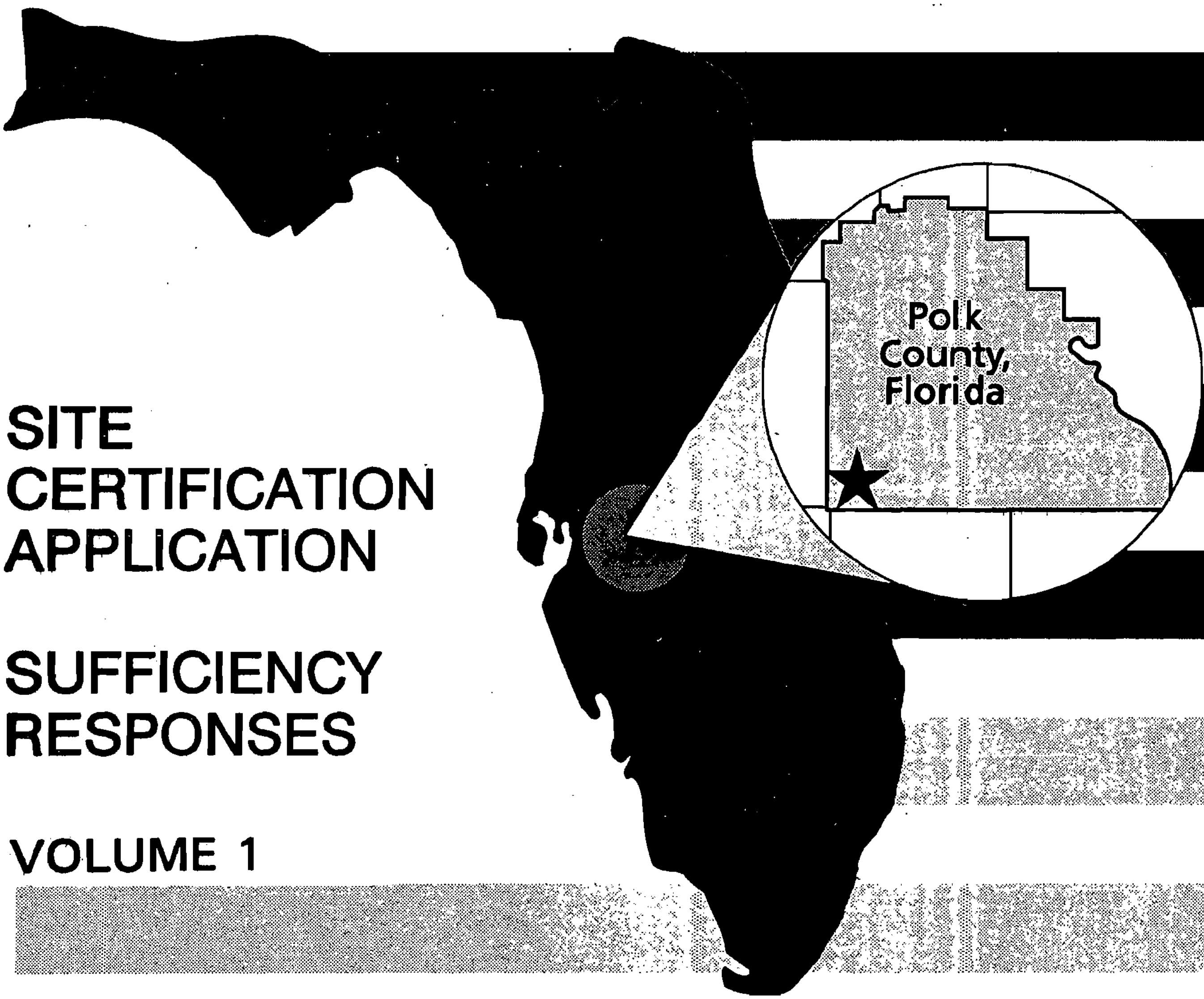
Polk Power Station



SITE CERTIFICATION APPLICATION

SUFFICIENCY RESPONSES

VOLUME 1

TAMPA ELECTRIC
A TECO ENERGY COMPANY

TABLE OF CONTENTS

LIST OF ACRONYMS

7Q10	7-day, 10-year flow rate
AAQS	ambient air quality standard
acre-ft	acre-feet
Agrico	Agrico Chemical Company
API	American Petroleum Institute
BACT	best available control technology
$Btu/ft^2/day$	British thermal unit per square foot per day
Btu/hr	British thermal unit per hour
Btu/kwh	British thermal unit per kilowatt hour
Btu/scf	British thermal unit per standard cubic foot
CAA	Clean Air Act
$CaCO_3$	calcium carbonate
CC	combined cycle
CEMS	continuous emission monitoring system
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CFRPC	Central Florida Regional Planning Council
cfs	cubic foot per second
CG	coal gasification
CGCU	cold gas cleanup
cm/sec	centimeter per second
CO	carbon monoxide
CO_2	carbon dioxide
CompQAP	Comprehensive Quality Assurance Plan
CPRTS	coal pile runoff treatment system
CR	County Road
CRC	Capital Recovery Cost
CSM	cubic foot per second per square mile
CT	combustion turbine

