.

22. "WMD" shall mean water management district.

23. "ISO" shall mean International Organization for Standardization, ISO 3977-1978(E) standard conditions for gas turbines = 14.7 psia, $15^{O}C$, relative humidity 60%.

B. Identification of Permittees Responsible for Compliance

In general, where a specific condition is intended to apply solely to one of the Permittees, this shall be indicated in the title for that specific condition by the following abbreviations:

TPS - TECO Power Services Corporation
TEC - Tampa Electric Company
SECI - Seminole Electric Cooperative, Inc.

Similarly, where a specific condition is intended to apply to any two of the Permittees, this shall be indicated by listing in the title the respective abbreviations. Where a specific condition is intended to apply to TPS, TEC, and SECI, the designation "HPS" (for "Hardee Power Station") shall appear.

C. Applicable Rules

The construction and operation of the HPS shall be in accordance with all applicable provisions of at least the following regulations of the Department: Chapters 17-2, 17-3, 17-4, 17-5, 17-6, 17-7, 17-12, 17-21, 17-22, 17-25, 17-274, 17-302, and 17-610, Florida Administrative Code (F.A.C.) or their sucessors as they are renumbered.

II. AIR (TPS)

A. Emission Limitations for HPS

The construction and operation of HPS shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C. In addition to the foregoing, HPS shall comply with the following conditions of certification as indicated.

1. On or before April 1 of each year, the Permittee shall submit to the Division of Air Resource Management and the Air Section, Southwest District Office an annual report for the previous calendar year showing:

(a) The annual average capacity factor for each individual generating unit;

(b) The cumulative lifetime average capacity factor for each individual generating unit;

(c) The annual average capacity factor for the Hardee Power Station; and,

(d) The cumulative lifetime average capacity factor for the Hardee Power Station.

The annual average capacity factor shall be calculated by dividing each unit's megawatt hours output of generation by the product of the official megawatt rating of the unit and the number of hours in a year. Cumulative lifetime average capacity factor shall be calculated by dividing the cumulative total of megawatt hours output of generation by the product of the official combined cycle megawatt rating and the cumulative period of hours since commercial operation.

2. The Permittee shall install duct module(s) suitable for later installation of SCR equipment when constructing any combined cycle generating unit at the Hardee Power Station. Should any annual report demonstrate that the cumulative lifetime average capacity factor for the Hardee Power Station exceeds 60% at any time, the Permittee shall install SCR or another technology of equal or greater NOx reduction capability. In no event shall any such SCR or equivalent NOx control technology installation and compliance testing occur later than 30 months from the date that the Permittee requested or the facility exceeded the 60% cumulative lifetime average capacity factor.

3. Only natural gas or No. 2 fuel oil shall be fired in the turbine.

4. The maximum heat input to each CT shall neither exceed 1268.4 MMBtu/hr while firing natural gas, nor 1312.3 MMBtu/hr while firing fuel oil (@ 32°F). Each CT's fuel consumption shall be continuously measured and recorded.

5. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following:

Pollutant	Fuel	Emission Limitations	
		concentration	lb/hr/CT
NOx	Gas	42 ppmvd @ 15% O_2	215.9
	Oil	65 ppmvd "	383.8
VOC	Gas	2 ppmvd	3.6
	Oil	5 ppmvd	10.3
CO	Gas	10 ppmvd	31.3
	Oil	26 ppmvd	93.4
PM/PM_{10}	Gas	--	5.0
	Oil	--	10.0
SO_2	Gas	--	35.8
	Oil	0.3% S oil	734.4

6. The following allowable emissions, most determined by BACT, are tabulated for PSD and inventory purposes:

Pollutant	Fuel	Maximum Allowable Emission (@ 32°F)	
		concentration	lb/hr/CT
H_2SO_4 Acid Mist	Gas	---	1.6
	Oil	---	22.0 (avg)/33.7 (max)
Mercury	Gas	---	0.0144
	Oil	---	0.0039
Fluoride	Oil	---	0.0427
Beryllium	Oil	---	0.0333

NOTE: Sulfur dioxide emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

7. Visible emissions shall neither exceed 10% opacity while burning natural gas, nor 20% opacity while burning distillate oil.

8. Initial (I) compliance tests shall be performed using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1988 version of 40 CFR 60 Appendix A:

a. 5 for PM (I,A)
b. 8 for sulfuric acid mist (I, for oil only)
c. 9 for VE (I,A)
d. 10 for CO (I,A)
e. 20 for NOx (I,A)
f. 25A for VOC (I,A)
g. 104 for Beryllium (I, for distillate oil only) A fuel analysis for Be using either Method 7090 or 7091, and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846, is also acceptable.
h. ASTM D 2880-71 for sulfur content of distillate oil (I,A)
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DER)

Other DER approved methods may be used for compliance testing after prior Departmental approval.

9. The average annual sulfur content of the No. 2 fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the No. 2 fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing all oil shipments for sulfur content using ASTM D 2880-71, and testing for nitrogen content.

10. For all generating units, water injection shall be utilized for NOx control. The water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored for all units.

11. To determine compliance with the capacity factor condition, the Permittee shall maintain daily records of power generation for each turbine. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

12. The project shall comply with all the applicable requirements of Chapter 17-2, Florida Administrative Code (F.A.C.) and the July 1, 1988, version of 40 CFR 60 Subpart GG, Gas Turbines.

13. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to DER's Bureau of Air Regulation.

14. If start/black start capability for the CTs is provided by a combustion unit, the Department shall be notified of the type/model, output capacity, anticipated hours of operation, and air emissions of the unit.

15. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days prior notice of the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southwest District Office. Written reports of the tests shall be submitted to the Southwest District office within 45 days of test completion.

16. If construction does not commence on the first three units within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2). Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988 version 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office. Annual reports shall be submitted to the District office in accordance with F.A.C. Rule 17-2.700(7).

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted

to DER's Southwest District office and the Bureau of Air Regulation.

19. Stack sampling facilities shall be provided for both the bypass stack (CT) and the main stack (HRSG).

20. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

III. SURFACE WATER DISCHARGES (TPS)

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of Chapters 17-3, 17-4, 17-302, 17-650, and 17-660, Florida Administrative Code, and the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the HPS the following conditions shall apply:

1. Receiving Body of Water (RBW) - The receiving body of water has been determined by the Department to be those waters of Payne Creek which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD) - The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in Payne Creek from either the storm water runoff retention pond or the cooling reservoir; however, compliance monitoring will be required at the cooling pond overflow weir and the stormwater detention pond discharge pipes.

3. Thermal Mixing Zones - The instantaneous zone of thermal mixing for the HPS cooling system shall not exceed a distance of 50 feet from the POD. The temperature at the POD into Payne Creek shall not be greater than 95 degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Section 17-302.520(5)(b), F.A.C.

4. Chemical Wastes from HPS - All discharges of low volume wastes (demineralizer regeneration, floor drainage, labs drains, and similar wastes) shall be treated in an adequately sized and constructed treatment facility prior to discharge into the cooling reservoir.

5. pH - The pH of the combined discharges to the cooling reservoir from Outfall Serial Number (OSN) 003 shall be such that the pH will fall within the range of 6.0 to 9.0 and any discharge from the reservoir at OSN 001 to Payne Creek shall not fall outside the 6.0 to 8.5 range.

11-27-90

Patty, To supplemental ~~copy~~ case files
CPL

BEFORE THE GOVERNOR AND CABINET
OF THE STATE OF FLORIDA

IN RE: HARDEE POWER STATION)
POWER PLANT SITE CERTIFICATION)
APPLICATION, TECO POWER SERVICES,)
TAMPA ELECTRIC COMPANY, AND) DOAH CASE NO. 89-3560
SEMINOLE ELECTRIC COOPERATIVE, INC.) OGC FILE NO. 89-0703
PA 89-25)
____)

FINAL ORDER

BY THE GOVERNOR AND CABINET

On November 27, 1990, this matter came before the Governor and Cabinet, sitting as the siting Board pursuant to the Florida Electrical Power Plant Siting Act, Section 403.501 et seq., Florida Statutes (1989), for final action concerning a Recommended Order dated October 15, 1990, attached as Exhibit A, which recommends certification of the Hardee Power Station. On November 8, 1990,[1] Intervenors Katzen and Slack filed exceptions to the Recommended Order, attached as Exhibit B. On November 16, 1990, Co-Applicants TECO Power Services Corporation (TPS), Tampa Electric Company (TECO) and Seminole Electric Cooperative, Inc. (SECI) filed a Response to those exceptions.

Intervenors' Exceptions 1-4 contest to findings of fact set forth in the Recommended Order. Section 120.57(1)(b)10., Florida Statutes, limits an agency's authority to reject or modify findings of fact to the situation when, based upon

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[1] Intervenors' exceptions were filed late with the consent of the Co-applicants.

review of the entire record, it can be concluded that such findings "were not based upon substantial competent evidence or the proceedings upon which the findings were based did not comport with the essential requirements of law." Heifetz v. Department of Business Regulation, 475 So.2d 1277 (Fla. 1st DCA 1985) Upon review of the record, it is clear in this case that the findings of fact contested by the Intervenors' Exceptions are supported by competent substantial evidence. Therefore, Intervenors' Exceptions Nos. 1-4 are denied.

Intervenors' exception No. 5 objects to several conclusions of law contained in the Recommended Order. For the Board to adopt the Intervenors' suggested conclusions of law, as proposed in paragraphs A through G under Exception No. 5, the Board would be required to disregard numerous findings of fact contained in the Recommended Order. As already noted, there is no basis for rejecting any findings of fact. It is settled that the Board may not reject well-supported findings of fact by treating them as conclusions of law. Leapley v. Board of Regents, 423 So.2d 431 (Fla. 1st DCA 1982)

The Intervenors' contention that the procedure for alternate corridor consideration established in Section 403.527(5), Florida Statutes, pursuant to the Transmission Line Siting Act should be made available in this Power Plant Siting Act proceeding is rejected. The intention of the Florida Legislature is specifically articulated in each act. Had the

Legislature intended the same procedure to apply, it would have so stated. No provision was made for alternate corridor consideration under the Power Plant Siting Act.

The Intervenors' "denial of due process" claims are rejected as without legal foundation and contrary to the facts of this case, which demonstrate that the Co-Applicants have met or exceeded all statutory notice requirements. Moreover, Intervenors were given full opportunity to be heard. Intervenors have no entitlement to any process beyond that specified in the Act. Peoples State Bank of Indian River County v. State, Department of Banking and Finance, 395 So.2d 52 (Fla. 1980) Consequently, Intervenors' Exception No. 5 is rejected.

Pursuant to Sections 403.501-403.517, Florida Statutes (1989), having reviewed the Recommended Order, the Exceptions to Recommended Order, the Responses to the Exceptions, argument of counsel, and otherwise being fully advised herein, it is

ORDERED:

1. The Exceptions to the Recommended Order are rejected.

2. The Recommended Order (dated October 15, 1990) prepared by the Hearing Officer pursuant to Section 403.508(3), F.S., concerning the certification of the proposed Hardee Power Station is adopted in toto.

3. The Siting Board finds that the proposed Hardee Power Station should be certified subject to the conditions of certification included in the Recommended Order and attached hereto.

4. Pursuant to Section 403.509(3), F.S., this Final Order shall constitute approval for the granting of any necessary easements by the Game and Fresh Water Fish Commission over lands within the Cecil M. Webb Wildlife Management Area, in accordance with the Conditions of Certification.

Any party to this Order has the right to seek judicial review of the order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of Siting Board, the Department of Environmental Regulation in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; 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 of Appeal must be filed within thirty (30) days from the date this Order is filed with the clerk of the Siting Board.

DONE and ENTERED this 27th day of November, 1990, in Tallahassee, Florida pursuant to the vote of the Governor and Cabinet, sitting as the Siting Board, at a duly constituted Cabinet meeting November 27, 1990.

BY THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

Bob Martinez

THE HONORABLE BOB MARTINEZ
GOVERNOR

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kathy C. Carter 11-27-90
Clerk Date

APPENDIX C

CONDITIONS OF CERTIFICATION

I hereby certify that a true and correct copy of the foregoing Final Order and its attachments have been furnished by U.S. Mail to the following this 28th day of November, 1990:

Lawrence J. Curtin, Esq.
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R T Donelan, Jr

RICHARD T. DONELAN, Jr.
Assistant General Counsel
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Check Sheet

Company Name: Tampa Electric Company
Permit Number:
PSD Number: PSDFL-140
Permit Engineer:

Application:

- ☑ Initial Application
  - ☐ Incompleteness Letters
  - ☐ Responses
  - ☐ Waiver of Department Action
  - ☐ Department Response
  - ☐ Other

Cross References:
- ☑ Hardee Power Station
- ☑ Seminole Electric
- ☐

Intent:

- ☑ Intent to Issue
- ☑ Notice of Intent to Issue
- ☑ Technical Evaluation
- ☐ BACT or LAER Determination
- ☐ Unsigned Permit
- Correspondence with:
  - ☐ EPA
  - ☐ Park Services
  - ☐ Other
- ☑ Proof of Publication
  - ☐ Petitions - (Related to extensions, hearings, etc.)
  - ☐ Waiver of Department Action
  - ☐ Other

Final Determination:

- ☑ Final Determination
- ☑ Signed Permit
- ☐ BACT or LAER Determination
  - ☑ Other

Post Permit Correspondence:

- ☐ Extensions/Amendments/Modifications
- ☑ Other

TAMPA
ELECTRIC
A TECO ENERGY COMPANY

RECEIVED

SEP 27 1990

DER - BAQM

September 26, 1990

VIA FEDERAL EXPRESS
Airbill #7284300951

Mr. Claire Fancy
Florida Department of
Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, FL 32399-2449

Re: Hardee Power Station
Response to Request for Additional Information

Dear Mr. Fancy:

During our meeting of August 10, 1990, you made two requests. Your first request was to estimate the cost effectiveness of utilizing the SCR on oil with a removal efficiency of 65%, with a fuel split of 80% natural gas and 20% oil, and at a capacity factor of 60%. The results of our estimate show a cost effectiveness of $5,078 per ton of NO_x removed. It must be noted that this is an estimate only, since there is no experience base of SCRs successfully running on oil. Included was an estimate for heat rate degradation due to fouling in the HRSG, capacity degradation for same, costs for periodic wash down of the HRSG, and costs for HRSG tube maintenance associated with corrosion. Costs for reduced availability and for research and development of this process have not been included. No cost has been assigned to increased particulate emissions.

Your second request was for a copy of our models. Enclosed is a disc containing three files: DER6YR, DER65OIL, and DER42PPM. DER6YR contains the information used for the three-year catalyst replacement with O&M costs varied by fired hours up to a maximum of six years. In this case the SCR runs on gas only. DER65OIL is essentially the same case, only the SCR also runs with oil (20% of operation) at a 65% removal efficiency. DER42PPM contains the case demonstrating the cost to obtain 42 ppm when firing with oil.

TAMPA ELECTRIC COMPANY
P.O. Box 111 Tampa, Florida 33601-0111 (813) 228-4111

Attached is a printout of each file. Attachment 1 is the printout of DER6YR. Attachment 2 is the printout of DER65OIL. Attachment 3 is the printout of DER42PPM. At the end of each printout is a printout of the formulas utilized with an explanation of these formulas. These latter worksheets are also contained within each of their respective files. Each file is a LOTUS 123 (Version 2.01) WK1 file.

I hope that this fulfills your requests.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director TPS
Environmental

JLW/sn/LL428.DOC

Enclosures

cc: TECO Power Services Corp.
Seminole Electric Cooperative, Inc.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,547	1,547	1,547	1,547	1,935	2,324	2,713	3,101	3,490
Ammonia (3)	120	144	192	240	288	336	384	432	480
Energy (4)									
Heat Rate Penalty	448	538	717	896	1,076	1,255	1,434	1,614	1,793
SCR Power Consumption	209	251	335	419	503	586	670	754	838
Lost Generation Capacity (5)	370	370	370	370	370	370	370	370	370
Total Direct Annual Cost	2,694	2,850	3,161	3,472	4,172	4,871	5,571	6,271	6,971
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	7,560	7,716	8,027	8,338	9,038	9,737	10,437	11,137	11,837
NOx Emissions									
42ppm natural gas, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
9ppm natural gas, tpy	168	202	269	336	404	471	538	606	673
Removed, tpy	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
Cost Effectiveness, $/ton	11,237	9,557	7,457	6,196	5,597	5,169	4,848	4,598	4,398

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	100	100	100	100	100	100	100	100	100
% No. 2 Fuel Oil firing	0	0	0	0	0	0	0	0	0
Annual Costs, $X1000									
===================									
Direct Annual Cost									
Differential O&M Cost (2)	1,547	1,547	1,547	1,547	1,935	2,324	2,713	3,101	3,490
Ammonia (3)(7)	150	180	240	300	360	420	480	540	600
Energy (4)									
Heat Rate Penalty	428	513	685	856	1,027	1,198	1,369	1,540	1,711
SCR Power Consumption	262	314	419	524	628	733	838	942	1,047
Lost Generation Capacity (5)	370	370	370	370	370	370	370	370	370
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Annual Cost	2,756	2,924	3,260	3,596	4,320	5,045	5,769	6,494	7,219
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	7,622	7,790	8,126	8,462	9,186	9,911	10,636	11,360	12,085
NOx Emissions									
=============									
42ppm natural gas, tpy	1,051	1,262	1,682	2,103	2,523	2,944	3,364	3,785	4,205
9ppm natural gas, tpy (6)	210	252	336	421	505	589	673	757	841
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
Cost Effectiveness, $/ton	9,063	7,719	6,039	5,031	4,551	4,209	3,952	3,752	3,592

TECO Power Services - Hardee Power Station
SCR CAPITAL COSTS ($X1000)

SCR Reactor	12,750
SCR Auxilliaries and Ammonia Storage	1,500
SCR Erection	2,625
Foundations, Ammonia System Erection & BOP Equipment	450
Contingency (10%)	1,733

Subtotal	19,058
Sales Tax (6%)	1,143
Indirect costs (14.5%)	2,763

Subtotal	22,964
Escalation (4.7%)	1,620

Total Escalated Cost	24,584
Interest During Construction	3,095

Total Capital Investment	27,679

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

NOTE:

1. Based on a Total Capital Investment of $27,680,000 with a project specific capital recovery factor of 15.42%. Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.
2. Differential O&M includes maintenance & labor and catalyst replacement. Complete replacement after 3 years of fired hours with a maximum interval of 6 years.
3. Ammonia cost is based on $250/ton and a stoichmetric ratio of 1.2.
4. Energy includes auxilliary power for the SCR as well as a 0.42% CT heat rate penalty for the SCR. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's (TEC) current levelized fuel cost forecast of $11.68/MBtu for natural gas and $14.49 for oil. Increased BOP power consumption is charged at $99.98/MWh. This latter factor also utilized the TEC fuel cost forecast.
5. The SCR lost generation capacity is based on an 0.42% penalty. An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.
6. SCR removal efficiency is assumed to be 80%.
7. Ammonia feed is assumed to be off when unit is being fired with oil.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	60		6	60
			7	
% Natural Gas firing	100		8	100
% No. 2 Fuel Oil firing	0		9	0
			10	
Annual Costs, $X1000			11	
====================			12	
Direct Annual Cost			13	
Differential O&M Cost (2)	1,935	A	14	3490*(1.11375*U6-11.375)/100
Ammonia (3)	360	B	15	600*(U6/100)*U8/100
Energy (4)			16	
Heat Rate Penalty	1,027	C	17	1.1*(1380*(11.68/10.36)*(U8/100)*(U6/100)+1700*(14.49/12.79)*(U9/100)*(U6/100))
SCR Power Consumption	628	D	18	930*(99.98/88.8)*(U8/100)*(U6/100)
Lost Generation Capacity (5)	370	E	19	220*(81.64/48.54)
	-----		20	-----
Total Direct Annual Cost	4,320		21	@SUM(U19..U14)
			22	
Indirect Annual Cost			23	
Capital Recovery (1)	4,268	F	24	27680*0.1542
Admin, Property Taxes, and Insurance	598	F	25	27680*0.0216
			26	
	-----		27	-----
Total Indirect Annual Cost	4,866		28	@SUM(U26..U24)
			29	
Total Annual Cost	9,186		30	+U28+U21
			31	
NOx Emissions			32	
=============			33	
42ppm natural gas, tpy	2,523	G	34	4205*(U8/100)*(U6/100)
9ppm natural gas, tpy	505		35	0.2*U34
	-----		36	-----
Removed, tpy	2,018		37	+U34-U35
			38	
			39	
Cost Effectiveness, $/ton	4,551		40	(U30*1000)/U37

FORMULA NOTES

A. Differential O&M Cost: The $3,490,000 (from B&V/GE input and TPS project specific factors) is for the 3 year catalyst replacement at 100% capacity factor. The equation which follows was developed to distribute the appropriate figure depending on the capacity factor (and firing hours) of the station.
B. Ammonia: The $600,000 (from B&V/GE) is based on ammonia at $250/ton. This figure varies with capacity factor and gas usage.
C. Heat Rate Penalty: The $1,380,000 and the $1,700,000 (from B&V/GE) are based on a 0.42% heat rate degradation accross the CT and $10.36/MBtu and $12.79/MBtu for levelized fuel forecasts for natural gas and oil, respectively. These values were corrected for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($11.68/MBtu and $14.49/MBtu for natural gas and oil respectively). The heat rate penalty varies with capacity factor and respective fuel usage.
D. SCR Power Consumption: The $930,000 (from B&V/GE) is the estimate for power consumption by the dilution air fans, additional pump power, and the ammonia vaporizer at a charge of $88.80/MWHr. This was corrected to the recent TEC forecasts of $99.98/MWHr. This penalty varies with capacity factor and gas usage.
E. Lost Generation Capacity: The $220,000 (from B&V/GE) is based on a 0.45% decrease in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a project specific demand charge of $81.64/kw/yr.
F. Capital Recovery: See note 1.
G. Emissions: The 4205 tons per year (from B&V/GE) varies with capacity factor and gas usage.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

ATTACHMENT 2
PAGE 1 OF 5

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,571	1,572	1,575	1,563	1,954	2,346	2,738	3,130	3,522
Ammonia (3)	150	180	240	300	360	420	480	540	600
Energy (4)									
Heat Rate Penalty	1,041	1,250	1,666	2,083	2,499	2,916	3,332	3,749	4,166
SCR Power Consumption	274	329	439	549	658	768	878	988	1,097
Lost Generation Capacity (5)	485	485	485	485	485	485	485	485	485
Total Direct Annual Cost (7)	3,521	3,816	4,405	4,979	5,957	6,935	7,913	8,892	9,870
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	8,387	8,682	9,271	9,845	10,823	11,801	12,780	13,758	14,736
NOx Emissions									
42ppm natural gas, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
9ppm natural gas, tpy	168	202	269	336	404	471	538	606	673
Removed on gas, tpy	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
65ppm oil, tpy	331	397	530	662	795	927	1,060	1,192	1,325
Emissions with 65% removal	116	139	185	232	278	325	371	417	464
Removed on oil, tpy	215	258	344	430	517	603	689	775	861
Total removed, tpy (6)	888	1,066	1,421	1,776	2,131	2,487	2,842	3,197	3,552
Cost Effectiveness, $/ton	9,444	8,147	6,525	5,543	5,078	4,746	4,497	4,303	4,148

TECO Power Services - Hardee Power Station
SCR CAPITAL COSTS ($X1000)

SCR Reactor	12,750
SCR Auxilliaries and Ammonia Storage	1,500
SCR Erection	2,625
Foundations, Ammonia System Erection & BOP Equipment	450
Contingency (10%)	1,733
Subtotal	19,058
Sales Tax (6%)	1,143
Indirect costs (14.5%)	2,763
Subtotal	22,964
Escalation (4.7%)	1,620
Total Escalated Cost	24,584
Interest During Construction	3,095
Total Capital Investment	27,679

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

NOTE:

1. Based on a Total Capital Investment of $27,680,000 with a project specific capital recovery factor of 15.42%. Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%. No capital additions were made for the case of running SCR with oil. Operation experience is necessary to determine appropriate modifications.
2. Differential O&M includes maintenance & labor and catalyst replacement. Complete replacement after 3 years of fired hours with a maximum interval of 6 years. For the case of SCR on oil, O&M also includes some annual tube replacements and washing of the HRSG.
3. Ammonia cost is based on $250/ton and a stoichmetric ratio of 1.2.
4. Energy includes auxilliary power for the SCR as well as a 0.42% CT heat rate penalty for the SCR. An additional 5% heat rate penalty was assessed against the steam turbine generator due to fouling of the HRSG when firing on oil.
   The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's (TEC) current levelized fuel cost forecast of $11.68/MBtu for natural gas and $14.49 for oil.
   Increased BOP power consumption is charged at $99.98/MWh. This latter factor also utilized the TEC fuel cost forecast.
5. The SCR lost generation capacity is based on an 0.42% penalty, as well as a 5% steam turbine penalty when firing on oil and operating the SCR.
   An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.
6. SCR removal efficiency is assumed to be 80% on natural gas firing and 65% on oil firing.
7. Costs associated with reduced availability and with the research and development expected during operation of the SCR when firing on oil have not been included. Included costs are a rough estimate since there is no experience base for successfully firing on oil.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

			COLUMN R ROW	
Capacity factor	60		7	60
			8	
% Natural Gas firing	80		9	80
% No. 2 Fuel Oil firing	20		10	20
			11	
Annual Costs, $X1000			12	
====================			13	
Direct Annual Cost			14	
Differential O&M Cost (2)	1,954	A	15	(3490*(1.11375*R7-11.375)/100)+160*(R7/100)*R10/100
Ammonia (3)	360	B	16	600*(R7/100)
Energy (4)			17	
Heat Rate Penalty	2,499	C	18	1.1*(1380*(11.68/10.36)*(R9/100)*(R7/100)+1700*(6.6)*(14.49/12.79)*(R10/100)*(R7/100))
SCR Power Consumption	658	D	19	930*((99.98/88.8)*(R9/100)+(124.03/88.8)*(R10/100))*(R7/100)
Lost Generation Capacity (5)	485	E	20	220*(81.64/48.54)*1.31
	-----		21	-----
Total Direct Annual Cost	5,957		22	@SUM(R20..R15)
			23	
Indirect Annual Cost			24	
Capital Recovery (1)	4,268	F	25	27680*0.1542
Admin, Property Taxes, and	598	F	26	27680*0.0216
Insurance			27	
	-----		28	-----
Total Indirect Annual Cost	4,866		29	@SUM(R27..R25)
			30	
Total Annual Cost	10,823		31	+R29+R22
			32	
NOx Emissions		G	33	
=============			34	
42ppm natural gas, tpy	2,018		35	4205*(R9/100)*(R7/100)
9ppm natural gas, tpy	404		36	0.2*R35
	-----		37	-----
Removed on gas, tpy	1,615		38	+R35-R36
			39	
65ppm oil, tpy	795		40	6623*(R10/100)*(R7/100)
Emissions with 65% removal	278		41	+R40*0.35
	-----		42	-----
Removed on oil, tpy	517		43	+R40-R41
			44	
Total removed, tpy	2,131		45	+R43+R38
			46	
Cost Effectiveness, $/ton	5,078		47	(R31*1000)/R45

FORMULA NOTES

A. Differential O&M Cost: The $3,490,000 (from B&V/GE input and TPS project specific factors) is for the 3 year catalyst replacement at 100% capacity factor. The equation which follows was developed to distribute the appropriate figure depending on the capacity factor (and firing hours) of the station. The $160,000 is the estimated cost for tube replacements and HRSG wash downs. This figure varies with capacity factor and oil usage.

B. Ammonia: The $600,000 (from B&V/GE) is based on ammonia at $250/ton. This figure varies with capacity factor.

C. Heat Rate Penalty: The $1,380,000 and the $1,700,000 (from B&V/GE) are based on a 0.42% heat rate degradation accross the CT and $10.36/MBtu and $12.79/MBtu for levelized fuel forecasts for natural gas and oil, respectively. These values were corrected for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($11.68/MBtu and $14.49/MBtu for natural gas and oil respectively). The factor of 6.6 on oil was the developed estimate for utilizing the SCR on oil. It was based on a 5% heat rate degradation accross the steam turbine due to fouling of the HRSG. The heat rate penalty varies with capacity factor and respective fuel usage.

D. SCR Power Consumption: The $930,000 (from B&V/GE) is the estimate for power consumption by the dilution air fans, additional pump power, and the ammonia vaporizer at a charge of $88.80/MWHr. This was corrected to the recent TEC forecasts of $99.98/MWHr and $124.03/MWHr for gas and oil respectively. This penalty varies with capacity factor and gas and oil usage respectively.

E. Lost Generation Capacity: The $220,000 (from B&V/GE) is based on a 0.45% decrease in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a project specific demand charge of $81.64/kw/yr. The factor of 1.31 on oil was the developed estimate of the lost generation for utilizing the SCR on oil. It was based on a 5% capacity degradation.

F. Capital Recovery: See note 1.

G. Emissions: The 4205 tons per year and the 6623 tons per year (from B&V/GE) vary with oil usage and capacity factor.

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

ATTACHMENT 3
PAGE 1 OF 4

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
===================									
Direct Annual Cost									
Differential O&M Cost (2)	464	465	468	470	473	475	478	480	483
Energy (3)									
Heat Rate Penalty	473	568	757	947	1,136	1,325	1,515	1,704	1,893
Pump Power Consumption	10	13	17	21	25	29	34	38	42
Lost Generation Capacity (4)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	719	817	1,013	1,209	1,405	1,601	1,797	1,993	2,189
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1340	1438	1634	1830	2026	2222	2418	2614	2810
NOx Emissions									
=============									
65ppm oil, tpy	331	397	530	662	795	927	1,060	1,192	1,325
42ppm oil, tpy	214	257	342	428	514	599	685	770	856
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	117	141	187	234	281	328	375	422	469
Cost Effectiveness, $/ton	11,437	10,228	8,717	7,810	7,206	6,774	6,450	6,199	5,997

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil
Capital costs ($X1000)

Differential Combustion Turbine Costs	0
HRSG Modification	763
Water Treatment, Storage, and Injection Equipment	1,163
Foundations & BOP Equipment	288
Contingency (10%)	221
Subtotal	2,435
Sales Tax (6%)	146
Indirect costs (14.5%)	353
Subtotal	2,935
Escalation (4.7%)	205
Total Escalated Cost	3,140
Interest During Construction	395
Total Capital Investment	3,535

NOTE:

1. Based on a Total Capital Investment of $3,533,000 with a project specific capital recovery factor of 15.42% Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.
2. Differential O&M includes BOP maintenance and water treatment chemical costs. Inspection intervals decrease from 6500 operating hours to 1500 operating hours. This increases maintenance $2,288,000 per year of 100% oil firing.
3. Energy includes increased BOP power consumption as well as a 1.2% CC heat rate penalty for the additional injection. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's current levelized fuel cost of $14.49/MBtu for oil. Increased BOP power consumption is charged at $124.03/MWh for oil.
4. Additional generation capacity is based on a 1.8% increase. An incremental levelized demand charge of $81.64/kw/yr was utilized based on project specific parameters.

Department of Environmental Regulation

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1. Barry

2.

3.

4.

Remarks:

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From: Clair

Date 10/3

Phone

```
TECO Power Services - Hardee Power Station          COLUMN Q
Additional Injection - 42 ppm gas and oil                ROW

Capacity factor                  60                   4 60
                                                      5
% Natural Gas firing             80                   6 80
% No. 2 Fuel Oil firing          20                   7 20
                                                      8
Annual Costs, $X1000                                  9
====================                                 10
Direct Annual Cost                                   11
  Differential O&M Cost (2)     473 A                12 (127*(Q4/100)+2288)*(Q7/100)
  Energy (3)                                         13
    Heat Rate Penalty         1,136 B                14 1.1*(0.012/0.01)*(6330*(14.49/12.79)*(Q7/100)*(Q4/100))
    Pump Power Consumption       25 C                15 150*((Q7/100)*(124.03/88.8))*Q4/100
  Lost Generation Capacity    (229)D                 16 -370*(81.64/48.54)*(Q7/100)*(0.0184/0.01)
                              -----                  17 -----
  Total Direct Cost           1,405                  18 @SUM(Q16..Q12)
Indirect Annual Cost                                 19
  Capital Recovery (1)          545 E                20 (3533)*0.1542
  Admin, Property Taxes, Insur   76 E                21 (3533)*0.0216
                              -----                  22 -----
  Total Indirect Annual Cost    621                  23 +Q21+Q20
                                                     24
Total Annual Cost              2026                  25 +Q23+Q18
                                                     26
NOx Emissions                                        27
=============                                        28
  65ppm oil, tpy                795 F                29 6623*(Q7/100)*(Q4/100)
  42ppm oil, tpy                514 F                30 4280*(Q7/100)*(Q4/100)
                              -----                  31 -----
  Removed, tpy                  281                  32 +Q29-Q30
                                                     33
                                                     34
Cost Effectiveness, $/ton     7,206                  35 (Q25*1000)/Q32
=========================
```

A. Differential O&M Cost: The $127,000 (from B&V/GE) is for additional water treatment and BOP O&M. It varies with capacity factor and oil usage. The $2,288,000 (from GE) is for decreased inspection intervals and varies linearly with oil usage.

B. Heat Rate Penalty: The $6,330,000 (from B&V) is based on a 1% heat rate penalty utilizing a fuel cost of $12.79/Mbtu for oil at the lower heating value. This was corrected for the 1.2% heat rate penalty (from GE) and for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($14.49/mbtu). This penalty varies with oil usage and capacity factor.

C. Pump Power Consumption: The $150,000 (from B&V/GE) is based on a power cost of $88.80/Mwh. This was corrected to the recent TEC forecast of $124.03. This penalty varies with oil usage and capacity factor.

D. Lost Generation Capacity: The $370,000 (from GE/B&V) is based on a 1% increase in capacity utilizing a $48.54/kW/yr demand charge. This was corrected to a 1.84% increase in capacity (from GE) using a project specific demand charge of $81.64/kw/yr. This varies with oil usage.

E. Capital Recovery: See note 1.

F. Emissions: The 6623 tons per year and the 4280 tons per year (from B&V/GE) vary with oil usage and capacity factor.

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Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
 Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: TECO Power Services Corp. Hardee Power Station (PSD-FL-140)

Dear Mr. Fancy:

This is to acknowledge receipt of the preliminary determination for the above referenced facility by letter dated August 2, 1990. We have reviewed the package as submitted and have the following comments.

MODELING/MONITORING

As noted in our comments on the permit application dated August 11, 1989, we indicated that preconstruction monitoring based on regional monitors was acceptable if such monitors could be found to be representative. For SO_2, the monitors located north of the site fall into the representative category and we will accept one of those monitors as fullfilling the PSD requirement for SO_2.

For ozone, we believe the Tampa monitoring site is the most representative site based on the prevailing winds and distance to the Hardee County site. Also, since maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is possible that the background levels at the site are higher than at sites that are not downwind of the Tampa area. The purpose of PSD monitoring is to quantify the background levels in the impact area.

BACT ANALYSIS

The BACT determination requires the use of wet injection and limits the hours of operation of the combined cycle units to 2190 hours per year. This is equivalent to 25% of capacity which is typical of a "peaking" unit. The simple cycle turbine of Phase IA, however, is not limited on hours of operation. In addition, the combined cycle units have the capacity to use by-pass vents and thus function as simple cycle units. It would appear, then, that the combined cycle units could operate continuously provided the hours of operation in the combined phase did not exceed 2190.

If the units are "peaking" units as the applicant claims, then the combined capacity of all the units (both combined cycle and simple cycle) should be limited to 25% of facility capacity. This is in keeping with the precedent set with Key West and facilities in North and South Carolina. Otherwise, the BACT analysis would indicate the need for add-on NO_x controls.

In addition, the burner design should be evaluated for BACT. The applicant proposes to use General Electric turbines. GE manufactures a "quiet combustor" which achieves NO_x levels of 25 ppm using wet injection when firing natural gas. Other burner designs are available which are capable of achieving equal or better emission levels. For example, the South Bay Power Plant in Chula Vista, CA, has recently proposed a 140 MW combined cycle turbine with emission limits of 9 ppm NO_x and 8 ppm CO firing natural gas, using steam injection. The technology proposed is currently in practice at the Delmarva Power and Light, Hay Road Station, Delaware. NO_x emissions at this facility have been tested at lower than 25 ppm.

In any case, it does not seem appropriate to allow a simple cycle "peaking" unit to operate 8760 hours per year without a lower emission rate. Also, clarification should be given as to whether the combined cycle units will be allowed to operate in simple cycle mode.

As with the Key West permit, the permit should contain provisions to require that the facility must reevaluate BACT, with SCR as a minimum, in the event that the 25% capacity factor is exceeded or the source wishes to operate as other than a peaking unit.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please do not hesitate to contact Mr. Gregg Worley of my staff at (404) 347-2904.

Sincerely yours,

Jewell A. Harper

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Mr. Barry Andrews, FDER
TECO Hardee
B. Thomas, SW Dist

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From: ____________________ Date: ____________________

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Steve Smallwood, Director DARM

FROM: John Shearer, Assistant Secretary

RE: Hardee Power Station BACT Revision
Case No. PA-89-25

DATE: August 10, 1990

On August 8, 1990, I met with representatives of Tampa Electric Company (TECo), TECo Power Services (TPS), and Seminole Electric Cooperative (SECT) to discuss revision of the Department's recommended BACT determination for NO_x as issued June 14, 1990, for the TECO/SECI Hardee Power Station project, Case No. PA-89-25. Updated information presented to me by the applicant appears to substantiate that, at the cumulative capacity factors projected for the Hardee Power Station, a requirement for the installation of selective catalytic reduction (SCR) as BACT is not justified because of the excessive cost (between $4500 and $5600 per ton as compared to EPA's guidelines of $3000 to $4000 per ton) of NO_x reduction with SCR at a cumulative capacity factor of 60%.

The applicant has committed to construct the duct module to accommodate later installation of SCR equipment if the Hardee Power Station operates at a cumulative capacity factor in excess of 60%. Should BACT be re-evaluated, selective catalytic reduction for NO_x control will be required at a minimum for BACT.

Attached are amended conditions of certification which are necessary to implement the revised BACT determination for NO_x to be made the subject of a formal stipulation at the Hardee Power Station certification hearing, August 13-17, 1990. Should the assumptions on costs, fuel usage, or other considerations that were used to arrive at this decision materially change, then the Department shall re-evaluate this determination.

Please direct that a revised BACT narrative incorporating the agreed conditions of certification be prepared for submission to the EPA.

JS/ht

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Mr. Claire Fancy
Florida Department of
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Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2440

Re: Hardee Power Station
BACT Cost Analysis

Dear Mr. Fancy:

Enclosed, please find a copy of a BACT cost analysis for reducing NO_x emissions from 65 ppm to 42 ppm while burning oil at the Hardee Power Station (HPS).

For the unlikely case of the HPS burning 100% fuel oil at a capacity factor of 100%, the cost per ton of NO_x removed is $4,937. When analyzing the $/ton of NO_x removed for HPS' likely fuel scenario of 80% natural gas and 20% fuel oil, the values are significantly higher. In any case, these values far exceed any $/ton of NO_x removal justified as BACT to date. We therefore believe that the analysis clearly shows that an emissions limit of 42 ppm while burning oil should not be considered BACT for the HPS.

Should you have any questions, please call.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

PSD-FL-140

cc: EPA, NPS ?

JLW/dsr/LL412.DOC

Enclosures

cc: Mr. Steve Smallwood, DER
Mr. Hamilton Oven, DER
Mr. Barry Andrews, DER ✓
BA/CHF 7-26-90 [illegible]

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State: FL
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PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE	OVER SIZE
Total	Total	Total	

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TECO Power Services - Hardee Power Station
ditional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	463	465	468	470	473	475	478	480	483
Energy (3)									
Heat Rate Penalty	379	568	757	947	1,136	1,325	1,515	1,704	1,893
Pump Power Consumption	8	13	17	21	25	29	34	38	42
Lost Generation Capacity	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)
Total Direct Cost	621	817	1,013	1,209	1,405	1,601	1,797	1,993	2,189
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1242	1438	1634	1830	2026	2222	2418	2614	2810
NOx Emissions									
65ppm oil, tpy	265	397	530	662	795	927	1,060	1,192	1,325
42ppm oil, tpy	171	257	342	428	514	599	685	770	856
Removed, tpy	94	141	187	234	281	328	375	422	469
Cost Effectiveness, $/ton	13,250	10,228	8,717	7,810	7,206	6,774	6,450	6,199	5,997

TECO Power Services - Hardee Power Station
'dditional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	60	60	60	60	60	60	60	60	60
% No. 2 Fuel Oil firing	40	40	40	40	40	40	40	40	40
Annual Costs, $X1000									
===================									
Direct Annual Cost									
Differential O&M Cost (2)	925	930	936	941	946	951	956	961	966
Energy (3)									
Heat Rate Penalty	757	1,136	1,515	1,893	2,272	2,651	3,029	3,408	3,786
Pump Power Consumption	17	25	34	42	50	59	67	75	84
Lost Generation Capacity	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	1,241	1,634	2,026	2,418	2,810	3,202	3,594	3,986	4,378
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1862	2255	2647	3039	3431	3823	4215	4607	4999
NOx Emissions									
===========									
65ppm oil, tpy	530	795	1,060	1,325	1,590	1,854	2,119	2,384	2,649
42ppm oil, tpy	342	514	685	856	1,027	1,198	1,370	1,541	1,712
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	187	281	375	469	562	656	750	843	937
Cost Effectiveness, $/ton	9,937	8,019	7,060	6,485	6,101	5,827	5,622	5,462	5,334

TECO Power Services - Hardee Power Station
ditional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	40	40	40	40	40	40	40	40	40
% No. 2 Fuel Oil firing	60	60	60	60	60	60	60	60	60
Annual Costs, $X1000									
====================									
Direct Annual Cost									
Differential O&M Cost (2)	1,388	1,396	1,403	1,411	1,419	1,426	1,434	1,441	1,449
Energy (3)									
Heat Rate Penalty	1,136	1,704	2,272	2,840	3,408	3,976	4,544	5,112	5,680
Pump Power Consumption	25	38	50	63	75	88	101	113	126
Lost Generation Capacity	(687)	(687)	(687)	(687)	(687)	(687)	(687)	(687)	(687)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	1,862	2,450	3,038	3,627	4,215	4,803	5,391	5,979	6,567
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	2483	3071	3660	4248	4836	5424	6012	6600	7188
NOx Emissions									
===========									
65ppm oil, tpy	795	1,192	1,590	1,987	2,384	2,782	3,179	3,576	3,974
42ppm oil, tpy	514	770	1,027	1,284	1,541	1,798	2,054	2,311	2,568
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	281	422	562	703	843	984	1,125	1,265	1,406
Cost Effectiveness, $/ton	8,832	7,283	6,508	6,043	5,733	5,512	5,346	5,217	5,113

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	20	20	20	20	20	20	20	20	20
% No. 2 Fuel Oil firing	80	80	80	80	80	80	80	80	80
Annual Costs, $X1000									
===================									
Direct Annual Cost									
Differential O&M Cost (2)	1,851	1,861	1,871	1,881	1,891	1,902	1,912	1,922	1,932
Energy (3)									
Heat Rate Penalty	1,515	2,272	3,029	3,786	4,544	5,301	6,058	6,816	7,573
Pump Power Consumption	34	50	67	84	101	117	134	151	168
Lost Generation Capacity	(916)	(916)	(916)	(916)	(916)	(916)	(916)	(916)	(916)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	2,483	3,267	4,051	4,835	5,620	6,404	7,188	7,972	8,757
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	3104	3888	4672	5457	6241	7025	7809	8593	9378
NOx Emissions									
============									
65ppm oil, tpy	1,060	1,590	2,119	2,649	3,179	3,709	4,239	4,769	5,298
42ppm oil, tpy	685	1,027	1,370	1,712	2,054	2,397	2,739	3,082	3,424
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	375	562	750	937	1,125	1,312	1,500	1,687	1,874
Cost Effectiveness, $/ton	8,280	6,914	6,232	5,822	5,549	5,354	5,208	5,094	5,003

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	0	0	0	0	0	0	0	0	0
% No. 2 Fuel Oil firing	100	100	100	100	100	100	100	100	100
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	2,313	2,326	2,339	2,352	2,364	2,377	2,390	2,402	2,415
Energy (3)									
Heat Rate Penalty	1,893	2,840	3,786	4,733	5,680	6,626	7,573	8,520	9,466
Pump Power Consumption	42	63	84	105	126	147	168	189	210
Lost Generation Capacity	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)
Total Direct Cost	3,103	4,084	5,064	6,044	7,025	8,005	8,985	9,965	10,946
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	3725	4705	5685	6665	7646	8626	9606	10586	11567
NOx Emissions									
65ppm oil, tpy	1,325	1,987	2,649	3,312	3,974	4,636	5,298	5,961	6,623
42ppm oil, tpy	856	1,284	1,712	2,140	2,568	2,996	3,424	3,852	4,280
Removed, tpy	469	703	937	1,172	1,406	1,640	1,874	2,109	2,343
Cost Effectiveness, $/ton	7,948	6,694	6,066	5,690	5,439	5,259	5,125	5,020	4,937

NOTE:

Based on a Total Capital Investment of $3,533,000 with a project specific capital recovery factor of 15.42% Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.

2. Differential O&M includes BOP maintenance and water treatment chemical costs. Inspection intervals decrease from 6500 operating hours to 1500 operating hours. This increases maintenance $2,288,000 per year of 100% oil firing.
3. Energy includes increased BOP power consumption as well as a 1.2% CC heat rate penalty for the additional injection. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's current levelized fuel cost of $14.49/MBtu for oil. Increased BOP power consumption is charged at $124.03/MWh for oil.
4. Additional generation capacity is based on a 1.8% increase. An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.

TECO Power Services - Hardee Power Station
DITIONAL INJECTION (42 PPM ON OIL) CAPITAL COSTS ($X1000)

Differential Combustion Turbine Costs	0
HRSG Modification	763
Water Treatment, Storage, and Injection Equipment	1,163
Foundations & BOP Equipment	288
Contingency (10%)	221
Subtotal	2,434
Sales Tax (6%)	146
Indirect costs (14.5%)	353
Subtotal	2,933
Escalation (4.7%)	205
Total Escalated Cost	3,138
terest During Construction	395
Total Capital Investment	3,533

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

Interoffice Memorandum

TO: Steve Smallwood

THRU: Clair Fancy

FROM: Barry Andrews BA

DATE: June 5, 1990

SUBJ: BACT Determination for Hardee Power Station

Based on my initial review and additional information that has been obtained through meetings with representatives of TECO/Seminole Electric, communication with equipment vendors, and discussions with the EPA and other permitting agencies, this memo outlines my conclusions regarding BACT for the Hardee Power Station. The BACT recommendations are outlined on a pollutant-by-pollutant basis as follows.

Particulates, CO, VOC

BACT to be established as the lesser of the emission levels proposed or the levels established as BACT for identical equipment (GE Frame 7 EA) permitted in other states.

Sulfur Dioxide

BACT to be established by limiting the average annual sulfur content of fuel oil to 0.3 percent.

Nitrogen Oxides

BACT to be established by requiring selective catalytic reduction (SCR) for operating at a capacity factor in excess of 25 percent (2,190 hours per year). For operation at or below a 25 percent capacity factor BACT will be established as the lesser of the emission level proposed or the level established as non SCR BACT for identical equipment (GE Frame 7 EA) in other states.

Basis

For the natural gas firing mode, the use of SCR has been proven to be technically feasible in many cases. The BACT/LAER Clearinghouse indicates that there have been several combined cycle (gas turbine/heat recovery steam generators) facilities that have used SCR as either a proposed or required BACT. A review of recent permitting activities indicates that SCR has been established as BACT for two facilities using the identical equipment (GE Frame 7 EA) that is proposed for the Hardee Power Station. In each case, the economics of SCR NOx control was determined to be similar to that proposed at the Hardee facility (approx. $3,600/ton of NOx removed at 100% capacity factor).

The decision to establish SCR as BACT for natural gas firing is consistent with the guidance that EPA has given with regard to recent permitting activities (Tropicana, Cedar Bay Cogen) and the recent New Source Review workshop in Denver. Basically EPA is saying that if BACT has been established for a particular type of equipment (model), then the same BACT determination should be established for similar proposals unless it can be demonstrated that there are unique differences between the two projects. EPA feels that this type of decision making basis has advantages over the cost per ton method, since it is often difficult to quantify what the <u>actual</u> cost of providing control will be.

For the Hardee facility, the applicant has indicated that the capacity factor is not expected to exceed 25 percent during the first 5 years of operation. This operating scenario is different than the two facilities mentioned above in which operation levels are expected to exceed 80 percent of full capacity. As this is the case, a determination which would only require SCR if operation exceeds 25 percent of full capacity is judged to be reasonable. A determination of this type is consistent with what is happening in other states. NESCAUM, for example, is now evaluating what level of operation should not require SCR. Presently they are looking to establish a cut-off at somewhere between 1,500 and 2,500 hours per year operation. This decision is also consistent with what was established as BACT for the Key West Electric facility. In that case BACT was determined to be the use of SCR for full load operation above 1,870 hours per year.

For oil firing the use of SCR also appears to be technologically feasible. Although the formation of ammonium bisulfate has caused concerns for the oil firing mode, recent information suggests that SCR is still feasible if the ammonia injection ratio is adjusted.

For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NOx injection ratio. For natural gas firing operation, NOx emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NOx can be controlled with efficiencies of approximately 70 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on these findings, a requirement that SCR be used for both gas and oil firing is deemed appropriate for operation above the 25 percent capacity factor.

BA/plm

For Routing To Other Than The Addressee

To: Pradeep Location:

To: Location:

To: Location:

From: Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Randy Armstrong
Howard Rhodes
Mimi Drew

FROM: Steve Smallwood

DATE: February 28, 1990

SUBJECT: TECO/Seminole - Hardee Power
Project power Plant Siting Application
PA 89-25 - 8185

Personnel in your respective divisions have been reviewing the above referenced application since July 1989. The department needs to prepare its final report by the end of March. Please have the appropriate personnel submit their final reviews and recommendations to Buck Oven by March 13, 1990.

HO/SM/rrs

cc: Power Plant Review Committee
Richard Donelon

SEMINOLE
ELECTRIC
COOPERATIVE
INCORPORATED

January 29, 1990

RECEIVED
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DER-BAQM

Mr. Wayne E. Daltry
Executive Director
Southwest Florida Regional
Planning Council
P.O. Box 3455
North Ft. Myers, Florida 33918-3455

Re: Hardee Power Station
PA 89-25

Dear Mr. Daltry:

Thank you for your November 20, 1989 letter withdrawing the Southwest Florida Regional Planning Council's (SWFRPC) preliminary findings regarding the Hardee Power Station power plant certification pending clarification and review of various matters. We sincerely appreciate your agency's cooperation. With this letter, Seminole Electric Cooperative, Inc. (SECI) would like to address the "comments and concerns" listed as items 1 through 12 in your November 20 letter and present an overview explaining the procedures of Florida's Electrical Power Plant Siting Act. Our specific responses are set forth in numbered paragraphs corresponding to your November 20 letter.

Specific Responses

Comment No. 1:

> In order to avoid any impacts to fish and wildlife, and their habitat, in the Cecil M. Webb Wildlife Management Area the applicant should be required by the Florida Public Service Commission to propose an alternate corridor, completely outside the Webb W.M.A.

Response:

> SECI is actively working with the Florida Game and Fresh Water Fish Commission, the agency responsible for managing the Webb area, and have recently submitted a mitigation proposal that would more than offset the minimal wildlife impacts caused by the proposed transmission line. We will keep you apprised of the status of these discussions. Please note that the proposed corridor would affect only the northern and western edges of the Webb area, passing through areas already affected by a sewage treatment plant and a highway.

Comment No. 2:

The proposed corridor passes through, or adjacent to a number of Developments of Regional Impact in Charlotte and Lee Counties. These are Seminole Trail, Fairway Woodlands, Pine Lakes Country Club, Hancock Creek Commerce, Del Prado North, and Indian Oaks Trade Center. Regional staff can provide the applicant (Seminole Electric Cooperative) with names and addresses of representatives to determine the impact of the corridor, if any, on the DRI's.

Response:

SECI has reconfigured the corridor to avoid passing through the Seminole Trail and Fairway Woodlands DRI's. Pine Lakes Country Club is approximately two miles from the proposed corridor in Lee County, thus there will be no effect on this development. Hancock Creek Commerce is located south of the Lee substation in Lee County and will not be impacted by the corridor. Del Prado North is located within the City of Cape Coral, and is adjacent to the northern boundary of the proposed corridor alignment in Section 30. Although the corridor is adjacent to the Del Prado North boundary for a distance of 0.50 miles, the proposed corridor alignment should not directly impact this development. The Indian Oaks Trade Center is located in Lee County approximately 0.25 miles south of the Lee substation and no impacts from the proposed corridor are anticipated.

Comment No. 3:

That portion of the proposed corridor within the City of Cape Coral should avoid those properties which are designated as a future City Park site within the Cape Coral Comprehensive Plan. City staff has informed Regional Staff that the City will monitor the Florida Public Service Commission Public Hearings Process for this project, and that the City is prepared to intervene in the process, should the proposed corridor appear to traverse the park site.

Response:

SECI has worked closely with City of Cape Coral representatives, including the City Manager, City Attorney, and planning and zoning officials. Also, SECI has appeared before the City Council. Agreement regarding the best route through Cape Coral was achieved several months ago. We currently are awaiting finalization of an amendment to the Cape Coral Zoning Ordinance, after which the City and SECI will enter into a stipulation agreeing that the corridor is consistent and in compliance with the land use plan and zoning ordinance.

Comment No. 4:

The applicant should be required to prepare a wetlands inventory for the proposed corridor. The inventory should map all wetlands within and adjacent to the corridor and should include mitigation for impacts to these wetlands. This inventory should be coordinated with the respective local governments, the Florida Department of Environmental Regulation, the United States Army Corps of Engineers and the South Florida Water Management District.

Response:

As inventory is provided in the Site Certification Application at pages 6-54 through 6-60, and Appendix, Figure 6.1.7-2. This information comports with what typically is provided for linear, transmission line facilities. More detailed information will be developed and made available to the agencies in accordance with the conditions of certification after SECI determines the actual transmission line right of way.

Comment No. 5:

The applicant should be required to mitigate any adverse impacts to water quality caused by corridor clearing and filling, and/or construction of the transmission facilities. Mitigation should be determined by appropriate federal, state, regional and local review and permitting agencies.

Response:

SECI anticipates complying with all applicable mitigation guidelines.

Comment No. 6:

All crossings of streams, wetlands, or other bodies of water, by the proposed facilities should be constructed at such points where road or utility crossings already exist, where feasible.

Response:

SECI agrees with this concern, and anticipates that the final certification order will set forth appropriate, corresponding conditions.

Comment No. 7:

The applicant, in cooperation with a state-certified archaeologist, should perform an archaeological/historical site survey within the proposed corridor. All new or existing sites revealed in the survey should be thoroughly investigated, and appropriate actions taken, before corridor construction is allowed to proceed.

Response:

As stated in the application (Vol. II, pages 6-52 through 6-54) the corridor study area was reviewed by the Florida Department of State, Division of Historical Resources (DHR). This review included known archaeological or historic sites affected by the corridor and also "archaeologically sensitive" areas that need to be surveyed prior to construction. In compliance with The DHR recommendations (Vol. III, Appendix 11.3) SECI will employ a certified professional archaeologist and perform a site specific archaeological/historical survey on those areas identified as "archaeologically sensitive". Prior to commencing this survey, the locations and methodology will be submitted to DHR for approval.

Comment No. 8:

Cutting, clearing, filling, and maintenance for the proposed corridor should be strictly limited to the area necessary for construction of the proposed transmission facilities. The remainder of the corridor width should be managed as a conservation easement.

Response:

SECI agrees with the first sentence, except that the words "and operation" should be inserted after the word "construction". The second sentence is problematic, both from a practical and legal perspective. For example, please note that SECI ultimately will obtain easements along the transmission line corridor in accordance with the grant of eminent domain authority provided by the Florida Legislature. Acquiring a conservation easement in accordance with this process would appear to violate Section 704.06(2), Florida Statutes, which provides that conservation easements may not be acquired "by condemnation or by other exercise of the power of eminent domain."

Comment No. 9:

The roadways required within the proposed corridor should be constructed of dirt and/or gravel, and should not utilize any type of paving material, except in such cases where existing public or private roadways are utilized.

Response:

The transmission line access roads will be constructed of dirt, gravel, or limerock.

Comment No. 10:

The transmission line facilities, or their construction, should avoid adverse impacts to navigation on the Peace River, Shell Creek, and surrounding waterways.

Response:

SECI agrees with this comment and anticipates appropriate, corresponding conditions in the certification order.

Comment No. 11:

Within the site certification application/environmental assessment, the applicant has made a number of commitments and/or statements of intent. These should be incorporated as conditions for approval, provided they do not conflict with the above recommendations, or recommendations of other review agencies.

Response:

SECI agrees with this comment and anticipates appropriate, corresponding conditions in the certification order.

Comment No. 12:

As the proposed transmission line appears to have significant impacts in Charlotte and Lee Counties, the Council recommends that public hearings be required in each impacted County.

Response:

Before proposing the referenced transmmission line corridor, SECI conducted, after publication of notice in newspapers in each county, several public workshops to receive input regarding location of the transmission line. Moreover, SECI has worked closely with government officials of Lee County, Charlotte County, and Cape Coral. SECI representatives appeared before the Charlotte County Board of Commissioners and the Cape Coral City Council. The next public hearing in this process is the land use hearing, which will be held in Hardee County on March 6 and 7, 1990. The certification hearing will be in Hardee County in mid-May, 1990.

General Response

SECI's joint application to construct the Hardee Power Station and directly associated transmission lines is governed by the procedures set forth in the Electrical Power Plant Siting Act ("PPSA", Section 4403.501-.517, Fla. Stat.) and the Department of Environmental Regulation's (DER) implementing regulations, as set forth at Chapter 17-17, Florida Administrative Code.

The PPSA provides a unified and exclusive process for permitting new powerplants and directly associated transmission lines. A PPSA certification order signed by the Governor constitutes "the sole license of the state and any agency [including local governments] as to the approval of the site and the construction and operation of the proposed electric power plant. . .[and associated transmission lines]" Two separate steps in the PPSA certification process are the land use hearing and certification hearing. The land use hearing involves consideration of only whether the plant and directly associated transmission lines are consistent and in compliance with the local government land use plans and zoning ordinances; the certification hearing involves assessment of all other relevant environmental and natural resource issues.

Both hearings are convened before a Division of Administrative Hearings (DOAH) hearing officer. After each hearing, the DOAH hearing officer forwards a recommended order to the Governor and Cabinet, sitting as the Siting Board, for "final agency action". Upon the Siting Board's affirmative finding of consistency and compliance with local land use plans and zoning ordinances, the applicant may proceed with the final certification hearing. However, if the Siting Board concludes that the proposed site does not conform with local government land use plans and zoning ordinances, it is the applicant's responsibility to apply to the respective local governments for rezoning. Should such an application for rezoning be denied, the applicant could appeal to the Siting Board for authorization of a nonconforming use or variance.

The PPSA process ultimately entails balancing the need for the proposed facility and the environmental impact resulting from construction and operation of same. In addition to environmental and natural resource protection, the PPSA contemplates consideration of the need "to provide abundant, low-cost electrical energy." Section 403.502(3), Fla. Stat.

The state agency responsible for sheperding the Hardee Power Station application through the PPSA certification process is DER, not the PSC. (The PSC is responsible for an initial determination of "need" for powerplants.) The appropriate contact is Hamilton (Buck) Oven of DER (904/488-1344). If SWFRPC wishes to participate in the PPSA hearings, it must file a "notice" to this effect with the hearing officer and forward copies to all existing parties. A copy of a recent notice is attached for your convenience.

Thank you for considering our responses. We will contact you in the near future to arrange a meeting so that we may answer all of your questions.

Sincerely,

Mike R

Mike Roddy
Senior Environmental Engineer

MR:bmc

cc: Mr. Richard Melson
Mr. James D. Beasley
Ms. Trudie Bell
Mr. Alton Roane
Dr. Richard Garrity
Mr. Phillip Edwards
US Dept. of Agriculture
Mr.John Adams
Mr. Bill Howell
Mr. Howard Knight
Ms. Patricia Adams
Mr. Mike Best
Mr. Steve Minnis
Mr. John Morgan
Mr. Bryan Sodt
Board of Trustees of the Internal Improvement Trust Fund
Ms. Linda Sumarlidason
Ms. Kim Dryden
Mr. Kevin Doyle
Mr. Robert Taylor
Mr. Norman Feder
Mr. Hamilton Oven
Mr. Jerry Williams
Mr. Bruce Miller
Mr. Paul Darst

Southwest Florida Regional Planning Council

4980 Bayline Drive, 4th Floor, N. Ft. Myers, FL 33917-3909 (813) 995-4282

P.O. Box 3455, N. Ft. Myers, FL 33918-3455 SUNCOM 721-7290 / 7291

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November 20, 1989

Mr. Steve Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32399-0850

RE: IC&R PROJECT #89-168
PROJECT NAME: TECO Power Services, et. al., Proposed Hardee Power Station Site Certification Application/Environmental Assessment

Dear Mr. Tribble:

On November 9, 1989, Regional Staff submitted to you a preliminary finding of "regionally significant and inconsistent" for the above-mentioned project. The letter stating staff findings for this project also contained a series of recommendations. At the November 16, 1989, Council meeting, representatives from the Seminole Electric Cooperative, Inc. requested that the Council table their formal findings of consistency to allow an opportunity to address the Council's concerns. Therefore, at Council direction staff wishes to withdraw the preliminary finding of regionally significant and inconsistent. The Council, however, directed staff to forward the following comments and concerns to be addressed during the formal review of this project:

1. In order to avoid any impacts to fish and wildlife, and their habitat, in the Cecil M. Webb Wildlife Management Area the applicant should be required by the Florida Public Service Commission to propose an alternate corridor, completely outside the Webb W.M.A.

2. The proposed corridor passes through, or adjacent to a number of Developments of Regional Impact in Charlotte and Lee Counties. These are Seminole Trail, Fairway Woodlands, Pine Lakes Country Club, Hancock Creek Commerce, Del Prado North, and Indian Oaks Trade Center. Regional staff can provide the applicant (Seminole Electric Cooperative) with names and addresses of representatives to determine the impact of the corridor, if any, on the DRIs.

3. That portion of the proposed corridor within the City of Cape Coral should avoid those properties which are designated as a future City Park site within the Cape Coral Comprehensive Plan. City staff has informed Regional Staff that the City will monitor the Florida Public Service Commission Public Hearings Process for this project, and that the City is prepared to intervene in the process, should the proposed corridor appear to traverse the park site.

4. The applicant should be required to prepare a wetlands inventory for the proposed corridor. The inventory should map all wetlands within and adjacent to the corridor and should include mitigation for impacts to these wetlands. This inventory should be coordinated with the respective local governments, the Florida Department of Environmental Regulation, the United States Army Corps of Engineers and the South Florida Water Management District.

5. The applicant should be required to mitigate any adverse impacts to water quality caused by corridor clearing and filling, and/or construction of the transmission facilities. Mitigation should be determined by appropriate federal, state, regional and local review and permitting agencies.

6. All crossings of streams, wetlands, or other bodies of water, by the proposed facilities should be constructed at such points where road or utility crossings already exist, where feasible.

7. The applicant, in cooperation with a state-certified archaeologist, should perform an archaeological/historical site survey within the proposed corridor. All new or existing sites revealed in the survey should be thoroughly investigated, and appropriate actions taken, before corridor construction is allowed to proceed.

8. Cutting, clearing, filling and maintenance for the proposed corridor should be strictly limited to the area necessary for construction of the proposed transmission facilities. The remainder of the corridor width should be managed as a conservation easement.

9. The roadways required within the proposed corridor should be constructed of dirt and/or gravel, and should not utilize any type of paving material, except in such cases where existing public or private roadways are utilized.

10. The transmission line facilities, or their construction, should avoid adverse impacts to navigation on the Peace River, Shell Creek, and surrounding waterways.

11. Within the site certification application/environmental assessment, the applicant has made a number of commitments and/or statements of intent. These should be incorporated as conditions for approval, provided they do not conflict with the above recommendations, or recommendations of other review agencies.

12. As the proposed transmission line appears to have significant impacts in Charlotte and Lee Counties, the Council recommends that public hearings be required in each impacted County.

Please be advised that it is the intent of the Southwest Florida Regional Planning Council to become a party to the on-going site certification process for this project under Chapters 403.501 to 403.519, Florida Statutes (The Florida Electrical Power Plant Siting Act). Please notify the Council of any appropriate comment deadlines so that final comments may be submitted in a timely manner.

Sincerely,

SOUTHWEST FLORIDA REGIONAL PLANNING COUNCIL

Wayne E. Daltry
Executive Director

WED/GEH/rr

cc: Mr. W Michael Roddy, Seminole Electric
Mr. Richard Melson, Hopping, Boyd, Green & Sams
Mr. James D. Beasley, Ausley, McMullen, McGehee, et. al.
Ms. Trudie Bell, FDER
Mr. Alton Roane, Lee County Planning
Dr. Richard Garrity, FDER
Mr. Phillip R. Edwards, FDER
US Dept. of Agriculture
Mr. John F. Adams, USACE
Mr. Bill Howell, FDNR
Mr. Howard Knight, Cape Coral Planning
Ms. Patricia G. Adams, FDER
Mr. Mike Best, Charlotte County Planning
Mr. Steve Minnis, SWFWMD
Mr. John Morgan, SFWMD
Mr. Bryan Sodt, Central Florida RPC
Board of Trustees of the Internal Improvement Trust Fund
Ms. Linda Sumarlidason, FDNR
Ms. Kim Dryden, FG&FWFC
Mr. Kevin Doyle, FDOT
Mr. Robert Taylor, Florida Dept. of State
Mr. Norman Feder, FDOT
Mr. Hamilton S. Oven, Jr., FDER
Mr. Jerry L. Williams, Tampa Electric
Mr. Bruce P. MIller, US EPA
Mr. Paul Darst, Florida DCA

Pradeep - 11-27
FYI - Just
return to file
I guess - Patty

For Routing To Other Than The Addressee

To: Pradeep Location:

To: Location:

To: Location:

From: Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Power Plant Siting Review Committee
Bill Thomas
Clabe Polk

FROM: Buck Oven

DATE: August 22, 1989

SUBJECT: TECO Power Services Corp./Seminole Electric Cooperative, Inc. Hardee Power Station/Power Plant Siting Application PA 88-24, Module No. 8185

Attached please find an amendment to the application for the Hardee Power Station Power Plant Siting Application as submitted by TECO and Seminole. If you have any requests for additional data, please let me know. If you feel the need for a meeting with TECO/Seminole and their consultants, please let me know.

cc: Rick Garritty
Phil Edwards

Attachment

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

AUG 11 1989

RECEIVED
AUG 16 1989
DER-BAQM

4APT/APB-aes

Ms. Patricia G. Adams
Planner
Bureau of Air Quality Management
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: TECO Power Services Corp./Seminole Electric Cooperative Hardee Power Station/Power Plant Siting Application PSD-FL-140

Dear Ms. Adams:

This is to acknowledge receipt of the above referenced faility's application for a prevention of significant deterioration (PSD) construction permit, transmitted by your letter dated July 5, 1989. As discussed between Mr. Barry Andrews of FDER and Gregg Worley of my staff on July 27, 1989, we have the following comments regarding this application.

Modeling/Monitoring

Based on the PSD significant air monitoring impact levels, the source is required to monitor for ozone and sulfur dioxide (SO_2). Florida has granted an exemption for both pollutants based on the rural nature of the site. We do not agree that the source should be exempt from monitoring for ozone and sulfur dioxide.

This is a large source with over 9,000 tons per year of expected SO_2 emissions from the first phase of construction. Potential VOC emissions from this phase are over 250 tons per year. The site is only 9 kilometers from Hillsborough County, an ozone nonattainment area. For both SO_2 and ozone monitoring, unless regional monitoring data can be justified as representative, preconstruction monitoring should be required.

SO_2 BACT Analysis

The applicant proposes the use of low sulfur fuel as the best available control technology (BACT) for SO_2. It is stated that the primary fuel for the project will be natural gas but that the turbines will also be capable of firing #2 fuel oil and synthetic gas (syn-gas) derived from coal gasification. The maximum emissions from the combustion of fuel oil are projected at over 16,000 tons per year of SO_2. These emissions are roughly equivalent to those expected from the combustion of syn-gas.

The permit should be conditioned so that fuel oil could be used in place of natural gas only as an emergency fuel as defined in the NSPS. Should the applicant desire to fire fuel oil on a more frequent basis, the gas streams from the turbines should be analyzed for the feasibility of flue-gas desulfurization (FGD) applications.

NO_x BACT Analysis

In evaluating alternatives for nitrogen oxides (NO_x) controls, the applicant dismissed the use of selective catalytic reduction (SCR) based on "technical considerations as well as significant economic and environmental impacts." The technical considerations addressed by the applicant appear to center on the arguments that SCR is not technically feasible for applications on simple-cycle turbines or on operations firing fuel oil.

Admittedly, SCR currently must be used in conjunction with a heat recovery steam generator (HRSG) in order to achieve the proper reaction temperature window. Thus, the operation of an SCR system, in its current stage of development, would not be technically feasible during a simple-cycle mode of turbine operation. The use of the simple-cycle mode, however, raises many questions. For example: Why is it necessary to use the simple-cycle when the use of the combined cycle mode is more efficient in terms of power production? What is the feasibility of supplemental firing of the HRSG such that the combined cycle is prepared for quick start-ups?

The applicant also claims that SCR would be technically infeasible due to the firing of fuel oil. As noted in the comments on the SO_2 BACT analysis, though, the firing of fuel oil should be limited to use as an emergency fuel. In addition, while the use of SCR when firing fuel oil may shorten the life of the catalyst and result in higher costs, the fact that the system will operate properly when fuel oil is fired is evidence that SCR is technically feasible for oil-fired applications. Recent permits issued in Rhode Island contain requirements that the SCR systems be operated both when the turbines are fired with natural gas and when they are fired with #2 fuel oil.

In the economic analysis, the applicant estimated a total annualized cost of $22,014,000 for the installation of SCR for the entire 660 MW plant. This results in a total cost effectiveness of roughly $2,000 per ton of NO_x removed, a figure that is within the range that other recently permitted turbine sources are paying for NO_x control.

The applicant then argued that "environmental benefits from installing SCR are small since the predicted impacts are much less than the PSD increment and AAQS." Controlling NO_x with SCR would, however, reduce emissions by over 3,700 tons per year when firing natural gas. The small change in ambient impact is not justification for dismissing a control option. This is reinforced by the recent Administrative Order on PSD Appeal No. 88-11 (enclosed), which stated that the argument "that the modelled negligible impact of the proposed facility on overall air quality is an environmental impact that can be factored into the BACT analysis to justify using less than the most effective technology to control NO_x emissions. . is without merit." Likewise, environmental effects from ammonia slippage or the handling of spent catalyst do not specifically constrain this source from using the most effective control. In summary, the applicant has not demonstrated that SCR should not be considered BACT for the control of NO_x emissions from the combustion turbines.

Thank you for the opportunity to review this application. If you have any questions regarding the comments on modeling or monitoring, please contact Mr. Lew Nagler, staff meteorologist, at (404) 347-2864. Any other quetions may be directed to Gregg Worley of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
  Management DIvision

cc: TECO

cc: P. Raval
B. Andrews
M. Fenn
B. Oven
B. Thomas, SW Dist.
CHF/BT

Hardee Power Station
Site Certification Application and Environmental Assessment

Clarification No. 1

Date: July 18, 1989

Affected Sections: 5.6.1.2 Model Results
11.1.4 Prevention of Significant Deterioration (Section 7.1)

Question: Why were 32°F and 95°F used in the modeling instead of 68°F?

Response: Because the working fluid for combustion turbines (CTs) is air, their performance is affected by the ambient temperature. Therefore, any change in temperature has a concomitant change in emissions and flow rate. The operating range for the CTs of 32°F to 95°F represents the maximum expected range in both emissions and flow rate. At 32°F, the maximum expected emissions will occur with the maximum flow rate. In contrast, at 95°F the minimum expected emissions will occur with the minimum flow rate. At a temperature of 68°F, the emissions and flow rate will be intermediate between the 32°F and 95°F conditions. Since flow rate can be a major factor in determining the impact of sources, both 32°F and 95°F conditions were modeled. By modeling this maximum expected range in operating conditions, it is assured that the maximum impacts will be determined.

Table 5.2.1-1. Summary of Estimated Cooling Reservoir and Intake Water Quality Conditions, and Reservoir Quality for the Hardee Power Station (Page 1 of 2)

Parameter	Reservoir Intake/Influent Water Quality				Cooling Reservoir Quality[1]	FDER Class III Water Quality Criteria
	Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neutralization Basin Effluent		
Calcium, mg/L as CaCO3	63	83	113	1130	220	
Magnesium, mg/L as CaCO3	39	30	49	490	100	
Sodium, mg/L as CaCO3	17	30	37	3050	180	
Potassium, mg/L as CaCO3	0	1	8	80	10	
Total Hardness, mg/L as CaCO3	102	113	162	1620	320	
Alkalinity, mg/L as CaCO3	61	83	160	0	230	>20
Sulfate, mg/L as CaCO3	37	30	26	4540	230	
Chloride, mg/L as CaCO3	21	34	21	210	50	
Silca, mg/L	5.4	17	27	270	50	
Fluoride, mg/L	1.0	0.57	2.0	20	3.6	10
Cyanide, mg/L	<0.004	<0.004	<0.005	0.05	0.01	0.005
MBAS, mg/L	0.040	0.040	<0.180	1.8	0.316	0.5
Oil and Grease, mg/L	<5	<5	<5	0	<5	5
Turbidity, NTU	1.7	51	14	10	32	29 above Background
pH, units	7	7.5	7.5	6-9	7.5	6.0-8.5
Total Dissolved Solids, mg/L	190	158	342	6860	798	
Specific Conductivity, umhos/cm	173	225	320	12100	980	1275
Total Kjeldahl Nitrogen, mg/L	0.74	0.14	0.39	3.9	0.8	
Ammonia Nitrogen, mg/L	0.11	0.07	0.20	2.0	0.4	
Unionized Ammonia, mg/L[2]	0.001	0.002	0.007	0.022	0.014	0.02
Organic Nitrogen, mg/L	0.65	0.07	0.19	1.9	0.4	
Nitrate+Nitrite-Nitrogen, mg/L	0.50	0.085	0.031	0.3	0.1	
Total Nitrogen, mg/L	1.24	0.24	0.421	4.2	0.9	
Orthophosphorus, mg/L	0.41	0.47	0.20	2.0	0.7	
Total Phosphorus, mg/L	0.44	2.08	0.20	2.0	1.1	
Arsenic, ug/L	<5	<9	<10	0.1	20	50
Barium, ug/L	<10	<10	75	750	130	
Beryllium, ug/L	<3	10	<0.9	9	4.5	1100
Cadmium, ug/L	<0.4	6	<0.7	7	2.8	1.2
Chromium, ug/L	<10	<10	13	130	26	50
Copper, ug/L	7	65	7	70	30	30
Iron, ug/L	293	1700	420	0	1200	1000

Table 5.2.1-1. Summary of Estimated Cooling Reservoir and Intake Water Quality Conditions, and Reservoir Quality for the Hardee Power Station (Page 2 of 2)

Parameter	Reservoir Intake/Influent Water Quality Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neutralization Basin Effluent	Cooling Reservoir Qulaity[1]	FDER Class III Water Quality Criteria
Lead, ug/L	6.1	<6.7	14	140	26	30
Manganese, ug/L	7.9	28	28	0	44	
Mercury, ug/L	0.24	0.24	<0.2	2	0.4	0.2
Nickel, ug/L	16	16	23	230	45	100
Selenium, ug/L	<5	<5	16	160	29	25
Silver, ug/L	<0.08	<0.08	<0.4	4	0.7	0.07
Strontium, ug/L	100	100	300	3000	540	
Zinc, ug/L	7.4	<50	143	1400	250	1000
Alpha, Gross (pC/L)	1.7	30	8.4	84	22.1	15
Radium 226 (pC/L)	0.7	2.0	3.0	30	5.6	5

Notes: 1. Reservior quality estimates are based on mass balances and do not take into account any chemical reaction, precipitation, sedimentation, deposition or biological activity which may occur in the reservoir and act to remove material from the water column and thus reduce reservoir concentrations.

2. Unionized ammonia concentrations are based on a worst case reservoir water temperature of 95°F (35°C).

data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

The maximum predicted 24-hour and annual average PM concentrations are 7.5 and 0.82 ug/m^3, respectively. Because the maximum 24-hour concentration is below the _de_ _minimis_ monitoring level, preconstruction monitoring is not required for the permit application.

The maximum predicted annual NO_2 concentration is 4.6 ug/m^3, which is below the _de_ _minimis_ monitoring level. Similar to the PM concentrations, preconstruction monitoring requirements is not required for the permit application.

The maximum predicted 1- and 8-hour average CO concentrations are 179 and 38.0 ug/m^3, respectively, which are less than the significance levels. The maximum 8-hour concentration is also less than the _de_ _minimis_ monitoring levels and, therefore, preconstruction monitoring is not required. Because the maximum predicted impacts due to the proposed facility are less than the CO significance levels, additional modeling is not required for this pollutant.

The maximum predicted 24-hour average Be and Hg concentrations are 0.0004 and 0.0016 ug/m^3, respectively, which are less than the _de_ _minimis_ monitoring levels. Therefore, preconstruction monitoring is not required for these pollutants.

PSD CLASS II INCREMENT CONSUMPTION

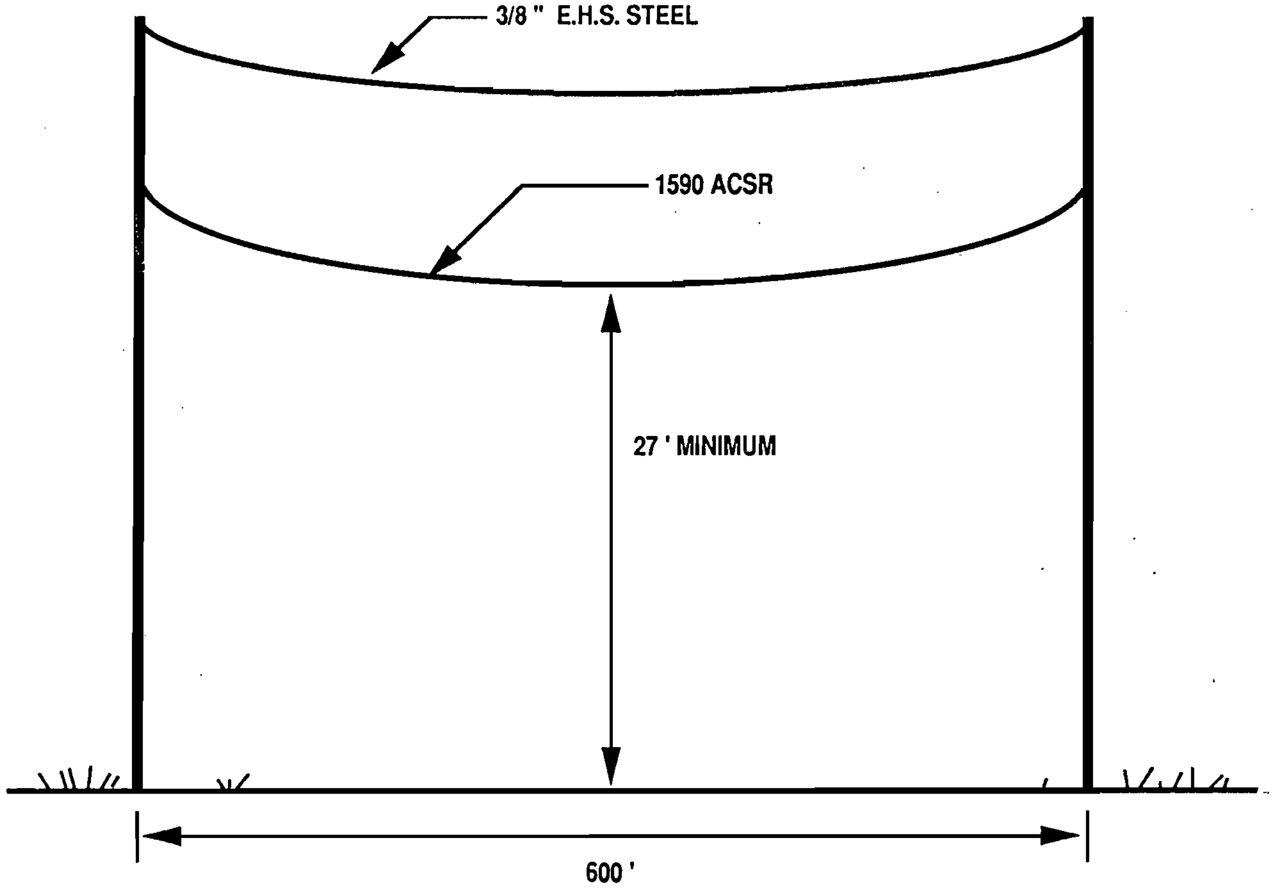
For the refined modeling analysis, summaries of the maximum SO_2, PM, and NO_2 concentrations predicted for comparison to the PSD Class II increments are presented in Table 5.6.1-7. These results show that maximum concentrations due to all PSD sources are less than the maximum allowable PSD Class II increments for all averaging periods and pollutants.

Table 5.6.1-7. Maximum Predicted SO_2, PM, and NO_2 Concentrations for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	PSD Class II Increment (ug/m^3)
<u>SO_2 Concentrations</u>		
3-Hour*	424	512+
24-Hour*	66.0	91+
Annual	8.1	20
<u>PM (TSP) Concentrations</u>		
24-Hour*	8.0	37+
Annual	0.9	19
<u>NO_2 Concentrations</u>		
Annual	4.6	25

* Highest, second-highest concentrations predicted for this averaging period.

+ Not to be exceeded more than once per year.



1590 ACSR (LAPWING)
600 ' RULING SPAN

Figure 6.1.3-2 CONDUCTOR PROFILE FOR H-FRAME CONSTRUCTION

Hardee Power Station

Conductor profiles for H-frame and single pole configurations are presented in Figures 6.1.3-2 and 6.1.3-3, respectively.

Span lengths between structures will average between 183-213 m (600 to 700 ft). Individual span lengths will be determined by the topography of the route and the width of the ROW. The entire line will meet National Electrical Safety Code Standards for clearance to ground and obstructions. Additionally, the minimum clearance from any energized conductor to ground will be 8 m (27 ft).

Existing roadways will be used for access to the transmission line wherever possible. If adequate access roads do not exist, new roads will be constructed which will typically be unpaved and have a maximum width of 6 m (20 ft). It is estimated that approximately 40 miles of new access road will need to be constructed. No new bridges will be required as part of the corridor construction.

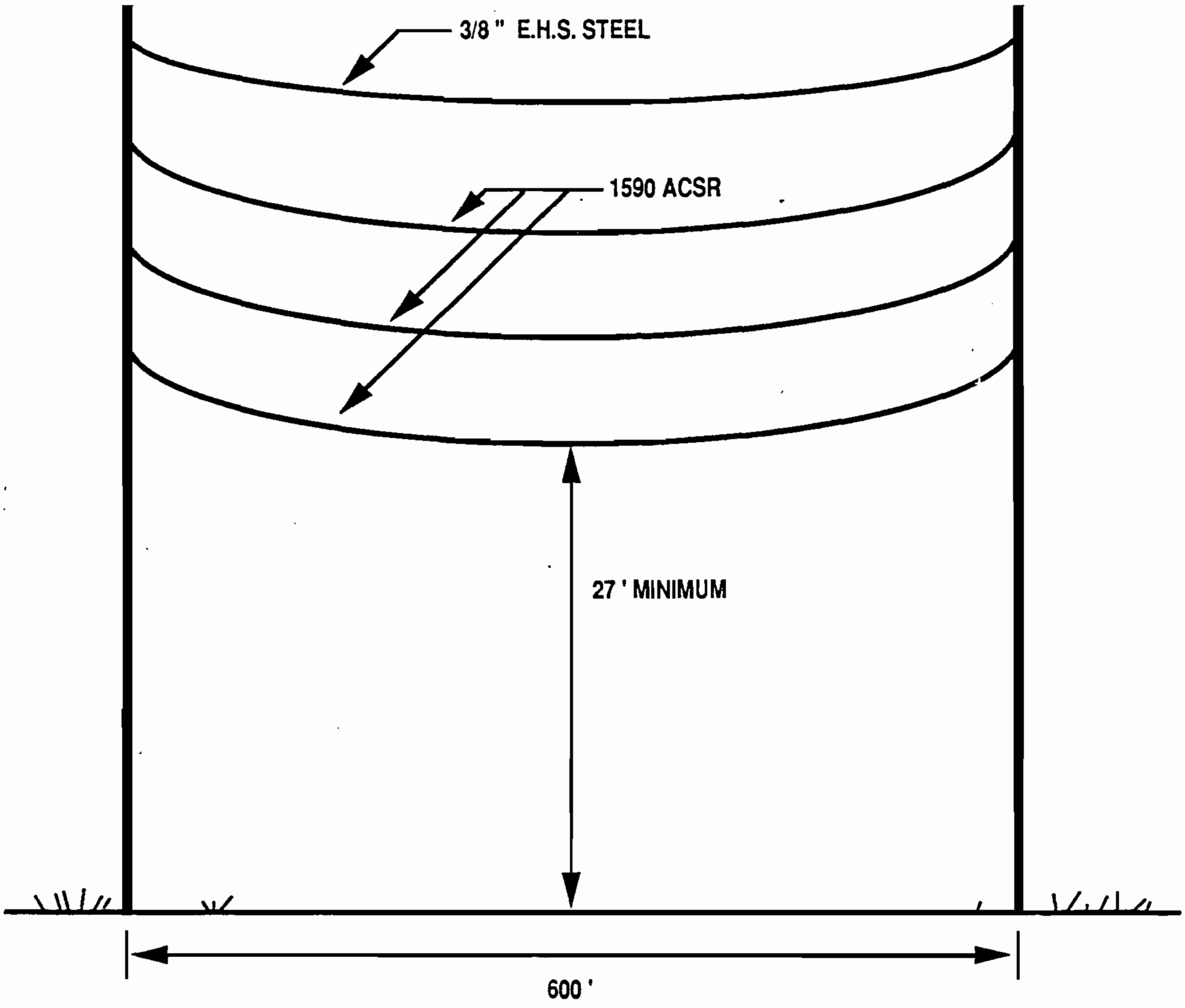
Structure pads will typically be constructed adjacent to the access roads. The pads will be approximately 7 m (24 ft) in width, with the length varying as a function of the distance between the structure and the access road.

6.1.4 Cost Projections

Approximate costs for the transmission lines are presented in Table 6.1.4-1. The actual cost of the transmission lines may vary depending on the final ROW and structure location, cost of ROW acquisition and other site specific conditions.

6.1.5 Corridor Selection

The objective of the transmission line corridor siting study was to select the most favorable corridor in the study area based on a combination of socioeconomic, environmental, engineering and economic considerations. The study area for the corridor selection study (Figure 6.1.5-1) was defined by the geographic distribution of the Hardee Power Station and the three end point substations, i.e., Pebbledale, Vandolah and Lee Substations.