CUP	Conditional Use Permit
DC	direct current
DCS	distributed control system
DOAH	Division of Administrative Hearings
DOE	U.S. Department of Energy
DRI	Development of Regional Impact
EIS	environmental impact statement
EIV	Volume of Environmental Information
EP	electrostatic precipitator
EPA	U.S. Environmental Protection Agency
EPC	Environmental Protection Commission
ET	evapotranspiration
°F	degree Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel bound nitrogen
FDCA	Florida Department of Community Affairs
FDER	Florida Department of Environmental Regulation
FDHR	Florida Department of State, Division of Historical Resources
FDLES	Florida Department of Labor and Employment Security
FDNR	Florida Department of Natural Resources
FDOT	Florida Department of Transportation
FLUCCS	Florida Land Use and Cover Classification System
FLUCFS	Florida Land Use, Cover, and Forms Classification System
FPC	Florida Power Corporation
FPSC	Florida Public Service Commission
F.S.	Florida Statutes
ft	foot
ft bls	foot below land surface
ft/day/ft	feet per day per foot

ft^2	square foot
ft^2/sec	square feet per second
ft^3	cubic foot
ft^3/day	cubic foot per day
ft^3/hr	cubic foot per hour
ft-msl	foot above mean sea level
ft-NGVD	foot national geodetic vertical datum
ft/sec	feet per second
GE	General Electric Company
GEP	Good Engineering Practice
gpd	gallon per day
gpm	gallon per minute
gpm/ft^2	gallon per minute per square foot
g/sec	gram per second
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HGCU	hot gas cleanup
HHV	higher heating value
HRSG	heat recovery steam generator
hr/yr	hours per year
IAF	induced air flotation
IFAS	Institute of Food and Agricultural Science
IGCC	integrated coal gasification combined cycle
IMC	IMC Fertilizer, Inc.
ISC2	Industrial Source Complex
ISCLT2	Industrial Source Complex, Long-Term
ISCST2	Industrial Source Complex, Short-Term
IWT	industrial wastewater treatment
K	Kelvin

kJ/wh	kiloJoules per watt-hour
km	kilometer
kV	kilovolt
kw	kilowatt
kwh	kilowatt hour
lb	pound
lb/10^6 Btu	pounds per million British thermal units
lb/day	pound per day
lb GVW	pounds gross vehicle weight
lb/hr	pound per hour
lb/ton	pounds per ton
m	meter
m/sec	meter per second
MDL	method detection limit
mg/L	milligram per liter
MGD	million gallons per day
mm Hg	millimeters of mercury
MMBtu/hr	million British thermal units per hour
MOU	Memorandum of Understanding
mph	miles per hour
MW	megawatt
NEPA	National Environmental Policy Act of 1969
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NWI	National Wetland Inventory

NWS	National Weather Service
OAQPS	Office of Air Quality Planning and Standards
OGC	Office of General Counsel
OSHA	Occupational Safety and Health Administration
pCi/L	picoCurie per liter
PEC	purchased equipment cost
PLC	program logic controller
PM	particulate matter
PM_{10}	particulate matter less than or equal to 10 micrometers aerodynamic diameter
POS	Plan of Study
ppm	part per million
ppmvd	dry volume parts per million
PPSA	Power Plant Siting Act
PSD	prevention of significant deterioration
psia	pound per square inch absolute
psig	pound per square inch gauge
QA	quality assurance
QAS	Quality Assurance Section
QC	quality control
R.O.	reverse osmosis
RCRA	Resource Conservation and Recovery Act
S	sulfur
SCA	Site Certification Application
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SCS	U.S. Soil Conservation Services
SO_2	sulfur dioxide
SO_2-SO_3	sulfur dioxide-sulfur trioxide

LIST OF ACRONYMS
(Continued, Page 6 of 6)

SO_3	sulfur trioxide
SPCC	Spill Prevention, Control, and Countermeasure
SPT	standard penetration test
SR	State Road
SRU	sulfur recovery unit
ST	steam turbine
stpd	short-tons per day
su	standard units
SWFWMD	Southwest Florida Water Management District
TCI	total capital investment
TCLP	toxicity characteristic leaching procedure
TDC	total direct costs
TDS	total dissolved solids
TGTU	tail gas treating unit
TOC	total organic compound
tpd	ton per day
tpy	ton per year
TSP	total suspended particulate
TSS	total suspended solids
UE&C	United Engineers & Constructors
USACE	U.S. Army Corps of Engineers
USGS	U.S. Geological Survey
VOC	volatile organic compound
vppm	volume part per million
WUCA	Water Use Caution Area
WUP	water use permit

INTRODUCTION

This document (Volumes 1 and 2) provides Tampa Electric Company's responses to comments from the Florida Department of Environmental Regulation (FDER) and other reviewing agencies regarding the sufficiency of the Site Certification Application (SCA) for the proposed Polk Power Station. The sufficiency comments were provided in the FDER letter, including attachments, from Mr. Hamilton S. Oven to Ms. Diane K. Kiesling of the Division of Administrative Hearings (DOAH), dated October 5, 1992, and other agency comments received since the date of this letter. The Tampa Electric Company Polk Power Station SCA has been designated as DOAH Case No. 92-4896EPP and Office of General Counsel (OGC) Case No. 92-1399. The SCA number is PA 92-32.

In this document, the responses to the reviewing agency sufficiency comments are provided in reference to the following agency letters and in the following order:

Volume I

- FDER--Letter from Mr. Hamilton S. Oven to Ms. Diane K. Kiesling, dated October 5, 1992 (includes U.S. Environmental Protection Agency [EPA] letter from Ms. Jewell A. Harper to Mr. Clair H. Fancy of FDER, dated October 9, 1992);
- Florida Department of Community Affairs (FDCA)--Letter from Mr. Tony A. Arrant to Mr. Hamilton S. Oven, dated September 21, 1992;
- Florida Department of Natural Resources (FDNR)--Letter from Mr. B.J. White to Mr. Hamilton S. Oven, dated September 21, 1992;
- Florida Department of Transportation (FDOT)--Letter from Mr. Vernon L. Whittier to Mr. Hamilton S. Oven, dated September 21, 1992; and
- Florida Department of State, Division of Historical Resources (FDHR)--Letter from Mr. George W. Percy to Mr. A. Spencer Autry of Tampa Electric Company, dated September 22, 1992 (included as Appendix to Volume 1 since

FDHR determined the SCA to be sufficient and had no comments requiring responses).