1590 ACSR (LAPWING)
600 ' RULING SPAN

Figure 6.1.3-3 CONDUCTOR PROFILE FOR SINGLE POLE CONSTRUCTION

Hardee Power Station

Table 6.1.4-1. Cost Projections for the Preferred and Alternative Corridors for the Hardee Power Station Project in 1988 Dollars

Corridor	Section	Approximate Length (Miles)	Estimated ROW Cost ($)	Total ROW Preparation Cost ($)	Line Construction Cost ($)	Estimated Cost per mile ($)	Total Cost ($)
Preferred	C1	16	606,000	836,000	2,560,000 to 4,000,000	250,000 to 340,000	4,002,000 to 5,442,000
	C2	8*	580,800	200,000	3,219,200	250,000	4,000,000
	C3	70	2,540,000	875,000	14,084,000	250,000	17,500,000
Alternative	C1	18	1,091,000	528,000	2,880,000 to 4,500,000	250,000 to 340,000	4,499,000 6,119,000

* Two parallel lines of 13 km (8 miles) each.

C1 = Hardee Power Station to Pebbledale Substation
C2 = Hardee Power Station to Vandolah Substation
C3 = Vandolah Substation to Lee Substation

produced during regeneration of the makeup demineralizers. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer will be provided to hasten pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the demineralizer regeneration equipment. The pH adjusted chemical wastewaters will be routed to the cooling reservoir. Table 3.6.7-1 presents the estimated water quality of the neutralization basin effluent.

3.6.8 Miscellaneous Plant Drains

Separate collection systems will be used to collect chemical drain wastewater and miscellaneous plant drain wastewater. Chemical drain wastewaters have been discussed previously in Section 3.6.6. Miscellaneous plant drain wastewater can result from general cleaning and maintenance, such as hosing general plant (i.e., non-chemical) areas. Miscellaneous floor drains will be directed to an oil separator and then routed to the cooling reservoir for reuse as cooling water.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 Solid Waste

Only small quantities of solid wastes will be generated by the Hardee Power Station facilities since there will be no ash or FGD waste generated or requiring disposal. Solid wastes will be limited to general trash, sanitary waste treatment sludge and infrequent replacement of demineralizer resins. The sanitary waste sludge will be disposed of by a contractor who will remove sludge in the sludge holding compartment once or twice per year. Sanitary waste sludge will be hauled off site for disposal by the contractor. Other solid wastes will be disposed off-site in a sanitary landfill.

3.7.2 Hazardous Waste

The demineralized waste streams can contain up to 10% sulfuric acid or up to 5% sodium hydroxide along with the minerals removed from the ion exchange resins. The wastes will be combined in an elementary neutralization basin

Table 3.6.7-1. Estimated Characteristics of the Neutralization Basin Effluent for the Hardee Power Station (Page 1 of 2)

Parameter	Treated Neutralization Basin Effluent
Calcium, mg/L as $CaCO_3$	1130
Magnesium, mg/L as $CaCO_3$	490
Sodium, mg/L as $CaCO_3$	3050
Potassium, mg/L as $CaCO_3$	80
Total Hardness, mg/L as $CaCO_3$	1620
Alkalinity, mg/L as $CaCO_3$	0
Sulfate, mg/L as $CaCO_3$	4540
Chloride, mg/L as $CaCO_3$	210
Silca, mg/L	270
Fluoride, mg/L	20
Cyanide, mg/L	0.05
MBAS, mg/L	1.8
Oil and Grease, mg/L	0
Turbidity, NTU	10
pH, units	6-9
Total Dissolved Solids, mg/L	6860
Specific Conductivity, umhos/cm	12100
Total Kjeldahl Nitrogen, mg/L	3.9
Ammonia Nitrogen, mg/L	2.0
Organic Nitrogen, mg/L	1.9
Nitrate+Nitrite-Nitrogen, mg/L	0.3
Total Nitrogen, mg/L	4.2
Orthophosphorus, mg/L	2.0
Total Phosphorus, mg/L	2.0
Arsenic, ug/L	0.1
Barium, ug/L	750
Beryllium, ug/L	9
Cadmium, ug/L	7
Chromium, ug/L	130
Copper, ug/L	70
Iron, ug/L	0
Lead, ug/L	140

forest. Generally, however, in the habitat types prevalent in the corridor, creation of desirable edge habitat and maintenance of early successional vegetation could have a positive effect on sensitive species. Gopher tortoises, and several other species of concern in this region prefer relatively open habitats.

Herbicide use will be implemented in such a manner so as to minimize impact to wildlife or aquatic organisms.

Access roads can act as barriers to animals reluctant to cross openings, and can displace (or subject to routine trampling) a certain amount of vegetation. These impacts should be minimal, however, because Tampa Electric intends to use existing roads wherever feasible and minimize the lengths of any essential new roads.

6.1.6.5.4 Effects of Public Access

It is Tampa Electric's policy to install locked gates at all points where the transmission line access road intersects previously fenced property. Therefore, with the exception of Tampa Electric's personnel performing routine maintenance, no increased vehicle access is anticipated. Since no significant increase in human traffic into formerly inaccessible habitats will result, there will be no subsequent increased disturbance to wildlife.

6.1.6.5.5 Other Post Construction Effects

The transmission line will meet EMF limits set forth in Chapter 17-274, F.A.C. Maximum electric and magnetic field strengths at the edge of the ROW for the transmission line were calculated using the Bonneville Power Administration Corona and Fields Effects program. Input data used in the program were based on the generating capacity of the Hardee Power Station and included the following parameters:

1. A maximum current rating of 2,040 amperes;
2. A minimum conductor clearance of 27 ft from the earth;
3. Currents were assumed to be balanced in phase and in magnitude with no zero sequence current;
4. A maximum operating voltage of 242 kV; and
5. Voltages were assumed to be balanced in phase and in magnitude.

Electromagnetic fields strengths will vary depending on the ROW width and structure type. The maximum field strengths at the edge of the transmission ROW will be below the field strength standards listed in Chapter 17-274.450, F.A.C. (i.e., 2.00 kV/m for electric field, and 150 milliGauss for magnetic field). The entire transmission line facility will meet the applicable sections of the National Electrical Safety Code. Due to the design and routing of the proposed transmission line and its location relative to residential areas, EMF and acoustic and electric noise will not be a problem.

6.1.7 Hardee Power Station to Vandolah and Lee Substations Transmission Line

6.1.7.1 Description of Preferred and Alternative Corridors

The preferred corridors from the Hardee Power Station to both the Vandolah and Lee Substations are described below. The corridor description starts at the Hardee Power Station and proceeds south to Vandolah Substation and from Vandolah Substation south to Lee Substation. These transmission lines will be constructed and maintained by SECI.

HARDEE POWER STATION TO VANDOLAH SUBSTATION

This section of the corridor starts at the Hardee Power Station and proceeds south, approximately 13 km (8 miles) to the Vandolah Substation located on Vandolah Road (see Figure 6.1.7-1 in Appendix 11.10). Much of the land between the Hardee Power Station and the Vandolah Substation is owned by various phosphate mining companies and may be mined in the future. Due to the potential for mining activities in this area, the siting study concentrated on routing the corridor adjacent to existing highway and railroad ROWs.

The Hardee Power Station to Vandolah corridor is approximately 13 km (8 miles) and starts at the switchyard of the Hardee Power Station and proceeds south along CR 663. The width of this section of corridor is 0.8 km (0.5 mile) with the exception of a 1.6-km (1-mile) section where it increases to 1.2 km (0.75 mile) near the town of Ft. Green Springs. The expanded corridor width near Ft. Green Springs is designed to allow additional flexibility in siting the ROW in this area to minimize potential impacts to developed areas.

Two parallel 230 kV transmission lines are planned for the Hardee Power Station to Vandolah section of the corridor. Separate ROWs and structures are needed for each of the two transmission lines in this area. Both lines

6.1.7.5.2 Multiple Uses

Various activities including citrus farming, grazing, and agriculture are typically allowed within the ROW as long as these activities do not interfere with full use of the ROW. An easement will be obtained for the construction and operating of the Vandolah and Lee transmission lines, including ingress and egress to the transmission line. Specific uses within the ROW will be addressed individually with affected parties. Multiple use of the ROW may be restricted in certain areas, but in general, compatible multiple uses will be allowed.

6.1.7.5.3 Changes in Species Populations

WILDLIFE AND AQUATIC LIFE

Potential post-construction impacts along the Vandolah and Lee transmission lines fall into four major categories: 1) impacts related to the actual transmission lines and supporting poles; 2) impacts of ROW maintenance procedures; 3) disturbances associated with access roads; and 4) effects of electromagnetic fields.

The primary concern associated with the actual transmission line is the potential increase in bird mortality due to collisions with the wires. The impacts of collisions with power lines on avian mortality are difficult to quantify. It is generally agreed, however, that collisions are a potentially significant cause of mortality among birds. It is also agreed that a large percentage of avian mortality from collisions with power lines can be avoided through careful planning (Anderson, 1978; Lee, 1978; Faanes, 1987). For this reason, the corridor was routed to minimize the potential for collisions by avoiding areas of known bird concentrations and areas used for roosting or nesting by sensitive species.

Special attention has been given to habitats used by wood storks and other wading birds, sandhill cranes, and red-cockaded woodpeckers. Prior to ROW selection, additional field surveys will be undertaken to identify undocumented sites used by sensitive species and smaller areas of significant habitat. The ROW will be routed to minimize impact on these areas.

The ROW must be maintained so that trees cannot grow into the overhead wires. This implies maintenance of a permanent gap in the canopy through any forested areas. In hydric or mesic habitats this may have a slight deleterious effect in drying and heating the microclimate of the adjacent forest. However, creation of desirable edge habitat and maintenance of openings will probably have a positive effect on such sensitive species as gopher tortoises and burrowing owls.

Herbicide use will be implemented in a manner that will minimize impacts to wildlife or aquatic organisms.

Access roads can act as barriers to animals reluctant to cross openings, and can displace (or subject to routine trampling) a certain amount of vegetation. These impacts should be minimal, however, because SECI intends to use existing roads wherever feasible and minimize the lengths of any essential new roads.

6.1.7.5.4 Effects of Public Access

It is SECI's policy to install locked gates at all points where the transmission line access road intersects previously fenced property. Therefore, with the exception of SECI personnel performing routine maintenance, no increased vehicle access is anticipated. Since no significant increase in human traffic into formerly inaccessible habitats will result, there will be no subsequent increased disturbance to wildlife.

6.1.7.5.5 Other Post Construction Effects

The transmission line will meet EMF limits set forth in Chapter 17-274, F.A.C. Maximum electric and magnetic field strengths at the edge of the ROW for the transmission line were calculated using the Bonneville Power Administration Corona and Fields Effects program. Input data used in the program were based on the generating capacity of the Hardee Power Station and included the following parameters:

1. A maximum current rating of 2,040 amperes;
2. A minimum conductor clearance of 27 ft from the earth;
3. Currents were assumed to be balanced in phase and in magnitude with no zero sequence current;
4. A maximum operating voltage of 242 kV; and
5. Voltages were assumed to be balanced in phase and in magnitude.

Electromagnetic fields strengths will vary depending on the ROW width and structure type. The maximum field strengths at the edge of the transmission line ROW will be below the field strength standards listed in Chapter 17-274.450, F.A.C. (i.e., 2.00 kV/m for electric field, and 150 milliGauss for magnetic field). The entire transmission line facility will meet the applicable sections of the National Electrical Safety Code. Due to the design and routing of the proposed transmission line and its location relative to residential areas, EMF and acoustic and electric noise will not be a problem.

6.2 **ASSOCIATED NATURAL GAS PIPELINE**

6.2.1 Project Description

THe proposed primary fuel for the Hardee Power Station is natural gas. It will be brought to the site by a new gas pipeline, the Hardee Power Station Lateral, connecting with an existing gas pipeline near Polk City, Florida. The Federal energy Regulatory Commission (FERC) issued an environmental assessment on,

January 31, 1989 for a series of proposed Florida Gas Transmission System (FGT) gas pipelines, which inlcuded a portion of the proposed Hardee Power Station Lateral, referred to as the Sarasota Lateral Loop. FERC determined that the construction of the proposed facilities including the Sarasota lateral Loop would not constitute a major federal action significantly affecting the human environment (FERC, 1989).

The Hardee Power Station Lateral incorporates the proposed Sarasota Lateral Loop and continues to the plant site. The Hardee Power Station Lateral begins about 1.6 km (1 mile) north of Polk City where it interconnects with the existing FGT 18-inch St. Petersburg lateral and continues south to the Hardee Power Station (Figure 6.2.1-1).

The gas pipeline will consist of an underground pipeline along a 22 m (75 ft) ROW.. There are no proposed compressor stations along the preferred pipeline corridor.

6.2.2 Corridor Location and Layout

Figures 6.2.1-2 through 6.2.1-5 identify the full length of the proposed 30 m (100 ft) corridor relative to major geographic features. Existing gas pipeline are shown as these figures. Approximately 91% of the proposed gas

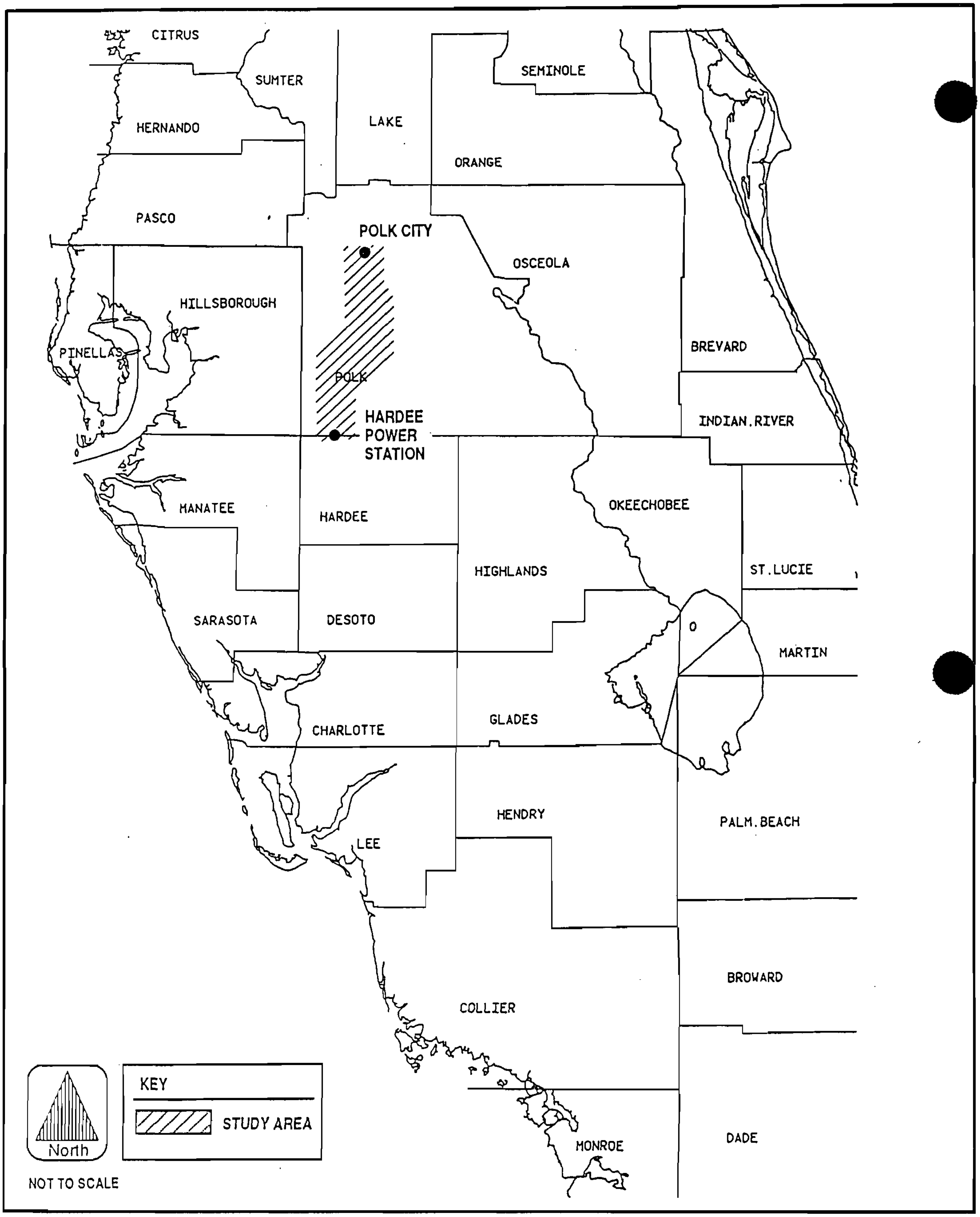


Figure 6.2.1-1 NATURAL GAS PIPELINE STUDY AREA AND INTERCONNECT POINTS

Hardee Power Station

and will use existing highway and railroad ROWs. It will enter the site from CR 663, co-located with the access road.

A 20.3 cm (8-inch) liquid fuel pipeline will be constructed from the plant site west to Port Manatee (see Section 6.3). The proposed pipeline will approach the site from the west (see Section 6.3).

10.2.2 Plant and Associated Facilities Operational Aspects

The operational impacts of the Hardee Power Station are described in Chapter 5 Effects of Plant Operation. The Hardee Power Station project will not have any significant adverse effect on existing or future natural and cultural resources, including reclaimed areas. Table 10.1.2-1 lists applicable FDNR requirements which assure protection of natural resources including: soils and topography, wetlands and water bodies, water quality, vegetation, and wildlife. The following is a summary of the relevant operational aspects of the project to these natural resources and the reclamation requirements.

SOIL AND TOPOGRAPHICAL CONSIDERATIONS

The proposed cooling reservoir is the only major facility planned to be constructed on mined lands. The reclamation requirements [16C-16.0051 (2)] call for slopes of reclaimed lands to be no greater than 4 to 1. The cooling reservoir design is discussed in Section 3.5.1. Its proposed slopes (4 to 1 inside and 20 to 1 outside) and other design aspects are consistent with FDNR requirements. Appropriate vegetative cover will be grown, established and maintained on the outside slopes.

WETLANDS AND WATER BODIES

The plant and associated facilities will be constructed outside of the 100-year floodplain. No impacts to offsite wetlands will result from the Hardee Power Station. One contiguous forested wetland [2.4 ha (5.9 acres)] will be lost during construction of the cooling reservoir (see Sections 2.3.6.1 and 4.2.1.2). The loss of these wetlands are not considered significant adverse effects because of the small size and isolation due to surrounding mining activities. However, these wetland losses will be mitigated as part of Agrico's amended reclamation plan. Water subsidies to the wetlands after construction of the plant and associated facilities will be similar to, if not better than, those prior to mining (see Section 5.8 Changes To Non-Aquatic Population). No adverse water quality impacts, including impacts on aquatic life, will result from the operation of the cooling reservoir (see Sections 5.1 Effects of Operation of the Heat Dissipation System, 5.2 Effects of Chemical and Biocide Discharges, and 5.3 Impacts on Water Supplies).

Although some emergent vegetation may occur along the edges of the cooling reservoir, it is not the function of the cooling reservoir to provide wetland habitat and to be considered as wetland mitigation. The growth of too much emergent vegetation will impede the cooling function of the reservoir. As a result, some of the suggested wetland/water body reclamation and restoration standards (16C-16.0051) are not applicable, e.g., "at least 25% of the highwater surface area" be designed for "emergent and transition zone vegetation." Other suggested reclamation and restoration standards can be achieved, e.g., "berm of earth around each water body which is of sufficient size to retain at least the first inch of runoff."

WATER QUALITY AND QUANTITY

All waters leaving the cooling reservoir and the site will meet applicable water quality standards of the Florida Department of Environmental Regulation at the point of discharge or at the end of a mixing zone and will have no adverse impact to fish and wildlife (see Sections 5.1 Effects of Operation of the Heat Dissipation System, 5.2 Effects of Chemical and Biocide Discharges, and 5.3 Impacts on Water Supplies).

As recommended by FDNR, the HEC-1 model was used to evaluate event specific discharges to Payne Creek and associated dilution for the 10-year, 24-hour storm and the 25-year, 24-hour storm (see Section 5.1.1 Temperature Effect On Receiving Body of Water). The format methodology followed that described

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The combined cycle facility will be constructed in modules to achieve the desired capacity additions. The final design will depend on the selected combustion turbine with either five or six combustion turbines required to achieve theultimate capacity of 660 MW. Both simple cycle and combined cycle operation are planned; the latter would use by-pass stacks when only combustion turbine operation is needed, or the steam cycle is inoperable. The HRSG would not be supplementally fired.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The performance information and stack parameters that envelope the combustion turbine manufacturer's designs currently being considered for the project are presented in Table 2-1. This information provides conservative emission estimates of criteria pollutants (Table 2-2), other regulated pollutants (Table 2-3), and non-regulated pollutants (Table 2-4). Specific manufacturer designs would provide emissions no greater than those shown in these tables. The fuel specifications for natural gas and distillate oil are presented in Tables 2-5 and 2-6, respectively.

For a 660-MW (nominal) facility, the maximum emissions are produced with five combustion turbines; the design, stack, and emission characteristics are presented in Tables 2-1 through 2-4. This configuration will also have the highest exhaust flow. Lower exhaust flow rates and emissions will occur for a 660-MW (nominal) facility using six of the smaller combustion turbines. The exhaust flow and corresponding emissions are important in establishing air quality impacts and must be determined separately for each configuration. As a result, the range in stack parameters used in modeling, as well as corresponding sulfur dioxides (SO_2) emissions, are presented in Table 2-7. In either configuration the maximum potential air quality impacts will occur during combined cycle operation when the exhaust temperature is 240°F.

Table 2-7. Stack Parameters and SO_2 Emissions Used in Modeling for the Hardee Power Station

	5 Turbine Option Highest Emission		6 Turbine Option Lowest Flow Rate	
	32°F CASE 1	95°F CASE 2	32°F CASE 3	95°F CASE 4
Stack Gas Flow (ACFM)	947,056	833,126	770,627	654,455
Stack Gas Temperature (°F)	240	240	240	240
Stack Velocity (ft/sec)	78.5	69.1	63.9	54.2
Stack Diameter (ft)	16	16	16	16
Stack Height (ft)*	75	75	75	75
SO_2 Emissions (lb/hr)	734.37	619.56	558.04	456.34

* This stack height was used for the HRSG exhaust along with worst case structure dimensions (see Table 6-13) to conservatively estimate air quality impacts.

Note: Cases 1 and 2 are for five combustion turbines.
Cases 3 and 4 are for six combustion turbines.
Stack parameters and emissions are shown on a per-unit basis.

Table 6-5. Summary of SO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility*	Location from Proposed Facility		Maximum SO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses:	
	Distance (km)	Direction (degrees)				Screen.	Refined
Gardinier	12.0	61	1,173	241	YES	YES	YES
Imperial Phosphate	12.1	0	275	242	YES	NO	YES
Agrico Chemical Co. (S. Pierce)	14.4	11	4,557	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	569	317	YES	NO	YES
U.S. Agri-Chemicals	16.1	44	2,933	322	YES	YES	YES
Wachula City Power Plant	17.1	127	180	342	NO	--	--
IMC Fort Lonesome	18.6	304	1,714	371	YES	YES	YES
Agrico Chemical Co. (Pierce)	21.6	357	417	433	NO	--	--
Mobil-Electrophosphate Division	22.0	2	1,428	440	YES	NO	YES
Farmland Industries	23.2	12	3,692	464	YES	YES	YES
IMC	23.4	340	10,251	469	YES	YES	YES
IMC/Noralyn Mine Road	24.9	23	505	499	YES	NO	YES
C.F. Industries	25.3	8	8,443	505	YES	YES	YES
Kaplan Industries	25.7	32	385	515	NO	--	--
American Orangr Corp.	27.0	112	198	539	NO	--	--
Conserv. Chemicals	27.5	347	1,597	550	YES	NO	YES
Royster Co.	27.8	4	1,283	555	YES	NO	YES
Mobil Chemical Co./Nichols	28.6	347	1,516	572	YES	NO	YES
IMC/Prairie	29.7	356	137	593	NO	--	--
W.R. Grace & Co.	29.7	10	8,186	594	YES	YES	YES
U.S. Agri-Chemicals	30.1	16	1,575	602	YES	NO	YES
FPL Manatee	37.6	265	85,305	753	YES	YES	YES
Tricil Recovery Services	38.9	27	240	777	NO	--	--
Consolidated Minerals	40.4	344	3,302	809	YES	YES	YES
Teco Big Bend	46.4	292	371,733	927	YES	YES	YES
Citrus World	47.0	50	597	939	NO	--	--
Columbus Company	47.5	295	167	950	NO	--	--
Gardinier	48.4	301	5,181	967	YES	YES	YES
Lakeland City Power	49.0	5	4,014	980	YES	YES	YES
Lakeland City Power	49.0	5	30,176	980	YES	YES	YES
Adams Packing	49.8	20	172	995	NO	--	--

			551,901				

* Refer to Table 6-2 for facility UTM coordinates (East, North) and relative locations (x, y) to proposed site.

Table 6-6. Summary of NO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility*	Location From Proposed Facility		Maximum NO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses:	
	Distance (km)	Direction (degrees)				Screen.	Refined
Gardinier	12.0	61	176	241	NO	--	--
Agrico Chemical	14.4	11	139	287	NO	--	--
Mobil Oil Big Four Mine	15.8	320	156	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	131	322	NO	--	--
IMC Fort Lonesome	18.6	304	610	371	YES	NO	YES
Farmland Industries	23.2	12	226	464	NO	--	--
IMC	23.4	340	322	469	NO	--	--
Kaplan Industries	25.7	32	100	515	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	134	572	NO	--	--
W.R. Grace & Co.	29.7	10	528	594	NO	--	--
FPL Manatee	37.6	265	22,734	753	YES	YES	YES
Consolidated Minerals	40.4	344	534	809	NO	--	--
Sherex Polymers	41.9	352	617	838	NO	--	--
Juice Bowl Products	42.7	354	109	855	NO	--	--
Owens-Illinois	44.9	358	391	898	NO	--	--
Teco Big Bend	46.4	292	82,624	927	YES	YES	YES
Citrus World	47.0	50	1,382	939	YES	NO	YES
Gardinier	48.4	301	466	967	NO	--	--
Lakeland City Power	49.0	5	5,028	980	YES	YES	YES

		Total	116,407				

* Refer to Table 6-3 for facility UTM coordinates (East, North) and relative locations (x, y) to proposed site.

Table 6-7. Summary of PM Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

	Location from Proposed Facility		Maximum PM Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses:	
Facility*	Distance (km)	Direction (degrees)				Screen.	Refined
Gardinier	12.0	61	132	241	NO	--	--
Imperial Phosphates	12.1	0	162	242	NO	--	--
Agrico Chemical	14.4	11	1,705	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	263	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	871	322	YES	NO	YES
Biochemical Energy, LTD	16.5	125	281	329	NO	--	--
IMC Fort Lonesome	18.6	304	679	371	YES	NO	YES
IMC	19.5	340	168	389	NO	--	--
Agrico Chemical	21.6	357	631	433	YES	NO	YES
C&M Products	21.7	358	162	434	NO	--	--
Mobil-Electrophos Division	22.0	358	555	440	YES	NO	YES
Farmland Industries	23.2	12	977	464	YES	NO	YES
IMC	23.4	340	162	469	NO	--	--
IMC	24.9	337	973	499	YES	NO	YES
C.F. Industries	25.3	352	788	505	YES	NO	YES
IMC/ Uranium Recovery	25.7	8	831	513	YES	NO	YES
American Orange Corp.	27.0	112	180	539	NO	--	--
Conserv Chemical	27.5	13	1,620	550	YES	NO	YES
Royster	27.8	4	210	555	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	433	572	NO	--	--
W.R. Grace & Co.	29.7	10	636	594	YES	NO	YES
Ridge Pallets	30.1	27	180	601	NO	--	--
U.S. Agri-Chemicals	30.1	16	182	602	NO	--	--
Allsun Products	37.4	13	317	749	NO	--	--
FPL Manatee	37.6	265	7,578	753	YES	YES	YES
Consolidated Minerals	40.4	344	740	809	NO	--	--
Pavers, Inc.	41.8	347	114	836	NO	--	--
Rinker Cencon Corp.	42.3	350	159	846	NO	--	--
Quikrete	42.4	349	253	847	NO	--	--
Landia Chemical	44.4	1	2,313	888	YES	NO	YES
Kraft Citrus	44.8	353	108	896	NO	--	--
Owens-Illinois	44.9	358	102	898	NO	--	--
Jahna Concrete, Inc.	45.5	97	139	910	NO	--	--
Teco Big Bend	46.4	292	7,699	927	YES	YES	YES
Agrico Chemical Co.	46.6	66	184	932	NO	--	--
Macasphalt	46.9	99	165	938	NO	--	--
Citrus World	47.0	50	166	939	NO	--	--
FPL Avon Park	47.1	98	212	942	NO	--	--
Gardinier	48.4	301	863	967	NO	--	--
Lakeland City Power	49.0	5	14,705	980	YES	YES	YES
Coca Cola Citrus	49.3	20	334	985	NO	--	--
Adams Packing Association	49.8	20	129	995	NO	--	--

		Total	49,061				

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* Refer to Table 6-4 for facility UTM coordinates (East, North) and relative location (x, y) to proposed site.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

For the screening analysis, a summary of the maximum SO_2, NO_2, PM, CO, and Be concentrations due to the proposed facility is presented in Table 7-1. Model results were calculated for a range of operating conditions for which maximum impacts could occur (see Section 2.0 for the operating data and rational for modeling these conditions). These operating conditions, which were based on either maximum emissions or minimum flow rate for the units, were as follows (Refer to Table 2-7 for Stack parameters and SO_2 emission):

1. Case 1: Maximum emissions at 32°F;
2. Case 2: Maximum emissions at 95°F;
3. Case 3: Minimum flow rate at 32°F; and
4. Case 4: Minimum flow rate at 95°F.

As indicated in Table 7-1, the maximum concentrations are predicted for the operating conditions with minimum flow rates (Cases 3 and 4). It should be noted that the modeled SO_2 emissions were specific for each case because the maximum predicted SO_2 concentrations were relatively high when compared to PSD Class II increments. For the other pollutants, the emissions from Case 1, which had the highest emissions among the cases, were modeled using the stack parameters for Cases 2,3, and 4; therefore, the maximum impacts predicted for cases 2 through 4 are conservative (lower impacts would be predicted if the emissions associated with each case were modeled). See Section 2.0 for a more detailed discussion about the emission data and associated operating parameters used in the modeling.

The maximum predicted 3-, 24-hour and annual SO_2 concentrations are 424, 62.5 and 6.7 ug/m^3, respectively. The maximum 24-hour concentration is above the <u>de minimis</u> monitoring level and, therefore, preconstruction monitoring data are required to be submitted by the Applicant as part of the permit application. As indicated in Section 5.0, existing monitoring data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

TECO
POWER SERVICES
A TECO ENERGY COMPANY

TO WHOM IT MAY CONCERN:

Please be advised that Jerry L. Williams, Director of Environmental for Tampa Electric Company, is the authorized representative of TECO Power Services Corporation concerning matters with which this permit application deals.

Sincerely,

Richard E. Ludwig
President

REL:ams

TECO POWER SERVICES CORPORATION
P.O. Box 111 Tampa, Florida 33601-0111 (813) 228-4111

6-21-89

BEFORE THE ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In the Matter of: Columbia Gulf Transmission Company ID No. 105-0640-0021 Applicant	PSD Appeal No. 88-11

ORDER

By petition dated November 14, 1988, and pursuant to 40 CFR §124.19 (1987), the Regional Administrator, U.S. Environmental Protection Agency, Region IV, Atlanta, Georgia, requested review of a determination by the Kentucky Department of Air Quality to issue a prevention of significant deterioration (PSD) permit to Columbia Gulf Transmission Company. The permit would allow Columbia Gulf to construct an 11,864 horsepower (8.9 MW) gas turbine to compress gas at its compressor station in Clementsville, Kentucky. The Department made its permit determination pursuant to a general delegation of PSD-issuing authority from EPA Region IV. Because of the delegation, Kentucky's authority to issue PSD permits is subject to the review provisions of 40 CFR §124.19, and any permit it issues will be an EPA-issued permit for purposes of federal law. 40 CFR §124.41; 45 Fed. Reg. 33413 (May 19, 1980).

The Regional Administrator claims Kentucky's determination of best available control technology (BACT) for the proposed facility is clearly erroneous. The proposed permit calls for no add-on controls to reduce NOx emissions, relying instead on combustor design (so-called "dry controls"), whereas the Region believes water injection controls must be added to satisfy BACT requirements. Kentucky responds by arguing that dry controls are BACT because: (1) the impact of NOx emissions on ambient air quality will be negligible if dry controls are used, thus making the addition of water injection environmentally unnecessary and economically unreasonable; (2) use of water injection will cause additional energy to be consumed and it will cause an increase in CO emissions; and (3) federal new source performance standards (NSPS) do not require water injection for "small" turbines.

Under the rules governing this proceeding, there is no appeal as of right from the permit determination. Ordinarily, a petition for review of a PSD permit determination is not granted unless it is based on a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review. The preamble to the regulations states that "this power of review should be only sparingly exercised," and that "most permit conditions should be finally determined at the Regional [state] level * * *." 45 Fed. Reg. 33,412 (May 19, 1980). The burden of demonstrating that the permit conditions should be reviewed is therefore on the petitioner. EPA Region IV has met its burden.

The issues raised by Kentucky's contentions are discussed below.

1. Ambient Air Quality and the BACT Determination

Kentucky argues that the benefits to ambient air quality from adding water injection are negligible, and are clearly outweighed by the additional economic costs associated with this form of NOx control, which it estimates are $2,121.00 for each additional ton of NOx removed. According to modelling results, ambient concentrations of NO_2 from all sources (including the proposed facility) within 50 kilometers of the proposed facility will be 50.67 $\mu g/m^3$ without use of water injection and 50.65 $\mu g/m^3$ with use of water injection. In other words, the total reduction in NO_2 pollution is a mere 0.02 $\mu g/m^3$. This slight numerical improvement in air quality, according to Kentucky and the applicant, is not statistically significant, for it falls within the margin of error employed in the air quality model.

The Region does not dispute Kentucky's evaluation of air quality impacts as presented; however, according to the Region, when the focus is on actual NO_x emissions reductions from the facility itself, the costs of water injection are reasonable. Specifically, by using water injection the facility will emit 114.08 fewer tons of NO_x per year, at a cost of $2,121.00 per ton of NO_x removed, which is below the range of costs ($3,000 -

$6,500) normally expended for NO_x removal. [1] According to the Region, the definition of BACT mandates use of water injection, the most effective available technology for NO_x removal under consideration in this case, [2] unless the applicant can demonstrate that the economic, environmental, or energy impacts from using this technology make the choice unreasonable. In the Region's opinion, Columbia Gulf did not demonstrate that any of these considerations made the choice of water injection unreasonable.

By looking at the modelled impact of the proposed facility's NO_x emissions, the Department argues that it has identified an environmental impact that it may consider for purposes of its BACT determination. I disagree. BACT is defined in the Clean Air Act as an "emission limitation" set by the permit issuer, based on the "maximum degree of reduction" that can be achieved for each regulated pollutant, on case-by-case basis, after "taking into account energy, environmental, and economic impacts

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[1] The Region also argues that Kentucky has overestimated the incremental costs of NO_x removal using water injection. Kentucky computed the costs per ton assuming 6,000 hours of operation per year. The Region correctly points out that this assumption is unwarranted because the permit does not contain any restrictions limiting hours of operation to 6,000 hours per year. Unrestricted, the facility could operate 8,760 hours per year (24 hrs. x 365 days).

[2] The Region has conceded that although a more effective control technology, selective catalytic reduction, has been successfully employed on gas-fired turbines, that technology would be technically infeasible in this case due to source-specific factors.

and other costs." 42 U.S.C. §7479(3).[3] The latter clause is in the BACT definition to temper the stringency of the technology requirements whenever one or more of the specified "collateral" impacts -- energy, environmental, or economic -- renders use of the most effective technology inappropriate. As explained by Senator Edmund S. Muskie, the principal architect of the Clean Air Act amendments of 1977:

> One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of difference [sic] in feedstock material, plant configuration or other reasons. For this and other reasons, the committee voted to permit emission limits based on best available technology on a case-by-case judgment at the State level. This flexibility should allow such differences to be accommodated and still maximize the use of improved technology.

Senate Debate on S.252 (June 8, 1977), reprinted in 3 Senate Committee on Environment And Public Works, A Legislative History

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[3] The complete text of the statutory definition of BACT states:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 [new source standards] or 7412 [hazardous pollutant standards] of this title.

42 U.S.C. §7479(3).

of the Clean Air Act Amendments of 1977 at 729 (Comm. Print August 1978) (Congressional Research Service, Serial No. 95-16). In other words, the collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology. The permit applicant must install the most effective technology if it fails to demonstrate to the satisfaction of the permit issuer that such unusual circumstances exist. [4]

Here, the Department argues that the modelled negligible impact of the proposed facility on overall air quality is an environmental impact that can be factored into the BACT analysis to justify using less than the most effective technology to

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[4] The process of selecting the most effective technology is described in Pennsauken County Resource Recovery Facility, PSD Appeal No. 88-8 (EPA Administrator, Nov. 10, 1988) (Remand Order). <u>Pennsauken</u> cites recent Agency guidance on the subject, which refers to the process as the "top-down" approach to BACT analysis, and quotes from the guidance as follows:

> The first step in this approach is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source 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. Thus, the "top-down" approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available. It also differs from other processes in that it requires the applicant to analyze a control technology only if the applicant opposes that level of control; the other processes required a full analysis of all possible types and levels of control above the baseline case.

<u>Id</u>. at 5.

control NO_x emissions. This argument is without merit. It gives no effect to the primary purpose of the collateral impacts clause, which, as the legislative history indicates, is to focus on local impacts that <u>constrain</u> the source from using the most effective technology. For example, if the most effective technology would impose exceptional demands on local water resources, so that use of the technology would have adverse impacts on the environment, then, under those circumstances, the applicant would have a sound basis for foregoing use of the most effective technology in favor of some less water-intensive technology. This would be a "water resources" equivalent of a "feedstock" or "plant configuration" constraint referred to by Senator Muskie. [5/]

In the present case, the Department and the applicant have not demonstrated the existence of any environmental impacts that would constrain or even remotely circumscribe the applicant's ability to use the most effective technology. The negligible air

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[5/] Depending on the factors present in a particular case, consideration of collateral impacts can also result in a <u>more</u> stringent BACT determination than would otherwise occur. For example, unusually high costs may represent an adverse economic impact that could, standing alone, justify rejection of the most effective control technology. However, the permitting authority could ultimately conclude that such adverse economic impacts are outweighed by adverse collateral environmental impacts associated with the less effective control option. <u>See</u> North County Resource Recovery Associates, PSD Appeal No. 85-2 (EPA June 3, 1986) (remand order) (environmental impact of pollutants not regulated under the Clean Air Act may necessitate a more stringent emission limit for regulated pollutants undergoing BACT review).

quality impact of the proposed NO_x emissions is clearly not a constraint on implementing the most effective technology. Because it is not a constraint, the modelled impact of the proposed facility's NO_x emissions on air quality should not be considered for purposes of making the BACT determination.

This conclusion is further confirmed by the statutory scheme of the Clean Air Act, which separates issues of overall air quality from issues of technology. Section 165(a)(3) of the Act, 42 USC §7475(a)(3), addresses the direct impact of regulated pollutants on ambient air quality by requiring an applicant for a PSD permit to demonstrate that the proposed facility will not cause or contribute to a violation of national ambient air quality standards or PSD increments, whereas section 165(a)(4) of the Act, 42 USC §7475(a)(4), is concerned exclusively with BACT, which is principally a technology-forcing measure that is intended to foster rapid adoption of improvements in control technology. [6] Both of these provisions of the Clean Air Act

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[6] Section 165 of the Clean Air Act provides, in relevant part, as follows:

> (a) No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless --
>
> * * *
>
> (3) the owner or operator of such facility demonstrates * * * that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) [increment], (B) national ambient air quality standard in any air quality control region, or (C)

(continued...)

must be satisfied by an applicant seeking a PSD permit, and compliance with one provision does not relieve or lessen an applicant's burden of complying fully with the other. Thus, even though Columbia Gulf's NO_x emissions will not cause a violation of ambient air quality standards in contravention of section 165(a)(3) of the Act, it must still satisfy the BACT technology requirements imposed by section 165(a)(4).

It does not appear to have done so in this instance, for the record on appeal does not show that any collateral impacts -- in particular, environmental impacts -- operate as a constraint on implementing the most effective technology.

2. Energy Consumption and Increased CO Emissions From Water Injection

Kentucky also claims that water injection is not BACT because it increases fuel consumption by 2.2 percent and carbon monoxide (CO) emissions by 4 tons per year (TPY) -- from 2 TPY to 6 TPY. The Region rejected these arguments, because the projected 2.2 percent increase in energy consumption is, in its opinion, insignificant, since the increase does not place any substantial strain on natural gas demand, and the additional 4 TPY increase

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[6] (...continued)

any other applicable emission standard or standard of performance under this chapter; [and]

(4) the proposed facility is subject to the best available control technology [BACT] for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility * * *.

in CO emissions will be offset by a much greater reduction in NO_x emissions -- from 193 TPY to 79 TPY -- which, in the Region's opinion, represents an environmentally beneficial trade-off.

I agree completely with the Region about the trade-off between the CO and NO_x emissions; the increase in CO emissions is simply insignificant in light of the reductions that can be achieved in NO_x emissions. I am less certain about the 2.2 percent increase in energy consumption and what it implies. Nevertheless, it is generally incumbent on the permit issuer and the permit applicant to demonstrate in the record the relevance or significance of any claimed basis for rejecting the most effective technology on energy or other statutory grounds. It is not enough for them to assert, without substantiation, that adoption of the most effective technology will result in an energy penalty. They must provide substantiation and they must show that the penalty is so substantial or unusual as to merit rejection of the most effective technology. They have not done so in this instance, for the record does not disclose any substantial information on the impact of the alleged energy penalty.

3. <u>New Source Performance Standards (NSPS) and BACT</u>

Kentucky believes that because the emission limitation it proposed for Columbia Gulf's NOx emissions (178 ppm) is below the level specified by the NSPS (196 ppm), [7] this fact should serve as further proof that its BACT determination is correct.

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[7] <u>See</u> 40 CFR §60.332(d).

Kentucky notes in this respect that the NSPS contemplate use of dry controls for small gas turbines. Kentucky's reliance on the NSPS is misplaced. Simply meeting or exceeding the NSPS does not attest to the correctness of a BACT determination. As the language of the statute plainly indicates, [8] the applicable NSPS limitation merely serves as a floor for the BACT limitation, i.e., the BACT limitation must never fall below the level of stringency set by the NSPS. Although the NSPS are developed by considering many of the same factors that go into a BACT determination, [9] their utility is limited in any individual case by at least two considerations. The first is that BACT determinations are made on a case-by-case basis whereas the NSPS are set on an industry-wide basis. The second is that BACT determinations are made on the basis of currently available information, whereas the NSPS, although based on current information when promulgated, may not reflect the most current information avail-

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[8] <u>See</u> footnote 3 (last sentence).

[9] The similarity between BACT and NSPS is reflected in the following definition of a "standard of performance" for new sources and by comparing it with the definition of BACT in footnote 3 above:

> [A] standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through the application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

42 U.S.C. §7411(a)(1).

able at the time of making an individual BACT determination. These two considerations can combine in an individual case to create a substantial gap between the two emission levels. That appears to be the case here, based on the information in the record of this appeal. According to the Region, the applicable NSPS is ten years old and thus does not reflect the most current technological considerations. It therefore appears that Kentucky relied too heavily and, in the final analysis, relied improperly on the NSPS in this case. Moreover, I note that the Region cites three examples of comparable turbines currently using water injection or scheduling it for use -- thus effectively removing concern about the availability of this technology for small turbines. [10/] Kentucky has not shown that water injection is not an available technology for BACT purposes.

Conclusion

The Region has met its burden of showing that Kentucky's permit determination warrants review. As explained above, Kentucky's reliance on negligible ambient air quality impacts to justify using a control technology less effective than water injection represents clear error. Kentucky's rejection of water injection because of associated increases in CO emissions and because of its interpretation of BACT in relationship to the NSPS also represents clear error. Kentucky's concerns over increased

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[10/] See Letter from Bruce T. Miller, Chief, Air Programs Branch, EPA Region IV, to Ronald L. McCallum, Chief Judicial Officer, Attachment at 6, dated January 25, 1989.

energy consumption fail to establish that the increases are so substantial or unusual as to warrant rejection of the most effective technology. I therefore conclude that clear error has been shown here also.