Volume 2

- Southwest Florida Water Management District (SWFWMD)--Letter from Mr. Martin D. Hernandez to mr. Hamilton S. Oven, dated September 23, 1992;
- Polk County and Central Florida Regional Planning Council (CFRPC)--Letter from Mr. Donald S. Martin to FDER, attention of Mr. Hamilton S. Oven, dated September 18, 1992;
- Hillsborough County--Letter from Mr. Frederick B. Karl to Mr. A. Spence Autry, dated September 9, 1992; and
- Hillsborough County Environmental Protection Commission (EPC)--Letter from Ms. Patricia Frantz to Mr. Hamilton S. Oven, dated September 22, 1992.

Copies of these agency sufficiency comment letters are provided prior to the responses within each of the tabbed sections of this document with cross-referencing numbers added to the comments in the letters to assist in identifying the appropriate, subsequent responses. The previously cited letter from Mr. Oven of FDER to Ms. Kiesling of DOAH included as attachments interoffice memorandums from various bureaus, sections, and offices of FDER. All of the sufficiency comments from these various groups within FDER were specifically listed in the letter to Ms. Kiesling. Copies of these FDER interoffice memorandum comments are provided after the cited letter with cross-references added to identify the comments in the cited letter and the subsequent responses.

As noted in the responses, certain revisions to the Polk Power Station SCA have been identified since the filing of the SCA on July 30, 1992. These revisions have been identified as needed based on the reviewing agency comments or on Tampa Electric Company's ongoing preliminary engineering and design efforts for the project. Specific revisions to the SCA have been provided in conjunction with these sufficiency responses for replacement/insertion in the SCA. These revisions are identified as and constitute Revision 1 (Rev. 1, 11/25/92) of the Polk Power Station SCA. Therefore, the responses to the agency sufficiency comments are provided and should be reviewed based on the revised information for the SCA. A table is provided at the end of this introduction section and attached to the package of revisions for insertion in the SCA which identifies which pages or sections of the SCA have been revised.

As indicated above, certain revisions of the Polk Power Station SCA have been identified based on Tampa Electric Company's ongoing preliminary engineering and design efforts for the project. Based on these ongoing efforts, additional, more specific information has been developed on certain proposed components, systems, and operations of the overall project. Tampa Electric Company has identified and has provided appropriate revisions to the SCA in order to assure that the Polk Power Station project is evaluated by the reviewing agencies based on the most current engineering/design information for the project. The following discussions highlight the primary design criteria and/or reasons for the revisions to the SCA information. Of note, these revisions in the preliminary design information for the project have not changed or have enhanced the reasonable assurance that the proposed Polk Power Station will meet all applicable federal, state, and local environmental regulations and standards.

Revision in Design of Potable and Service/Process Water Supply Treatment System

The potable/service water supply system has been revised to add a degasifier to strip potential hydrogen sulfide components from the Floridan aquifer well water. A hydrogen sulfide stripping system was not included in the original groundwater supply system design. In addition, the system has been modified to physically separate the potable water storage from service water storage, preventing any potential for cross contamination of the potable water supply.

In addition, the demineralizer mixed bed ion exchange system to supply high quality water for boiler makeup and other plant process uses has been revised to eliminate the onsite regeneration of the ion exchange mixed beds onsite and the resulting discharge of high total dissolved solids wastewater to the cooling reservoir. Under the revised design, the mixed bed ion exchange system will be a portable unit which will be periodically interchanged and transported offsite for regeneration by the unit contractor.

Revision in Design of Industrial Wastewater Treatment System

The industrial wastewater treatment (IWT) system described originally in the SCA involved combining and treating all plant wastewaters in one overall IWT system. This design was determined to be inefficient since the treatment of large volumes of wastewater in the entire IWT system would result in the treatment of certain streams with small concentrations of potential contaminants which would not be affected by certain components of the overall IWT system. Based on these inefficiency considerations, the overall IWT system has been modified based on the following design criteria:

- Segregation of wastewater streams with different contaminants and combination of streams with similar contaminants in order to focus treatment on specific contaminants,
- Treatment of lower-volume wastewater streams for specific contaminants of concern,
- Mixing of acidic and basic wastewater streams, and
- Combinations of wastewater streams in equalization basin for final treatment by filtration or reuse.

The currently proposed revision in the IWT system has improved the quality of wastewaters routed to the cooling reservoir. In turn, these revisions have contributed to the estimated, improved water quality conditions within the reservoir and of discharges from the reservoir which previously and currently are predicted to meet all surface water quality standards, except for a mixing zone required to meet the thermal standard under highly unlikely worst-case conditions.

Other Modifications/Refinements of Preliminary Project Designs

Certain other revisions of the SCA have been identified and included in the Revision 1 replacements based on the following preliminary design information and for further clarification purposes:

- Cooling Reservoir Bottom--The reservoir bottom will be irregular with a maximum elevation of 123 feet National Geodetic Vertical Datum (ft-NGVD) and average elevation of 120 ft-NGVD based on refined soil material balance information.
- Construction Dewatering Water--The dewatering water from the cooling reservoir and reclaimed wetland areas on the east side of State Road (SR) 37 may not need to be routed to retention areas on the west side of SR 37 based on additional, more detailed evaluations of water storage capabilities in areas east of SR 37.
- Integration of Coal Gas Cleanup (CGCU) Off-Gas with Sulfuric Acid Plant--The original SCA indicated that off-gas from the CGCU system would be treated and converted to elemental sulfur, and off-gas from the demonstration hot gas cleanup (HGCU) system would be treated and converted to sulfuric acid (H_2SO_4). Based on current design information, some off-gas from the CGCU system may be converted to H_2SO_4, this alternative would not change the size of the H_2SO_4 plant or the amount of H_2SO_4 produced on an annual basis or stored on the site. If implemented, this alternative would reduce the amount of elemental sulfur generated by the operations.