According to the procedural rules governing petitions for review, a briefing period is supposed to follow the granting of review. 40 CFR §124.19(c). In a sense, one has already begun, since both Kentucky and the Region, following the filing of the petition, have submitted additional statements of their positions on the issues. Columbia Gulf, however, did not file any extensive submissions during this post-petition period, nor was it required to file any at this stage of the proceedings. Therefore, to restore balance to the record, I propose to set a briefing schedule that takes this background into consideration. Specifically, Columbia Gulf (and, as permitted by the rules, other interested persons) may submit a brief on the issues discussed in this order within thirty (30) days after public notice of the granting of review has been given. <u>See</u> 40 CFR §124.19(c). (Kentucky shall give notice of the briefing schedule and this order, as provided in 40 CFR §124.10.) Kentucky and the Region shall then file their respective responses within twenty (20) days after receipt of each brief filed during the first round of briefing. Columbia Gulf and, if applicable, other interested persons shall then have fifteen (15) days in which to file a reply to the responses.

Also, on or before the date public notice is given, Kentucky shall transmit to the undersigned a complete copy of the administrative record on which it made its permit determination, accompanied by an index of the contents of the administrative record. Copies of the index shall also be sent to the Region and Columbia Gulf and, if requested, to other interested persons. Thereafter, all persons filing briefs in this matter shall support their arguments and factual assertions with appropriate citations to the documents listed in the index.

So ordered.

William K. Reilly

William K. Reilly
Administrator

Dated: JUN 21 1989

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Order in the matter of Columbia Gulf Transmission Company, PSD Appeal No. 88-11 were sent by First Class Mail to the following persons:

William C. Eddins, Director
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345 Courtland Street, NE
Atlanta, GA 30365

Dated: JUN 21 1989

Brenda H Selden

Brenda H. Selden, Secretary
to the Chief Judicial Officer

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Bob Martinez, Governor Dale Twachtmann, Secretary John Shearer, Assistant Secretary

July 5, 1989

Mr. Wayne Aronson, Chief
Program Support Section
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Aronson:

RE: TECO Power Services Corp./Seminole Electric Cooperative
Hardee Power Station/Power Plant Siting Application
PSD-FL-140

Enclosed for you review and comment are Volumes I and II of the above referenced application. Please direct any comments or questions to Pradeep Raval, Barry Andrews, or Max Linn at the above address or (904)488-1344 by August 1, 1989.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Quality
Management

/pa

Enclosures

LIST OF TABLES

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1.0 INTRODUCTION

The Hardee Power Station, will consist of a combined cycle power plant that will burn natural gas and distillate fuel oil. The facility will be constructed in modules that will consist of combustion turbines and associated electric generator, and heat recovery steam generators (HRSG); the HRSG will utilize the waste heat from the combustion turbines to generate steam for producing additional electricity in a steam turbine. Each module will have a nominal generating capacity of 220 MW (net) and would likely consist of two combustion turbines and associated electric generators, and two HRSGs and one steam electric generator. The ultimate capacity of the facility is being planned for 660 MW; however, but only 295 MW will be initially constructed.

The Hardee Power Station will emit air pollutants above regulatory threshold amounts which will require a Prevention of Significant Deterioration (PSD) review promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation by the Florida Department of Environmental Regulation (FDER) and its regulations codified in Chapter 17-2.510 Florida Administrative Code (F.A.C.). This document provides the technical information and analyses required by these regulations. The information and analyses provided herein are based on a nominal 660 MW plant configuration; however they are transferable for smaller configurations since conservative emissions and impact analyses were assumed.

While this document is an appendix to the Site Certification Application (SCA), it has been prepared as a stand alone PSD application. The application is divided into seven major sections. Section 2.0 presents a description of the facility, and emissions and stack parameters. PSD review requirements and applicability are presented in Section 3.0. The control technology review, including the Best Available Control Technology (BACT) evaluation is presented in Section 4.0. Sections 5.0, 6.0, 7.0 and 8.0 present the air quality monitoring information and the methodology and results of the impact analyses performed for the project.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The combined cycle facility will be constructed in modules to achieve the desired capacity additions. The final design will depend on the selected combustion turbine with up to 6 combustion turbines required to achieve the ultimate capacity of 660 MW. Both simple cycle and combined cycle operation are planned; the latter would use by-pass stacks when only combustion turbine operation is needed, or the steam cycle is inoperable. The HRSG would not be supplementally fired.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The performance information and stack parameters that envelope the combustion turbine manufacturer's designs currently being considered for the project are presented in Table 2-1. This information provides conservative emission estimates of criteria pollutants (Table 2-2), other regulated pollutants (Table 2-3), and non-regulated pollutants (Table 2-4). Specific manufacturer designs would provide emissions no greater than those shown in these tables. The fuel specifications for natural gas and distillate oil are presented in Tables 2-5 and 2-6, respectively.

The maximum potential air quality impacts will occur during combined cycle operation when the exhaust temperature is 240°F. In addition, lower exhaust flow rates will occur for smaller combustion turbines which could also influence predicted impacts. As a result, the range in stack parameters used in modeling as well as corresponding sulfur dioxides (SO_2) emissions are presented in Table 2-7.

Table 2-1. Maximum Design and Stack Parameters for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant

Data	Gas Turbine Natural Gas @ 32°F	Gas Turbine No.2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No.2 Oil @ 95°F
General:				
Heat Input (mmBtu/hr)	1,268.4	1,312.3	1,074.1	1,107.2
Natural Gas (mcf/hr)	1,251.4	NA	1,059.8	NA
Fuel Oil (lb/hr)	NA	73,437.1	NA	61,956.3
Fuel:				
Heat Content - Gas (LHV)	1014 Btu/cf	NA	1014 Btu/cf	NA
Heat Content - Oil (LHV)	NA	17,870 Btu/lb	NA	17,870 Btu/lb
% Sulfur	NA	0.5	NA	0.5
Stack:				
Volume Flow (acfm)	1,924,021	1,929,288	1,707,645	1,782,889
Volume Flow (scfm)	713,401	714,351	615,452	628,415
Mass Flow (lb/hr)	3,110,000	3,114,140	2,683,000	2,739,512
Temperature (°F)*	964	966	1,005	1,038
Diameter (ft)	16.0	16.0	16.0	16.0
Velocity (ft/sec)	159.5	159.9	141.6	147.8
Height (ft)	75.0	75.0	75.0	75.0
Moisture (%)	10.3	9.3	13.5	12.4
Oxygen (%)	12.8	12.1	12.5	12.0
Water Injected (lb/hr)	76,010	96,698	63,350	82,047

* Exhaust from HRSG Stack will be 240°F.

NA = Not Applicable

Note: Data Presented in this table represent the design information used to produce maximum emissions from a single combustion turbine. Tables 2-2 through 2-3 present the maximum estimated emissions.

Table 2-2. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Criteria Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Particulate:				
Basis*	0.8 g/s	7.2 g/s	0.63 g/s	6 g/s
lb/hr	6.3	57.1	5.6	55.5
TPY	27.8	250.1	24.3	243.1
Sulfur Dioxide:				
Basis*	20 gr/100 scf	0.5 % Sulfur	20 gr/100 scf	0.5 % Sulfur
lb/hr	35.75	734.37	30.28	619.56
TPY	156.6	3,216.5	132.6	2,713.7
Nitrogen Oxides:				
Basis*	42 ppm**	65 ppm**	42 ppm**	65 ppm**
lb/hr	215.9	383.8*	174.9	311.5
TPY	945.7	1,680.9	766.0	1,364.3
ppm	42.0	65.0	42.0	65.0
Carbon Monoxide:				
Basis*	41 ppm**	13 ppm**	41 ppm**	13 ppm**
lb/hr	128.3	46.7	103.9	37.9
TPY	562.0	204.6	455.2	166.1
ppm	41.0	13.0	41.0	13.0
VOC's:				
Basis*	10 ppm**	10 ppm**	10 ppm**	10 ppm**
lb/hr	17.9	20.5	14.5	16.7
TPY	78.2	89.9	63.4	73.0
ppm	10.0	10.0	10.0	10.0
Lead:				
Basis		USEPA(1988)		USEPA(1988)
lb/hr	neg.	0.01	neg.	0.01
TPY	neg.	0.05	neg.	0.04

* From manufacturers estimates.
** Corrected to 15% 02 dry conditions.
Neg. = negligible

Emission factors used: No. 2 Fuel Oil; Lead - 8.9 lb/10^{12} Btu from USEPA (1988).

Table 2-3. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Other Regulated Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Arsenic (As) (lb/hr)	neg.	0.0055	neg.	0.0047
(TPY)	neg.	0.0241	neg.	0.0204
Beryllium (Be) (lb/hr)	neg.	0.0033	neg.	0.0028
(TPY)	neg.	0.0144	neg.	0.0121
Mercury (Hg) (lb/hr)	0.0144	0.0039	0.0122	0.0033
(TPY)	0.0633	0.0172	0.0536	0.0145
Fluorides (F) (lb/hr)	neg.	0.0427	neg.	0.0360
(TPY)	neg.	0.1868	neg.	0.1576
H2SO4 Mist (lb/hr)	1.6	33.7	1.4	28.4
(TPY)	7.2	147.6	6.1	124.6

Neg. = Negligible
Emission factors used:
Natural gas:
Hg - 11.34 lb/10^{12} Btu,
H_2SO_4 mist - 3% of Sulfur Emissions;

No. 2 Fuel Oil:
As - 4.2 lb/10^{12} Btu, Be - 2.5 lb/10^{12} Btu,
Hg - 3.0 lb/10^{12} Btu, F^- - 32.5 lb/10^{12} Btu,
H_2SO_4 mist - 3% of Sulfur Emissions.

Sources: USEPA, 1980 for Hg from natural gas firing; USEPA 1981 for F^- from oil
USEPA, 1988 for all others.

Table 2-4. Maximum Estimated Emissions for Each Combustion Turbine Associated with the Hardee Power Station Combined Cycle Plant Non-Regulated Pollutants

Pollutant	Gas Turbine Natural Gas @ 32°F	Gas Turbine No. 2 Oil @ 32°F	Gas Turbine Natural Gas @ 95°F	Gas Turbine No. 2 Oil @ 95°F
Manganese (lb/hr)	neg.	0.0085	neg.	0.0071
(TPY)	neg.	0.0370	neg.	0.0312
Nickel (lb/hr)	neg.	0.2231	neg.	0.1882
(TPY)	neg.	0.9772	neg.	0.8244
Cadmium (lb/hr)	neg.	0.0138	neg.	0.0116
(TPY)	neg.	0.0604	neg.	0.0509
Chromium (lb/hr)	neg.	0.0623	neg.	0.0526
(TPY)	neg.	0.2730	neg.	0.2303
Copper (lb/hr)	neg.	0.3674	neg.	0.3100
(TPY)	neg.	1.6094	neg.	1.3578
Vanadium (lb/hr)	neg.	0.0915	neg.	0.0772
(TPY)	neg.	0.4007	neg.	0.3381
Selenium (lb/hr)	neg.	0.0308	neg.	0.0260
(TPY)	neg.	0.1349	neg.	0.1138
POM (lb/hr)	0.0008	0.0004	0.0007	0.0003
(TPY)	0.0036	0.0016	0.0031	0.0014
Formaldehyde (lb/hr)	0.1120	0.5315	0.0949	0.4484
(TPY)	0.4906	2.3279	0.4155	1.9640

Neg. = Negligible

Emission Factors Used:

Natural Gas: Polycyclic Organic Matter (POM) - 0.65 lb/10^{12} Btu,
Formaldehyde - 0.088 lb/10^9 Btu;

No. 2 Fuel Oil: Manganese - 6.44 lb/10^{12} Btu,
Nickel - 170 lb/10^{12} Btu, Cadmium - 10.5 lb/10^{12} Btu,
Chromium - 47.5 lb/10^{12} Btu, Copper - 280 lb/10^{12} Btu,
Vanadium - 69.7 lb/10^{12} Btu, Selenium - 23.5 lb/10^{12} Btu,
POM - 0.279 lb/10^{12} Btu (emission factor indicated as a less than in reference),
Formaldehyde - 405 lb/10^{12} Btu.

Source: USEPA, 1988.

Table 2-5. Typical Natural Gas Specification*

Constituents, Percent by Volume	
Hydrogen (H_2)	--
Methane (CH_4)	83.40
Ethylene (C_2H_4)	--
Ethane (C_2H_6)	15.80
Carbon Monoxide (CO)	--
Carbon Dioxide (CO_2), max.	2.0
Nitrogen (N_2)	0.80
Oxygen (O_2), max.	0.40
Hydrogen Sulfide (H_2S), max.	1 grain/100 SCF
Water (H_2O) Vapor, max.	4 lb/10^6 SCF
Synthetic Lubricants (Phosphate-Ester Based)	Trace
Specific Gravity (relative to air)	0.636
Ultimate, Percent by Weight	
Sulfur (S), max.	20 grains/100 SCF
Hydrogen (H_2)	23.53
Carbon (C)	75.25
Nitrogen (N_2)	1.22
Oxygen (O_2)	--
Btu/ft^3 @ 60 F and 30 inches HgA (HHV)	950 (min) - 1129
Btu/lb of Fuel (HHV)	23,170
(LHV)	20,870

* Pipeline Grade.

Table 2-6. Typical Fuel Oil Specification*

Specific gravity, 60°F	0.82 - 0.86
Viscosity, cSt, 100°F, min.	0.5
Pour point, max, °F	0
Gross heating value, kcal/kg	10,500 - 10,950
Gross heating value, Btu/lb	19,000 - 19,600
Filterable dirt, mg/100 ml	4
Carbon residue (10% Bottoms), %, max.	0.25
Carbon residue (100% Sample), %, max.	1.0
Sulfur, %, maximum	0.5
Nitrogen, %	0.005 - 0.015
Hydrogen, %	12.2 - 13.2
Ash (fuel as delivered), ppm, max.	50
Trace metal contaminants (untreated)	
Sodium plus potassium, ppm, max.	1
Vanadium, ppm, max.	0.5
Lead, ppm, max.	1
Calcium, ppm, max.	2

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* Specification is typical of American Society of Testing and Materials (ASTM) Grade of No. 2 (ASTM D-398).

Table 2-7. Stack Parameters and SO_2 Emissions Used in Modeling for the Hardee Power Station

	Highest Emission		Lowest Flow Rate	
	32°F	95°F	32°F	95°F
Stack Gas Flow (ACFM)	947,056 23.93	833,126 21.05	770,627 19.47	654,455 16.54
Stack Gas Temperature (°F)	240 388.7 K	240	240	240
Stack Velocity (ft/sec)	78.5 23.9	69.1 21.1	63.9 19.5	54.2 16.5
Stack Diameter (ft)	16 4.88	16	16	16
Stack Height (ft)*	75 22.86	75	75	75
SO_2 Emissions (lb/hr)	734.37 92.53	619.56 78.06	558.04 70.31	456.34 57.50

* This stack height was used for the HRSG exhaust along with worst case structure dimensions (see Table 6-13) to conservatively estimate air quality impacts.

5 - machines

5 - machines

6 - machines

1, 2

3, 4

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the project. These regulations must be satisfied before the proposed facility can operate.

3.1 NATIONAL AND STATE AAQS

The existing applicable National and Florida ambient air quality standards (AAQS) are presented in Table 3-1. Primary National AAQS were promulgated to protect the public health, and secondary National AAQS were promulgated to protect the public welfare from any known or anticipated adverse affects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 General Requirements

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and approved by the U.S. Environmental Protection Agency (USEPA). (For sources in Florida, PSD review and approval has been delegated to FDER.) A "major stationary source" is defined as any one of 28 named source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more, of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

A "major modification" is defined under PSD regulations as a change at an existing major stationary source which increases emissions by greater than "significant amounts." PSD significant emission rates are shown in Table 3-2.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels (ug/m^3)

		AAQS					
		National		State			Significant
		Primary	Secondary	of	PSD Increments		Impact
Pollutant	Averaging Time	Standard	Standard	Florida	Class I	Class II	Levels
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum[+]	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	NA	NA	1
	24-Hour Maximum[*]	150	150	150	NA	NA	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[+]	365	NA	260	5	91	5
	3-Hour Maximum[+]	NA	1,300	1300	25	512	25
Carbon Monoxide	8-Hour Maximum[+]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[+]	40,000	40,000	40,000	NA	NA	2000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5[**]	25[**]	1
Ozone	1-Hour Maximum[++]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

[+] Maximum concentration not to be exceeded more than once per year.

[*] Achieved when the expected number of exceedances per year is less than 1.0.

[**] The State of Florida has not yet adopted the PSD Increments for NO_2 concentrations.

[++] Achieved when the expected number of days per year with concentrations above the standard is less than 1.0.

NA = Not applicable, i.e., no standard exists.

Sources: <u>Federal Register</u>, Vol. 43, No. 118, June 19, 1978.
40 CFR 50
40 CFR 52.21

Table 3-2. PSD Significant Emission Rates and De Minimis Air Quality Impact Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Air Quality Impact (ug/m^3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, Annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY+
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	*
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	*
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	0	*
Radionuclides	NESHAP	0	*
Inorganic Arsenic	NESHAP	0	*

*No ambient measurement method.
+Increases in VOC emissions.

Notes: Ambient monitoring requirements for subject pollutants may be exempted if the impact of the increase in emissions is below air quality impact de minimis levels.
NAAQS = National Ambient Air Quality Standards.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.

Sources: 40 CFR 52.21.
Chapter 17-2, Florida Administrative Code

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. Major sources and modifications are required to undergo the following analysis related to PSD for each pollutant emitted in "significant" amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 Increments/Classifications

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality "baseline concentration" level of SO_2 and PM concentrations would constitute "significant deterioration." The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). Class III areas, which would be allowed greater deterioration than Class II areas, have not been designated. USEPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, the USEPA promulgated regulations to prevent significant deterioration due to NO_x emissions and established PSD increments for NO_2 concentrations. The USEPA class designations and allowable PSD increments are presented in Table 3-1. The Florida DER has adopted the USEPA class designations and allowable PSD increments for SO_2 and PM but has not yet adopted the NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and denotes a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended August 7, 1980, baseline concentration means the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of sources in existence on the applicable baseline date; and
2. The allowable emissions of major stationary sources which commenced construction before January 6, 1975, but were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary source on which construction commenced after January 6, 1975 for SO_2 and TSP concentrations and February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary source occurring after the baseline date.

"Baseline date" means the earliest date after August 7, 1977 for SO_2 and TSP concentrations and February 8, 1988, for NO_2 concentrations, on which the first complete application under 40 CFR 52.21 is submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21.

3.2.3 Control Technology Review

The control technology review requirements of the federal PSD regulations require that all applicable federal and state emission limiting standards be met and that Best Available Control Technology (BACT) be applied to control emissions from the source (40 CFR 52.21). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the source or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in 40 CFR 52.21 as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act...which the Administrator, 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 or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.... If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (USEPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in USEPA's "Guidelines for Determining Best Available Control Technology (BACT)," (USEPA, 1978) and in the "PSD Workshop Manual" (USEPA, 1980). These guidelines were promulgated by USEPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area.

According to USEPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts (USEPA, 1978).

3.2.4 Air Quality Analysis

In accordance with requirements of 40 CFR 52.21(m), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary source or major modification. For a new major source, the affected pollutants are those that the source would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

According to CAA, ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four (4) months of data is required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in USEPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (USEPA, 1987a).

The regulations include an exemption which excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that the Administrator may exempt a proposed major stationary source or major modification from the monitoring requirements of 40 CFR 52.21(m) with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2.

3.2.5 Source Impact Analysis

A source impact analysis must be performed by a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically require the use of atmospheric dispersion models in performing impact analysis, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated USEPA models must normally be used in performing the impact analysis. Specific applications for other than USEPA-approved models require USEPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the USEPA publication, "Guideline on Air Quality Models (Revised)" (USEPA, 1987b). The source impact analysis for criteria pollutants may be limited to only the new or modified source if the net increase in impacts due to the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be utilized for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, federal PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for PSD Class I areas. Impacts due to general commercial, residential, industrial, and other growth associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 Good Engineering Practice Stack Height

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, USEPA promulgated final stack height regulations (USEPA, 1985). GEP stack height is defined as the highest of:

1. 65 meters (m), or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: H_g = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s).
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than

0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where "plume impaction" occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with "elevated terrain." "Elevated terrain" is defined as terrain which exceeds the height calculated by the GEP stack height formula. Because the terrain in the vicinity of the proposed facility is flat, plume impaction was not considered in determining the GEP stack height.

3.3 NONATTAINMENT RULES

On August 7, 1980, USEPA promulgated rules for review of major new sources and major modifications in areas where air quality does not meet federal standards [Emission Offset Interpretative Ruling (40 CFR 51, Appendix S), which applies to new and modified major sources affecting nonattainment areas.] Under Section IV.A of the Ruling, such sources are required to: (1) meet an emission limitation which specifies the lowest achievable emission rate for such sources, (2) certify that all existing major sources owned or operated by the applicant in the same state are in compliance with all applicable emission limitations and standards under the Act, (3) obtain emission offsets such that there will be reasonable progress toward attainment of the applicable national AAQS, and (4) demonstrate that the emission offsets would provide a positive net air quality benefit in the affected area [not applicable for volatile organic compounds (VOC) or NO_x]. FDER has promulgated rules that are consistent with the USEPA requirements [17-2.510 Florida Administrative Code]. Based on these current nonattainment provisions, all major new sources and modifications to existing major sources located in the nonattainment area must undergo the nonattainment review procedures if the proposed facility or source has the potential to emit 100 TPY or more of the nonattainment pollutant, or the major modification results in a significant net emission increase at the facility of the nonattainment pollutant.

For major sources or major modifications which locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area (F.A.C, Section 17-2.510). The area of influence is defined as an area which is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on F.A.C, Section 17-2.510(2)(a) 2.a, all VOC sources which are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources which emit other pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 PSD Review

3.4.1.1 Potential Emissions

The proposed facility would be considered a "major source" if the emission rate for one of the regulated pollutants exceeds 100 TPY. Once the source is considered to be a major source, PSD review is required for any pollutant that exceeds the PSD significant emission rates presented in Table 3-2. As presented in Table 3-3, the proposed source will have potential emissions of SO_2, NO_2, PM, CO, VOC, and sulfuric acid mist that are major and will exceed the PSD significant emission rates for Be, Hg and As. Therefore, the proposed facility is a major source and is subject to PSD review for those pollutants.

3.4.1.2 Area Classification

The proposed facility unit will be located in Hardee County which is designated by FDER as an attainment area for all criteria pollutants, and a PSD Class II area for SO_2, TSP and NO_2. The nearest nonattainment area is Hillsborough County which is nonattainment for ozone. Also, portion

Table 3-3. Potential Emissions and Predicted Impacts of the Project Compared to PSD Significant Emission Rates and De Minimis Air Quality Impacts Levels (Page 1 of 2)

	Emissions (TPY)		Impacts (ug/m^3)	
Pollutant	Potential From Proposed Source^{++}	Significant Emission Rate	Predicted Impacts	De Minimus Air Quality Impact Level
Sulfur Dioxide	16,083	40	62.5	13, 24-hour
Particulate Matter (TSP)	1,250	25	7.5	10, 24-hour
Particulate Matter (PM10)	1,250	15	7.5	10, 24-hour
Nitrogen Dioxide	8,405	40	4.6	14, Annual
Carbon Monoxide	2,810	100	38.0	575, 8-hour
Votatile Organic Compounds	450	40	--	Emissions Increase of 100 TPY
Lead	0.25	0.6	**	0.1, Calendar quarter
Sulfuric Acid Mist	738	7	*	*
Total Fluorides	0.93	3	**	0.25, 24-hour
Total Reduced Sulfur	NEG	10	**	10, 1-hour
Reduced Sulfur Compounds	NEG	10	**	10, 1-hour
Hydrogen Sulfide	NEG	10	**	0.2, 1-hour
Asbestos	NEG	0.007	*	*
Beryllium	0.072	0.0004	0.0004	0.001, 24-hour
Mercury	0.32	0.1	0.0016	0.25, 24-hour
Vinyl Chloride	NEG	1	**	15, 24-hour
Benzene	NEG	0	*	*
Radionuclides	NEG	0	*	*
Inorganic Arsenic	0.12	0	+	*

Table 3-3. Potential Emissions and Predicted Impacts of the Project Compared to PSD Significant Emission Rates and De Minimis Air Quality Impacts Levels (Page 2 of 2)

Note : NA = Not applicable.
NEG = Negligible.

* No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by USEPA.

\+ Predicted impacts are presented in Section 8 to assess effects on soils and vegetation.

** Predicted impacts are not required because emissions are less than significant emission rates.

++ Based on 100 percent capacity factor at 100 percent load when firing oil at 32°F conditions; all pollutant emissions based on 5 combustion turbines which produce the maximum emisssions for an ultimate capacity of 660 MW.

of Hillsborough County has been reclassified by FDER from a TSP nonattainment area to unclassifiable for PM10. This change will go into effect upon USEPA approval. The proposed facility will also be located more than 100 km from the PSD Class I areas of the Chassahowitzka National Wilderness Area and the Everglades National Park. Because impacts from the proposed source's emissions are not expected to be significant at such distances, potential impacts on the Class I area were not addressed in the analysis.

3.4.1.3 Ambient Monitoring

Based upon the pollutant impacts presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for SO_2, NO_2, PM, CO, VOC, sulfuric acid mist, Be, Hg and As. However, if the impact of these pollutant emissions is less than the de minimis levels, then an exemption from the preconstruction ambient monitoring requirement may be granted. Predicted impacts are less than de minimis levels for all pollutants, except SO_2 (refer to Table 3-3). For SO_2 concentrations, the Applicant has requested and received from the Florida DER an exemption from PSD preconstruction monitoring. For ozone concentrations, the de minimis air quality impact level is specified as an increase of 100 TPY or more of VOC emissions. Because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY, preconstruction monitoring review is required for O_3 concentrations. However, because of the rural nature of the proposed ~~site and locations of~~ existing monitoring stations, data from existing monitoring stations will be used to fulfill the ambient monitoring requirements for this application. A more detailed discussion about the preconstruction monitoring exemption and use of existing ambient data is presented in Section 5.0.

VOC also

It may be too far away

3.4.1.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters high. The proposed stack heights are 75 and 90 ft (23 and 27 meters), respectively, for the by-pass and HRSG stacks; therefore, they do not exceed the GEP stack height. Impact analyses were performed with both stacks at

75 ft (23 m) to produce worst case ambient impacts. The potential for downwash of the units' emissions due to nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.2 Nonattainment Review

Although the proposed facility is located in an attainment area for all regulated pollutants, it may be subject to nonattainment review if it is located within the area of influence of a nonattainment area (F.A.C., Section 17-2.510).

The proposed facility is located approximately 9 km from Hillsborough County, which is designated as nonattainment for O_3 concentrations, and 40 km from that portion of Hillsborough County designated as nonattainment for TSP concentrations. Therefore, the proposed facility is located within the area of influence of both nonattainment areas. However, based on FDER ? regulations, the proposed facility is exempt from nonattainment review for VOC emissions but must comply with PSD review requirements. Based on the maximum concentrations predicted for the proposed facility presented in Section 7.0, the maximum allowable TSP emissions will produce impacts that are not significant within the reclassified nonattainment area. In fact, the proposed facility has a significant TSP impact that extends out to only about 10 km from the project site. Based on these results, the proposed facility is not subject to nonattainment review for either VOC or PM emissions.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The Control Technology review requirements of the PSD regulations are applicable to emissions of NO_x, CO, SO_2, TSP/PM10, VOC, mercury, inorganic arsenic and sulfuric acid mist and beryllium (see Section 3.0). This section presents the applicable New Source Performance Standards (NSPS) and the proposed BACT for these pollutants. The approach to BACT analyses are based on the regulatory definitions of BACT.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR part GG. These regulations apply to:

1. "Electric utility stationary gas turbine" with a heat input at peak load of greater than 100 million Btu/hr [40 CFR 60.332 (b)];
2. "Stationary gas turbines" with a heat input at peak load between 10 and 100 million Btu/hr [40 CFR 60.332 (c)]; or
3. "Stationary gas turbines" with a manufacture's rate based load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The "electric utility stationary gas turbine" provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale [40 CFR 60.331 (q)]. The requirements for "electric utility stationary gas turbines" are applicable to the project and are the most stringent provision of the NSPS and are a technically feasible control alternative for the project. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS can be adjusted upward to allow for fuel bound nitrogen. For a fuel bound nitrogen concentration of 0.015% or less no increase in the NSPS is provided; for a fuel bound nitrogen concentration of 0.06% the NSPS is increased by 0.0024% or 24 ppm.

Table 4-1. Federal NSPS for Stationary Gas Turbines

Pollutant	Emission Limitation*
Sulfur Dioxide	Maximum of 0.015 percent by volume at 15 percent oxygen on a dry basis <u>or</u> sulfur in fuel no greater than 0.8 percent by weight
Nitrogen Oxides+	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

* Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

\+ Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load Y cannot be greater than 14.4.

** Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
N<0.015	0
0.015<N<0.1	0.04(N)
0.1<N<0.25	0.004+0.0067(N-0.1)
N>0.25	0.005

where:
N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 Nitrogen Oxides

4.3.1.1 Emission Control Hierarchy

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air to fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-2 presents a listing of the LAER/BACT decisions for gas turbines made by state environmental agencies and EPA regional offices. This table was developed from the information contained in the LAER/BACT clearinghouse documents (USEPA, 1985, 1986b, 1987c 1988c) and by contacting state agencies such as the California Air Control Board and the South Coast Air Quality Management District.

Presently, there are about 35 operating and permitted facilities with Selective Catalytic (SCR) in the United States. Almost all of these facilities were required to have SCR due to nonattainment status of the area where the facility was located. The requirement for SCR in these cases was to meet the Lowest Achievable Emission Rate (LAER). LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or

Table 4-2. LAER/BACT Decisions

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Virginia Power	VA	GE Turbine	1,875 MMBTU/hr	Apr-88	NOx 42ppm 490 lb/hr	Steam Injection W/Maximazation NSPS subpart GG
Trunkline LNG	LA	Gas Turbine	147,102 SCF/hr	May-87	NOx 59 lb/hr	
Wichita Falls E. I., I.	TX	Gas Turbine	20 MW	Jun-86	NOx 684 TPY CO 420 TPY	Steam Injection
Merck Sharp & Pohme	PA	Turbine	310 MMBTU/hr	May-88	NOx 42 ppm @ 15% O2	Steam Injection
California Dept. of Corr.	CA	Gas Turbine	5.1 MW	Dec-86	NOx 38 ppmv @ 15% O2	1 to 1 H2O injection
City of Santa Clara	CA	Gas Turbine		Jan-87	NOx 42 ppmvd @ 15% O2	Water Injection
Combined Energy Resources	CA	Cogeneration Fac.	27 MW	Mar-87	NOx 199 lb/D	SCR Unit, Duct Burner H2O Injection, Low NOx Design
Double 'C' Limited	CA	Gas Turbine	25 MW	Nov-86	NOx 194 lb/D	H2O Inj. & Selected Catalytic Red. 95.80 Efficiency
Kern Front Limited	CA	Gas Turbine	25 MW	Nov-86	NOx 194 lb/D 4.5 ppmvd @ 15% O2	H2O Inj. & Selected Catalytic Red. 95.80 Efficiency
Midway - Sunset Project	CA	Gas Turbine	973 MMBTU/hr	Jan-87	NOx 113.4 lb/hr 16.31 ppmv	H2O Injection, 73% Efficiency
O'Brien Energy Systems	CA	Gas Turbine	359.5 MMBTU/hr	Dec-86	NOx 30.3 lb/hr 15 ppmvd @ 15% O2	Duct Burner, H2O Injection and Scrubber
PG & E, Station T	CA	GE Gas Turbine	396 MMBTU/hr	Aug-86	NOx 25 ppm @ 15% O2 63 lb/hr	Steam Injection @ Steam/Fuel Ratio of 1.7/1, 75% Efficiency
Sierra LTD.	CA	GE Gas Turbine	11.34 MMCF/D		NOx 4.04 lb/hr 0.016 lb/MMBTU	Scrubber & CO Catalytic Converter Steam Injection 95.86 Efficiency

Table 4-2. LAER/BACT Decisions (Page 2 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Sycamore Cogeneration Co.	CA	Gas Turbine	75 MW	Mar-87	CO 10 ppmv @ 15% 02 3 hr Avg	CO Oxidizing Catalyst Combustion Control
U.S. Borax & Chemical Corp.	CA	Gas Turbine	45 MW	Feb-87	NOx 40 lb/hr 25 ppm @ 15% 02 Dry CO 23 lb/hr	Scrubber Proper Combust. Techniques
Western Power System, Inc	CA	GE Gas Turbine	26.5 MW	Mar-86	NOx 9 ppmvd @ 15% 02	H20 Injection, Selective Cat. Red. 80% Efficiency
Calcogen, Cal Polytechic	CA	Gas Turbine	21.4 MW	Apr-84	NOx 42 ppm @ 15% 02	H20 Injection, 70% Efficiency
Greenleaf Power Co.	CA	GE Gas Turbine	35.62 MW	Apr-85	NOx 42 ppm @ 15% 02 91 lb/hr CO 20.4 lb/hr	H20 Injection Good Eng. Practices
		Duct Burner	63.7 MMBTU/hr	Apr-85	NOx 0.1 lb/MMBTU 6.4 lb/hr CO 0.12 lb/MMBTU 7.6 lb/hr	Low NOx Design
OLS Energy	CA	GE Gas Turbine	256 MMBTU/hr	Jan-86	NOX 9 PPMVD @ 15% 02	H20 Injection & Scrubber 80% Eff. for Scrubber
Ciba Giegy Corp.	NJ	Gas Turbine	3 MW	Jan-85	NOx 11.06 lb/hr CO 9.4 lb/hr	SIP, H20 Injection, 55% Eff.
Energy Reserve, Inc.	CA	Gas Turbine	322.5 MMBTU/hr	Oct-85	NOx 185.4 lb/D	H20 Injection, Select. Cat. Red. 92.5% Efficiency
Gilroy Energy Co.	CA	Gas Turbine	60 MW	Aug-85	NOx 25 PPMDV @ 15% 02	Steam Inj., Quiet Combustor
		Auxiliary Boiler	90 MMBTU/hr		NOx 40 PPMDV @ 3% 02	Low NOx Burners

Table 4-2. LAER/BACT Decisions (Page 3 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Kern Energy Corp.	CA	Gas Turbine	8.8 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH_3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Moran Power, Inc.	CA	Gas Turbine	8.0 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH_3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Northern California Power	CA	GE Gas Turbine	25.8 MW	Apr-85	NOx 75 ppm	H_2O Injection
Shell California Production	CA	Gas Turbine	22 MW	Apr-85	NOx 42 ppm @ 15% O_2 35 lb/hr	H_2O Inj.
					CO 10 PPMV @ 15% O_2 22 lb/hr	Proper Combustion
Southeast Energy, Inc.	CA	Gas Turbine	8.0 MMCF/D	Apr-86	NOx 8.29 lb/hr 0.023 lb/MMBTU	Scrubber w/ NH_3 Red. Agent Steam Inj. & Low NOx Config. Exh. Duct Burner 87% Efficiency
Sunlaw/Industrial Park	CA	Gas Turbine	412.3 MMBTU/hr	Jun-85	NOx 9 PPMVD @ 15% O_2	Scr. & Steam Inj., 80% Eff.
					CO 10 PPMVD @ 15% O_2	Mfg Guarantee on CO Emissions
Union Cogeneration	CA	Gas Turbine w/ Duct Burner	16 MW	Jan-86	NOx 25 PPMV @ 15% O_2	H_2O Injection & Scrubber
					CO 8 lb/hr 29.2 TPY	Oxidizing Catalyst, 80% Efficiency
Willamette Industries	CA	GE Gas Turbine	230 MMBTU/hr	Apr-85	NOx 15 PPMVD @ 15% O_2	H_2O Inj. w/ Selective Cat. Red. 92% Efficiency

Table 4-2. LAER/BACT Decisions (Page 4 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Witco Chemical Corp.	CA	Gas Turbine	350 MMBTU/hr	Dec-84	NOx 0.18 lb/MMBTU Oil 0.20 lb/MMBTU Gas	
		Duct Burner	111.6 MMBTU/hr		NOx 0.12 lb/MMBTU	Gas Firing Only
AES Placerita, Inc.	CA	Turbine & Recovery Boiler	519 MMBTU/hr	Mar-86	NOx 629 lb/d 7 PPMVD @ 15% O_2 CO 103 lb/d 2 PPMVD @ 15% O_2	H_2O Inj, Select. Cat. Red. 80% Efficiency
AES Placerita, Inc.	CA	Turbine & Recovery Boiler	530 MMBTU/hr	Jul-87	NOx 340 lb/D 9 PPMVD @ 15% O_2	Steam Inj, Select. Cat. Red.
AES Placerita, Inc.	CA	Gas Turbine	530 MMBTU/hr	Jul-87	NOx 289 lb/D 9 PPMVD @ 15% O_2	Steam Inj, Select. Cat. Red.
Alaska Electrical Generation	AK	Gas Turbine	80 MW	Mar-87	NOx 75 PPMVD @ 15% O_2 CO 109 lb/SCF Fuel	H_2O Injection
Alaska Electrical Generation	AK	Gas Turbine	38 MW	Mar-85	NOx 75 PPM @ 15% O_2	H_2O Injection
BAF Energy	CA	Turbine, Generator	887.2 MMBTU/hr	Jul-87	NOx 9 PPM @ 15% O_2 30.1 lb/hr	Steam Injection, Scrubber 80% Efficiency
BAF Energy	CA	Auxiliary Boiler	150 MMBTU/hr	Oct-87	NOx 17.4 lb/D 40 PPMVD @ 3% O_2 CO 63.6 lb/D 0.018 lb/MMBTU	Flue Gas Recirculation Low NOx Burners Oxidation Catalyst
Champion International Corp.	TX	Gas Turbine	30.6 MW (1342 MMBTU/hr)	Mar-85	NOx 720.34 TPY CO 70.08 TPY	Low NOx Burners
Cogen Technologies	NJ	GE Gas Turbines	40 MW	Jun-87	NOx 9.6 PPMVD @ 15% O_2 CO 50 PPMVD @ 15% O_2	H_2O Inject. & SCR, 95% Efficiency

Table 4-2. LAER/BACT Decisions (Page 5 of 5)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Combined Energy Resources	CA	Gas Turbine	2 MW	Feb-88	NOx 199 lb/hr	H2O Inj. & Scrubber, 81% Efficiency
Formosa Plastic Corp.	TX	GE Gas Turbine	38.4 MW	May-86	NOx 640 TPY CO 32.4 TPY	Steam Injection
Midland Cogeneration Venture	MI	Turbine	984.2 MMBTU/hr	Feb-88	NOx 42 PPMV @ 15% O2 CO 26 lb/hr	Steam Injection Turbine Design
		Duct Burner	249 MMBTU/hr		NOx 0.1 lb/MMBTU	Burner Design
Pacific Gas Transmission	OR	Gas Turbine	14000 HP	May-87	NOx 154 PPM 50 lb/hr CO 6 lb/hr 25 TPY	Combustion Control
Power Development Co.	CA	Gas Turbine	49 MMBTU/H	Jun-87	NOX 36 lb/D 9 PPMVD @ 15% O2	Scrubber & H2O Injection
San Joaquin Cogen Limited	CA	Gas Turbine	48.6 MW	Jun-87	NOx 250 lb/D 6 PPMVD @ 15% O2 CO 1326 lb/d 55 PPMVD @ 15% O2	Scrubber & H2O Injection 76% Efficiency Combustion Controls
TBG/Grumman	NY	Gas Turbine	16 MW	Mar-88	NOx 75 PPM + NSPS Corr. 0.2 lb/MMBTU CO 0.181 lb/MMBTU	H2O Inj. & Combustion Controls CO Catalyst
Texas Gas Transmission Corp.	KY	Gas Turbine	14300 HP	Feb-88	NOx 0.015 % by Volume	
Orlando Utilities Commission	FL	Gas Turbine	4 x 445 MMBTU/H	Sept-88	NOx 42 PPMDV Gas 65 PPMDV Oil CO 10 PPMMDV	Steam Injection Good Combustion
Anheuser-Busch	FL	Gas Turbine	95.7 MMBTU/hr	Apr-87	NOx 0.1 lb/MMBTU	

> category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51 Appendix S. II, A.18).

As noted from the discussion contained in Subsection 3.2.3, there is a regulatory distinction between LAER and BACT.

In Florida, the most recent permits have required wet injection for NO_x control. The emission limits were 42 ppm and 65 ppm (corrected to 15% O_2, dry conditions) respectively, for natural gas and fuel oil firing.

The hierarchy for NO_x control suggested by the existing and permitted facilities is as follows:

1. Selective Catalytic Reduction (SCR).
2. Wet Injection using standard or advanced combustor design.

The selected control level of SCR used for the BACT analysis was 9 ppm NO_x corrected to 15% dry conditions using natural gas. This level of control assumes 80% removal of NO_x by the SCR equipment with an input concentration of 42 ppm. For fuel oil firing, a control level of 14 ppm was used to account for fuel bound nitrogen. These levels of control are the most stringent being established as BACT. For wet injection, the advanced combustor design can limit NO_x to 25 ppm when firing natural gas and 42 ppm when firing fuel oil while the standard combustor design can limit No_x to 42 ppm when firing natural gas and 65 ppm when firing fuel oil.

4.3.1.2 Technology Description and Feasibility

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR uses ammonia (NH_3) to react with NO_x in the gas stream under the presence of a catalyst. NH_3, which is diluted with air to about 5% by volume, is introduced into the gas stream at reaction temperatures between 600°F and 700°F. The reactions are as follows:

$$4NH_3 + 4NO = 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 = 3N_2 + 6H_2O$$

SCR has mainly been installed at facilities located in nonattainment areas for NO_2 and mainly in California. While the operating experience has not been extensive, certain cost, technical and environmental considerations have surfaced. These considerations are summarized in Table 4-3.

The operating experience consists primarily of baseload natural gas fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle combustion turbines are generally in the range of 1000°F, which exceeds the optimum range for SCR. While cooling could be accomplished through the introduction of ambient air, the increased volume of air would increase the catalyst size, and thus the cost, considerably. Water quenching is not feasible since the catalyst can be damaged and ammonium hydroxide, a corrosive, would be formed.

The use of fuel oil in SCR facilities has been limited since SCR catalysts are contaminated by sulfur containing fuels. For most fuel oil burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. As presented in Table 4-3, ammonium bisulfate is formed by the reaction of NH_3 and SO_3. Experience at the United Airlines cogeneration facility using 0.05% fuel oil found catalyst contamination after 2,500 hours of operation. For this facility, the catalyst has been replaced three times and the recommended hours of operation by the manufacturer is now 500 hours.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80%. Emission limiting standards with SCR are in the 9 ppm range for natural gas firing. However, two facilities have reported emission limits

Table 4-3. SCR Cost, Technical and Environmental Considerations for Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40% of total capital cost and is the dominate annual cost factor.
Ammonia	Ratio of at least 1:1 NO_x to NH_3 generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Pressure	Addition of catalyst creates back pressure on the turbine which reduces overall heat rate.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust steam to assure optimum mixing with NO_x prior to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate, i.e., about 100°F, must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.
Ammonia Control System	Quantity of NH_3 introduced must be carefully controlled. With too little NH3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions occur.