Other revisions to the SCA information have been primarily made by Tampa Electric Company based on the comments and informational requests from the agencies reviewing the SCA. The primary SCA revisions based on these agency comments have involved the following:

- Air Quality Modeling--The air quality modeling analyses have been revised based on the emission source inventory comments from FDER comments and include MESOPUFF modeling for each year of the 5-year period.

- Water Quality Monitoring Plans--The operational surface water and groundwater quality monitoring plans have been revised based on the FDER comments and additional information on the facility operations.

The responses to other agency sufficiency comments primarily present additional detail and clarification to information provided in the SCA for Polk Power Station.

TAMPA ELECTRIC COMPANY
POLK POWER STATION
SITE CERTIFICATION APPLICATION

REVISION 1

Revision 1, 11/25/92, of the Site Certification Application for the Tampa Electric Company Polk Power Station consists of the following revisions to the document.

Remove	Insert from Rev. 1, 11/25/92
<u>Volume 1</u>	
Pages 2.3.2-11 and 2.3.2-12	Pages 2.3.2-11 and 2.3.2-12
Pages 2.3.2-26 through 2.3.2-29	Pages 2.3.2-26 through 2.3.2-29
Pages 2.3.4-20 through 2.3.4-31	Pages 2.3.4-20 through 2.3.4-31
Pages 2.3.4-44 through 2.3.4-48	Pages 2.3.4-44 through 2.3.4-48
<u>Volume 2</u>	
Pages 3.1.1-26 through 3.1.1-31	Pages 3.1.1-26 through 3.1.1-31
Pages 3.1.4-3 through 3.1.4-11	Pages 3.1.4-3 through 3.1.4-11
Page 3.3.0-1	Page 3.3.0-1
Page 3.3.1-2	Page 3.3.1-2
Pages 3.3.1-5 through 3.3.1-8	Pages 3.3.1-5 through 3.3.1-8
Pages 3.3.3-3 and 3.3.3-4	Pages 3.3.3-3 and 3.3.3-4
Pages 3.5.0-2 and 3.5.0-3	Pages 3.5.0-2 and 3.5.0-3
Page 3.5.0-5	Page 3.5.0-5
Pages 3.5.1-6 through 3.5.1-11	Pages 3.5.1-6 through 3.5.1-10
Pages 3.5.3-1 through 3.5.3-3	Pages 3.5.3-1 through 3.5.3-3
Pages 3.5.4-1 through 3.5.4-21	Pages 3.5.4-1 through 3.5.4-19
Pages 3.6.2-1 through 3.6.2-5	Pages 3.6.2-1 through 3.6.2-5
Pages 3.7.1-1 through 3.7.1-8	Pages 3.7.1-1 through 3.7.1-8
Pages 3.8.3-1 through 3.8.3-3	Pages 3.8.3-1 through 3.8.3-3
Pages 3.8.4-4 through 3.8.4-11	Pages 3.8.4-4 through 3.8.4-11
Page 4.1.1-5	Page 4.1.1-5
Page 4.2.1-1	Page 4.2.1-1
Page 4.3.1-2	Page 4.3.1-2
Pages 5.1.1-2 through 5.1.1-8	Pages 5.1.1-2 through 5.1.1-8
Page 5.1.5-1	Pages 5.1.5-1 through 5.1.5-3
Pages 5.2.1-1 through 5.2.1-6	Pages 5.2.1-1 through 5.2.1-6
Page 5.3.1-1	Pages 5.3.1-1 through 5.3.1-4
Page 5.3.5-1	Page 5.3.5-1
Page 5.4.1-1	Page 5.4.1-1

Remove	Insert from Rev. 1, 11/25/92
Page 5.6.1-5 Page 5.6.1-7 Page 5.6.1-15 Pages 5.6.1-17 and 5.6.1-18 Page 5.7.0-3	Page 5.6.1-5 Page 5.6.1-7 Page 5.6.1-15 Pages 5.6.1-17 and 5.6.1-18 Page 5.7.0-3
Volume 3	
Page 6.1.1-2 Pages 6.1.3-2 through 6.1.3-4	Page 6.1.1-2 Pages 6.1.3-2 through 6.1.3-4
Appendix 11.1.1--Federal Permit Applications	
Seventh through twenty-sixth pages (EPA Form 3510-2D, Figure 1, Table 1, and Stormwater Discharges Associated with Industrial Activity from Construction Site attachment	EPA Form 3510-2D, Figure 1--Water Mass Balance, Annual Average Makeup, and Table 1--Estimated Cooling Reservoir Discharge (Outfall 001) Effluent Water Quality
	Add at end of Appendix 11.1.2: EPA Form 3510-6, attachment to the Notice of Intent, and Preliminary Pollution Prevention Plan
Volume 4	
Appendix 11.1.3--Prevention of Significant Deterioration Permit Application	
Page 2-62 Pages 4-57 and 4-58 Pages 5-1 through 5-3 Pages 6-15 through 6-35 Pages 7-11 through 7-15 Pages 7-17 and 7-18 Pages 7-26 through 7-28	Page 2-62 Pages 4-57 and 4-58 Pages 5-1 through 5-3 Pages 6-15 through 6-35 Pages 7-11 through 7-15 Pages 7-17 and 7-18 Pages 7-26 through 7-28

Remove	Insert from Rev. 1, 11/25/92
Pages 7-30 through 7-39	Pages 7-30 through 7-39
Pages 9-6 and 9-7	Pages 9-6 and 9-7
Page 9-9	Page 9-9
Pages 9-15 through 9-37	Page 9-15 through 9-39
Pages A-5 through A-7	Pages A-5 through A-7
Pages B-1 through B-39 (All of Appendix B)	Pages B-1 through B-43 (Appendix B)
	Add after Appendix B: Appendix C, Summaries of MESOPUFF-II Results

Volume 5

Appendix 11.2.1--Application to Construct/Operate Air Pollution Sources

Pages 1 of 12 through 12 of 12 (DER Form 17.1.202[1])	DER Forms 17.1.202(1)

Appendix 11.2.2--Water Use Permit Application

Page 2 of 6 (WUP-3, Form 46.20-003)	Page 2 of 6 (WUP-3, Form 46.20-003)
Page 4 of 6 (WUP-3, Form 46.20-003)	Page 4 of 6 (WUP-3, Form 46.20-003)
Figure 11.2.2-3 in WUP attachment	Figure 11.2.2-3 in WUP attachment
Figures 11.2.2-6 and 11.2.2-7 in WUP attachment	Figures 11.2.2-6 and 11.2.2-7 in WUP attachment

Volume 6

Appendix 11.7.8--Groundwater Monitoring Plan

Third page (monitoring program description)	Monitoring Program
	Add after Figure 11.7.8-3: Figure 11.7.8-4

TAMPA ELECTRIC COMPANY
POLK POWER STATION
SITE CERTIFICATION APPLICATION

REVISION 1
(Continued, Page 4 of 4)

Remove	Insert from Rev. 1, 11/25/92

Appendix 11.8.4--USGS Stream Flow Data

Page 1	Page 1 (Table, Monthly Discharges at South Prong Alafia River Near Lithia (USGS Station No. 02301300)

Appendix 11.8.8--Surface Water Quality Monitoring Data

	Add after Table 6: Tables 7 through 12

Appendix 11.8.9--Pre-Mining and Post-Reclamation Surface Water Runoff Modeling Results

Sixth page through end (HEC-1 computer output files)	HEC-1 computer output files

Volume 7

Appendix 11.13.2--Preliminary Resource Conservation and Recovery Act Contingency Plan

Pages 1 and 2	Pages 1 through 5

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

October 5, 1992

RECEIVED
OCT 12 1992
ENVIRONMENTAL PLANNING

Ms. Diane K. Kiesling
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

Re: TECO Polk Power Station, DOAH Case No. 92-4896EPP
PA 92-32

Dear Ms. Kiesling:

The Florida Department of Environmental Regulation has reviewed the Tampa Electric Company Polk Power Station project application for sufficiency pursuant to Section 403.5067, F.S. The Department in conjunction with reviewing agencies finds the application to be insufficient in a number of areas. The sufficiency comments from the Department of Community Affairs, Southwest Florida Water Management District, Florida Game and Fresh Water Fish Commission, Central Florida Regional Planning Council, Polk County, Hillsborough County and Department of Transportation are attached and incorporated herein.

DER - AIR

1. The applicant needs to supply the input and output files for the Bowman GEP program runs that were performed to determine the downwash parameters for the ISCST2 and ISCLT2 modeling runs. FDER-1

2. Stack parameters and the emission rates for the various pollutants modeled need to be supplied for Source 14 (Flare). FDER-2

3. Source 13 (Tail Gas Treating Unit Thermal Oxidizer) has a sulfur dioxide emission rate of 6.56 g/s in Table 2-4, but was modeled with an emission rate of 8.2 g/s. Which of these values is correct? FDER-3

4. The carbon monoxide emission rates for IGCC Fugitive Sources 42 and 43 in Table 2-30 are listed as 0.0001 g/s (.1E-3 g/s), but these sources were modeled with an emission rate of .001 g/s (.1E-2). What is the correct emission rate for these sources? FDER-4

5. AAQS Modeling for Sulfur Dioxide FDER-5

a. Identify sources 101a and 101b.

b. Source 121n has a tabled emission rate of 87.00 g/s, but 42.87 g/s was modeled. Which of these values is correct?

c. Source 126h has a tabled stack height of 63.1 m, but was modeled at 67.1 m. Which of these values is correct?

d. Source 126g has a tabled stack exit velocity of 7.88 m/s, but 7.28 m/s was modeled. Which of these values is correct?

e. Source 127j has a tabled emission rate of 45.72 g/s, but was modeled at 41.96 g/s. Which of these values is correct?

h. Source 131i has a tabled exit temperature of 319 K, but was modeled at 314 K. Which of these values is correct?

g. Source 134a has a tabled emission rate of 25.40 g/s, but was modeled at 6.43 g/s. Which of these values is correct?

h. Sources 167 a and b have tabled exit temperatures of 441.3k and 449.7 K, respectively, but were modeled as a combined source with an exit temperature of 466.0 K. Please justify the modeled value.

6. AAQS Modeling for Nitrogen Oxides FDER-6

a. The TECO CT's in simple cycle mode have a tabled emission rate of 4.87 g/s (Table 2-25), but were modeled at 4.74 g/s. Which of these values is correct?

b. The TECO CT's in combined cycle mode have a tabled emission rate of 9.42 g/s (Table 2-25), but were modeled at 9.07 g/s. Which of these values is correct? Note: The higher emission rates were used in the significant impact area analysis.

c. Source 100d was in the emission inventory, but was not modeled. Please explain.

d. Source 118g has a tabled stack diameter of 5.79 m, but was modeled at 1.83 m.

Which of these values is correct?

e. Source 136a was in the emission inventory, but was not modeled. Please explain.