Table 4-3. SCR Cost, Technical and Environmental Considerations for Combustion Turbines (Page 2 of 2)

Consideration	Description
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip, or NH_3 that passes unreacted through the catalyst and into the atmosphere can occur if: 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or the proper temperature is not maintained.
Ammonia Bisulfate and Chloride Salts	Ammonium bisulfate and chloride salts can lead to increased corrosion. These usually occur when firing fuel oil. These compounds are emitted as particulates.
N_2O and Nitrosoamines formation	The mechanism under which these compounds form is not totally understood. Secondary impacts can occur.

of about 4.5 ppm. These emission limits were clearly determined to be LAER on machines using water injection below 42 ppm. For fuel oil firing, permitted NO_x emissions with SCR has ranged from 14 ppm to 42 ppm.

The available information suggests that SCR is a technically feasible alternative for the project. However, the following technical limitations exist:

1. SCR is not technically applicable to the simple cycle portion of the combined cycle configuration, i.e., the combustion turbine by-pass stack exhaust, and
2. Continuous operation of SCR using distillate oil has not demonstrated; technical, economic and environmental uncertainties would result.

WET INJECTION

The injection of water or steam in the combustion zone of turbines reduces the flame temperature with a decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water to fuel ratio used. An increase in the water to fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the turbine becomes inefficient and unreliable, and significant increases in products of incomplete combustion will be emitted, i.e., CO and VOC.

With standard combustion chamber design, there is a point where the amount of water or steam injected into the turbine seriously degrades its reliability and operational life. This generally occurs at NO_x emissions levels of about 65 ppmvd (with no heat rate adjustment) on oil and 42 ppmvd on natural gas. These NO_x emission levels can be achieved with little additional cost and with limited impact on reliability or power output over those costs required to comply with the NSPS.

Since the combustion turbine NSPS was last revised in 1982, combustion turbines have improved their tolerance to the water or steam necessary to control NO_x emissions below the NSPS requirement. Some manufactures have begun to market an improved low NO_x burner design. [These burners provide improved air/fuel mixing with water or steam injection result in reduced flame temperatures and concomitantly lower concentrations of NO_x as compared to a standard combustion chamber design (with water or steam injection).] These design improvements result in a NO_x emission rate of 25 ppmvd compared to 42 ppmvd with a standard combustor design. However there is the lack of operating experience with such designs and there is a significant increase in capital cost of the turbines. Also, approximately 25 gpm of additional demineralized water per turbine would be required for injection into the combustion chamber. The improved combustors would, however, increase CO concentrations relative to the standard combustor. Low NO_x burner designs are however, not available for several of the manufacturers being considered. Because of this and the lack of operating experience of those manufacturers with burners, low NO_x burner design are considered marginally feasible for the project.

Wet injection is a technically feasible alternative for the project. The application of this technology has the following limitations:

1. Wet injection can be accomplished until a condition of maximum moisturization occurs; this design condition depends on the combustor design but usually occurs at 42 ppm on natural gas and 65 ppm on fuel oil,

2. Wet injection will not substantially reduce NO_x formation due to fuel bound nitrogen, any emission limiting requirements must account for this effect, and

3. Wet injection will increase the emissions of CO and VOC depending on the water to fuel ratio.

For the BACT analysis, emissions with wet injection were considered to be 25 ppm and 42 ppm when firing natural gas and 42 ppm and 65 ppm when firing fuel oil (both corrected to 15% O_2 dry conditions). These emission levels are the most stringent being established as BACT.

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies (see 40 CFR 52.21(b)(12) and 17-2.100(25) and 17-2.500(5)(c) FAC). The analysis must be specific to the project, i.e., case-by-case. The economic and environmental impacts of the control technologies evaluated for NO_x are summarized in Table 4-4. The specific analyses are discussed below.

ECONOMIC

The total annualized cost for alternative NO_x control technologies range from $22,014,000 for SCR to $2,490,000 for wet injection to meet NSPS (Table 4-5). Incremental cost effectiveness for SCR was estimated to range from $8,250/ton NO_x removed for natural gas firing to $4,641/ton NO_x removed for fuel oil firing. This incremental cost is about a factor of four higher than the improved combustor design. Indeed, the incremental cost effectiveness was estimated to be over 25 times that of the standard combustor. For the improved combustor design the incremental cost effectiveness ranged from $1,626 to $915/ton of NO_x removed, which was about seven times or more higher than the standard combustor design. These costs reflect increased CO emissions. Assuming CO controls the incremental cost effectiveness would be $5,007/ton of NO_x removed when firing natural gas and $2,817/ton of NO_x removed when firing fuel oil. The incremental cost effectiveness for the standard combustor ranged from $176 to $504/ton of NO_x removed.

ENVIRONMENTAL

The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment (i.e., 25 ug/m^3) and AAQS (i.e., 100 ug/m^3). Additional controls beyond NSPS improve air quality to less than about 20% of the PSD increment and about 5% of the AAQS.

Table 4-4. Summary of BACT Analysis

Pollutant	Control Option			Economic Impact		Environmental Impacts	
	Description	Fuel	Emissions (TPY)	Annualized Cost ($)	Incremental Cost Effectiveness ($/ton)	Impacts for Controlled Pollutant	Other Impacts
NOx	Water Injection with SCR to 9 ppm	Natural Gas	1,018	22,014,000	8,250	0.6 (Max. Annual)	Ammonia @ 10ppm
	Water Injection with SCR to 14 ppm	Fuel Oil	1,810	22,014,000	4,641	1.0 (Max. Annual)	Ammonia @ 10ppm Ammonium Bisulfate
	Improved Combustor Design to 25 ppm	Natural Gas	3,058	5,210,000 (10,868,000)	1,626 (5,007)	1.7 (Max. Annual)	Increase in CO & VOC; water use
	Improved Combustor Design to 42 ppm	Fuel Oil	5,431	5,210,000 (10,868,000)	915 (2,817)	3.0 (Max. Annual)	Increase in CO & VOC; water use
	Standard Combustor Design to 42 ppm	Natural Gas	4,729	2,490,000	176*	2.6 (Max. Annual)	Water use
	Standard Combustor Design to 65 ppm	Fuel Oil	8,405	2,490,000	504*	4.6 (Max. Annual)	Water use
CO	Catalytic Oxidation to 10 ppm	Natural Gas	685	5,658,000	2,663	10 (Max. 8 hr)	
	Combustion Techniques to 41 ppm	Natural Gas	2,810	--	--	39 (Max. 8 hr)	
SO2	0.20 % Sulfur Fuel	Fuel Oil	6,433	21,009,000	NA	25 (Max. 24 hr)	
	0.50 % Sulfur Fuel	Fuel Oil	16,083	--	--	63 (Max. 24 hr)	

* Based on an NSPS Emission Level of 98 ppm and an estimated annualized cost of $1,813,000.

Table 4-5. Annualized Cost Estimate for Alternative NOx Control Technology

Item	Basis	Standard Combustor & SCR	Improved Combustor	Standard Combustor
DIRECT COSTS (DC):				
Differential Turbine Costs		$ 1,800,000	$8,750,000	$1,800,000
SCR Reactor		$22,140,000	$0	$0
Ammonia Storage & Injection Equipment		$5,530,000	$0	$0
Water Treatment, Storage & Injection		$2,810,000	$4,240,000	$2,810,000
Balance of Plant		$1,160,000	$1,380,000	$1,060,000
Subtotal:		$33,440,000	$14,370,000	$5,670,000
CONTINGENCY:	10% of DC	$3,344,000	$1,437,000	$567,000
TOTAL CAPITAL COSTS (TCC):		$36,784,000	$15,807,000	$6,237,000
ESCALATION:		$5,429,318	$2,333,113	$920,581
TOTAL ESCALATED COST (TEC):		$42,213,318	$18,140,113	$7,157,581
SALES AND USE TAX:	6% of TEC	$2,532,799	$1,088,407	$429,455
SUBTOTAL:		$44,746,118	$19,228,520	$7,587,036
INDIRECT COSTS:	14.5% of Subtotal	$6,488,187	$2,788,135	$1,100,120
INTEREST DURING CONSTRUCTION:	10.45%	$5,353,985	$2,300,740	$907,808
INSTALLED COST:		$56,588,289	$24,317,396	$9,594,964
OPERATING COSTS:				
Operating & Maintenance*		$10,208,333	$986,111	$652,778
Ammonia		$ 1,305,556	$0	$0
Energy		$ 2,125,000	$625,000	$416,667
ANNUAL OPERATING COST:		$13,638,889	$1,611,111	$1,069,444
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$ 8,375,067	$3,598,975	$1,420,055
TOTAL LEVELIZED ANNUAL COST:		$22,013,956	$5,210,086	$2,489,499

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* Includes Catalyst Replacement

Additional air quality impacts would occur with the installation of SCR. Emissions of ammonia, ammonium sulfates, such as ammonium bisulfate, and chloride salts would occur. Ammonia would be emitted at a concentration of at least about 10 ppm based on previous experience; previous permit conditions have selected this level. For a 660 MW plant, ammonia emissions would be about 400 ton/year. However, ammonia emissions could be five times this level since actual operating experience has found ammonia slippage rates as high as 50 ppm.

The replacement of SCR catalyst will create additional economic and environmental impacts since such catalyst, e.g. vanadium pentoxide, are listed as hazardous chemical wastes under RCRA regulations (40 CFR 261).

ENERGY

Energy penalties will occur with all control alternatives evaluated. The most significant is with SCR would reduce the output of the combustion turbine by about 0.1% over wet injection. This would amount to about a 5,800,000 kw/hr loss in potential generation/year.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the Hardee Power Station is wet injection using standard combustor design. The NO_x emissions levels using standard combustor with wet injection would be 42 ppm when firing natural gas and 65 ppm when firing fuel oil. This alternative control is proposed for the following reasons:

1. SCR was rejected based on technical economic and environmental grounds. Operation of SCR during simple cycle CT operation has not been demonstrated since the temperature range of the exhaust exceeds operational requirements for optimum catalytic reaction. Fuel oil firing when operating SCR would cause operating problems and result in catalyst poisoning. The estimated total and incremental costs exceed $2,000 and $5,000/tons of NO_x removed, respectively. These costs are over an order of magnitude more costly than the proposed BACT levels. Additional environmental

impacts would result from SCR operation including emissions of ammonia and ammonium bisulfates, and the generation of hazardous waste, i.e., spent catalyst replacement.

2. The improved combustor design is rejected based on technical economic and environmental reasons. Not all manufacturers offer improved combustor designs. For those who do, an economic penalty would result: the annualized cost of such systems is over twice that of the standard combustor design. In addition, these improved combustor designs have not been demonstrated to achieve the reliability and maintenance requirements as standard designs. Environmental impacts would also result including increases in CO and VOC emissions and water consumption. Control of CO and VOC emissions greatly increase the cost of the advanced combustor. The cost effectiveness would exceed $2,500/ton of NO_x removed. Water use has been estimated to increase 25 gpm per turbine or about 130,000 gpd more than a standard combustor design.

3. The proposed BACT provides the least costly alternative and results in the maximum environmental impacts of less than 20% of the PSD increments and 5% of the AAQS. Wet injection at the proposed emissions levels has been adopted as BACT previously and manufacturers have guaranteed this level.

4.3.2 Carbon Monoxide (CO)

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more prevalent control technique used in combustion turbines. Sufficient time, temperature and turbulence is required within the combustion zone to minimize the emissions of CO. As such, combustion efficiency is dependent upon combustor design and, in NO_x control systems, the amount of water or steam injected in the combustion zone. For the combustion turbines being evaluated, CO emissions range from 10 ppm to 41 ppm, corrected to 15% O_2 dry conditions.

Catalytic oxidation is a post combustion control that has been installed where CO nonattainment regulations have required CO reduction due to increases caused by wet injection. These LAER installations typically have CO limits in the 10 ppm range (corrected to 15% O_2 and dry conditions).

4.3.2.2 Technology Description

Oxidation catalyst control CO emissions by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as a platinum coated surface. Combustion of CO starts at about 300°F with efficiencies above 90% occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50% lower than that of thermal oxidation which reduces the amount of thermal energy required. For combustion turbine and HRSG combinations, the oxidation catalyst can be located directly after the turbine or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas. Controlled CO levels of 10 ppm have generally been established as BACT.

Oxidation catalysts have not been used on fuel oil fired combustion turbines or combined cycle facilities. The use of sulfur containing fuels in a system with oxidation catalyst would result in an increase of SO_3 emissions and concomitant corrosive effects to the back end of the HRSG and stack. In addition, trace metals in the fuel would result in catalyst poisoning during prolonged periods of operation.

Since the facility would likely require numerous start-ups, variations in exhaust conditions would influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling. The size and fuel requirements for the project would suggest rejection of catalytic oxidation as a technically feasible alternative. However, continuous operation using natural gas is technically feasible and therefore evaluated or an alternative BACT technology.

Combustion design is dependent upon the manufacturer's operating specifications which include air to fuel ratio and the amount of water injected. All combustion turbines presently being considered have designs to optimize combustion efficiency and minimize CO emissions.

4.3.2.3 Impact Analysis

ECONOMIC

The estimated annualized cost of a CO oxidation catalyst is $5,658,000 (Table 4-6) with a total cost effectiveness of $2,663/ton of CO removed. The latter assumes that the "worst-case" emissions will be in the range of 41 ppm corrected to 15% O_2 dry conditions. At a CO emission of 25 ppm, the cost effectiveness would exceed $5,000/ton of pollutant removed. No costs are associated with combustion techniques since they are inherent to the process.

ENVIRONMENTAL

The air quality impacts of both techniques are below the significant impact levels for CO. Therefore, no environmental benefit would be realized by the installation of a CO catalyst.

ENERGY

An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1 1/2 to 2 1/2 water gauge would be expected. At a catalyst back pressure of about 2 in, an energy penalty of about 4,000,000 kw-hr/year would result.

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT due to the technical and economic consequences of installing catalytic oxidation. Catalytic oxidation is not

Table 4-6. Annualized Cost Estimate for CO Catalyst

Item	Basis	Cost
DIRECT COSTS (DC):		
Catalyst	Manufacturer	$7,644,000
Installation	45% of Catalyst	$3,439,800
Subtotal:		$11,083,800
CONTINGENCY:	10% of DC	$1,108,380
TOTAL CAPITAL COSTS (TCC):		$2,032,030
ESCALATION:		$1,799,568
TOTAL ESCALATED COST (TEC):		$13,831,651
SALES AND USE TAX:	6% of TEC	$839,504
SUBTOTAL:		$14,831,253
INDIRECT COSTS:	14.5% of Subtotal	$2,150,532
INTEREST DURING CONSTRUCTION:	10.45% of Subtotal	$1,549,866
INSTALLED COST:		$18,531,651
OPERATING COSTS:		
Labor	1 man-year	$270,000
Catalyst Replacement*	Manufacturer	$2,400,000
Miscellaneous Parts	1% of Installed Cost	$185,316
Energy Penalty	Estimated	$60,000
ANNUAL OPERATING COST:		$2,915,316
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$2,742,684
TOTAL LEVELIZED ANNUAL COST:		$5,658,000

* 2-year replacement interval on fuel oil

considered feasible, not withstanding the lack of environmental benefit, for the following reasons:

1. Catalytic oxidation has not been demonstrated on cycling combustion turbines or those using fuel oil; and
2. The economic impacts are significant, i.e. annualized cost of $5,658,000 with a likely cost effectiveness of over $5,000/tons of pollutant removed.

4.3.3 Sulfur Dioxide (SO_2)

4.3.2.1 Emission control Hierarchy

Sulfur dioxide (SO_2) emissions are a result of the oxidation of sulfur in fossil fuel and can be minimized by reducing the sulfur content in fuel or through applying post combustion removed techniques. For combustion turbines, the use of low sulfur fuels is the only demonstrated control technology determined to be technically feasible. Post combustion techniques, such as flue gas desulfurization (FGD) have not been applied to combustion turbines.

FGD systems have been applied to oil and coal-fired steam electric power plants. However, the relative gas volume for such facilities is significantly less than that for combustion turbines (i.e., about 2 to 3 times) and the resultant SO_2 concentration is considerably more. While the former factor will influence the cost of FGD, the later poses significant technological constraints to removing SO_2.

The BACT/LAER clearinghouse documents (1985, 1986b, 1987c, 1988c) show fuel sulfur contents from 0.8% to less than 0.2%. The lowest sulfur containing fuels were required in California where LAER decisions dictate more stringent standards. Furthermore, such requirements generally limited fuel oil use for backup or emergency purposes only. For the Hardee Power Station the only technically feasible control technology for SO_2 is therefore low sulfur fuel use. The use of natural gas will clearly minimize SO_2 emission. SO_2 emissions from distillate fuel can be minimized by specification of a lower sulfur content fuel, or blending of a lower sulfur content fuel, such as No. 1 fuel oil or kerosene, with No. 2 fuel oil. To reduce the uncertainties of supplier reliability, the blending of kerosene was selected as an alternative control technology of the project. A sulfur content of 0.2% was selected as the BACT level since it is near the lowest of sulfur contents contained in the BACT clearinghouse documents.

4.3.3.2 Technology Description

The sulfur content of No. 2 fuel oil will have a maximum sulfur content of 0.5% with a nominal average of 0.3%. For the purposes of the analysis the maximum sulfur content was assumed. Kerosene has a sulfur content of 0.05%.

To obtain an average sulfur content of 0.2%, No. 2 fuel oil and Kerosene would have to be blended in a ration of about 1 to 2. Blending would require a separate storage tank, transfer pumps, mixing tank and mixing equipment.

4.3.3.3 Impact Analysis

ECONOMIC

The total annualized cost for achieving a maximum 0.2% sulfur fuel was estimated at $21,009,000 (Table 4-7). The incremental cost of $2,177/ton of pollutant removed reflects the assumption that the No.2 fuel oil received would be 0.5%. At the more nominal sulfur content of 0.3% for No. 2 fuel oil the cost effectiveness would be $6,531/ton of pollutant removed. In addition, the cost effectiveness would substantially increase as the percentage of fuel oil decreases. As discussed previously primary fuel for the project is natural gas.

ENVIRONMENTAL

Both alternatives are less than the PSD increment and AAQS. Substantial air quality benefits are not expected given the primary use of natural gas and the fact that the maximum SO_2 concentrations were predicted to occur at the property boundary.

Table 4-7. Annualized Cost Estimate for SO_2 Control

Item	Basis	Cost
DIRECT COSTS (DC):		
Oil Tank & Mixers	Estimate	$5,000,000
Installation	45% of Equipment	$2,250,000
Subtotal:		$7,250,000
CONTINGENCY:	10% of DC	$725,000
TOTAL CAPITAL COSTS (TCC):		$7,975,000
ESCALATION:		$1,177,110
TOTAL ESCALATED COST (TEC):		$9,152,110
SALES AND USE TAX:	6% of TEC	$549,127
SUBTOTAL:		$9,701,237
INDIRECT COSTS:	14.5% of Subtotal	$1,406,679
INTEREST DURING CONSTRUCTION:	10.45% of Subtotal	$1,013,779
INSTALLED COST:		$12,121,695
OPERATING COSTS:		
Labor	1 man-year	$45,000
Fuel Cost	$0.07/gallon differential	$19,049,008
Miscellaneous Parts	1% of Installed Cost	$121,217
ANNUAL OPERATING COST:		$19,215,225
FIXED CHARGES ON CAPITAL:	14.8% of Installed Cost	$1,794,011
TOTAL LEVELIZED ANNUAL COST:		$21,009,236

* 2-year replacement interval on fuel oil

ENERGY

No substantial energy penalties were assumed to occur with the blending of kerosene with No. 2 fuel oil.

4.3.3.4 Proposed BACT and Rationale

The proposed BACT for the Hardee Power Station is the use of natural gas and No. 2 fuel oil with a maximum sulfur content 0.5%. The basis for this control alternative are:

1. The blending of Kerosene is not economically feasible. Indeed, it is uncertain if the quantities of kerosene required to be blended with No. 2 fuel oil could be obtained.
2. The primary fuel for the project is natural gas which would increase the relative cost effectiveness of blending kerosene with No. 2 fuel oil.

4.3.4 Particulate Emissions

The emission of particulates from the combustion turbine facility are a result of some incomplete combustion that may occur and of having some trace solids in the fuel, especially fuel oil. The design of the combustion turbines will insure that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of the USEPA's BACT/LAER Clearinghouse documents did not reveal any post combustion particulate control technologies being used on gas/oil fueled combustion turbines. The natural gas and distillate fuel oil to be used in the proposed combustion turbines will only contain trace quantities of particulate. Therefore, the fuel and combustion design will ensure maximum possible fuel combustion and are the proposed BACT for total suspended particulate, and particulate matter smaller than 10 microns (PM10). Indeed, the maximum particulate emissions will be of less concentration than that normally specified for fabric filter designs; i.e., the grain loading of the maximum particulate emissions (57 lbs/yr) is less than 0.01 grains/SCF which a typical design specification for a baghouse.

4.3.5 Other Criteria and Non-Regulated Pollutants Emissions

Emission estimates indicate that significance levels are exceeded for VOC, sulfuric acid mist, mercury beryllium and arsenic, requiring PSD review (including BACT) for these pollutants.

There are no technically feasible methods for controlling the emission of these pollutants from combustion turbines, other than complete combustion of the fuel, and the inherent quality of the fuel (see Section 4.3.3 and 4.3.4). Sulfuric acid mist emissions are a direct function of the sulfur content of the fuel. BACT regarding mercury beryllium, and arsenic is the inherent quality of the fuel.

For the non-regulated pollutants, none of the control technologies evaluated would reduce these concentrations. The air quality impacts of the pollutants are expected to be significantly below any levels that would cause health effects.

5.0 AIR QUALITY ANALYSIS

5.1 GENERAL MONITORING REQUIREMENTS

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed through the use of modeling and/or monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data will generally not be required if the ambient air quality concentration before construction is less than the *de minimis* impact monitoring concentrations, (refer to Table 3-3 for *de minimis* impact levels). Also, if the maximum predicted impact of the source or modification is less than the *de minimis* impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, USEPA recommends that an analysis based on the air quality modeling should generally be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant and emissions from the source or modification pose a threat to the standard;

2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, before a permit granting authority requires preconstruction monitoring, USEPA recommends that an acceptable measurement method approved by USEPA should be available and the maximum concentrations due to the major source or major modification are predicted to be above the significant monitoring concentrations.

The USEPA "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (PSD) (USEPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring, if the existing data are "representative." The criteria used in determining the representativeness of data are: 1) monitor location, 2) quality of data, and 3) currentness of data.

For the first criteria, monitor location, the existing monitoring data should be representative of three types of areas: (1) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration hypothetically would occur based on the combined effect of existing sources and the proposed new source or modification. The locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for SO_2, NO_2, PM, CO, VOC, sulfuric acid mist, Hg, Be and As. However, dispersion modeling analysis demonstrates that impacts due to the emissions from the proposed facility are less than the de minimis impact levels established for NO_2, PM, CO, Hg, and Be, but above the de minimis level for SO_2. The proposed emissions of VOC, sulfuric acid mist and arsenic are above the significant emission rates. However, for sulfuric acid mist and arsenic, no de minimis levels have been established for these pollutants because acceptable monitoring methods have not been developed. Therefore, monitoring is not required for sulfuric acid mist or arsenic.

? For SO_2, the Florida DER has approved an exemption from PSD ambient air quality monitoring for this project. The request was made in the Environmental Licensing Plan of Study (KBN, 1988) with FDER's recommendation for monitoring exemption in September 1988 (FDER, 1988). The exemption is appropriate because:

1. The site is not located near (i.e., within 10 km) any major sources of pollutant emissions;
2. Background concentrations are expected to be low and near the PSD monitoring de minimis impact levels; and
3. Data from existing monitors will provide conservative background concentrations because these sites are located in more industrial areas than the project site.

Because of the rural area and minimal amount of air pollution sources in Hardee County, the Florida DER does not operate any monitoring stations in the county. Existing air quality data were obtained from monitoring stations operated by the Florida DER in Polk County, which has monitoring stations closest to the proposed project site. The closest ambient air monitoring stations to the proposed project site that measure SO_2 concentrations are located in Nichols, about 25 km north-northwest of the site, and in Lakeland, about 50 km north of the site. Because these monitors are located in urban areas, and/or in proximity (i.e., within 10 km) of major sources, the observed concentrations are considered to be higher than those expected to occur at the proposed facility. A more detailed discussion about the monitoring data collected at these stations is presented in Section 6.6 on background concentrations.

Preconstruction monitoring review is required for O_3 concentrations because the maximum potential VOC emissions from the proposed plant are greater than 100 TPY. The proposed facility is located in Hardee County which is an attainment area for O_3 concentrations. As discussed earlier, the proposed facility is located in a rural area with minimal industrial development (i.e., lack of major VOC emission sources) within 15 km of the site.

with 3m/s wind, only 1½ hr traveling time ?

A summary of the nearest monitoring stations to the proposed facility that measure O_3 concentrations is presented in Table 5-1. These stations are operated by the FDER or are part of the Florida Acid Deposition Monitoring Program (FADMP) (ESE, 1988). These sites are located between 50 and 79 km in directions from the east clockwise through west from the site. Except for the FDER station in Hillsborough County, all stations have measured maximum 1-hour average O_3 concentrations that are less than 1-hour AAQS of 0.12 ppm. The Hillsborough County monitoring station has measured 1-hour concentration greater than the AAQS but this station is located in an urban area near and within the vicinity of major VOC emission sources. Data measured at this station are not considered representative of the proposed facility's site.

Therefore, based on the modeling results and the use of existing monitoring data, an exemption from preconstruction monitoring for all pollutants is appropriate.

Table 5-1. Ozone Concentration Measured in 1987 at FDER and FADMP Monitoring Sites Near the Proposed Hardee Power Station

County/Location	Identification Number	UTM Coordinate (km)* East	North	Number of Observations	1-Hour Concentration (ppm) First	Second
FDER Sites						
Manatee/Brandenton	0320-002-G002	340.0	3041.9	7839	0.115	0.105
		(257°, 66.6 km)				
Sarasota/Sarasota	4080-002-G01	350.0	3019.8	4907	0.094	0.090
		(236°, 66.5 km)				
Sarasota/Sarasota	4100-012-G01	371.7	3028.9	8054	0.093	0.092
		(229°, 43.7 km)				
Hillsborough/ Hillsborough Bay	1800-081-G03	355.2	3068.8	8593	0.171	0.151
		(283°, 50.8 km)				
FADMP Site						
Highlands/Archbold	1780-013-9A	465.2	3006.5	7773	0.110	0.091
		(130°, 79.0 km)				

* Relative location from the proposed plant given in parentheses.

Source: FDER, 1988.
ESE, 1988.

6.0 AIR QUALITY MODELING APPROACH

6.1 GENERAL MODELING APPROACH

The general modeling approach followed USEPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. In general, when model predictions are used to determine compliance with AAQS and PSD increments, current policies stipulate that the highest annual average and highest, second-highest short-term (i.e., 24 hours or less) concentrations can be compared to the applicable standard when 5 years of meteorological data are used. The highest, second-highest concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the proposed facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations, the number of emission points, and the number of meteorological periods evaluated. In general, concentrations for the screening phase were predicted using a coarse receptor grid, limited number of major sources, and a 5-year meteorological record.

After a final list of highest, second-highest short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the highest, second-highest concentration from the screening phase was produced. The air dispersion model was executed for the meteorological periods during which both the highest and second-highest concentrations were predicted to occur at that receptor, based on the screening phase results. This approach was used to ensure that valid highest, second-highest concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.2 MODEL SELECTION

The selection of a model was based on its applicability to simulate impacts in areas surrounding the proposed facility. Within 3.0 km of the proposed facility, the terrain can be described as simple, i.e., flat to gently rolling. As defined in the USEPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Beyond 3.0 km and within 50 km of the proposed facility's site, the terrain has maximum elevations of 50 ft above ground elevation at the facility. These areas are also considered to be simple since the stacks being modeled are greater than the terrain elevation. Therefore, a simple terrain model was used to predict maximum ground-level concentrations.

The ISC dispersion model (USEPA, 1988a) was used to evaluate the pollutant emissions from proposed facility and existing major facilities. This model is contained in USEPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (USEPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes which are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISCST model, is an extended version of the single-source (CRSTER) model (USEPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code of the ISC model is the ISC long-term (ISCLT) model, which is an extension of the Air Quality Display Model (AQDM) and the Climatological Dispersion Model (CDM). The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output.

Major features of the ISCST model are presented in Table 6-1. Concentrations due to stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's

Table 6-1. Major Features of the ISCST Model

ISCST Model Features
o Polar or Cartesian coordinate systems for receptor locations
o Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
o Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
o Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulmann and Hanna (1986) and Schulmann and Scire (1980) for evaluating building wake effects
o Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
o Separation of multiple point sources
o Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
o Capability of simulating point, line, volume and area sources
o Capability to calculate dry deposition
o Variation with height of wind speed (wind speed-profile exponent law)
o Concentration estimates for 1-hour to annual average
o Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm
o Receptors located above local terrain, i.e., "flagpole" receptors
o Consideration of time-dependent exponential decay of pollutants
o The method of Pasquill (1976) to account for buoyancy-induced dispersion
o A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
o Procedure for calm-wind processing

Source: USEPA, 1988a

surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50% of the area within a 3 km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by USEPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50% for every 4 hours of plume travel time).

In this analysis, the USEPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility and discussions with the FDER, the rural mode was selected because of the lack of residential, industrial and commercial development within 3 km the proposed facility site.

6.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts 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 Tampa International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Tampa, located approximately 67 km to the west-northwest of the proposed site, was selected for use in the study because it is the closest primary weather station to the study area with similar surrounding topographical feature. This station also has the most readily available and complete database which is representative of the plant site. In addition, FDER has requested the use of this meteorological data. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data at Ruskin using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by USEPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector using a USEPA preprocessing program to account for the expected variability in air flow.

6.4 EMISSION INVENTORY

Preliminary modeling indicated that the proposed facility's impacts could be above the significant impact levels for SO_2, NO_2 and PM at distances of approximately 50, 50, and 10 km, respectively, from the facility. Therefore, the emission inventories for those pollutants were developed from available databases, such as FDER's Air Pollution Inventory System (APIS) and previous studies performed by KBN. The initial step involved requesting and receiving from FDER the listing of all facilities within 100 km square centered on the proposed site. From this listing, a total of 305 facilities were identified. Using current data from APIS for each facility within the 100 km square, there were 32 facilities that had maximum allowable SO_2 emissions greater than 100 TPY and were within 50 km of the proposed facility; 19 facilities that had maximum allowable NO_2 emissions greater than 100 TPY and were within 50 km of the proposed facility; there were no facilities that had maximum allowable PM emissions greater than 100 TPY within 10 km of the proposed facility. However, within 50 km of the proposed facility, there were 42 facilities that had maximum allowable PM emissions greater than 100 TPY. Listings of the sources in the inventory with maximum allowable SO_2, NO_2, and PM emissions greater than 100 TPY and within 50 km of the proposed facility are presented in Tables 6-2 through 6-4, respectively.

Each facility was screened to determine the probability of interaction with the proposed facility. The screening technique is the "Screening Threshold" method, developed by the North Carolina Department of Natural Resources and Community Development, and approved for use by the USEPA and FDER. The method is designed to objectively eliminate from the emission inventory those sources which are not likely to have a significant interaction with the source undergoing evaluation. In general, sources that should be considered in the modeling analyses are those with emissions greater than Q (in TPY) which is calculated by the following criteria:

$$Q = 20 \times D$$

where D is the distance (km) from the source to the source undergoing review.

A listing of the emission sources and associated Q are presented in Tables 6-5 through 6-7. The sources with maximum allowable emissions which are below the calculated "screening threshold" emissions were eliminated from further consideration in the modeling analysis. A total of 22, 19, and 42 facilities (excluding the proposed facility) were included in the modeling analysis for SO_2, NO_2, and PM emissions.

In order to reduce the model computation time but effectively model sources that are most likely to interact with the proposed facility, modeling was performed in screening and refined phases. In the screening phase, only those sources with emissions above a certain threshold, based on the source's distance from the proposed facility, were modeled. The following

Table 6-2. SO2 Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

	UTM Coordinates (km)		Relative Location (km) To Proposed Site		Distance From Proposed Site	Direction From Proposed Site	Maximum SO2 * Emissions
Facility	East	North	X	Y	(km)	(degree)	(TPY)
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	1,173
Imperial Phosphate	404.8	3069.5	0.0	12.1	12.1	0	275
Agrico Chemical Co. (S. Pierce)	407.5	3071.5	2.7	14.1	14.4	11	4,557
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	569
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	44	2,933
Wachula City Power Plant	418.4	3047.0	13.6	-10.4	17.1	127	180
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	1,714
Agrico Chemical Co. (Pierce)	403.7	3079.0	-1.1	21.6	21.6	357	417
Mobil-Electrophosphate Division+	405.6	3080.0	0.8	22.6	22.6	2	1,428
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	3,692
IMC	396.7	3079.4	-8.1	22.0	23.4	340	10,251
IMC/Noralyn Mine Road	414.7	3080.3	9.9	22.9	24.9	23	505
C.F. Industries	408.4	3082.4	3.6	25.0	25.3	8	8,443
Kaplan Industries	418.3	3079.3	13.5	21.9	25.7	32	385
American Orange Corp.	429.8	3047.3	25.0	-10.1	27.0	112	198
Conserv. Chemicals	398.7	3084.2	-6.1	26.8	27.5	347	1,597
Royster Co.	406.8	3085.1	2.0	27.7	27.8	4	1,283
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	1,516
IMC/Praire	402.9	3087.0	-1.9	29.6	29.7	356	137
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	8,186
U.S. Agri-Chemicals	413.2	3086.3	8.4	28.9	30.1	16	1,575
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	85,305
Tricil Recovery Services	422.7	3091.9	17.9	34.5	38.9	27	240
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	3,302
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	371,733
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	597
Columbus Company	361.9	3077.8	-42.9	20.4	47.5	295	167
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	5,181
Lakeland City Power	409.0	3106.2	4.2	48.8	49.0	5	4,014
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	30,176
Adams Packing	421.7	3104.2	16.9	46.8	49.8	20	172

						Total	551,901

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* Maximum facility emissions from APIS, or other available information on facility.

Table 6-3. NO2 Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

Facility	UTM Coordinates (km) East	UTM Coordinates (km) North	Relative Location (km) To Proposed Site X	Relative Location (km) To Proposed Site Y	Distance From Proposed Site (km)	Direction From Proposed Site (degree)	Maximum NO2 * Emissions (TPY)
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	176
Agrico Chemical	407.5	3071.5	2.7	14.1	14.4	11	139
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	156
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	316	131
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	610
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	226
IMC	396.7	3079.4	-8.1	22.0	23.4	340	322
Kaplan Industries	418.3	3079.3	13.5	21.9	25.7	32	100
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	134
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	528
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	22,734
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	534
Sherex Polymers	410.7	3098.9	5.9	41.5	41.9	352	617
Juice Bowl Products	409.4	3099.9	4.6	42.5	42.7	354	109
Owens-Illinois	406.0	3102.3	1.2	44.9	44.9	358	391
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	82,624
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	1,382
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	466
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	5,028
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* Maximum facility emissions from APIS, or other available information on facility.

Table 6-4. PM Sources (>100 TPY) Within 50 km of Proposed Hardee Power Station

	UTM Coordinates (km)		Relative Location (km) To Proposed Site		Distance From Proposed Site (km)	Direction From Proposed Site (degree)	Maximum PM * Emissions (TPY)
Facility	East	North	X	Y			
Gardinier	415.3	3063.3	10.5	5.9	12.0	61	132
Imperial Phosphates	404.8	3069.5	0.0	12.1	12.1	0	162
Agrico Chemical	407.5	3071.5	2.7	14.1	14.4	11	1,705
Mobil Oil Big Four Mine	394.7	3069.6	-10.1	12.2	15.8	320	263
U.S. Agri-Chemicals	416.0	3069.0	11.2	11.6	16.1	316	871
Biochemical Energy, LTD	418.3	3048.0	13.5	-9.4	16.5	125	281
IMC Fort Lonesome	389.5	3067.9	-15.3	10.5	18.6	304	679
IMC	398.2	3075.7	-6.6	18.3	19.5	340	168
Agrico Chemical	403.7	3079.0	-1.1	21.6	21.6	357	631
C&M Products	405.5	3079.1	0.7	21.7	21.7	358	162
Mobil-Electrophos Division	405.6	3080.0	0.8	22.6	22.6	358	555
Farmland Industries	409.5	3080.1	4.7	22.7	23.2	12	977
IMC	396.7	3079.4	-8.1	22.0	23.4	340	162
IMC	414.7	3080.3	9.9	22.9	24.9	337	973
C.F. Industries	408.4	3082.4	3.6	25.0	25.3	352	788
IMC/ Uranium Recovery	408.4	3082.8	3.6	25.4	25.7	8	831
American Orange Corp.	429.8	3047.3	25.0	-10.1	27.0	112	180
Conserv Chemical	398.7	3084.2	-6.1	26.8	27.5	13	1,620
Royster	406.8	3085.1	2.0	27.7	27.8	4	210
Mobil Chemical Co./Nichols	398.4	3085.3	-6.4	27.9	28.6	347	433
W.R. Grace & Co.	409.8	3086.7	5.0	29.3	29.7	10	636
Ridge Pallets	418.6	3084.1	13.8	26.7	30.1	27	180
U.S. Agri-Chemicals	413.2	3086.3	8.4	28.9	30.1	16	182
Allsun Products	413.5	3093.8	8.7	36.4	37.4	13	317
FPL Manatee	367.2	3054.1	-37.6	-3.3	37.7	265	7,578
Consolidated Minerals	393.8	3096.3	-11.0	38.9	40.4	344	740
Pavers, Inc.	414.0	3098.2	9.2	40.8	41.8	347	114
Rinker Cencon Corp.	412.4	3099.0	7.6	41.6	42.3	350	159
Quikrete	412.8	3099.0	8.0	41.6	42.4	349	253
Landia Chemical	403.7	3101.8	-1.1	44.4	44.4	1	2,313
Kraft Citrus	399.0	3101.8	-5.8	44.4	44.8	353	108
Owens-Illinois	406.0	3102.3	1.2	44.9	44.9	358	102
Jahna Concrete, Inc.	450.0	3052.2	45.2	-5.2	45.5	97	139
Teco Big Bend	361.9	3075.0	-42.9	17.6	46.4	292	7,699
Agrico Chemical Co.	362.1	3076.1	-42.7	18.7	46.6	66	184
Macasphalt	451.1	3050.0	46.3	-7.4	46.9	99	165
Citrus World	441.0	3087.3	36.2	29.9	47.0	50	166
FPL Avon Park	451.4	3050.5	46.6	-6.9	47.1	98	212
Gardinier	362.9	3082.2	-41.9	24.8	48.7	301	863
Lakeland City Power	409.2	3106.2	4.4	48.8	49.0	5	14,705
Coca Cola Citrus	421.6	3103.7	16.8	46.3	49.3	20	334
Adams Packing Association	421.7	3104.2	16.9	46.8	49.8	20	129

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* Maximum facility emissions from APIS, or other available information on facility.

Table 6-5. Summary of SO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location from Proposed Facility Distance (km)	Direction (degrees)	Maximum SO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Refined
Gardinier ✓	12.0	61	1,173	241	YES	YES	YES
Imperial Phosphate ✓	12.1	0	275	242	YES	NO	YES
Agrico Chemical Co. (S. Pierce) ✓	14.4	11	4,557	287	YES	YES	YES
Mobil Oil Big Four Mine ✓	15.8	320	569	317	YES	NO	YES
U.S. Agri-Chemicals ✓	16.1	44	2,933	322	YES	YES	YES
Wachula City Power Plant	17.1	127	180	342	NO	--	--
IMC Fort Lonesome ✓	18.6	304	1,714	371	YES	YES	YES
Agrico Chemical Co. (Pierce)	21.6	357	417	433	NO	--	--
Mobil-Electrophosphate Division ✓	22.0	2	1,428	440	YES	NO	YES
Farmland Industries ✓	23.2	12	3,692	464	YES	YES	YES
IMC ✓	23.4	340	10,251	469	YES	YES	YES
IMC/Noralyn Mine Road ✓	24.9	23	505	499	YES	NO	YES
C.F. Industries ✓	25.3	8	8,443	505	YES	YES	YES
Kaplan Industries	25.7	32	385	515	NO	--	--
American Orangr Corp.	27.0	112	198	539	NO	--	--
Conserv. Chemicals ✓	27.5	347	1,597	550	YES	NO	YES
Royster Co. ✓	27.8	4	1,283	555	YES	NO	YES
Mobil Chemical Co./Nichols ✓	28.6	347	1,516	572	YES	NO	YES
IMC/Prairie	29.7	356	137	593	NO	--	--
W.R. Grace & Co. ✓	29.7	10	8,186	594	YES	YES	YES
U.S. Agri-Chemicals ✓	30.1	16	1,575	602	YES	NO	YES
FPL Manatee ✓	37.6	265	85,305	753	YES	YES	YES
Tricil Recovery Services	38.9	27	240	777	NO	--	--
Consolidated Minerals	40.4	344	3,302	809	YES	YES	YES
Teco Big Bend ✓	46.4	292	371,733	927	YES	YES	YES
Citrus World	47.0	50	597	939	NO	--	--
Columbus Company	47.5	295	167	950	NO	--	--
Gardinier ✓	48.4	301	5,181	967	YES	YES	YES
Lakeland City Power	49.0	5	4,014	980	YES	YES	YES
Lakeland City Power	49.0	5	30,176	980	YES	YES	YES
Adams Packing	49.8	20	172	995	NO	--	--

			551,901				

Table 6-6. Summary of NO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location From Proposed Facility Distance (km)	Location From Proposed Facility Direction (degrees)	Maximum NO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Modeled Sources in Analyses: Refined
Gardinier	12.0	61	176	241	NO	--	--
Agrico Chemical	14.4	11	139	287	NO	--	--
Mobil Oil Big Four Mine	15.8	320	156	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	131	322	NO	--	--
IMC Fort Lonesome	18.6	304	610	371	YES	NO	YES ✓
Farmland Industries	23.2	12	226	464	NO	--	--
IMC	23.4	340	322	469	NO	--	--
Kaplan Industries	25.7	32	100	515	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	134	572	NO	--	--
W.R. Grace & Co.	29.7	10	528	594	NO	--	--
FPL Manatee	37.6	265	22,734	753	YES	YES	YES ✓
Consolidated Minerals	40.4	344	534	809	NO	--	--
Sherex Polymers	41.9	352	617	838	NO	--	--
Juice Bowl Products	42.7	354	109	855	NO	--	--
Owens-Illinois	44.9	358	391	898	NO	--	--
Teco Big Bend	46.4	292	82,624	927	YES	YES	YES ✓
Citrus World	47.0	50	1,382	939	YES	NO	YES
Gardinier	48.4	301	466	967	NO	--	--
Lakeland City Power	49.0	5	5,028	980	YES	YES	YES ✓

		Total	116,407				

Table 6-7. Summary of PM Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility	Location from Proposed Facility		Maximum PM Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses:	
	Distance (km)	Direction (degrees)				Screen.	Refined
Gardinier	12.0	61	132	241	NO	--	--
Imperial Phosphates	12.1	0	162	242	NO	--	--
Agrico Chemical	14.4	11	1,705	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	263	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	871	322	YES	NO	YES
Biochemical Energy, LTD	16.5	125	281	329	NO	--	--
IMC Fort Lonesome	18.6	304	679	371	YES	NO	YES
IMC	19.5	340	168	389	NO	--	--
Agrico Chemical	21.6	357	631	433	YES	NO	YES
C&M Products	21.7	358	162	434	NO	--	--
Mobil-Electrophos Division	22.0	358	555	440	YES	NO	YES
Farmland Industries	23.2	12	977	464	YES	NO	YES
IMC	23.4	340	162	469	NO	--	--
IMC	24.9	337	973	499	YES	NO	YES
C.F. Industries	25.3	352	788	505	YES	NO	YES
IMC/ Uranium Recovery	25.7	8	831	513	YES	NO	YES
American Orange Corp.	27.0	112	180	539	NO	--	--
Conserv Chemical	27.5	13	1,620	550	YES	NO	YES
Royster	27.8	4	210	555	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	433	572	NO	--	--
W.R. Grace & Co.	29.7	10	636	594	YES	NO	YES
Ridge Pallets	30.1	27	180	601	NO	--	--
U.S. Agri-Chemicals	30.1	16	182	602	NO	--	--
Allsun Products	37.4	13	317	749	NO	--	--
FPL Manatee	37.6	265	7,578	753	YES	YES	YES
Consolidated Minerals	40.4	344	740	809	NO	--	--
Pavers, Inc.	41.8	347	114	836	NO	--	--
Rinker Cencon Corp.	42.3	350	159	846	NO	--	--
Quikrete	42.4	349	253	847	NO	--	--
Landia Chemical	44.4	1	2,313	888	YES	NO	YES
Kraft Citrus	44.8	353	108	896	NO	--	--
Owens-Illinois	44.9	358	102	898	NO	--	--
Jahna Concrete, Inc.	45.5	97	139	910	NO	--	--
Teco Big Bend	46.4	292	7,699	927	YES	YES	YES
Agrico Chemical Co.	46.6	66	184	932	NO	--	--
Macasphalt	46.9	99	165	938	NO	--	--
Citrus World	47.0	50	166	939	NO	--	--
FPL Avon Park	47.1	98	212	942	NO	--	--
Gardinier	48.4	301	863	967	NO	--	--
Lakeland City Power	49.0	5	14,705	980	YES	YES	YES
Coca Cola Citrus	49.3	20	334	985	NO	--	--
Adams Packing Association	49.8	20	129	995	NO	--	--

		Total	49,061				

criteria was used to determine the sources to be modeled in the screening analysis:

Distance (km)	Emission Threshold (TPY)
0 - 15	500
15 - 20	1000
20 - 25	1500
25 - 30	2000
30 - 50	3000

Facilities considered in the screening and refined analyses are presented in Tables 6-5 through 6-7. Summaries of the amount of modeled emissions in the screening phase compared to the refined phase by distance categories from the proposed facility are given in Tables 6-8 through 6-10. For the SO_2 modeling analysis, approximately 98% of the SO_2 emissions in the refined phase were modeled in the screening phase. As indicated, most of the emissions occur beyond 30 km from the proposed facility.