7. AAQS Modeling for Particulate Matter **FDER-7**

a. Source 26's Y coordinate is out of the output range. It should be 3067366.0. Please explain why it is out of range.

b. Source 112a has a tabled emission rate of 1089.3 g/s, but was modeled at 89.3 g/s. Which value is correct?

c. Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which value is correct?

8. PSD Class I and II Modeling for Sulfur Dioxide **FDER-8**

a. IMC Lonesome Mine Dry #1 and #2 were not modeled. Please explain this omission.

b. McKay Bay Refuse to Energy was not modeled. Please explain this omission.

c. Source 125 h has a tabled stack height of 38.35 m, but was modeled at 28.35 m. Which of these values is correct?

d. The applicant needs to justify the use of all negative (increment expanding) emissions used in the modeling.

9. PSD Class I and II Modeling for Nitrogen Oxides **FDER-9**

a. Sources 6 through 11 were modeled with an emission rate of 4.74 g/s, but for the SIA they were modeled at 4.87 g/s (Table 2-25). Which of these values is correct for the increment modeling?

b. The nitrogen oxides emission inventory provided by the applicant includes the following sources: 113i, 113j, 129h, 129i, 148a, 151a, and 157b. None of these sources were included in the increment modeling. Please explain this omission.

10. PSD Class I and II Modeling for Particulate Matter **FDER-10**

a. Source 26 has a Y coordinate that is out of the models output range. Please explain why.

b. Source 109d has a tabled emission rate of 13.26 g/s, but was modeled at 6.45 g/s. Which of these values is correct?

c. Source 125m has a tabled emission rate of 25.07 g/s, but was modeled at 12.61 g/s. Which of these values is correct?

d. Source 128f has a tabled emission rate of 4.22 g/s, but was modeled at 5.04 g/s. Which of these values is correct?

e. Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which of these values is correct?

f. Source 130h has a tabled emission rate of 17.73 g/s, but was modeled at 4.92 g/s. Which of these values is correct?

11. The applicant needs to supply a copy of the inputs and output from their VISCREEN program run. FDER-11

12. EPA Modeling Guidelines require that ISCLT modeling be performed on an annual basis. The applicant performed the annual modeling runs using a composite of five years. The applicant needs to explain why they deviated from the modeling guidelines. FDER-12

13. Any additional sulfur dioxide modeling must include the proposed Florida Power Corporation's Polk County facility and the Kissimmee Utility Cane Island facility. The applicant must also contact the Department with regard to emission changes at Orlando Utility's Stanton facility and Florida Power Corporation's Intercession City facility. Furthermore, since the TECO Hardee power Plant was certified for four units, four units must be modeled. In the application only three units were modeled. FDER-13

14. Beryllium Modeling

FDER-14

a. Where did the short-term emission rate for Source 1b come from?

b. Sources 6 through 11 have a table short-term emission rate of .0004 g/s (100% load at 20 F), but were modeled at .0003 g/s. Which of these values is correct?

c. The output for the 24-hour modeling for 1984 is missing.

15. Chromium Modeling FDER-15

a. Source 1b has a tabled emission rate of .0026 g/s, but was modeled at .000052 g/s. Which of these values is correct?

b. Sources 2b through 5b have table emission rates of .0035 g/s, but were modeled at .000018 g/s. Which of these values is correct?

c. Sources 6 through 11 have table emission rates of .0013 g/s, but were modeled at .000007 g/s. Which of these values is correct?

d. Source 13 has a tabled emission rate of .0132 g/s, but was modeled at .000264 g/s. Which of these values is correct?

e. Source 15 has a tabled emission rate of .0066 g/s, but was modeled at .000132 g/s. Which of these values is correct?

16. H_2SO_4 Modeling FDER-16

Sources 7 through 11 were modeled with an emission rate of 0.6305 g/s (100% Load, 90 F). Should these sources have been modeled at 0.7566 g/s (100% Load, 20 F)?

17. Fluoride Modeling FDER-17

Sources 7 through 11 were modeled with an emission rate of 0.0037 g/s (100% Load, 90 F). Should these sources have been modeled at 0.0045 g/s (100% Load, 20 F)?

18. The emission calculations for the criteria and non-criteria pollutants are not adequately shown in the application. All calculations affecting emissions should be shown in their entirety, and not just summarized in tabular form. This includes showing the equations used, assumptions made and any supporting documents used for emission calculations. FDER-18

19. Please provide a maximum value for fuel bound nitrogen for both natural gas and fuel oil. Also, calculate the maximum NOx emissions based upon your maximum value for fuel bound nitrogen for the Integrated Coal Gasification Combined Cycle (IGCC), Combined Cycle (CC) and the Simple Cycle combustion turbines. FDER-19

20. Please submit a detailed process flow diagram for the IGCC unit showing the volumetric air flow rates for each stream when burning fuel oil and the different scenarios for syngas combustion. Also, submit the same for the CC, Simple Cycle and the auxiliary boiler when burning natural gas and fuel oil. FDER-20

21. What is the efficiency of the combustion turbine for the IGCC, CC and the Simple Cycle units? Calculate Y (refer to NSPS 40 CFR 60, Subpart GG) in kilojoules per watt hour, showing all the calculations. FDER-21

22. Submit manufacturer's name, model number, generator name plate rating (gross MW), maximum steam production rate for the Heat Recovery Steam Generator (HRSG) for the IGCC and the CC units. FDER-22

23. What is the maximum and nominal power (MW) output of the steam turbine generator for the IGCC and the CC units? What is the steam input to these turbines? FDER-23

24. Please submit the manufacturer's design specification for the proposed IGCC General Electric 7F combustion turbine (CT), GE 7EA CTs and also for the auxiliary boiler. FDER-24

25. What is the estimated annual throughput and the type of air pollution control for the fuel oil storage tanks? What are the estimated emissions? FDER-25