For the NO_2 modeling analysis, approximately 98% of the NO_2 emissions in the refined analysis were modeled in the screening phase. Similar to the SO_2 emission sources, most of the NO_2 emissions occur beyond 30 km from the proposed facility.

For the PM modeling analysis, approximately 75% of the PM emissions were modeled in the screening phase. As indicated in Tables 6-7 and 6-10, there were no emission sources within 10 km of the proposed facility (the significant impact distance) with most emissions occurring beyond 30 km from the proposed facility.

6.5 RECEPTOR LOCATIONS

As discussed in Section 6.1, the general modeling approach considered screening and refined phases to address compliance with maximum allowable PSD Class II increments and AAQS. In the ISCST modeling, concentrations were predicted for the screening phase using several receptor grids. The

Table 6-8. Summary of Modeled SO2 Emissions Used for Screening and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis	Screening Analysis	
		Emissions (TPY)	Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	6,005	5,730	95.4
15 - 20	> 1000	5,216	4,647	89.1
20 - 25	> 1500	15,876	13,943	87.8
25 - 30	> 2000	21,025	16,629	79.1
30 - 50	> 3000	501,286	499,711	99.7
0 - 50		549,408	540,660	98.4

Table 6-9. Summary of Modeled NO2 Emissions Used for Screening and and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis	Screening Analysis	
		Emissions (TPY)	Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	0	0	--
15 - 20	> 1000	610	0	0.0
20 - 25	> 1500	0	0	--
25 - 30	> 2000	0	0	--
30 - 50	> 3000	111,768	110,386	98.8
0 - 50		112,378	110,386	98.2

Table 6-10. Summary of Modeled PM Emissions Used for Screening and Refined Analyses for the Hardee Power Station

Distance From Proposed Site (km)	Threshold Emissions (TPY)	Refined Analysis Emissions (TPY)	Screening Analysis Emissions (TPY)	Percent Modeled of Refined Analysis
0 - 15	> 500	1,705	1,705	100.0
15 - 20	> 1000	1,550	0	0.0
20 - 25	> 1500	3,136	0	0.0
25 - 30	> 2000	3,875	0	0.0
30 - 50	> 3000	32,295	29,982	92.8
0 - 50		42,561	31,687	74.5

locations of the receptors were based on identifying the areas in which maximum concentrations would be expected due to the proposed unit.

A description of the receptor locations for determining compliance with PSD Class II increments and AAQS is as follows:

1. 344 receptors located in a radial grid centered on the proposed facility. These receptors were classified into two main groups: (1) plant property receptors and (2) near-field receptors.
2. The grid for the plant property receptors consisted of 36 receptors, presented in Table 6-11.
3. The grid for the near-field receptors consisted of 308 receptors located at distances of 600, 900, 1,250, 1,750, 2,250, 2,750, 3,500, 4,500, and 6,000 m along 36 radials with each radial spaced at 10 degree increments. For directions of 10 through 160 degrees, receptors at a downwind distance of 600 m from the proposed facility were not included in the analysis because these receptors are on plant property.

After the screening modeling was completed, refined short-term modeling was conducted using a receptor grid centered on the receptor which had the highest, second-highest short-term concentrations. The receptors were located at intervals of 100 m between the distances considered in the screening phase along 9 radials, at 2 degree increments, centered on the radial which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90 degree radial at a distance of 1.75 km, the refined receptor grid would consist of receptors at the following locations:

Table 6-11. Plant Property Receptors Used in the Screening Analysis for the Hardee Power Station

Direction (degrees)	Distance (km)	Direction (degrees)	Distance (km)
10	1.050	190	0.450
20	1.100	200	0.420
30	1.160	210	0.390
40	0.960	220	0.380
50	0.820	230	0.360
60	0.760	240	0.420
70	0.710	250	0.490
80	0.830	260	0.410
90	1.060	270	0.360
100	0.700	280	0.330
110	0.700	290	0.320
120	0.740	300	0.300
130	0.820	310	0.300
140	0.890	320	0.300
150	0.790	330	0.320
160	0.760	340	0.350
170	0.540	350	0.400
180	0.500	360	0.450

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.35, 1.45, 1.55, 1.65, 1.75, 1.85, 1.95, 2.05, and 2.15 per direction

To ensure that a valid highest, second-highest concentration was calculated, concentrations were predicted for the refined grid for the periods that produced both the highest and second-highest concentration from the screening receptor grid.

Refined modeling analysis was performed for the annual average period but used a different approach than that used for short-term average periods. Because the spatial distributions of annual average concentrations are not expected to vary significantly from those produced from the screening analysis, concentrations were calculated at the receptor which produced the highest annual concentration in the screening analysis. For this analysis, concentrations were calculated for the entire year using the refined emission inventory.

6.6 BACKGROUND CONCENTRATIONS

Background concentrations are air quality concentrations due to air pollutant sources not explicitly accounted for in the air modeling analysis. Because the site is not located near any major sources of SO_2, PM, and NO_x emissions, background concentrations are expected to be low. As a result, existing monitoring data were used to estimate background concentrations. A summary of the maximum concentrations measured at the closest monitors to the proposed facility is presented in Table 6-12. The ambient data are collected in areas that are more industrialized and have higher emission densities than the proposed site. Therefore the estimated background concentrations are considered to be conservative (i.e., higher concentrations than actually exist at the proposed plant site).

For SO_2 concentrations, data collected at the monitoring stations in Nichols and Lakeland were reviewed and used in estimating background concentrations. The nearest station to the proposed site is located in Nichols,

Table 6-12. Summary of maximum SO_2, TSP, and NO_2 Concentrations Measured at the Closest Monitoring State on to the Proposed Hardee Power Station

Pollutant	Location	Site Number	UTM Coordinates (km)*		Year	Observations+		Concentration (ug/m^3)				
								3-Hour		24-Hour		Annual
			East	North		Number	%	1st	2nd	1st	2nd	
SO_2	Lakeland	2160-001-F01	407.5	3107.5	1987	8444	96.4	200	162	86	55	10
			(3°, 50 km)		1986	6520	74.4	267	178	81	71	13
	Nichols	3680-010-F02	399.5	3081.3	1987	8571	97.8	697	267	115	51	11
			(348°, 24.5 km)		1986	4994	57.0	203	162	38	35	7
TSP	Lakeland	2160-001-F01	407.5	3107.5	1987	58	95.1	-	-	87	86	50
			(3°, 50 km)		1986	58	95.1	-	-	109	87	47
	Nichols	3680-010-F02	399.5	3081.3	1987	58	95.1	-	-	73	73	38
			(348°, 24.5 km)		1986	58	95.1	-	-	119	81	38
	Bartow	0180-010-F01	418.4	3084.15	1987	42	68.9	-	-	74	71	40
			(27°, 29.9 km)		1986	57	93.4	-	-	70	70	37
	Mulberry	2860-003-F02	405.0	3085.5	1987	42	68.9	-	-	75	75	43
			(360°, 28 km)		1986	54	88.5	-	-	74	74	38
	Bradley	3680-011-F02	403.1	3074.8	1987	61	100.0	-	-	110	91	45
			(354°, 17.5 km)		1986	60	98.4	-	-	94	80	41
NO_2	Ybor City	4360-052-601	358.4	3093.5	1987	6005	68.6	-	-	-	-	45
			(308°, 59.8 km)		1986	7808	89.1	-	-	-	-	39

* Direction and distance from the site listed in parentheses.

\+ For TSP, based on observations every 6 days (61 per year).

Source: FDER, 1987/88

approximately 24.5 km to the north-northwest. During 1987, the second highest 3- and 24-hour and annual average concentrations were 267, 51, and 11 ug/m^3, respectively. These concentrations were assumed to represent background concentrations.

TSP concentration data collected at the monitoring station in Bradley were used in estimating background PM_{10} concentrations. These values were the second highest 24-hour and annual average concentrations of 91 and 45 ug/m^3, respectively. The data from this station were selected because this is the closest station to the project site with TSP concentrations. It should be noted that the AAQS for particulate matter is based on PM with a nominal diameter of 10 u or less. TSP concentrations include particles with diameters up to approximately (PM10) 30 u. Therefore, the use of TSP concentrations to estimate PM10 background concentrations will provide an additional conservative factor in determining compliance with AAQS.

There are no stations within 50 km of the proposed site location that measure NO_2 concentrations. The nearest station to the proposed site is located in Ybor City, Hillsborough County, approximately 60 km to the west-northwest. This station is in a highly urbanized area and has a significant impact from vehicular traffic. During 1987, this station measured an annual average concentration of 45 ug/m^3, based on 69% data capture. This concentration was used to represent a conservative estimate of the background concentration.

6.7 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings or structures at the proposed facility, the stack for the proposed unit will be less than GEP. Therefore, the potential for building downwash to occur must be considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model which are used to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than h_b + 0.5 L_B, where h_b is the building height and L_b is the lessor of the building height or projected width), the Schulman and Scire method is used. If this method is used, then direction-specific building dimensions are input for h_b and L_B for the 36 directions, with each direction representing a 10 degree sector. The features of the Schulman and Scire method are: 1) reduced plume rise due to initial plume dilution, 2) enhanced plume spread as a linear function of the effective plume height, and 3) specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than h_b + 0.5 L_B but less than GEP, the Huber-Snyder method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific width is to be modeled, then the value input to the model must be adjusted according to the following formula:

$$M_w = \sqrt{\left(\frac{H_w}{2}\right)^2}$$

$$M_w = 0.8886\ H_w$$

where M_w is input to the model to produce a building width of H_w used in the dispersion calculation.
H_w is the actual building width for which dispersion calculations are performed.

The building dimensions considered for the proposed facility are presented in Table 6-13. In these analyses, building downwash conditions were assumed to occur for all directions around each stack although these conditions may not occur for certain directions. Based on sensitivity analyses performed for the proposed facility, higher concentrations were produced with the

Table 6-13. Structure Dimensions and GEP Stack Height Calculations for the Hardee Power Station

Structure	Building Dimensions (ft) Height	Length	Width	Maximum Projected Width	GEP Stack Height
HRSG*	45	50	25	56	113
Combustion Turbine Enclosure**	40	1175	75	1178	100

Note: These structure dimensions produced the worst case impacts for a HRSG stack height of 75 feet.

* Used in modeling analyses.

** Based on a single structure that encloses all the combustion turbines associated with a 660 MW plant.

building dimension using a height of 45 ft which also produced the highest GEP height. Therefore, the building dimensions associated with this height were used in performing subsequent model calculations.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

For the screening analysis, a summary of the maximum SO_2, NO_2, PM, CO, and Be concentrations due to the proposed facility is presented in Table 7-1. Model results were calculated for a range of operating conditions for which maximum impacts could occur (see Section 2.0 for the operating data and rational for modeling these conditions). These operating conditions, which were based on either maximum emissions or minimum flow rate for the units, were as follows:

1. Case 1: Maximum emissions at 32°F;
2. Case 2: Maximum emissions at 95°F;
3. Case 3: Minimum flow rate at 32°F; and
4. Case 4: Minimum flow rate at 95°F.

As indicated in Table 7-1, the maximum concentrations are predicted for the operating conditions with minimum flow rates (Cases 3 and 4). It should be noted that the modeled SO_2 emissions were specific for each case because the maximum predicted SO_2 concentrations were relatively high when compared to PSD Class II increments. For the other pollutants, the emissions from Case 1, which had the highest emissions among the cases, were modeled for all four cases; therefore, the maximum impacts predicted for cases 2 through 4 are conservative (lower impacts would be predicted if the emissions associated with each case were modeled). See Section 2.0 for a more detailed discussion about the emission data and associated operating parameters used in the modeling.

The maximum predicted 3-, 24-hour and annual SO_2 concentrations are 424, 62.5 and 6.7 ug/m^3, respectively. The maximum 24-hour concentration is above the <u>de minimis</u> monitoring level and, therefore, preconstruction monitoring data are required to be submitted by the Applicant as part of the permit application. As indicated in Section 5.0, existing monitoring data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

Table 7-1. Maximum Concentrations Predicted for the Combined Cycle Plant (660 MW) for 4 Operating Designs

Pollutant	Averaging Period	Maximum Concentrations (ug/m3)				Air Quality Requirements (ug/m3)	
		Maximum Emissions		Minimum Flow Rate		Deminimis Levels	PSD Class II Increment
		32 oF	95 oF	32 oF	95 oF		
		Case 1	Case 2	Case 3	Case 4		
SO2	3-hour	196	281	359	424	NA	512
	24-hour	54.7	53.8	62.5	60.0	13	91
	Annual	5.8	5.7	6.7	6.5	NA	20
PM(TSP)	24-hour	5.1	5.9	6.4	7.5	10	37
	Annual	0.54	0.63	0.68	0.82	NA	19
PM(PM10)	24-hour	5.1	5.9	6.4	7.5	10	NA
	Annual	0.54	0.63	0.68	0.82	NA	NA
NO2	Annual	3.0	3.5	3.8	4.6	14	25
CO	1-hour	99.0	112.0	130.3	178.5	NA	NA
	8-hour	21.4	24.2	26.1	38.0	575	NA
Be	24-hour	0.0002	0.0003	0.0003	0.0004	0.001	NA
Hg	24-hour	0.0011	0.0012	0.0013	0.0016	0.25	NA

NA = Not applicable

* Modeled as 3 stacks, each separated by 100 m.

The maximum predicted 24-hour and annual average PM concentrations are 7.5 and 0.82 ug/m^3, respectively. Because the maximum 24-hour concentration is below the de minimis monitoring level, preconstruction is not required for the permit application.

The maximum predicted annual NO_2 concentration is 4.6 ug/m^3, which is below the de minimis monitoring level. Similar to the PM concentrations, preconstruction monitoring requirements is not required for the permit application.

The maximum predicted 1- and 8-hour average CO concentrations are 17.9 and 38.0 ug/^{3}, respectively, which are less than the significance levels. The maximum 8-hour concentration is also less than the de minimis monitoring levels and, therefore, preconstruction monitoring is not required. Because the maximum predicted impacts due to the proposed facility are less than the CO significance levels, additional modeling is not required for this pollutant.

The maximum predicted 24-hour average Be and Hg concentrations are 0.0004 and 0.0016 ug/m^3, respectively, which are less than the de minimis monitoring levels. Therefore, preconstruction monitoring is not required for these pollutants.

7.2 PSD CLASS II INCREMENT ANALYSIS

Summaries of the maximum SO_2, PM, and NO_2 concentrations predicted in the screening analysis for comparison to the PSD Class II increments are presented in Tables 7-2 through 7-4, respectively. These results show that maximum concentrations due to all PSD sources are less than the maximum allowable PSD Class II increments for all averaging periods and pollutants.

The refined analysis was based on modeling the meteorological periods during which the overall highest, second-highest and associated highest 3- and 24-hour SO_2 and 24-hour PM concentrations were predicted in the screening analysis. The refined analysis for the annual average concentrations was based on modeling the receptor and year which produced

Table 7-2. Maximum Predicted SO_2 Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location Direction (°)	Receptor Location Distance (km)	Period Julian Day	Period Hour Ending	Period Year
3-Hour[*]	194[+] 196	110	2.25	214	12	1982
	195[+]	310	1.75	211	12	1983
	198[+] 203**	130	2.75 2.25	59	6	1984
	424[**]	360	0.45	243	12	1985
	203[+]	90	0.90	194	15	1986
24-Hour[*]	62.6[+]	240	2.25	241	24	1982
	58.2[+]	240	3.50	289	24	1883
	58.5[**]	120	0.74	59	24	1984
	61.4[+]	90	2.75	118	24	1985
	60.5[+]	90	2.25	201	24	1986
Annual	8.0[++]	240	3.50	-	-	1982
	6.5[**]	240	3.50	-	-	1983
	8.1[**]	240	3.50	-	-	1984
	7.4[++]	250	3.50	-	-	1985
	8.0[**]	90	1.75	-	-	1986

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[*] Highest, second-highest concentrations predicted for this averaging period.

[+] Based on Operating Case 3.

[**] Based on Operating Case 4.

[++] Based on Operating Cases 3 and 4.

Table 7-3. Maximum Predicted PM Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location		Period		
		Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
24-Hour*	7.5 ✓	240 ✓	1.75 ✓	123 ✓	24	1982
	6.9 ✓	240 ✓	3.50 ✓	289 ✓	24	1883
	6.0 7.1	240 120	4.50 .74	313 59	24	1984
	7.2 ✓	90 ✓	2.25 ✓	118 ✓	24	1985
	6.5 ✓	90 ✓	1.75 ✓	201 ✓	24	1986
Annual	0.8 ✓	240 ✓	3.50 ✓	-	-	1982
	0.6 ✓	240 ✓	3.50 ✓	-	-	1983
	0.8 ✓	240 ✓	3.50 ✓	-	-	1984
	0.7 ✓	250 240	3.50, 4.50 ✓	-	-	1985
	0.8 ✓	90 ✓	1.75 ✓	-	-	1986

* Highest, second-highest concentrations predicted for this averaging period.

Table 7-4. Maximum Predicted NO_2 Concentrations in the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location		Period		
		Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
Annual	4.6	240	3.50	-	-	1982
	3.3	240	3.50	-	-	1983
	4.4	240	3.50	-	-	1984
	4.0	240	4.50	-	-	1985
	4.5	90	1.75	-	-	1986

the highest annual concentration using the refined emission inventory. A summary of the maximum SO_2, PM, and NO_2 concentrations predicted in the refined analysis is presented in Table 7-5.

The maximum 3-hour average SO_2 PSD increment consumption from the refined analysis is predicted to be 424 ug/m^3, which is 83% of the maximum allowable PSD Class II increment of 512 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 100% to this maximum 3-hour average concentration.

Screening

62.6 The maximum 24-hour average SO_2 PSD increment consumption is predicted to be 66.0 ug/m^3, which is 73% of the maximum allowable PSD Class II increment of 91 ug/m^3, not to be exceeded more than once per year. Approximately 99% of this concentration is due to the proposed facility.

The maximum annual average SO_2 PSD increment consumption is predicted to be 8.1 ug/m^3, which is 41% of the maximum allowable PSD Class II increment of 20 ug/m^3. Approximately 77% of this concentration is due to the proposed facility.

7.5 The maximum 24-hour average TSP PSD increment consumption is predicted to be 8.0 ug/m^3, which is 22% of the maximum allowable PSD Class II increment of 37 ug/m^3, not to be exceeded more than once per year. Approximately 99% of this concentration is due to the proposed source.

0.8 The maximum annual average TSP PSD increment consumption from the refined analysis is predicted to be 0.9 ug/m^3, which is 6% of the maximum allowable PSD Class II increment of 19 ug/m^3. Approximately 89% of this concentration is due to the proposed facility.

The maximum annual average NO_2 PSD increment consumption from the refined analysis is predicted to be 4.6 ug/m^3, which is 17% of the maximum allowable PSD Class II increment of 25 ug/m^3. This concentration is entirely due to the proposed facility.

Table 7-5. Maximum Predicted SO_2, PM, and NO_2 Concentrations in the Refined Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	Receptor Location Direction (°)	Receptor Location Distance (km)	Period Julian Day	Period Hour Ending	Period Year
SO_2 Concentrations						
3-Hour*	424	360	0.45	243	12	1985
24-Hour*	66.0	242	2.05	241	24	1982
Annual	8.1	240	3.5	--	--	1984
PM (TSP) Concentrations						
24-Hour*	8.0	242	1.95	123	24	1982
Annual	0.9	240	3.5	--	--	1982
NO_2 Concentrations						
Annual	4.6	240	3.5	--	--	1982

* Highest, second-highest concentrations predicted for this averaging period.

7.3 AAQS ANALYSIS

A summary of the maximum 3-hour, 24-hour, and annual average total SO_2 concentrations predicted in the screening analysis is presented in Table 7-6. Summaries of the maximum 24-hour and annual total PM and annual NO_2 concentrations are given in Tables 7-7 and 7-8, respectively. The total concentrations are determined from the impacts of the modeled sources added to the background concentration determined from monitoring data. These results show that the maximum SO_2, PM, and NO_2 concentrations due to all sources are below the AAQS for all averaging periods.

Similar to the PSD Class II increment analysis, the refined analysis was based on modeling the meteorological periods during which the overall highest, second-highest and associated highest 3- and 24-hour concentrations were predicted in the screening analysis. A summary of the maximum SO_2 and PM concentrations predicted in the refined analysis is presented in Table 7-9.

The maximum 3-hour average SO_2 concentration due to all sources from the refined analysis is predicted to be 691 ug/m^3, which is 53% of the AAQS of 1300 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 61% to this maximum 3-hour average concentration.

The maximum 24-hour average SO2 concentration due to all sources is predicted to be 169 ug/m^3, which is 65% of the AAQS of 260 ug/m^3, not to be exceeded more than once per year. The proposed facility contributed 29% to this maximum 24-hour average concentration.

The maximum annual average SO_2 concentration due to all sources is predicted to be 30.3 ug/m^3, which is 51% of the AAQS of 60 ug/m^3. The proposed facility contributed 20% to the maximum concentration.

The maximum 24-hour PM concentration due to all sources is predicted to be 112 ug/m^3, which is 75% of the AAQS of 150 ug/m^3. The proposed facility did not contribute to this maximum concentration.

Table 7-6. Maximum Predicted Total SO_2 Concentrations in the Screening Analysis for Comparison to AAQS

	Concentration (ug/m^3)							
		Total Due To		Receptor Location		Period		
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
3-hour*	607	340+ ✓	267	110	1.75	214	12	1982
	634	367++ ✓	267 and case 1	30	2.75	151	9	1983
	589	322+ 326	267 case 1	110 ✓	1.25 ✓	226 ✓	12 ✓	1984
	691	424** ✓	267	360	0.45	243	12	1985
	579	312**	267 and case 1	10	6.00	230	9	1986
24-hour*	163	112** ✓	51	120	1.75	234	24	1982
	152	101** ✓	51	190	2.75	299	24	1983
	149	97.9** ✓	51	120	2.75	96	24	1984
	152	101** ✓	51	90	2.25	153	24	1985
	146	94.9** ✓	51	110	2.25	106	24	1986
Annual	27.4	16.4** ✓	11	240	3.50	-	-	1982
	28.5	17.5** ✓	11	270	4.50	-	-	1983
	29.4	18.4** 19.5	11 case 1	50 ✓	6.00 ✓	-	-	1984
	29.2	18.2** ✓	11	70	2.75	-	-	1985
	29.5	18.5** ✓	11	80	1.75	-	-	1986

* Highest, second-highest concentrations predicted for this averaging period.

\+ Based on Operating Case 3.

** Based on Operating Case 4.

++ Based on Operating Cases 3 and 4.

Table 7-7. Maximum Predicted Total PM Concentrations in the Screening Analysis for Comparison to AAQS

	Concentration (ug/m^3)							
		Total Due To		Receptor Location		Period		
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
24-hour*	101	9.7 ✓	91	20	6.00	38	24	1982
	104	12.5 ✓	91	20	6.00	297	24	1983
	100	10.3 ✓	91	30	6.00	317	24	1984
	104	12.9 ✓	91	30	6.00	350	24	1985
	101	9.8 ✓	91	360	6.00	303	24	1986
Annual	46.4	1.4 ✓	45	240	2.75	-	-	1982
	46.3	1.3 ✓	45	300	6.00	-	-	1983
	46.4	1.4 ✓	45	240	3.50	-	-	1984
	46.4	1.4 ✓	45	80	2.25	-	-	1985
	46.4	1.4 ✓	45	90	1.75	-	-	1986

same as calc!

* Highest, second-highest concentrations predicted for this averaging period.

Table 7-8. Maximum Predicted Total NO_2 Concentrations in the Screening Analysis for Comparison to AAQS

	Concentration (ug/m^3)							
		Total Due To		Receptor Location		Period		
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
Annual	50.7	5.7	45	240	3.50	-	-	1982
	49.7	4.7	45	240	3.50	-	-	1983
	50.8	5.8	45	240	4.50	-	-	1984
	50.5	5.5	45	240	4.50	-	-	1985
	50.8	5.8	45	90	1.75	-	-	1986

Table 7-9. Maximum Predicted SO_2, PM and NO_2 Concentrations in the Refined Analysis for Comparison to AAQS.

Average Period	Concentration (ug/m^3)			Receptor Location		Period		
		Total due to						
	Total	Modeled Sources	Background	Direction (o)	Distance (km)	Julian Day	Hour Ending	Year
SO_2 Concentrations								
3-Hour*	691	424	267	360	0.45	243	12	1985
24-Hour*	169	118	51	116	2.15	234	24	1982
Annual	30.3	19.3	11	80	1.75	---	---	1986
PM (TSP) Concentrations								
24-Hour*	112	21.2	91	28	6.2	13	24	1985
Annual	48.6	3.6	45	240	3.5	---	---	1984
NO_2 Concentration								
Annual	50.9	5.9	45	90	1.75	---	---	1986

* Highest, second-highest concentrations predicted for this averaging period.

The maximum annual average concentration due to all sources is predicted to be 48.6 ug/m^3, which is 97% of the AAQS of 50 ug/m^3. The proposed facility contributed less than 2% to the maximum concentration.

The maximum annual average NO_2 concentrations of 50.9 ug/m^3 due to all sources is below the AAQS of 100 ug/m^3. The proposed facility contributed approximately 8% to the maximum concentration.

7.4 NONATTAINMENT ANALYSIS

As discussed in Section 3.4.2, the proposed facility is located approximately 40 km from that portion of Hillsborough County designated as nonattainment for TSP concentrations. Because the proposed facility is located within the area of influence of a nonattainment area (i.e., 50 km), nonattainment review requirements may apply to the facility except if the proposed facility's impacts are less than the significant impact levels. As presented in Table 3-1, the 24-hour and annual average significant impact levels for TSP concentrations are 5 and 1 ug/m^3, respectively. Based on the modeling performed for the proposed facility, the furthest distances from the site at which the proposed facility's impacts are less than the significant impact levels for any direction are as follows:

	Distance (km) of Significant Impact	
Year	24-hour	Annual
1982	7.5-10	Not significant
1983	7.5-10	Not significant
1984	7.5-10	Not significant
1985	7.5-10	Not significant
1986	7.5-10	Not significant

From this analysis, the proposed plant's impact is significant out to approximately 10 km from the site, based on the 24-hour average concentration. The proposed plant's impacts are not significant on an annual average basis. Because the proposed plant's predicted impacts are not significant at the TSP nonattainment area (i.e., 40 km), nonattainment review for TSP emissions is not required for this project.

8.0 IMPACTS ON AIR QUALITY RELATED VALUES, VEGETATION, AND SOILS

8.1 IMPACTS ON VEGETATION

The response of vegetation to atmospheric pollutants is influenced by the concentration of the pollutant, duration of the exposure and the frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants they will be from the short-term higher doses. A dose is the product of the concentration of the pollutant and the duration of the exposure. The impact of the Hardee Power Station on regional vegetation was assessed by comparing pollutant doses that are predicted from modeling with threshold doses reported from the scientific literature which could adversely affect plant species typical of those present in the region.

SULFUR DIOXIDE

The maximum total 3-hour average SO_2 concentration predicted in the Hardee Power Station region is 691 ug/m^3. This concentration is predicted to occur about 0.5 km (0.24 mile) north of the stacks and represents the concentration that would occur during the worst-case meteorological conditions of the past five years (see Section 7.0). The maximum 3-hour average ground-level concentration predicted for the other four years ranged from 579 to 634 ug/m^3. These concentrations would occur between 1 (0.6 mile) and 6 km (3.7 miles) from the stacks with directions ranging from north to east-southeast. Concentrations decrease with distance beyond the location of the maximum concentration.

The maximum total predicted 24-hour average SO_2 concentration is 169 ug/m^3 and is located approximately 2 km (1.24 miles) east-southeast of the stacks. The maximum total predicated annual SO_2 concentration is 30.3 ug/m^3. This concentration is predicted to occur 1.75 km (1.1 miles) to the east of the stacks.

These concentrations and averaging times can be compared with SO_2 doses known to adversely affect plant species that are presented in Table 8-1. The expected doses from operation of the Hardee Power Station combined with background sources are much lower than doses known to cause a detrimental effect on vegetation.

NITROGEN OXIDES

The maximum predicted 3-hour, 24-hour and annual average NO_2 concentrations due to the Hardee Power Station are predicted to be 297, 42 and 4.6 ug/m^3, respectively. The maximum total predicted annual average concentrations due to all sources is 50.9 ug/m^3 which includes a background concentration of 45 ug/m^3 derived from monitoring data in Bartow. The NO_2 doses known to adversely affect some plant species that have been tested are shown in Table 8-1. The predicted doses of NO_2 due to the proposed facility are far lower than the doses reported to injure vegetation; therefore, the proposed facility's NO_2 emissions are not expected to have an adverse affect on vegetation.

TOTAL SUSPENDED PARTICULATES

The maximum total 24-hour and annual average concentrations are predicted to be 112 and 48.6 ug/m^3, respectively. These concentrations are predicted to occur between 1.75 to 6 km from the stacks. High deposition of particulates on plant leaves can reduce photosynthesis through shading and impede diffusion of gases. However, at least 5 g/m^2 leaf surface of particulates are required to cause these impacts (Thompson, et al., 1984). This concentration is not expected due to the maximum predicted impacts from the Hardee Power Station.

Table 8-1. SO_2 and NO_2 Doses Reported to Affect Plant Species Similar to Vegetation in the Region of the Hardee Power Plant

Pollutant	Species	Dose and Effect	Reference
SO_2	Strawberry	1,040 ug/m^3 for 6 hours per day for 3 days had no affect on growth	Rajput, _et al_.,1977
SO_2	Citrus	2,080 ug/m^3 for 23 days with 10 day interruption reduced leaf area	Matsushima and Brewer 1972
SO_2	Ryegrass	42 ug/m^3 for 26 weeks or 367 ug/m^3 for 131 days reduced dry weight	Bell, _et al_., 1979 Ayazaloo and Bell, 1981
SO_2	Tomato	1,258 ug/m^3 for 5 hours per day, for 57 days, reduced growth	Kohut, _et al_., 1983
SO_2	Duckweed	390 ug/m^3 for 6 weeks reduced growth	Fankhauser, _et al_., 1976
SO_2	Lichens (_Parmotrema_ and _Ramalina_ spp.)	400 ug/m^3 6 hours per week for 10 weeks reduced CO_2 uptake and biomass gain of _Ramalina_, not _Parmotrema_	Hart, _et al_., 1988
SO_2	Bald Cypress	1,300 and 2,600 ug/m^3 for 48 hours. Only 2600 ug/m^3 reduced leaf area.	Shanklin and Kozlowski, 1985
SO_2	Green Ash	210 ug/m^3 for 4 hours per day, 5 days per week for 6 weeks reduced growth	Chappelka, _et al_., 1988
NO_2	Ryegrass	39.5 ug/m^3 for 6 minutes had no affect on shoot weight	Lane and Bell, 1984
NO_2	Citrus	470 ug/m^3 for 290 days injured trees	Thompson, _et al_., 1970
NO_2	Sphagnum	11.7 ug/m^3 averaged over 18 months compared with control of 4.8 ug/m^3 (exceeded 15 ug/m^3 4 times) reduced growth	Press, _et al_., 1986

CARBON MONOXIDE

The maximum predicted 1-hour and 8-hour average CO concentrations due to the facility are 179 and 38.0 ug/m^3, respectively. Soil microorganisms can use carbon monoxide as a carbon source and are a major sink for this pollutant (Bennett and Hill, 1975). Plants are not known to be injured by CO. No adverse impacts to vegetation are expected from CO emissions from the Hardee Power Station.

BERYLLIUM

The maximum 24-hour average Be concentration due to the proposed facility is predicted to be 0.0004 ug/m^3. Levels of Be greater than 2 ug/g in nutrient solution have been found to reduce growth of experimental plants (Gough, et al., 1979). Therefore, the low levels of Be predicted from plant operation are not expected to adversely affect vegetation.

MERCURY

The maximum 24-hour average Hg concentration due to the proposed facility is predicted to be 0.0016 ug/m^3. Siegel, et al., (1984) reported that 7 days of exposure to 50 ug/m^3 Hg vapor resulted in massive leaf abscission in 15 plant species and cultivars. This dose is orders of magnitude higher than the dose expected from operation of the Hardee Power Plant. Therefore, the predicted Hg concentrations due to the proposed facility are not expected to adversely affect vegetation.

8.2 **IMPACTS TO SOILS**

Soils in the site region have been disrupted and altered by phosphate mining. They were originally sandy, siliceous hyperthermic Haploquods with very strongly acid subsoils. The undisturbed soils of the Payne Creek floodplain formed in unconsolidated loamy textured sediment influenced by calcareous material (Robbins, et al., 1984). They are coarse-loamy siliceous, hyperthermic Typic Ochraqualfs.

SO_2 and NO_2 that reach the soil by deposition from the air are converted by physical and biotic processes to sulfates and nitrates. (CO, particulates, and metals have no affect on soils at the levels predicted.) The effects can be beneficial to plants if either sulfates or nitrates in native soils are less than plant requirements for optimum growth. However, sulfates and nitrates can also increase acidity of unbuffered soils, causing adverse effects due to changes in nutrient availability and cycling. The predicted concentrations of SO_2 and NO_2 from stack emissions are not expected to have a significant adverse affect on soils in the vicinity because (1) the predicted concentrations of both gases are low, (2) Payne Creek floodplain and other wetland soils contain organic matter and/or calcium carbonate nodules that buffer changes in acidity, and (3) ground limestone will be applied to lands being reclaimed for pasture and citrus. Therefore, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

8.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel will be added to the work force due to the proposed facility. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth of Hardee and Polk counties.

Fuel oil will be delivered by truck every week to the facility. Based on a truck capacity of 9,200 gallons, approximately 129 trucks per week trucks or 18 trucks per day will deliver oil to the site. These additional trucks are not expected to adversely affect existing traffic patterns or air quality in the vicinity of the plant.

Therefore, no air quality related impacts associated with residential, commercial and industrial growth are anticipated.

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11.1.5 APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

This application has been prepared for information purposes only as required by FDER Form 17-1.211(1). Refer to Applicant Information in the SCA.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

This application is being completed for information purposes as required by Section 3.4.1 of DERFORM 17-1.211 (1); Power Plant Site Cetification Application (SCA).

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [ ] Construction [ ] Operation [ ] Modification

COMPANY NAME: Refer to Applicant Information in the SCA COUNTY: Hardee

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) By-Pass and HRSG Stack

SOURCE LOCATION: Street ______ City ______

UTM: East 404.8 km North 3057.4 km

Latitude ___° ___' ___"N Longitude ___° ___' ___"W

APPLICANT NAME AND TITLE: Refer to Applicant Information in the SCA

APPLICANT ADDRESS: Refer to Applicant Information in the SCA

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT N/A

I am the undersigned owner or authorized representative* of ______

I certify that the statements made in this application for a ______ permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: ______

______
Name and Title (Please Type)

Date: ______ Telephone No. ______

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

N/A

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

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[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed ______________________________

____
Name (Please Type)

____
Company Name (Please Type)

____
Mailing Address (Please Type)

Florida Registration No. ____________ Date: ________________ Telephone No. ________________

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Refer to Section 2.0 of the PSD Application

B. Schedule of project covered in this application (Construction Permit Application Only)

Refer to Chapter 1 of the SCA.

Start of Construction ________________ Completion of Construction ________________

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Refer to Section 4.0 of the PSD Application; Table 4-4

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous permits have been issued.

E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52 ;

if power plant, hrs/yr 8760 ; if seasonal, describe:

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant?	No
a. If yes, has "offset" been applied?	N/A
b. If yes, has "Lowest Achievable Emission Rate" been applied?	N/A
c. If yes, list non-attainment pollutants.	N/A
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI.	Yes
3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII.	Yes
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source?	Yes
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source?	No
H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source?	No

a. If yes, for what pollutants? N/A

b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted. N/A

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

Refer to the following sections in the PSD Application:

PSD Applicability - Subsection 3.4.1
Non-Attainment Applicability - Subsection 3.4.2
BACT Applicability - Section 4.1
NSPS Applicability - Section 4.2

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Not Applicable

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) Not Applicable

1. Total Process Input Rate (lbs/hr): ________________

2. Product Weight (lbs/hr): ________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Refer to Tables 2-2 through 2-4 of the PSD Application

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/XX hr	T/yr	
TSP/PM10	57	250	--	--	57	250	Refer To
SO_2	734	3,217	0.5% sulfur fuel	1174	734	3,217	Figure 2-1 in PSD
NO_x	384	1,681	65 ppm corrected	> 440	384	1,681	Applica-tion
CO	128	562	--		128	562	
VOC	21	90	--		21	90	

Above information is maximum emissions for each CT.

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Refer to Section 4.0 in the PSD Application				

E. Fuels Refer to Table 3-3 in SCA and Table 2-1 in PSD Application

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	--	1251.4 MCF/hr	
No. 2 Fuel Oil	--	73,437 lb/hr	1312.3

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Refer to Tables 2-5 and 2-6 in the PSD Application

Percent Sulfur: ______ Percent Ash: ______

Density: ______ lbs/gal Typical Percent Nitrogen: ______

Heat Capacity: ______ BTU/lb ______ BTU/gal

Other Fuel Contaminants (which may cause air pollution): ______

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

Refer to Section 3.6 in the SCA

Refer to Table 2-7 in the PSD Application

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: ________________ ft. Stack Diameter: ________________ ft.

Gas Flow Rate: __________ ACFM __________ DSCFM Gas Exit Temperature: ________________ °F.

Water Vapor Content: ________________ % Velocity: ________________ FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ________________________________

Total Weight Incinerated (lbs/hr) ____________ Design Capacity (lbs/hr) ____________

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ________________________________

Date Constructed ________________ Model No. ________________

	Volume (ft)^3	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: __________ ft. Stack Diamter: ______________ Stack Temp. __________

Gas Flow Rate: ______________ ACFM ______________ DSCFM* Velocity: ______________ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ________________________

Brief description of operating characteristics of control devices: ______

______

______

______

______

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

______

______

______

______

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   See Table 2-1 in the PSD Application
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. Refer to Tables 2-2 through 2-4 in the PSD Application
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   Refer to Tables 2-2 through 2-4 in the PSD Application
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) Refer to Section 4.0 in the PSD Application
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). Refer to Section 4.0 in the PSD Application
6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. See Figure 2-1 in the PSD Application
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
   See Figures 3.2-1 and 3.2-2 in the SCA
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figures 3.2-1 and 3.2-2 in the SCA

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
Not Applicable

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

☒ Yes ☐ No 40 CFR Part 60 Subpart GG

Contaminant	Rate or Concentration
See Table 4-1 in PSD Application	

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

☒ Yes ☐ No

Contaminant	Rate or Concentration
Refer to Section 4.3 in the PSD Application	

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
Refer to Tables 2-2 and 2-5 in the PSD Application	

D. Describe the existing control and treatment technology (if any). Not Applicable

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter: ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). Refer to Section 4.3 in the PSD Application

1.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Costs:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected: Refer to Section 4.3 in the PSD Application

1. Control Device: 2. Efficiency:[1]

3. Capital Cost: 4. Useful Life:

5. Operating Cost: 6. Energy:[2]

7. Maintenance Cost: 8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

---

[1] Explain method of determining efficiency.
[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1] Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data Refer to Section 5.0 in the PSD Application

1. ______ no. sites ______ TSP ______ ( ) SO^2* ______ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ______________________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? ☐ Yes ☐ No

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

B. Meteorological Data Used for Air Quality Modeling Refer to Section 6.3 in the PSD Application

1. _____ Year(s) of data from ____/____/____ to ____/____/____
month day year month day year

2. Surface data obtained from (location)______________________________

3. Upper air (mixing height) data obtained from (location)______________________________

4. Stability wind rose (STAR) data obtained from (location)______________________________

C. Computer Models Used

1. ______________________________ Modified? If yes, attach description.

2. ______________________________ Modified? If yes, attach description.

3. ______________________________ Modified? If yes, attach description.

4. ______________________________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data Refer to Table 2-1 in PSD Application

Pollutant	Emission Rate	
TSP	______________________________	grams/sec
SO^2	______________________________	grams/sec

E. Emission Data Used in Modeling Refer to Table 2-7 in the PSD Application

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. Refer to PSD Application

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. Refer to Section 4.0 of the PSD Application

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. Refer to Section 4.0 of the PSD Application

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

DIVISION OF AIR AND HAZARDOUS MATERIALS
291 Promenade Street
Providence, R. I. 02908-5767

23 January 1989

Mr. Carlos Riva
Ocean State Power
110 Tremont Street
Boston, MA 02108

Dear Mr. Riva:

The Department of Environmental Management, Division of Air and Hazardous Materials has reviewed the application of Ocean State Power seeking a Prevention of Significant Deterioration (PSD) permit for the construction of a 500 MW, gas turbine based, combined cycle electric generation facility in Burrillville, Rhode Island. Public hearings were held with respect to the application on 17 November 1988, and on 13 December 1988 the Hearing Officer in the matter issued a Decision and Order.

On the basis of the Hearing Officer's 13 December 1988 Decision and Order, it has been determined that the facility, as proposed, is capable of complying with the applicable air pollution control rules and regulations of the Department of Environmental Management.

Therefore, pursuant to this Decision and Order, a PSD permit is issued to Ocean State Power subject to the attached permit conditions and emission limitations (RI-PSD-1).

Please be reminded that Condition G.15 of the enclosed permit requires Ocean State Power to file applications for approval to construct/install and receive approval prior to construction/installation of the following equipment:

1. The combustion turbine(s)
2. The heat recovery steam generator(s)
3. The auxiliary boiler
4. The SCR system(s)

Each application must be filed at least 120 days prior to the anticipated date of construction/installation of the specific piece of equipment.

If there are any questions concerning this permit, please contact me at (401) 277-2808.

Very truly yours,

Douglas L. McVay

Douglas L. McVay, Prin. Engineer
Division of Air & Hazardous Materials

DMV/kz
cc: w/attachments
Lynne Hamjian - USEPA Region I
Kathleen Lanphear - DEM
Don Squires, Tom Cusson - MA DEQE
Burrillville Town Council President
David Laferriere
Eugenia Marks
Doug Hartley - EFSB

ocen-dm/k18

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
DIVISION OF AIR AND HAZARDOUS MATERIALS

Permit Conditions and Emissions Limitations
OCEAN STATE POWER

RI - PSD - 1

A. Emission Limitations - Turbines

1. Natural Gas Firing

a. Nitrogen oxides (as nitrogen dioxide (NO_2)
   1. The concentration of nitrogen oxides in each turbine exhaust flue shall not exceed 9 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).
   2. The emission rate of nitrogen oxides from each turbine exhaust flue shall not exceed 37.4 lbs/hr. when both turbines in a two-turbine combined cycle system are operating, nor exceed 53.0 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

b. Carbon Monoxide (CO)
   1. The concentration of carbon monoxide in each turbine exhaust flue shall not exceed 25 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).
   2. The emission rate of carbon monoxide from each turbine exhaust flue shall not exceed 46.8 lbs/hr. when both turbines in a two-turbine combined cycle system are operating, nor exceed 64.8 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

c. Sulfur Dioxide (SO_2)
   1. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 0.0027 lbs per million BTU heat input (HHV) or a maximum of 3.1 lbs/hr., whichever is more stringent, when both turbines in a two turbine combined cycle system are operating.

   2. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 0.0027 lbs per million BTU heat input (HHV) or a maximum of 4.2 lbs/hr., whichever is more stringent, when only one turbine in a two turbine combined cycle system is operating.

d. Particulate Matter
   1. The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 11.5 lbs/hr, whichever is more stringent, when both turbines in a two turbine combined cycle system are operating.

   2. The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 18 lbs/hr., whichever is more stringent, when only one turbine in a two turbine combined cycle system is operating.

e. Total Nonmethane Hydrocarbons (NMHC)

1. The concentration of total nonmehtane hydrocarbons in each turbine exhaust flue shall not exceed 4.1 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

2. The emission rate of total nonmethane hydrocarbons from each turbine exhaust flue shall not exceed 4.7 lbs/hr. when both turbines in a two turbine combined cycle system are operating, nor exceed 7.2 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

f. Ammonia (NH_3)

1. The concentration of ammonia in each turbine exhaust flue shall not exceed 30 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

2. The emission rate of ammonia in each turbine exhaust flue shall not exceed 54 lbs/hr. when both turbines in a two turbine combined cycle system are operating, nor exceed 65 lbs/hr. when only one turbine in that two turbine combined cycle system is operating.

2. Oil Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)

1. The concentration of nitrogen oxides in each turbine exhaust flue shall not exceed 42 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average)
2. The emission rate of nitrogen oxides from each turbine exhaust flue shall not exceed 190.3 lbs/hr.

b. Carbon Monoxide (CO)

1. The concentration of carbon monoxide in each turbine exhaust flue shall not exceed 32 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average)
2. The emission rate of carbon monoxide from each turbine exhaust flue shall not exceed 81.7 lbs/hr.

c. Sulfur Dioxide (SO_2)

1. All fuel oil burned in any turbine shall contain 0.3 percent sulfur or less by weight.
2. The emission rate of sulfur dioxide from each turbine exhaust flue shall not exceed 349.7 lbs/hr.

d. Particulate Matter

The emission rate of particulate matter from each turbine exhaust flue shall not exceed 0.01 lbs per million BTU heat input (HHV) or a maximum of 11.5 lbs/hr whichever is more stringent.

e. Total Nonmethane Hydrocarbons (NMHC)

1. The concentration of total nonmethane hydrocarbons in each turbine exhaust flue shall not exceed 7.2 ppmv, on a dry basis, corrected to 15 percent O_2 (1 hour average).

2. The emission rate of total nonmethane hydrocarbons from each turbine exhaust flue shall not exceed 10.3 lbs/hr.

B. Emission Limitations - Duct Burners

1. Natural Gas Firing

a. Nitrogen Oxides (as nitrogen dioxide (NO_2)

The emission rate of nitrogen oxides from each duct burner shall not exceed 0.1 lbs per million BTU heat input (HHV) or a maximum of 38 lbs/hr., whichever is more stringent.

b. Particulate Matter

The emission rate of particulate matter from each duct burner shall not exceed 0.03 lbs per million BTU heat input (HHV) or a maximum of 11.4 lbs/hr., whichever is more stringent.

c. Sulfur dioxide (SO_2)

The emission rate of sulfur dioxide from each duct burner shall not exceed 0.2 lbs per million BTU heat input (HHV) or a maximum of 76 lbs/hr., whichever is more stringent.

C. Operating Requirements

1. Oil use shall be limited to that needed to maintain oil system readiness and emergency conditions such as a natural gas supply curtailment or a breakdown of the delivery system that make it impossible to fire natural gas in the combustion turbine. In no event shall the hours of operation on oil exceed 1200 hours per turbine in any consecutive 12 month period.

2. The duct burners shall be fired with natural gas only.

3. The auxillary boiler shall be operated only during periods when all of the combustion turbines are not operating or during startup periods. Operation during startup periods shall not exceed 3 hours.

4. Visible emissions from any stack at this facility shall not exceed 10% opacity except for a period or periods aggregating no more than three minutes in any one hour.

D. Continuous Monitors

1. Continuous emission monitoring equipment shall be installed, operated and maintained for opacity, nitrogen oxides, carbon monoxide and oxygen.

2. The continuous monitors must satisfy EPA performance specifications in 40 CFR 60, Appendix B.

3. Performance specifications, monitor location, calibration and operating procedures and quality assurance procedures for each monitor must be submitted to the Division for review and approval at least 180 days prior to expected start-up.

4. All data shall be monitored and recorded continuously.

5. Natural gas and fuel oil flows to each turbine and the duct burners shall be continuously measured and recorded.

6. A method for monitoring and recording ammonia concentrations in the turbine flue gases shall be proposed for the Division's approval and implementation.

7. Catalyst bed temperature shall be continuously measured and recorded.

8. Continuous emission monitoring equipment for opacity shall be installed, operated and maintained on the auxiliary boiler.

9. The facility shall have the capability of transmitting all of the collected continuous monitoring data to the Division's office via a telemetry system. The owner/operator must provide all of the necessary funds for installation and operation of this equipment. A plan for accomplishing this must be submitted to the Division for review and approval prior to installation of the equipment and at least 180 days prior to expected start-up. This plan shall also define procedures to test and protect the integrity of transmitted data.

E. Stack testing

1. Within 180 days of start-up, initial performance testing shall be conducted for each turbine. Performance testing shall be conducted for nitrogen oxides, carbon monoxide, particulate matter (total and PM-10), non-methane hydrocarbons, sulfur dioxide, and ammonia.

2. A stack testing protocol shall be submitted to the Division for review and approval prior to the performance of any stack tests. The owner/operator shall provide the Division at least 60 days prior notice of any performance test.

3. All test procedures used for stack testing shall be approved by the Division prior to the performance of any stack tests.

4. The owner/operator shall install any and all test ports or platforms necessary to conduct the required stack testing, provide safe access to any platforms and provide the necessary utilities for sampling and testing equipment.

5. Initial performance testing shall be conducted when burning natural gas and when burning fuel oil. All testing shall be conducted under operating conditions deemed acceptable and representative for the purpose of assessing compliance with the applicable emission limitation.

6. A final report of the results of stack testing shall be submitted to the Division no later than 45 days following completion of the testing.

7. All stack testing must be observed by the Division or its authorized representatives to be considered acceptable.

F. Recordkeeping and Reporting

1. The owner/operator shall maintain a record of all measurements, performance evaluations, calibration checks, and maintenance or adjustments for each continuous monitor.

2. The owner/operator must notify the Division no later than one hour after a violation of any emission limitation is discovered. Notification shall include:
   - Identification of the emission standard violated
   - Suspected reason for the violation
   - Corrective action taken or to be taken
   - Anticipated length of violation

3. The owner/operator must provide a written report within 5 days of any violation of an emission standard. This report shall, at a minimum provide the information required in F.2.

4. The owner/operator must notify the Division no later than one hour after the discovery that a continuous emission monitor has malfunctioned. Notification shall include:
   - The type and location of the malfunctioning monitor
   - The suspected reason for the malfunction
   - The corrective action taken or to be taken
   - The anticipated time needed to repair or replace the monitor.

5. The owner/operator shall notify the Division of any anticipated noncompliance with the terms of this permit or any other applicable air pollution control rules or regulations.

6. The owner/operator shall maintain the following records for each turbine:
   - The hours of operation, including any start up, shut down or malfunction in the operations of the facility.
   - The date, start time, end time and amount of fuel used for any period when fuel oil is burned.
   - Any malfunction of the air pollution control system.

7. The owner/operator shall notify the Division of the anticipated date of the initial start-up not more than 60 days nor less than 30 days prior to such date.

8. The owner/operator shall notify the Division in writing of the date construction of the facility commenced no later than 30 days after such date.

9. The owner/operator shall notify the Division in writing of the date of actual initial start-up no later than fifteen days after such date.

10. The owner/operator shall notify the Division in writing of any physical or operational change to the facility which may increase the emission rate of any air pollutant. Such notification shall include:
    - Information describing the nature of the change.
    - Information describing any planned changes to the air pollution control system.

- Information describing the effect of the change on the throughput capacity of the facility.
- The expected completion date of the change.

Such a change shall be consistent with the appropriate regulations and be subject to approval of the Director.

11. The owner/operator shall notify the Division in writing of the date upon which initial performance testing of the continuous emission monitors commences at least 30 days prior to such date.

12. The owner/operator shall submit a written report of excess emissions as measured by a continuous emission monitor for every calendar quarter. All quarterly reports shall be received no later than 30 days following the end of each calendar quarter and shall include the following information:
    - The date and time of commencement and completion of each time period of excess emissions and the magnitude of the excess emissions.
    - Identification of the suspected reason for the excess emissions and any corrective action taken.
    - The date and time period any continuous emission monitor was inoperative, except for zero and span checks and the nature of system repairs or adjustments.

When none of the above items have occurred, such information shall be stated in the report.

13. All records required in this permit shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Division upon request.

G. Other Permit Conditions

1. There shall be no by passing of the air pollution control equipment during start-up, operation or shutdown during natural gas firing.

2. An operation and maintenance plan for the facility must be submitted to the Division at least 180 days prior to start-up of the facility.

3. The facility shall be designed, constructed and operated consistent with the representation of the facility in the PSD permit application.

4. A malfunction of any air pollution control equipment that would result in the exceedance of any emission limitation in this permit will necessitate the shut down of the unit(s) which would cause the exceedance. The unit(s) must remain shutdown until the malfunction has been identified and corrected.

5. Employees of the Division and its authorized representatives shall be allowed to enter the facility at all times for the purpose of inspecting any air pollution source, investigating any condition it believes may be causing air pollution or examining any records required to be maintained by the Division.

6. The owner/operator shall have each delivery of fuel oil analyzed for sulfur content. The fuel oil must be sampled and analyzed according to ASTM methods which have the prior approval or are required by the Director. Records of the fuel oil analyses shall be maintained by the owner/operator.

7. This facility is subject to the requirements of the Federal New Source Performance Standards 40 CFR 60, Subparts A (General Provisions), Da (Electric Utility Steam Generating Units) and GG (Stationary Gas Turbines). Compliance with all applicable provisions of these regulations is required.

8. Construction access and circulation routes shall be provided a temporary crushed gravel or pavement surface.

9. All construction related travel routes, exposed or excavated areas, shall be watered down as frequently as necessary to minimize dust.

10. Construction vehicles transporting loose aggregate shall be covered with a tarpaulin or similar dust resistant membrane.

11. Construction vehicle operating speeds shall be controlled to minimize generation of dust.

12. All construction related open storage areas and/or piles of soil, aggregates or any other dust producing material shall be covered or watered down as necessary to prevent generation of dust.

13. Any spillage from construction trucks or other construction equipment on any public street shall be removed promptly.

14. The natural gas fired in each turbine shall be analyzed daily for nitrogen and sulfur content as specified in 40 CFR 60.334 and 60.335 unless an alternative monitoring plan is approved by the USEPA Region I.

15. The applicant must file applications for approval to construct/install and receive approval prior to construction/installation of the following equipment:

    (i) the combustion turbine(s)
    (ii) the heat recovery steam generator(s)
    (iii) the auxiliary boiler
    (iv) the SCR system(s)

    Each application must be submitted at least 120 days prior to the anticipated date of construction/installation.

16. During the first year of operation of the facility, the owner/operator shall sample and analyze the cooling tower water influent for total chromium and hexavalent chromium. Samples shall be taken daily and composited and analyzed monthly. The results of this analysis shall be submitted to the Division quarterly. The Division may continue this sampling and analysis requirement beyond the first year's operation at it's discretion, in consideration of the results.

H. Startup/Shutdown Conditions and Initial Commissioning

1. Turbine startup/shutdown shall be defined as that period of time from initiation of combustion turbine firing until the unit reaches steady state operation at 75-100 percent load conditions. This period shall not exceed 60 minutes.

2. Initial turbine commissioning shall be defined as the first 200 hours of combustion turbine operation following initial startup or to commercial acceptance whichever is less.

3. The emission limitations of Conditions A.1 and A.2 shall not apply during turbine startup/shutdown conditions or each turbine's initial commissioning.

4. The owner/operator shall submit to the Division for review and approval, at least 180 days prior to startup, the procedures to be followed during turbine startup/shutdown conditions and initial turbine commissioning. The procedures shall be designed to minimize the emission of air contaminants to the maximum extent practical.

I. Nitrogen oxides during oil firing

1. Every three years, from the date of issuance of this permit, the Division shall evaluate the evidence concerning the potential for downstream corrosion of the heat recovery steam generator during oil firing with an activated SCR system. If the Division determines that there is sufficient evidence to show that SCR use during oil firing will not lead to downstream corrosion of the heat recovery steam generator then the Division will modify Condition A.2.a to require the use of the SCR system during oil firing.

OCEAN STATE POWER
110 TREMONT STREET, BOSTON, MASSACHUSETTS 02108 TELEPHONE (617) 451-1103 TELEX: 95-1459

July 7, 1988

Mr. Douglas McVay, P.E.
Division of Air and Hazardous Materials
R.I. Department of Environmental Management
291 Promenade Street
Providence, RI 02908-5767

Dear Mr. McVay:

Attached is a document entitled, "NO_x Cost Control Assessment" which presents a BACT cost analysis for OSP for four levels of NO_x control, i.e., uncontrolled emissions of 155ppmv, water injection to 42ppmv, a "quiet" combustor rate of 25ppmv and an SCR rate of 9ppmv. The costs and technical data presented are more accurate and more inclusive than those originally submitted prior to the selection of GE as the turnkey contractor.

This cost analysis should be used in your review of BACT for NO_x control. We will be pleased to review this analysis with you at your earliest convenience.

Sincerely,

Neil Collins

J. O'Neill Collins,
Director, Environmental Affairs

/md

cc: T. Getz, RIDEM
C. Riva
R. Sherman, TC&G
B. Ormerod, GE
K. Vassar, Bechtel

Ref: MDOS0155

07-Jul-88

OCEAN STATE POWER
- 500 MW -
NOx COST CONTROL ASSESSMENT

($ IN 000,000'S)

PARTS PER MILLION VOLUME	155	42	25	9
CAPITAL COST ANALYSIS:				
DIFFERENTIAL COST OVER BASE (1)	0.00	3.60	12.66	24.96
FINANCING COST (2)	0.00	0.72	2.53	4.99
	0.00	4.32	15.19	29.95
OPERATING COSTS:				
OPERATION AND MAINTENANCE (3)	0.00	0.10	0.20	4.40
ENGINEERING COST:				
HEAT RATE (HHV) (4)	8110	8278	8376	8321
AVAILABILITY EXPECTED (5)	80.00%	80.00%	80.00%	75.00% (6)
ANNUAL ENERGY LOSS (BBTU) (7)	0	589	932	786
COST IMPACT @ $2/MMBTU (8)	0.00	1.18	1.86	1.57

ANNUAL DIFFERENTIAL COST

ANNUAL DEPRECIATION (9)	0.00	0.22	0.76	1.50
ANNUAL FINANCING (10)	0.00	0.54	1.90	3.74
OPERATION AND MAINTENANCE	0.00	0.10	0.20	4.40
HEAT RATE IMPACT	0.00	1.18	1.86	1.57
AVAILABILITY IMPACT (11)	0.00	0.00	0.00	13.14
TOTAL COST	0.00	2.03	4.72	24.35
INCREMENTAL COST	0.00	2.03	2.69	19.63

COST BENEFIT ANALYSIS
NOx TONS REMOVED

(ACTUAL DOLLARS)

NOx REMOVAL (12)				
TONS EMITTED	7312	2144	1344	420
TONS REMOVED	0	5168	5968	6892
INCREMENTAL TONAGE REMOVED	0	5168	800	924
COST OF NOx REMOVAL				
COST/TON REMOVED	$0	$393	$791	$3,533
INCREMENTAL COST/TON REMOVED (13)	$0	$393	$3,362	$21,245

NET REMOVAL AND COST OF SCR

TONS REMOVED (14)	6350
INCREMENTAL TONNAGE REMOVED	382
COST/TONS REMOVED	$3,835
INCREMENTAL COST/TON REMOVED	$51,391

NOTES:

1. Costs presented include GE power train costs only and exclude cost of water and oil pipelines.
2. Construction financing cost is assumed to be 20% of contract cost over a 27 month construction period.
3. Annual operational costs include estimated costs of $100,000 (at 42ppmv), $200,000 (at 25ppmv) and $1.1 million (at 9ppmv) for chemical usage in water treatment and ammonia for catalyst operation. SCR related maintenance costs of $3.3 million include cost of catalyst replacement at a capital cost of $1.54 million/HRSG/2 years (with 4 HRSG = $3.08 million/yr) and labor cost of 1,500 hours x $75/HRSG/2 years (at 4 HRSG = $.22 million/yr).
4. HHV as 1.105 x LHV presented in GE specifictions.
5. Expected availability is based on the fact that the OSP plant is most likely to operate at contract base rate of 80%. This is consistant with power sales contracts, financing and federal and state rate estimates and assumptions.
6. The 5% availability loss caused by SCR includes scheduled downtime of 6 weeks every 2 years for catalyst replacement for each HRSG (e.g., 6%) and 1% availability loss due to SCR unreliability, minus 2 weeks per year (2%) normally required for scheduled maintenance.
7. Annual Energy Loss in BBTU = Heat Rate differential x Total Power Output x Number of hours operated x appropriate conversion factor to BBTU.
8. Heat Rate Loss Cost is calculated as Annual Btu Loss x the $2.00/MMBtu assumed price of natural gas.
9. Depreciation at 20 year plant life, as 1/20 x Total Capital Cost Differential.
10. Annual financing is calculated as 12.5% of the Capital Cost Differential, per current project financing costs.
11. The cost of availability loss due to 5% SCR availability loss is the cost of replacement power, by oil-fired generation, at $.08/kw (e.g. 20-25% above OSP's consumer rate) minus the variable cost for OSP to produce power at $.02/kw; e.g., .05 x 8760 x 500 MW x 1000 kw/MW x $.06.
12. Plant emissions are derived from GE calculations for the 500 MW OSP plant, base load, natural gas fired, at ISO conditions. These include an expected 80% availability rate (e.g.,7,008 hours of operation at base load 500 MW), due to the fact that the OSP plant is most likely to operate at contract base rate of 80% consistent with sales contracts, financing and federal and state rate estimates and approvals are made. See note 13 for comparison of cost differences for 8760 hours of operation versus 7008 hours.
13. For comparison purposes, at 8760 hours of power production, assuming no maintenance time, etc., the incremental cost of NO_x removal for 25ppmv would be approximately $2,000 and for 9ppmv the incremental cost would be $16,000 without consideration of oil fired generation for the lost 5% availability and $30,000 when considering NO_x produced by replacement power.

14. NO_x production by an oil fired facility, replacing the 5% lost generation due to SCR availability loss is calculated per USEPA Guideline "AP-42" as 0.45 lbs. NO_x/1,000,000 Btu x 1 ton/2,000 lbs. x 11,000 Btu/kw hr x 500,000 kw x 8760 hrs x .05 availability loss = 542 tons NO_x/year.

Ref: MDOS0148

HPP
HARDEE POWER PARTNERS LIMITED

RECEIVED
DEC 5 1994
Division of Air
Resources Management

Clair/Larry
Al

HOWARD
12/6

Yi, please
update APIS;
forward to Clair
This is done.
Yi
12/9

December 1, 1994

Via Certified Mail - P 278 134 196
Howard Rhodes
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Via Certified Mail - P 278 134 197
Dr. Richard Garrity, Ph.D.
Florida Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, FL 33619

RE: Hardee Power Station
Conditions of Certification PA 89-25
Permit PSD-FL-140
Change of Assigned Agent

Gentlemen:

This letter will act as notification that Michael R. Schuyler will become the assigned agent and assume the responsibilities associated with this position, including signing future reports.

Gordon Gillette, the current assigned agent, has been promoted to vice president of Tampa Electric Company. Mr. Schuyler is assuming his position and responsibilities.

If you have any questions regarding this information, please call Michael Schuyler at 228-4493 or Paul Carpinone at 228-4858.

Sincerely,

George Jennings

George D. Jennings
Vice President

/gdb
cc: B. Oven
J. Harper

P.O. Box 111 ◦ Tampa, Florida 33601-0111 ◦ 813 / 228-1330 ◦ FAX 813 / 228-1308

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. ~~Clair Fancy~~

2. ~~Patty~~

3. Kanani - file

4. ____

5. ____

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE ____

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

____ FOR YOUR FILES

COMMENTS:

FROM: Yi

DATE: 12/9

PHONE: ____

DEP 15-026 (12/93)

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

September 27, 1994

Mr. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, Florida 33601-0111

Re: Hardee Power Station, PA 89-25

Dear Mr. Gillette:

The Department of Environmental Protection approved the use of either EPA Reference Method 5 or 17 for particulate testing when firing oil by my letter dated July 15, 1994. That letter also allowed the use of Method 17 when the stack temperature is less than 320° F. Particulate matter sampling is only required when firing oil. Particulate matter need not be tested when the units are operating solely on natural gas. This approval is granted pursuant to Condition II.A. 8. and to make the conditions of certification consistent with the modification of PSD Permit PSD-FL-140(A) as approved by the Division of Air Resources on September 22, 1994.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Section

cc: Clair Fancy, BAR
Bill Thomas, SWD

--ATTENTION MAIL ROOM--

PLEASE ROUTE THIS DOCUMENT TO:

Clair Fancy

Name of Individual/Office

5505

Mail Station Number

RECEIVED
SEP 28 1994
Bureau of Air Regulation

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, FL 33601-0111

4a. Article Number
Z 751 859 982

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

7. Date of Delivery SEP 28 1994

5. Signature (Addressee) R. Clark

6. Signature (Agent) R Clark

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

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

Z 751 859 982

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to
Mr. Gordon L. Gillette

Street and No.
P. O. Box 111

P.O., State and ZIP Code
Tampa, FL 33601-0111

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date

Mailed: 9-23-94
Permit: PSD-FL-140(A)

PS Form **3800**, March 1993

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

June 7, 1994

Mr. Gordon L. Gillette
Hardee Power Partners Limited
Post Office Box 111
Tampa, Florida 33601-0111

Re: Hardee Power Station, PA 89-25, PSD-FL-140

Dear Mr. Gillette:

I have reviewed your letter of June 3, 1994, requesting modification of Condition II.A.8.a. to include Method 17. Condition II.A.8. contains the sentence, "Other DER approved methods may be used for compliance testing after prior DER approval." A letter of approval from the Department can be provided to authorize use of this method.

If you wish the department to proceed with a formal modification of the Condtions of Certification, then you must file the $10,000.00 modification fee as required by the statute and rule. Any unexpended funds remaining after the department's review will be returned to you.

The Division of Air Resources Management may proceed to modify the PSD permit as they see fit.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

cc: Richard Donelan
Clair Fancy
Robert Soich
Larry Curtin

RECEIVED

JUN 07 1994

Bureau of
Air Regulation

Department of Environmental Protection [redacted]

Routing and Transmittal Slip

To: (Name, Office, Location)

1. ~~Clair Fancy~~ Patty

2. ~~MS 5505~~

3.

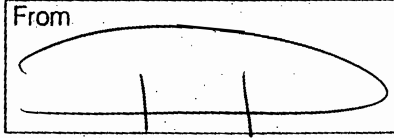
4.

Remarks: FYI

Please return to me for file

Thanks
Patty

From



Date 6-7-94

Phone 7-0472

HARDEE POWER PARTNERS LIMITED

Via Federal Express

August 20, 1992

RECEIVED
AUG 20 1992
Division of Air
Resources Management

Mr. Howard Rhodes
Director
Division of Air Resource Management
Florida Department of Environmental
 Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Hardee Power Partners
Hardee Power Station
Initial Compliance Test Notification
Conditions of Certification PA 89-25

Dear Mr. Rhodes:

Pursuant to Condition II.A.15 of the Conditions of Certification for Hardee Power Station, please be advised that the initial sampling test will begin in approximately 30 days. In accordance with this condition, after the required sampling is completed, a written report of the test results will be submitted to the Department within 45 days of test completion. We will notify you if there are any changes in our testing schedule.

If you need further information concerning this, please call me at (813) 228-4492 or Paul Carpinone, Senior Environmental Coordinator, at (813) 228-4858.

Sincerely,

Gordon L. Gillette
Director, Project Services

PLC/gdb

BEST AVAILABLE COPY

FEDERAL EXPRESS

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE
TRACKING NUMBER 2721284473

218BM 2721284473

RECIPIENT'S COPY

1 [redacted] Date 8/20/92
~~8/10/92~~

From (Your Name) Please Print: Gordon Gillette
Your Phone Number (Very Important): (813) 2~~28-139~~
Company: TECO POWER SERVICES CORP
Department/Floor No.: P7
Street Address: 702 N FRANKLIN ST
City: TAMPA
State: FL
ZIP Required: 33602

2 To (Recipient's Name) Please Print: Howard Rhodes
Recipient's Phone Number (Very Important): (   )
Company: FDER - Division of Air Resource Mgmt.
Department/Floor No.
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.): Twin Towers Bldg., 2600 Blair Stone Rd.
City: Tallahassee
State: FL
ZIP Required: 32399-2400

YOUR INTERNAL BILLING REFERENCE INFORMATION (optional) (First 24 characters will appear on invoice.): T11301S0003

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City
State
ZIP Required

3 PAYMENT
1 ☒ Bill Sender
2 ☐ Bill Recipient's FedEx Acct. No.
3 ☐ Bill 3rd Party FedEx Acct. No.
4 ☐ Bill Credit Card
5 ☐ Cash/Check

[redacted]

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)
11 ☐ YOUR PACKAGING
16 ☒ FEDEX LETTER*
12 ☐ FEDEX PAK*
13 ☐ FEDEX BOX
14 ☐ FEDEX TUBE

Standard Overnight (Delivery by next business afternoon. No Saturday delivery†)
51 ☐ YOUR PACKAGING
56 ☐ FEDEX LETTER*
52 ☐ FEDEX PAK*
53 ☐ FEDEX BOX
54 ☐ FEDEX TUBE

Economy Two-Day (Delivery by second business day †)
30 ☐ ECONOMY

Government Overnight (Restricted for authorized users only)
46 ☐ GOV'T LETTER
41 ☐ GOV'T PACKAGE

Freight Service (for packages over 150 lbs.)
70 ☐ OVERNIGHT FREIGHT** (Confirmed reservation required)
80 ☐ TWO-DAY FREIGHT**

† Delivery commitment may be later in some areas.
*Declared Value Limit $500.
**Call for delivery schedule.

5 DELIVERY AND SPECIAL HANDLING (Check services required)
1 ☐ HOLD FOR PICK-UP (Fill in Box H)
2 ☑ DELIVER WEEKDAY
3 DELIVER SATURDAY (Extra charge) (Not available to all locations) ☐
4 ☐ DANGEROUS GOODS (Extra charge)
5 ☐
6 ☐ DRY ICE ________ Lbs.
7 ☐ OTHER SPECIAL SERVICE ________
8 ☐
9 ☐ SATURDAY PICK-UP (Extra charge)
10 ☐
☐
12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

6

PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE
Total	Total	Total

DIM SHIPMENT (Chargeable Weight)
☐ ________ lbs.
L x W x H

Received At
1 ☑ Regular Stop
3 ☐ Drop Box
4 ☐ B.S.C.
2 ☐ On-Call Stop
5 ☐ Station

Emp. No.
Date
☐ Cash Received
☐ Return Shipment
☐ Third Party ☐ Chg. To Del. ☐ Chg. To Hold
Street Address
City State Zip
Received By:
X
Date/Time Received
FedEx Employee Number

7 Release Signature:

RECEIVED
AUG 20 1992
Division of Air Resources Management

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 2/92
PART #137204 FXEM 6/92
FORMAT #126
126

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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 Fee will provide you the signature of the person delivered to and the date of delivery.

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. G.D. Jennings, Jr., V.P.
Hardee Power Partners, Ltd.
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number
P 617 884 148

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

7. Date of Delivery
MAR -2 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 617 884 148

Certified Mail Receipt
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to
G.D. Jennings

Street & No.
Hardee Power Part. Ltd

P.O., State & ZIP Code
Tampa, Fl 33602

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$

Postmark or Date
2/26/92
PSD-FL-140

PS Form **3800**, June 1990

BEST AVAILABLE COPY

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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 next to the article number.

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. R. E. Ludwig, President
TECO Power Services Corporation
Post Office Box 111
Tampa, FL 33601

4a. Article Number
P 832 538 672

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

7. Date of Delivery
AUG 15 1991

5. Signature (Addressee)

6. Signature (Agent)

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

RECEIVED
AUG 19 1991
Division of Air Resources Management

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 832 538 672

Certified Mail Receipt

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. R. E. Ludwig, TECO Power Services	
Street & No. P. O. Box 111	
P.O., State & ZIP Code Tampa, FL 33601	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 8-12-91 Permit: PSD-FL-140	

PS Form **3800**, June 1990

BEST AVAILABLE COPY

3 and 4.
Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.

1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)*
2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to:
Mr. Jerry L. Williams
Tampa Electric Co.
P.O. Box 111
Tampa, Fl 33601-0111

4. Article Number
P 407 852 911

Type of Service:
☐ Registered
☒ Certified
☐ Express Mail
☐ Insured
☐ COD
☐ Return Receipt for Merchandise

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature — Addressee
X

6. Signature — Agent
X

7. Date of Delivery
JAN 10 1991

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

P 407 852 911

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

☆U.S.G.P.O. 1989-234-555

Sent to Jerry Williams	
Street and No. TECO	
P.O., State and ZIP Code PO Box 111	
Postage Tampa, Fl	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date 1-7-91 PSD-FL-140	

PS Form 3800, June 1985

● **SENDER:** Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.

Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.

1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)*
2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to:

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

4. Article Number
P 256 395 044

Type of Service:
- ☐ Registered
- ☐ Insured
- ☒ Certified
- ☐ COD
- ☐ Express Mail
- ☐ Return Receipt for Merchandise

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X Charles Davis

6. Signature – Agent
X DEC 11 1990

7. Date of Delivery

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

PS Form **3811**, Apr. 1989 ★U.S.G.P.O. 1989-238-815 **DOMESTIC RETURN RECEIPT**

P 256 395 044

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

☆U.S.G.P.O. 1989-234-555

Sent to
Ms. Jewell A. Harper

Street and No.
345 Courtland St., N.E.

P.O., State and ZIP Code
Atlanta, GA 30365

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$

Postmark or Date

Mailed: 12-6-90
Permit: PSD-FL-140

PS Form 3800, June 1985

NOTE:

1. Based on a Total Capital Investment of $3,533,000 with a project specific capital recovery factor of 15.42% Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.
2. Differential O&M includes BOP maintenance and water treatment chemical costs. Inspection intervals decrease from 6500 operating hours to 1500 operating hours. This increases maintenance $2,288,000 per year of 100% oil firing.
3. Energy includes increased BOP power consumption as well as a 1.2% CC heat rate penalty for the additional injection. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's current levelized fuel cost of $14.49/MBtu for oil. Increased BOP power consumption is charged at $124.03/MWh for oil.
4. Additional generation capacity is based on a 1.8% increase. An incremental levelized demand charge of $81.64/kw/yr was utilized based on project specific parameters.

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Barry

2.

3.

4.

Remarks:

This is original for file. I had copy of disc made for Shearer.

From: Clair

Date 10/3

Phone

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

			COLUMN Q ROW	
Capacity factor	60		4	60
			5	
% Natural Gas firing	80		6	80
% No. 2 Fuel Oil firing	20		7	20
			8	
Annual Costs, $X1000			9	
====================			10	
Direct Annual Cost			11	
Differential O&M Cost (2)	473	A	12	(127*(Q4/100)+2288)*(Q7/100)
Energy (3)			13	
Heat Rate Penalty	1,136	B	14	1.1*(0.012/0.01)*(6330*(14.49/12.79)*(Q7/100)*(Q4/100))
Pump Power Consumption	25	C	15	150*((Q7/100)*(124.03/88.8))*Q4/100
Lost Generation Capacity	(229)	D	16	-370*(81.64/48.54)*(Q7/100)*(0.0184/0.01)
	-----		17	-----
Total Direct Cost	1,405		18	@SUM(Q16..Q12)
Indirect Annual Cost			19	
Capital Recovery (1)	545	E	20	(3533)*0.1542
Admin, Property Taxes, Insur	76	E	21	(3533)*0.0216
	-----		22	-----
Total Indirect Annual Cost	621		23	+Q21+Q20
			24	
Total Annual Cost	2026		25	+Q23+Q18
			26	
NOx Emissions			27	
=============			28	
65ppm oil, tpy	795	F	29	6623*(Q7/100)*(Q4/100)
42ppm oil, tpy	514	F	30	4280*(Q7/100)*(Q4/100)
	-----		31	-----
Removed, tpy	281		32	+Q29-Q30
			33	
			34	
Cost Effectiveness, $/ton	7,206		35	(Q25*1000)/Q32
========================				

A. Differential O&M Cost: The $127,000 (from B&V/GE) is for additional water treatment and BOP O&M. It varies with capacity factor and oil usage. The $2,288,000 (from GE) is for decreased inspection intervals and varies linearly with oil usage.

B. Heat Rate Penalty: The $6,330,000 (from B&V) is based on a 1% heat rate penalty utilizing a fuel cost of $12.79/Mbtu for oil at the lower heating value. This was corrected for the 1.2% heat rate penalty (from GE) and for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($14.49/mbtu). This penalty varies with oil usage and capacity factor.

C. Pump Power Consumption: The $150,000 (from B&V/GE) is based on a power cost of $88.80/Mwh. This was corrected to the recent TEC forecast of $124.03. This penalty varies with oil usage and capacity factor.

D. Lost Generation Capacity: The $370,000 (from GE/B&V) is based on a 1% increase in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a 1.84% increase in capacity (from GE) using a project specific demand charge of $81.64/kw/yr. This varies with oil usage.

E. Capital Recovery: See note 1.

F. Emissions: The 6623 tons per year and the 4280 tons per year (from B&V/GE) vary with oil usage and capacity factor.

BEST AVAILABLE COPY

FEDERAL EXPRESS®

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

7284300951

AIRBILL
PACKAGE TRACKING NUMBER
7284300951

RECIPIENT'S COPY

[redacted]

Date 9/26/90

1 From (Your Name) Please Print: Jerry L. Williams
Your Phone Number (Very Important): 813-228-4111
Company: TAMPA ELECTRIC
Department/Floor No.:
Street Address: 702 NO FRANKLIN ST
City: TAMPA
State: FL
ZIP Required: 33602

2 To (Recipient's Name) Please Print: Mr. Claire Fancy
Recipient's Phone Number (Very Important): (904) 488-1344
Company: Fla. Dept. of Environmental Regulation
Department/Floor No.:
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip® Codes.): Twin Towers Building
2600 Blair Stone Road
City: Tallahassee,
State: FL
ZIP Required: 32399-2449

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.): 445-146-23-18-281

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address:
City:
State:
ZIP Required:

3 PAYMENT 1 ☐ Bill Sender 2 ☐ Bill Recipient's FedEx Acct. No. 3 ☑ Bill 3rd Party FedEx Acct. No. 4 ☐ Bill Credit Card
5 ☐ Cash

[redacted]

4 SERVICES (Check only one box)

Priority Overnight Service (Delivery by next business morning†)
11 ☐ YOUR PACKAGING
16 ☑ FEDEX LETTER *
12 ☐ FEDEX PAK *
13 ☐ FEDEX BOX
14 ☐ FEDEX TUBE

Standard Overnight Service (Delivery by next business afternoon†)
51 ☐
56 ☐ FEDEX LETTER *
52 ☐ FEDEX PAK *
53 ☐ FEDEX BOX
54 ☐ FEDEX TUBE

Economy Service (formerly Standard Air) (Delivery by second business day†)
30 ☐ ECONOMY SERVICE

Heavyweight Service (for Extra Large or any package over 150 lbs.)
70 ☐ HEAVYWEIGHT **
80 ☐ DEFERRED HEAVYWEIGHT **

† Delivery commitment may be later in some areas.
*Declared Value Limit $100.
**Call for delivery schedule.

DELIVERY AND SPECIAL HANDLING
1 ☐ HOLD FOR PICK-UP (Fill in Box H)
2 ☑ DELIVER WEEKDAY
3 ☐ DELIVER SATURDAY (Extra charge) (Not available to all locations)
4 ☐ DANGEROUS GOODS (Extra charge) (CSS not available for Dangerous Goods Shipments)
5 ☐ CONSTANT SURVEILLANCE SVC. (CSS) (Extra charge) (Release Signature Not Applicable)
6 ☐ DRY ICE ______ Lbs.
7 ☐ OTHER SPECIAL SERVICE
8 ☐
9 ☐ SATURDAY PICK-UP (Extra charge)
10 ☐
11 ☐ DESCRIPTION
12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE	OVER SIZE
Total	Total	Total	

DIM SHIPMENT (Heavyweight Services Only)
☐ lbs.

Received At:
1 ☑ Regular Stop 3 ☐ Drop Box
2 ☐ On-Call Stop 4 ☐ B.S.C. 5 ☐ Station

FedEx Emp. No.

Emp. No. | Date
☐ Cash Received
☐ Return Shipment
☐ Third Party ☐ Chg. To Del. ☐ Chg. To Hold
Street Address
City | State | Zip
Received By:
X
Date/Time Received | FedEx Employee Number

5 Release Signature:
Date/Time

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 11/89
PART #119501 FXEM 3/90
FORMAT #014
014

Fed Exp: # 7284301721
PM: 7/25/90
Tampa, FL

File Copy

TAMPA
ELECTRIC
A TECO ENERGY COMPANY

July 25, 1989

RECEIVED
JUL 26 1990
DER - BAQM

Federal Express
Airbill #7284301721

Mr. Claire Fancy
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2440

Re: Hardee Power Station
BACT Cost Analysis

Dear Mr. Fancy:

Enclosed, please find a copy of a BACT cost analysis for reducing NO_x emissions from 65 ppm to 42 ppm while burning oil at the Hardee Power Station (HPS).

For the unlikely case of the HPS burning 100% fuel oil at a capacity factor of 100%, the cost per ton of NO_x removed is $4,937. When analyzing the $/ton of NO_x removed for HPS' likely fuel scenario of 80% natural gas and 20% fuel oil, the values are significantly higher. In any case, these values far exceed any $/ton of NO_x removal justified as BACT to date. We therefore believe that the analysis clearly shows that an emissions limit of 42 ppm while burning oil should <u>not</u> be considered BACT for the HPS.

Should you have any questions, please call.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

PSD-FL-140
cc: EPA, NPS ?

JLW/dsr/LL412.DOC

Enclosures

cc: Mr. Steve Smallwood, DER
Mr. Hamilton Oven, DER
Mr. Barry Andrews, DER ✓
BA/CHF 7-26-90 RAM

TAMPA ELECTRIC COMPANY
P.O. Box 111 Tampa, Florida 33601-0111 (813) 228-4111

BEST AVAILABLE COPY

FEDERAL EXPRESS

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE
TRACKING NUMBER

7284301

7284301721

[redacted]

Date 7/X25/90

RECIPIENT'S COPY

1 From (Your Name) Please Print: Greg M. Nelson
Your Phone Number (Very Important): 813-228-4111
Company: TAMPA ELECTRIC
Department/Floor No.:
Street Address: 702 NO FRANKLIN ST
City: TAMPA State: FL ZIP Required: 33602

2 To (Recipient's Name) Please Print: Claire Fancy
Recipient's Phone Number (Very Important): (904) 488-1344
Company: Florida Dept. of Environmental Regulation
Department/Floor No.:
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip® Codes.): 2600 Blair Stone Road Twin Towers Office Bldg.
City: Tallahassee State: FL ZIP Required: 32399-2440

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.): 445-146-23-15-231

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City State ZIP Required

3 PAYMENT 1 ☒ Bill Sender 2 ☐ Bill Recipient's FedEx Acct. No. 3 ☐ Bill 3rd Party FedEx Acct. No. 4 ☐ Bill Credit Card
5 ☐ Cash [redacted]

4 **SERVICES** (Check only one box)

Priority Overnight Service (Delivery by next business morning†)
- 11 ☐ YOUR PACKAGING
- 16 ☒ FEDEX LETTER *
- 12 ☐ FEDEX PAK *
- 13 ☐ FEDEX BOX
- 14 ☐ FEDEX TUBE

Standard Overnight Service (Delivery by next business afternoon†)
- 51 ☐
- 56 ☐ FEDEX LETTER *
- 52 ☐ FEDEX PAK *
- 53 ☐ FEDEX BOX
- 54 ☐ FEDEX TUBE

Economy Service (formerly Standard Air) (Delivery by second business day†)
- ☐ ECONOMY SERVICE

Heavyweight Service (for Extra Large or any package over 150 lbs.)
- 70 ☐ HEAVYWEIGHT **
- 80 ☐ DEFERRED HEAVYWEIGHT **

very commitment may ter in some areas.
*Declared Value Limit $100.
**Call for delivery schedule.

DELIVERY AND SPECIAL HANDLING
- 1 ☐ HOLD FOR PICK-UP (Fill in Box H)
- 2 ☒ DELIVER WEEKDAY
- 3 DELIVER SATURDAY (Extra charge) (Not available to all locations) ☐
- 4 ☐ DANGEROUS GOODS (Extra charge) (CSS not available for Dangerous Goods Shipments)
- 5 ☐ CONSTANT SURVEILLANCE SVC. (CSS) (Extra charge) (Release Signature Not Applicable)
- 6 ☐ DRY ICE ______ Lbs.
- 7 ☐ OTHER SPECIAL SERVICE ______
- 8 ☐
- 9 ☐ SATURDAY PICK-UP (Extra charge)
- 10 ☐
- 11 ☐ DESCRIPTION
- 12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE	OVER SIZE
Total	Total	Total	

DIM SHIPMENT (Heavyweight Services Only)
☐ ______ lbs.