26. Please submit a detailed listing of all the continuous emission monitoring systems (CEMs) required for this project. This should include the type of the CEM (in-situ or extractive), the make and model number, the pollutant it will monitor, and any associated data acquisition system. FDER-26

27. What kind of control and monitoring equipment is proposed for continuously recording power generation, coal feed rate, fuel injection rate of syngas, natural gas and fuel oil, nitrogen and the water injection rate for the IGCC unit. FDER-27

28. Please provide the names and addresses of all the manufacturers and suppliers that were contacted for budgetary quotations and engineering estimates in developing capital and annualized cost estimates for this project. Also, provide a summary of all the equipment, raw material and the fuel costs. FDER-28

29. Does the applicant propose to do simultaneous fuel (natural gas and fuel oil) firing for the CC and Simple Cycle units? If so, provide details on how this will be accomplished. FDER-29

30. Please submit the information requested in Rule 17-256.600(3) regarding Industrial, Commercial, Municipal, and Research Open Burning as it relates to this project. FDER-30

31. Please quantify the nitrogen quantity in the soot blowing and purging process as outlined in the Air Separation Unit schematic of Figure 2-5, page 2-15 of Volume 4. FDER-31

32. The uncondensed gas (tail gas) is routed either to the tail gas treating unit or to the thermal oxidizer depending on the tail gas sulfur content. What is the determining sulfur content and what is the maximum load (cfm) of tail gas that the thermal oxidizer can treat. Also, what is the efficiency of the thermal oxidizers for both the tail gas treating unit and the sulfuric acid plant? FDER-32

33. The emission information provided for the IGCC, CC and the Simple Cycle combustion turbines different load conditions and ambient temperatures are based on which measurement methods? Please identify any differences between the measurement methods employed and the EPA test methods. Also, provide stack test information and data for each pollutant tested, and fuel analysis data for the fuel burned during the test. FDER-33

34. Please provide more information on the flare, whether its steam assisted, air assisted or non-assisted. Also, submit the net heating value of the gas being combusted, the exit velocity of the flare and what device will be used to detect the presence of a flame. FDER-34

35. Explain the basis for the stack exit temperature to be higher for Simple Cycle and CC CTs when firing natural gas compared to fuel oil as shown in Tables 2-26 to 2-29, pages 2-73 to 2-76 of Volume 4. FDER-35

36. The hot gas clean up technology for the IGCC facility will improve overall efficiency as well as lower SO2 emissions in comparison to cold gas clean up controls as suggested by the applicant on page 4-3 of Volume 4. Table 2-8, page 2-53 of Volume 4 does not reflect lower SO2 emissions but a considerable increase in NOx emissions during the demonstration period. Please quantify the decrease in SO2 emissions as well as improvement in the overall efficiency in terms of increased power production. FDER-36

37. Table 4-24, page 4-58 of Volume 4 gives a cost effectiveness figure of $5643/ton for a Simple Cycle CT with Oxidation catalyst. Please explain the steps in arriving at this figure. FDER-37

38. In Appendix A.2 of Volume 4 which deals with particulate matter emissions from coal handling sources, the moisture content of the coal was assumed to be 15%. AP-42, Section 11.2.3 suggests a mean moisture content for the coal to be 4.5%. Please explain the deviation from this value. FDER-38

39. Please re-submit the State permit application to FDER-39

operate/construct air pollution sources with all the items completely filled. The application included in Volume 5 has not been completely filled out and makes references to different sections of the Site Certification Application.

40. The 49.5 MMBtu/hr auxiliary boiler is not exempt from the permitting requirements unless it is fired exclusively by natural gas based on 17-2.210(3)(a). Please submit a state permit application for the auxiliary boiler. FDER-40

41. The projected Maximum Individual Risk (MIR) is estimated to be 1.9 x 10-6 for the project. Please state how many people in the shaded area as shown in Figure 7-7, page 7-52 of Volume 4 are exposed to levels greater than 1.0 x 10-6. FDER-41

42. Natural gas would be preferred to No. 2 fuel oil as a backup fuel for the GE 7F combustion turbine when syngas is not available. Please explain the choice of No. 2 fuel oil for backup. It appears that natural gas can be made available to the site since Tampa Electric proposed the use of natural gas in other sources. FDER-42

43. Please describe the ultimate fate of all the mercury entering the IGCC. For example, for every 100 pounds of mercury entering the IGCC, please describe where all of it will end up, assuming the worst case emissions to the atmosphere. The total amount of mercury accounted for must add up to 100 pounds for every 100 pounds of mercury entering the IGCC. FDER-43

44. Would NOx emissions be improved by combining conventional water injection with the proposed advanced dry low NOx burners? If not, then why not? If so, then please evaluate this option as an addendum to the proposed BACT analysis. FDER-44

45. What chemical additives will be added to the coal slurry to adjust viscosity and pH? What will be the maximum quantity of chemical additives utilized, and the ultimate fate of the chemical additives? FDER-45

46. Please provide some quantitative technical test data which demonstrates the effect on NOx emissions of various rates of pure nitrogen injection into combustion turbines. FDER-46

<u>WATER FACILITIES (Industrial Waste)</u>

47. The proposed surface water monitoring plan for the effluent at Outfall 001 is not acceptable. A compete analyses of the wastewater in the cooling reservoir for the Primary and Secondary Drinking Water parameters and the following additional parameters must be submitted: BOD_5, Total Organic Carbon (TOC), total nitrogen, organic nitrogen, ammonia nitrogen, total phosphorus, ortho-phosphate, and dissolved oxygen. FDER-47

48. Run-off from the fuel oil storage, switch yard and CT/CC areas will be treated through an oil/water separator. Please provide more details in regard to efficiency of the proposed system. Please evaluate the alternative to connect the effluent from the system to the IWT for additional treatment of the effluent. FDER-48