Received At
☑ Regular Stop 3 ☐ Drop Box
4 ☐ B.S.C.
2 ☐ On-Call Stop 5 ☐ Station

FedEx Emp. No. 71078

Emp. No. Date
☐ Cash Received
☐ Return Shipment
☐ Third Party ☐ Chg. To Del. ☐ Chg. To Hold
Street Address
City State Zip
Received By:
X
Date/Time Received FedEx Employee Number

5 Release Signature:
Date/Time 9/25

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 11/89
PART #119501 FXEM 3/90
FORMAT #014

014

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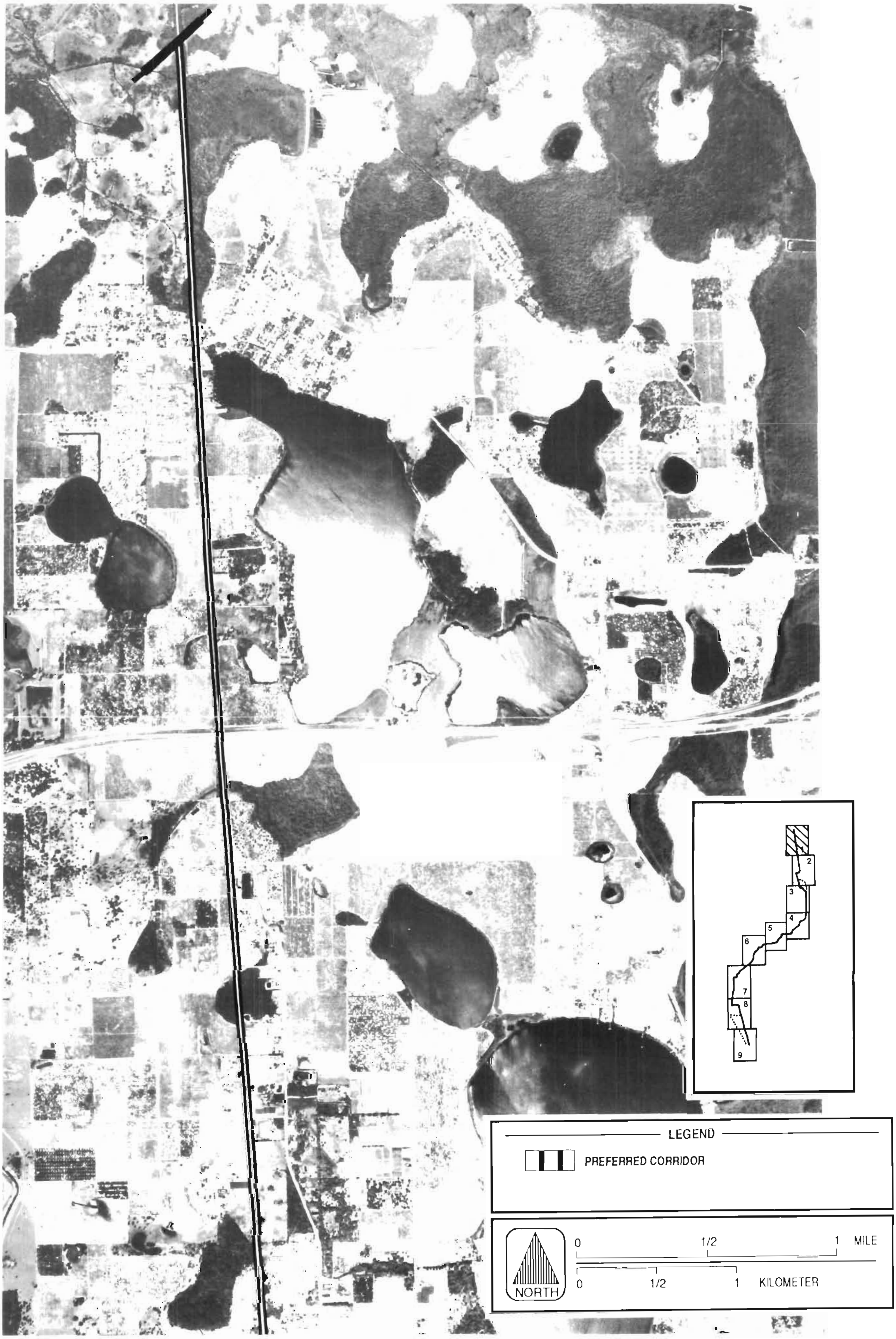
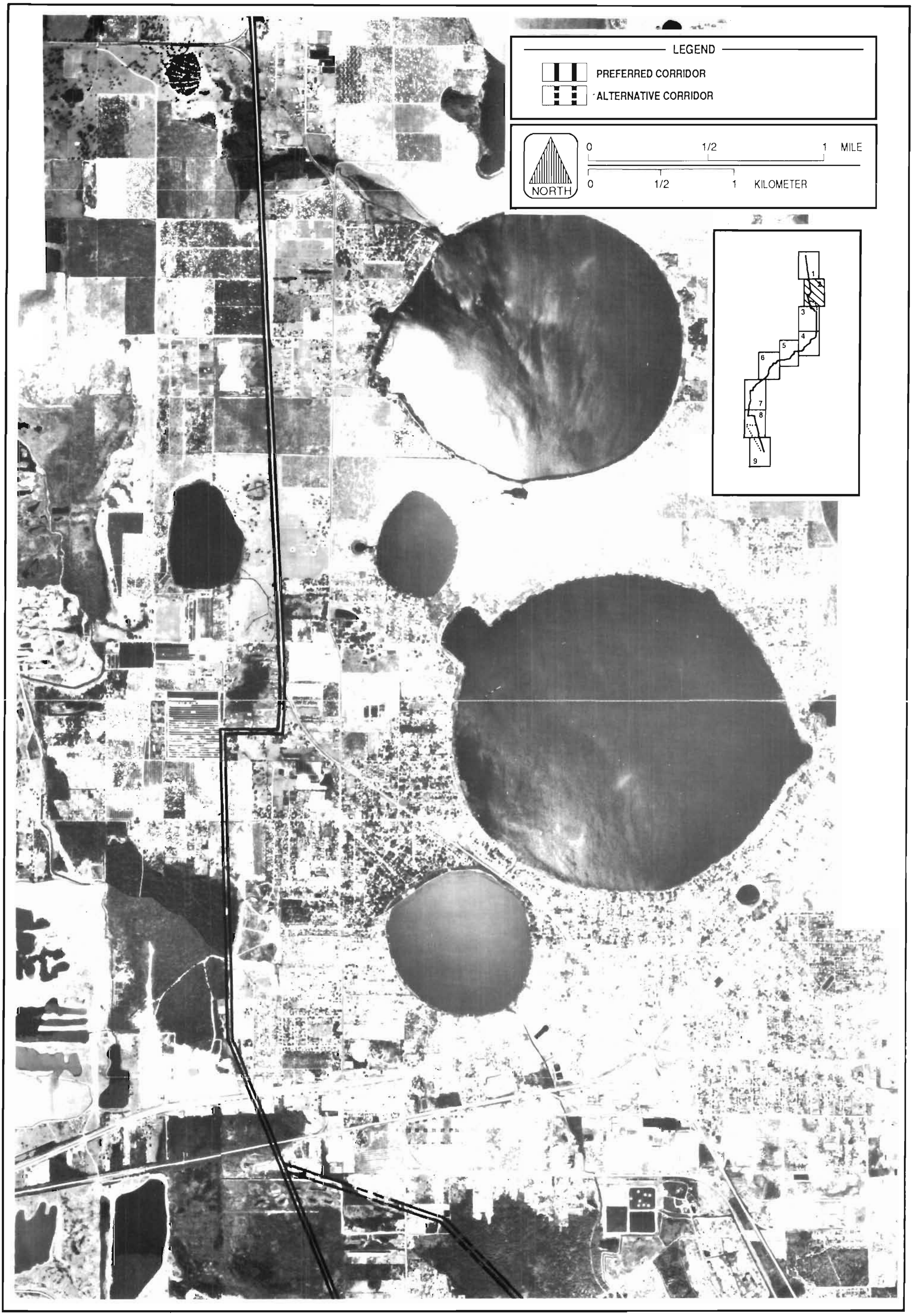
PRINTED IN U.S.A.



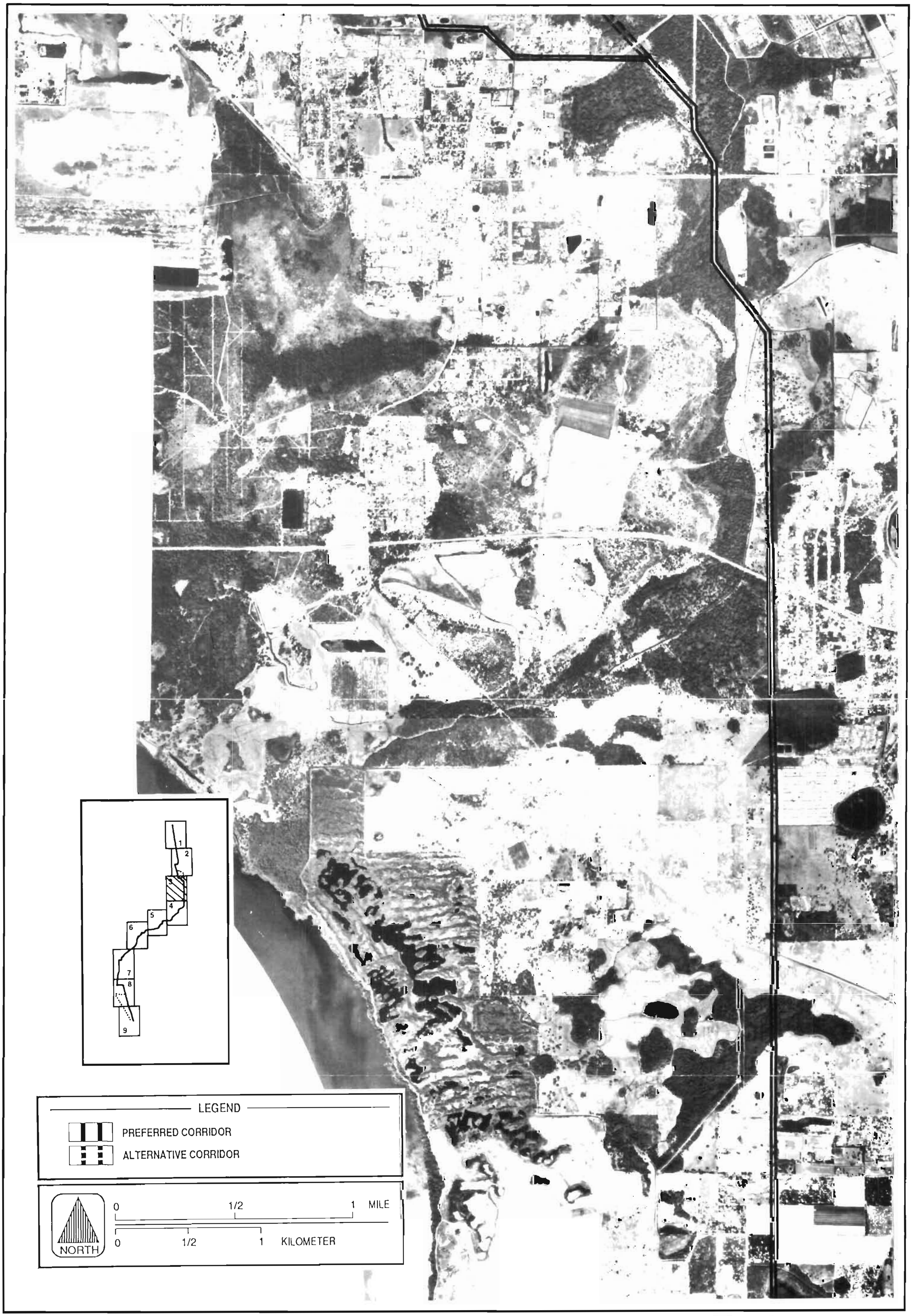
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL BEGINNING AT THE ST. PETERSBURG LATERAL
AND CONTINUING SOUTH TO PLANT SITE
(PAGE 1 OF 9)

Hardee
Power Station



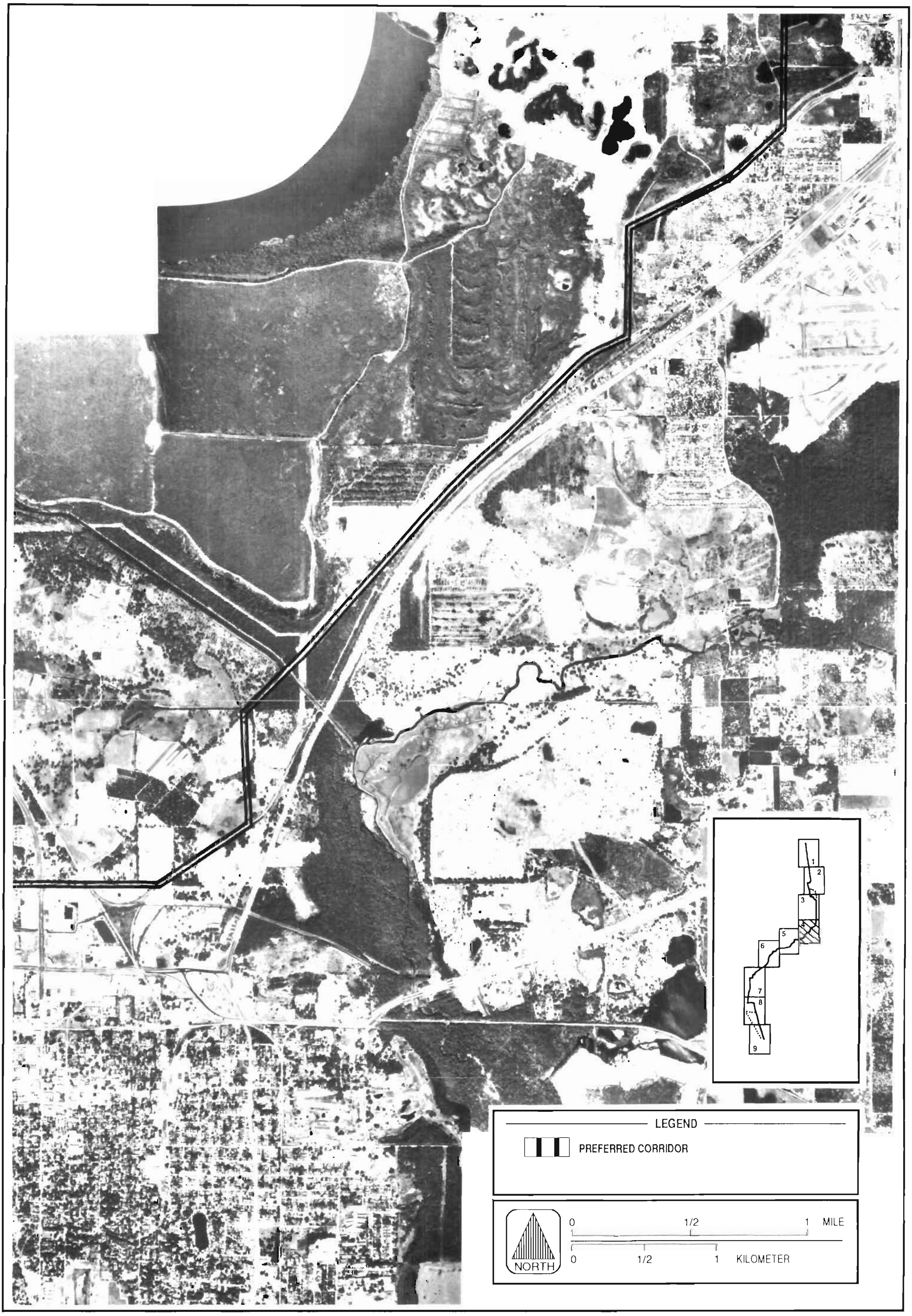
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 2 OF 9)

Hardee
Power Station



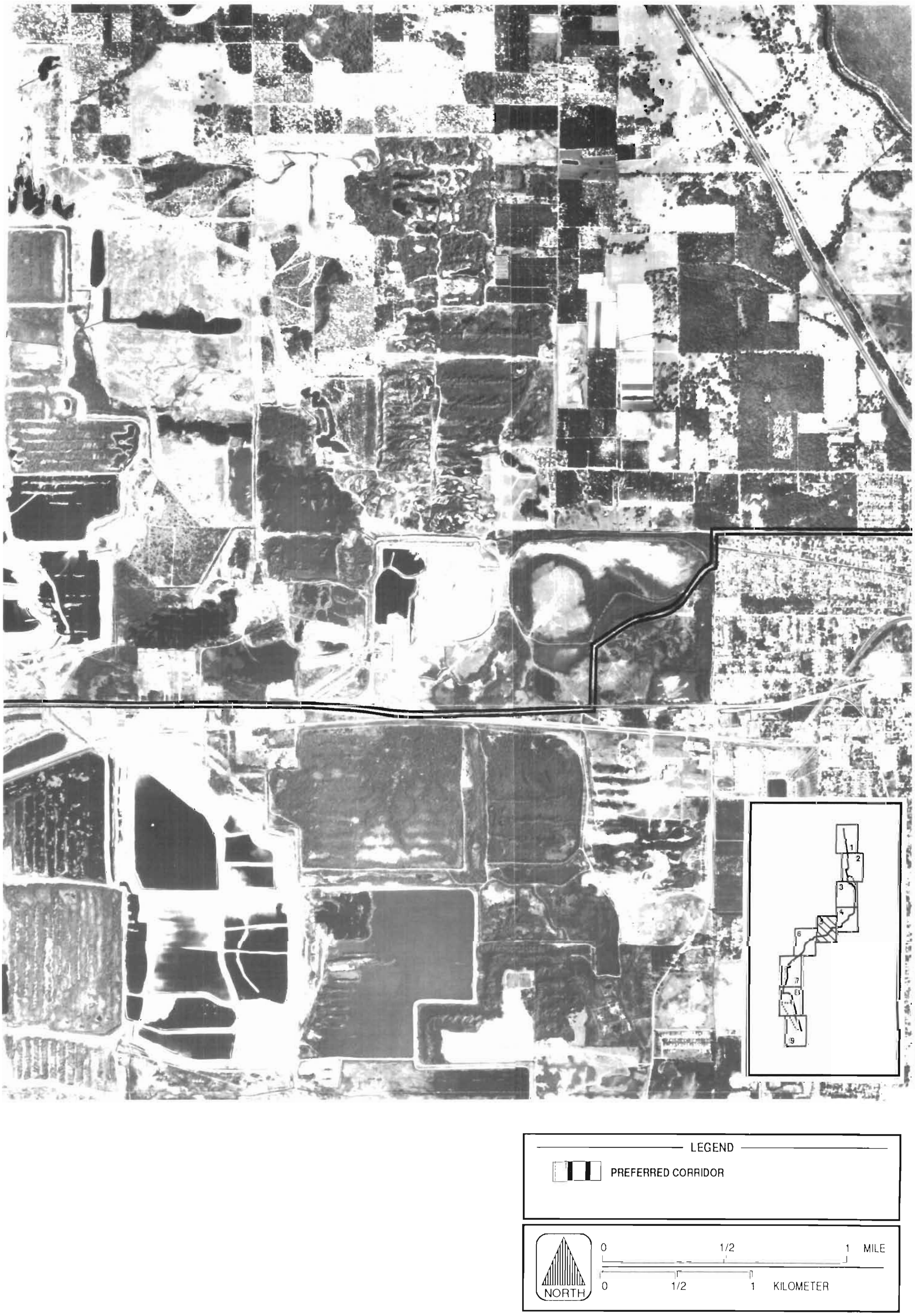
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 3 OF 9)

Hardee
Power Station



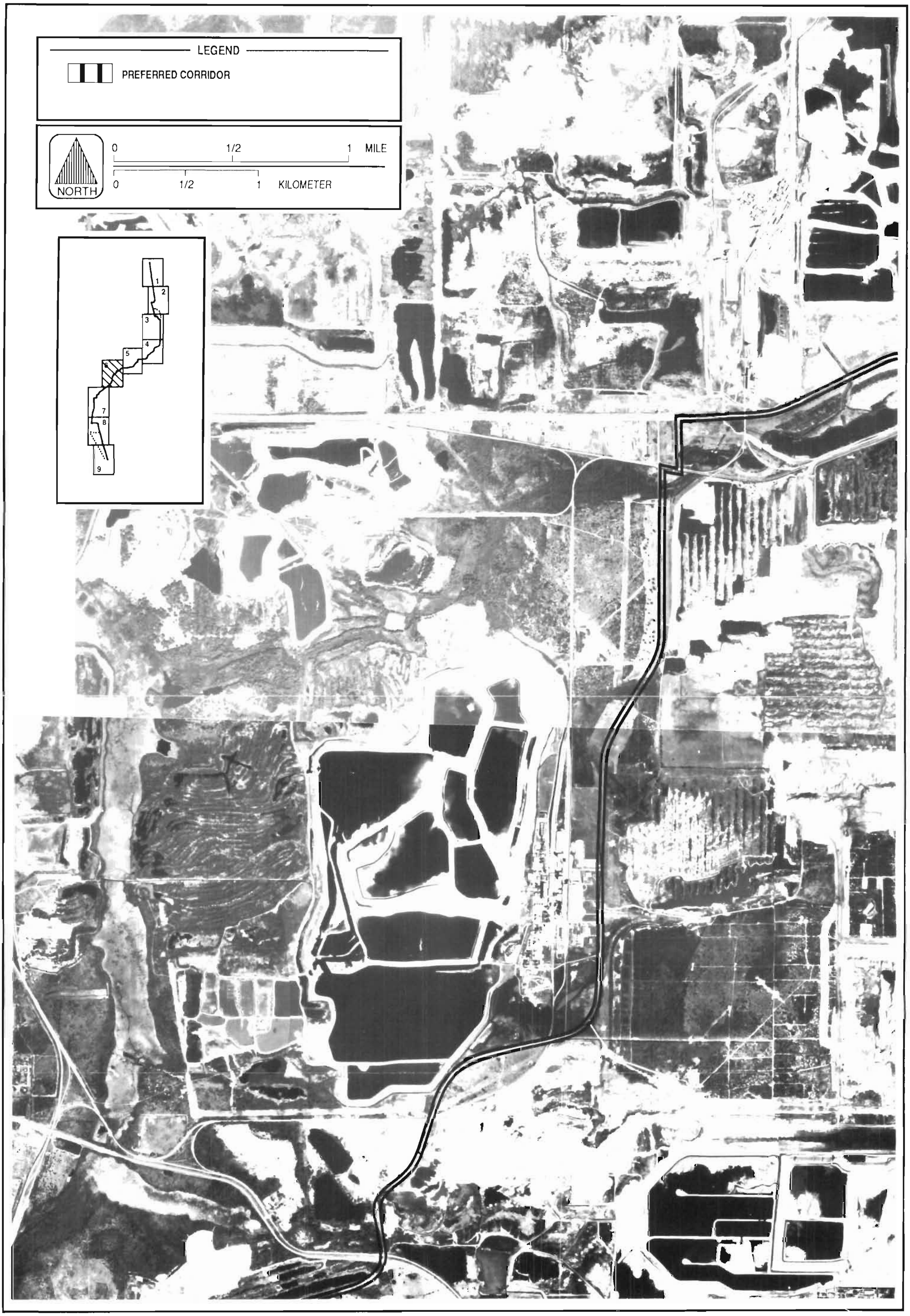
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 4 OF 9)

Hardee
Power Station



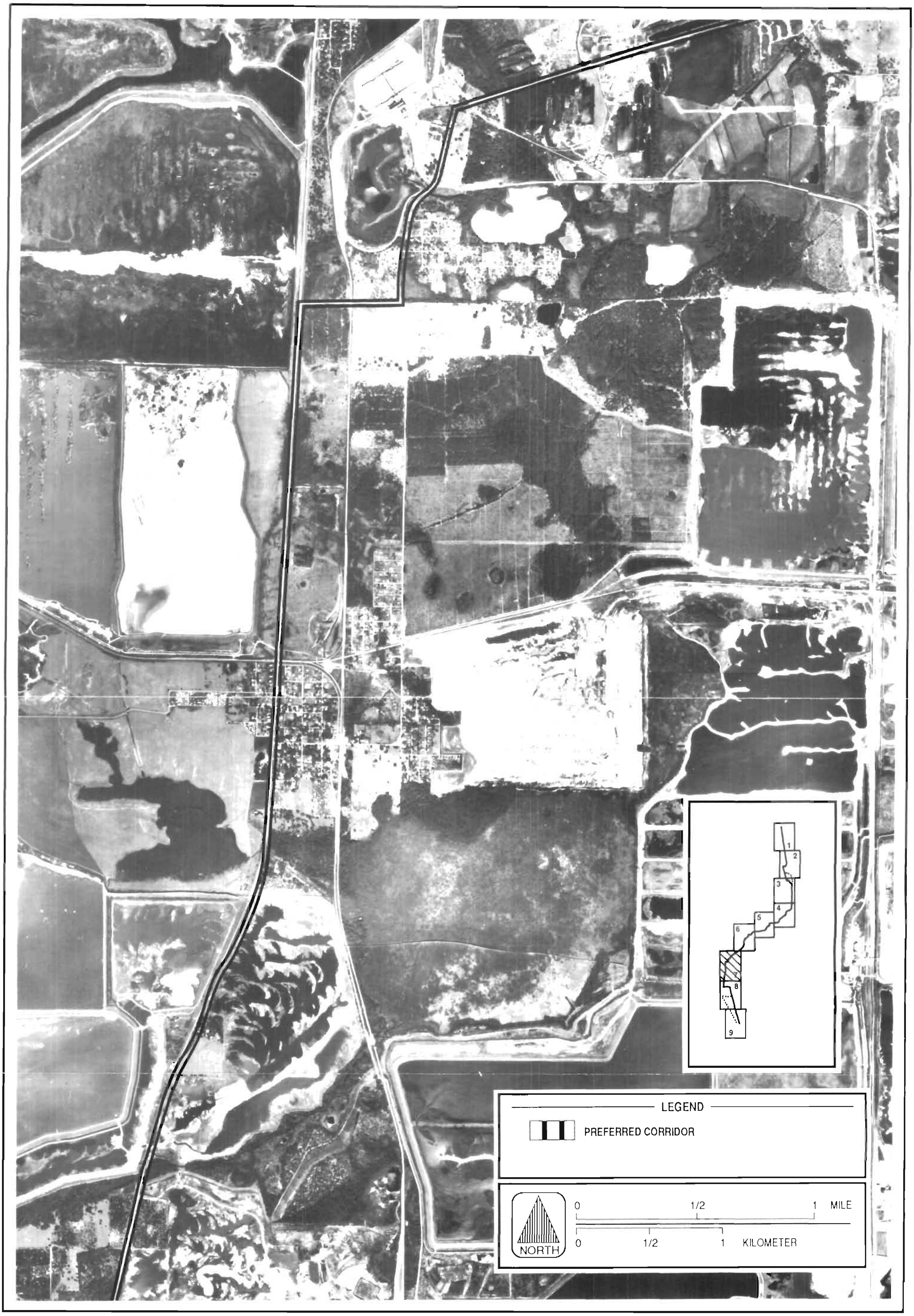
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 5 OF 9)

Hardee
Power Station



AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 6 OF 9)

**Hardee
Power Station**

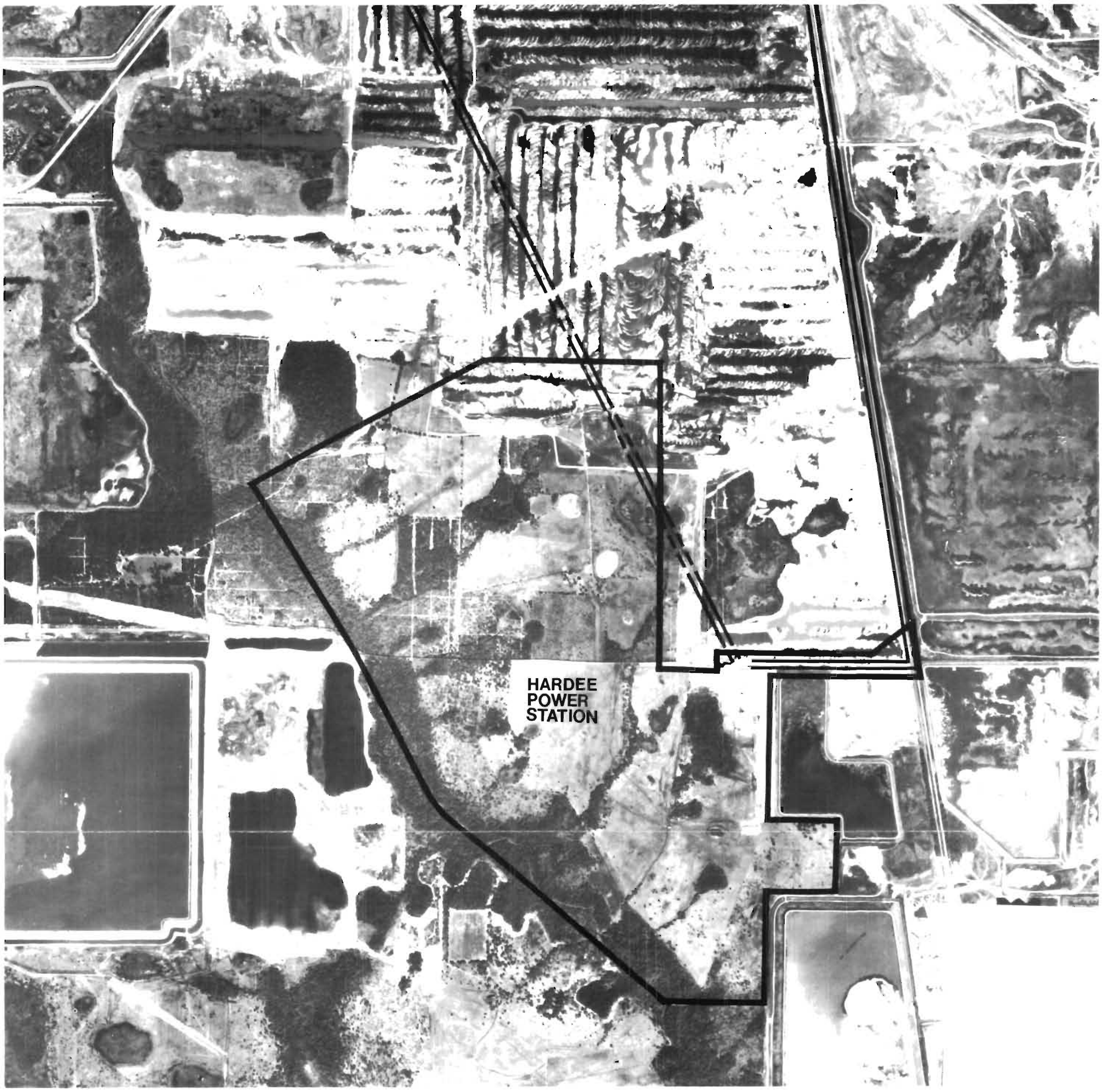


AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 7 OF 9)

Hardee
Power Station

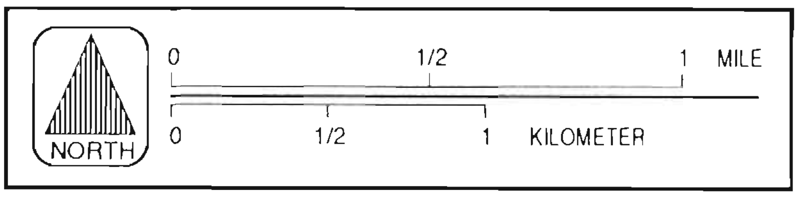
AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 8 OF 9)

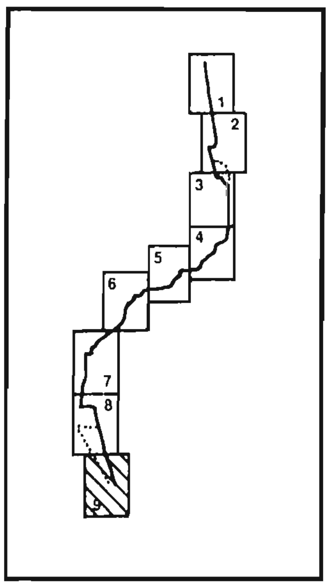
**Hardee
Power Station**



LEGEND

- ▮ PREFERRED CORRIDOR
- ▯ ALTERNATIVE CORRIDOR





AERIAL PHOTOGRAPHS OF PROPOSED GAS PIPELINE CORRIDOR:
HARDEE POWER STATION LATERAL SOUTH TO PLANT SITE
(PAGE 9 OF 9)

**Hardee
Power Station**

Figure 6.3.2-2 AERIAL PHOTOGRAPHS
(1 OF 10)

Hardee
Power Station

Figure 6.3.2-2: AERIAL PHOTOGRAPHS (2 OF 10)

Hardee Power Station

Figure 6.3.2–2 AERIAL PHOTOGRAPHS
(3 OF 10)

**Hardee
Power Station**

Figure 6.3.2–2 AERIAL PHOTOGRAPHS
(4 OF 10)

**Hardee
Power Station**

Figure 6.3.2-2 AERIAL PHOTOGRAPHS
(5 OF 10)

Hardee
Power Station

Figure 6.3.2–2 AERIAL PHOTOGRAPHS
(6 OF 10)

Hardee
Power Station

Figure 6.3.2–2 AERIAL PHOTOGRAPHS (7 OF 10)

Hardee Power Station

Figure 6.3.2–2 AERIAL PHOTOGRAPHS (8 OF 10)

Hardee Power Station

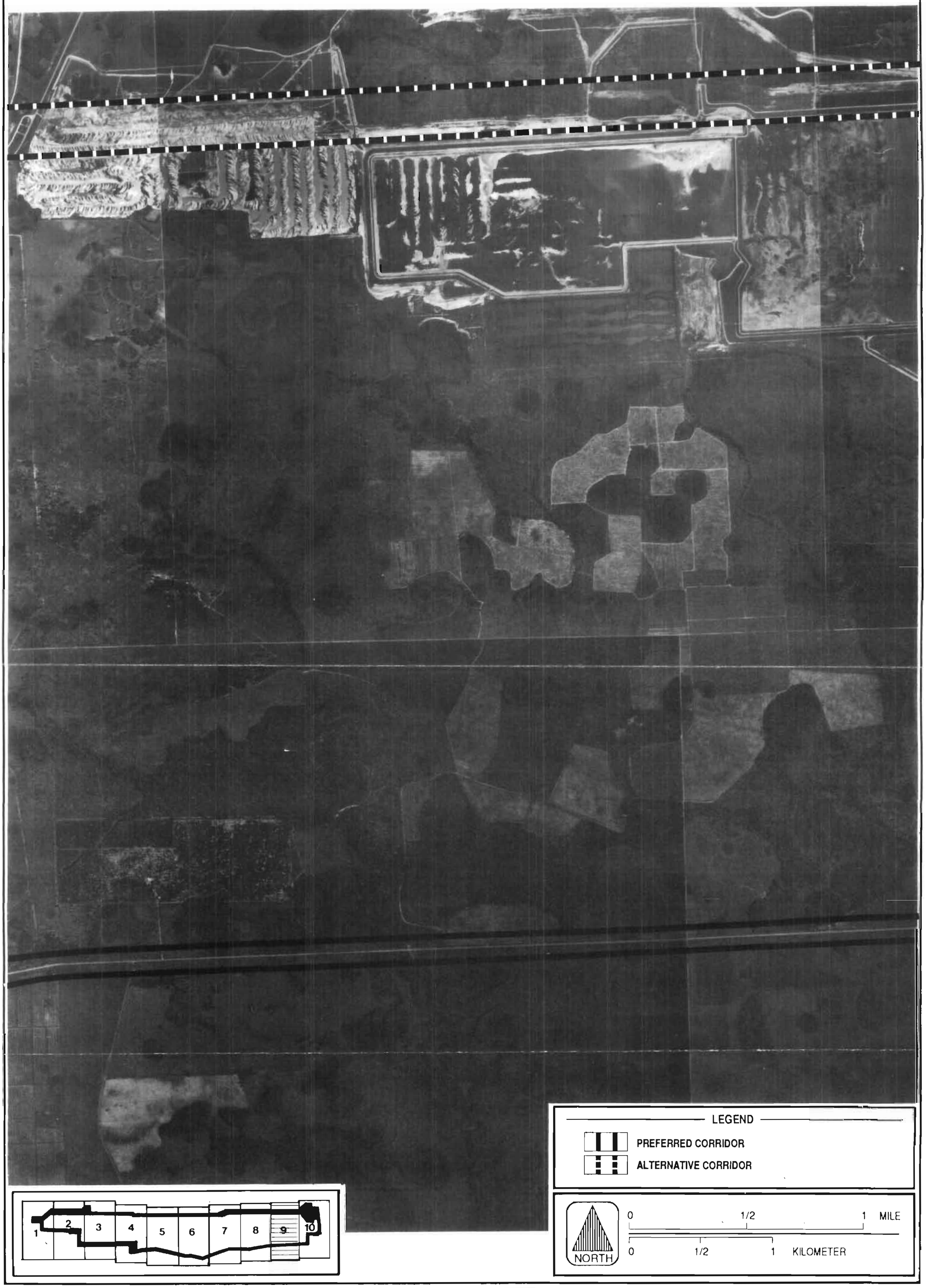


Figure 6.3.2-2 AERIAL PHOTOGRAPHS (9 OF 10)

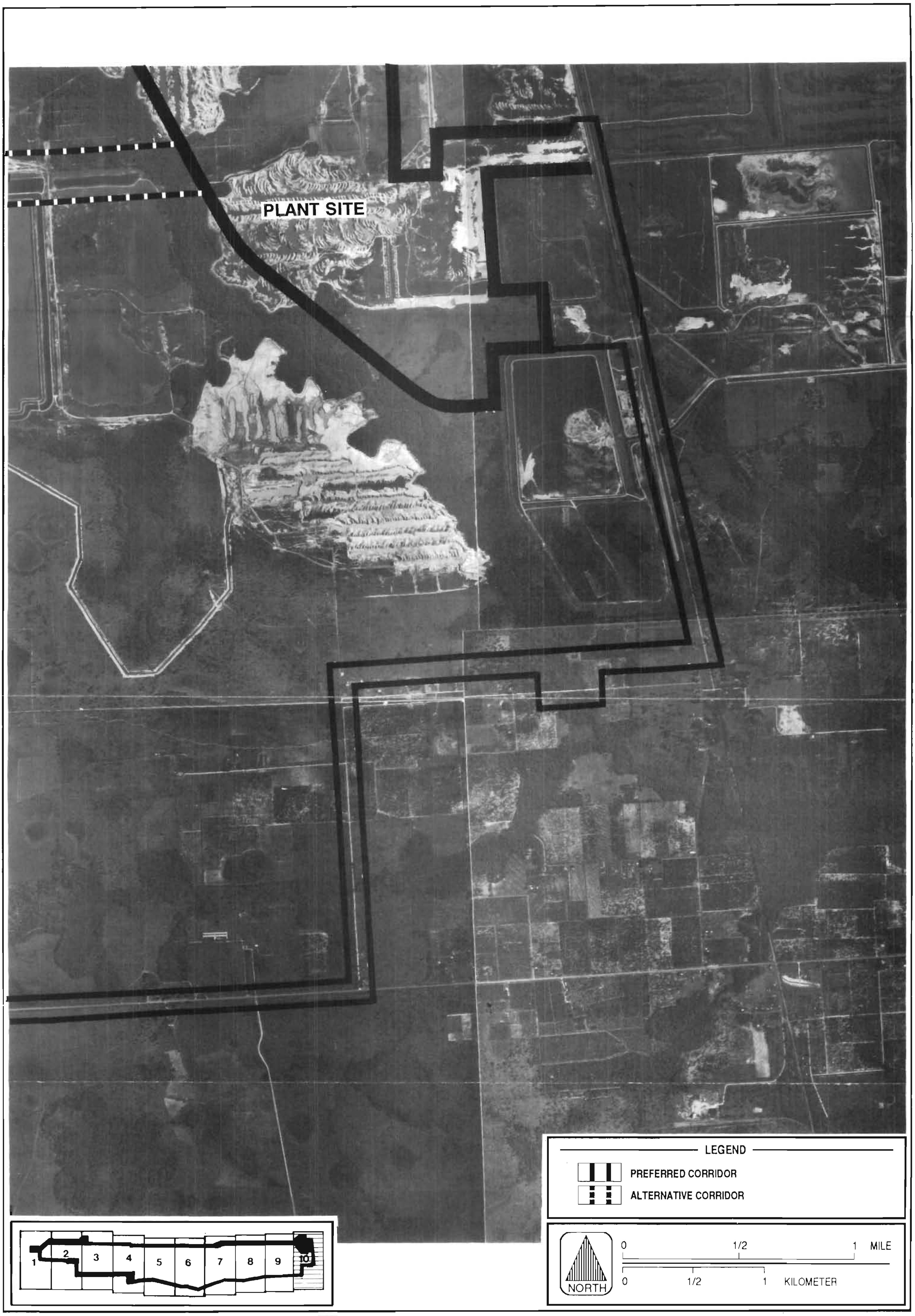


Figure 6.3.2–2 AERIAL PHOTOGRAPHS (10 OF 10)

Hardee Power Station

TAMPA
ELECTRIC
A TECO ENERGY COMPANY

RECEIVED
OCT 21 1996
BUREAU OF
AIR REGULATION

October 15, 1996

Mr. Gerald Kissell, P.E.
Air Permitting Supervisor
Southwest District
Florida Department of Environmental Protection
3804 Coconut Palm Drive
Tampa, Florida 33619

Certified Mail No. P 880 007 839
Return Receipt Requested

Re: Tampa Electric Company
Big Bend Station Fly Ash Silo No. 1
Request to Conduct Fly Ash Classifier Trial
Operating Permit No. AO29-160255

Dear Mr. Kissell:

Tampa Electric Company (TEC) is currently evaluating the viability of utilizing fly ash classification technology at Big Bend Station. To aid in this evaluation, TEC is seeking approval to conduct a temporary test of vibrating screen classifier technology. The testing is being requested to determine the effectiveness of this equipment in separating fines from coarse ash, with the ultimate goal of reducing the carbon content in the ash and thereby reducing the amount of ash which would be disposed of in a landfill. This trial should last approximately 45 days.

Background

Fly ash is a marketable by-product of power generation. The marketability of fly ash is determined by its carbon content. If the carbon content is very low, the ash is more saleable. However, if the carbon content exceeds a certain level, the by-product may no longer be marketable and would be land filled.

Fly ash fines are predominantly ash with little carbon content. Based on fly ash testing, TEC has found that the coarse portion of fly ash generally contains the major portion of unburned carbon. TEC is proposing a trial of vibrating screen classifier technology to separate the coarse portion from the fines. The coarse portion can then be reinjected into the furnace to burn the residual carbon and the low carbon fines will once again be an easily marketable by-product. The reinjection approach is similar to current practices, however, it becomes more efficient by using the classifier technology.

Equipment Description

The location of the equipment to be tested will be on a platform extension, beneath Big Bend Fly Ash Silo No. 1. The equipment to be tested, using Big Bend Unit No. 1 and No. 2 fly ash, will be a Rotex, Inc. Vibrating Screen.

Project Description

Fly ash will be taken from the No. 1 Fly ash Silo via an existing nozzle and routed to the inlet of the Rotex Vibrating Screen. The vibrating screen will be located on the new extension of the platform just below the silo outlet. The vibrating screen has two 6" diameter outlets, one for fines, and the other for coarse portion material. These outlets will each be equipped with a flexible discharge (i.e., elephant nose) for unloading into trucks or other containers. The flexible discharge will consist of an inner conduit and an outer conduit. The inner conduit will deliver the ash to the truck or the container. The annular space between the inner and outer conduits will serve to vent the displaced air from the truck or container. Vented air will be tied into the existing vent blower and will discharge into the silo and pass through the baghouse filter on top of the silo before returning to the atmosphere. The outer conduit will be sealed to the truck or container during the testing operation to prevent fugitive dust emissions.

Testing will not take place during normal fly ash unloading operations. Therefore, there will be no simultaneous use of the venting system by the two operations. As indicated above, the system will be sealed and will not generate any new emissions at the facility. A schematic drawing of the proposed test process is provided as an attachment to this request.

Planned Program of Testing

After the equipment has been installed as described above, testing will begin. It is anticipated that the screen will process 4,750 lb/hr (± 15%) of ash. The test results will indicate what the allowable flow rate is for the ash being tested. Other parameters to be determined by the testing include screen life, plugging tendency, carbon content of coarse and fine portions, and screening efficiency.

As previously stated, Tampa Electric is requesting a temporary test window to conduct testing of the classification system. If the testing shows that the equipment will perform satisfactorily, a more complete, full scale installation may be initiated at a later date.

TEC proposes to begin this test burn upon receiving the Department's approval. Therefore, an expeditious review and approval of this request would be appreciated. If you have any questions or comments on this matter, please feel free to contact me at (813) 641-5087.

Sincerely,

Laura A. Rector

Laura A. Rector
Engineer
Environmental Planning

EP\gm\LAR072

Attachment

c: Mr. Clair Fancy-FDEP
Mr. Jerry Campbell-EPCHC