49. Be advised that for <u>new</u> facilities, the Department does not usually approve discharges with a thermal mixing zone unless there is no feasible technology to reduce thermal loads. This issue must be addressed in considerable detail in order for any mixing zone to be granted for this facility. FDER-49

50. In order to properly evaluate the impact of the discharge on surface waters, a Plan of Study to develop Water Quality Based Effluent Limitations (WQBEL's) is required per Section 17-650.400, F.A.C. a detailed WQBEL Plan of Study (POS) should be submitted to the Department for review and approval prior to implementation. FDER-50

51. Surface water impacts must be evaluated as well by a 96-hour static acute screening toxicity bioassay test. All test species, procedures and quality assurance criteria used shall be in accordance with Method for Measuring the Acute Toxicity of Effluent to Freshwater and Marine Organism EPA-600/4-85-013. The recommended species are: Ceriodaphnia dupia and Notropis leedsi. FDER-51

52. The applicant shall complete the antidegradation permitting requirements as specified in Rule 17-4.242, F.A.C. FDER-52

53. Please provide the location and type of outfall control structure for discharges from the lake reservoir to the Little Payne Creek drainage system. What is the expected flow rate? Be advised that if the lake reservoir is not considered jurisdictional water body, the compliance outfall structure or POD must be constructed at the lake reservoir. FDER-53

54. Please provide in detail the filtration system design. FDER-54

55. Please explain in what stage of the IWT treatment process the volatile organics (VOC) will be removed. FDER-55

56. Where in the design of the wastewater treatment system has the removal of trihalomethanes, originated by chlorination been addressed? In what stage of the treatment are they removed? FDER-56

57. Please provide the concentrations of the various contaminants expected in the process wastewater streams listed in Table 3.5.4-2 and, the basis for flow estimates included in the table. FDER-57

58. Please provide estimates of the level of treatment expected from each of the industrial wastewater treatment units described in Section 3.5.4.4 of the SCA for the wastestreams listed in comment 1 above. FDER-58

59. Please provide the basis for the projected precipitation and evaporation volumes indicated in Figure 3.5.0-1 of the SCA. FDER-59

60. On page 2.3.4-15, it is stated that no flow data can be provided for Stations SW-6 and SW-7, as these stations are located in an area of reclaimed lakes and mine cuts. The proposed discharge of 3.1 to 9.05 MGD from the plant reservoir is planned to be at Station SW-6. If flow data cannot be provided to demonstrate that dilution waters will be available at time S. of discharge, then all water quality standards must be met at the point of discharge. FDER-60

61. Based on the characterization of the ground water from the Floridan and the hardness of samples taken from Station SW-6, it is not necessarily evident that a discharge from the cooling pond would comply with current surface water quality standards. Please provide complete characterization of the anticipated quality of the cooling pond discharge and the hardness of the cooling pond discharge. Compare the quality of the effluent against all applicable surface water standards, taking into consideration the hardness factor and whether or not the receiving stream will be effluent dominated under all conditions. FDER-61

62. With regard to the discussion in Section 3.5 of the application, explain why the use of groundwater at the site can't be reduced or eliminated. Explain why in all cases water can't be withdrawn from the cooling pond, treated, and used to replace ground water. This treatment would help reduce the build-up of trace metals in the cooling pond, thereby reducing the need to discharge from the pond. Accumulated brine reject from the reverse osmosis plant can be dried and disposed of off-site. FDER-62

(Domestic Waste)

63. Please complete DER Form 17-600.910(1) for the domestic wastewater facility. FDER-63

(Potable Water)

64. The applicant must submit a complete and fully executed potable water application [D.E.R. Form 17-555.910(1)] pursuant to the requirements of F.A.C. Rule 17-555.520(1); FDER-64

65. Well driller's well completion report for FDER-65

construction of each well to be approved as a potable water supply source pursuant to F.A.C. Rules 17-555.500 and 17-555.520(1), (3),

66. Analysis of the raw water from each well to be approved as a potable water supply source for primary inorganices, primary volatile organices, turbidity, radionuclides, and unregulated organic contaminants pursuant to F.A.C. Rules 17-555.500, 17-555.520(1), (3), and (4), and .530(1)(a); FDER-66

67. Engineering construction drawings which include well head detail, raw water transmission line(s), treatment elements, storage facilities, and finished water transmission lines pursuant to F.A.C. Rule 17-555.520(4)(c); FDER-67

68. Site plan showing all proposed and existing features within a complete two hundred (200) foot radius of each potable supply well in order to demonstrate compliance with F.A.C. Rule 17-555.312 pursuant to F.A.C. Rules 17-555.500, .520, and .530; FDER-68

69. Complete specifications of the potable water system for material and workmanship pursuant to F.A.C. Rule 17-555.520(3) and (4)(d); and FDER-69

70. Documentation that a minimum free chlorine residual of 0.2 milligrams per liter or its equivalent will be maintained throughout the distribution system at all times pursuant to the requirements of F.A.C. Rule 17-555.530(1)(b) instead of the residual chlorine concentration of 0.1 ppm referenced in the site certification application on Page 3.5.3-1. FDER-70

(Ground Water)

71. <u>11.7.5-Sinkhole Evaluation Report</u> FDER-71

This report is descriptive and comprehensive at the scale used in the study. However, site specific geotechnical investigation in the cooling water reservoir footprint was limited to a single boring, GW-2. Information on file at the District office indicates the presence of several lineaments within the Baird quadrangle. Specifically in Sections 1, 2, 3, 11, and 12; Township 32S; R23E. These sections are within or are directly adjoining the cooling water reservoir boundary. Site specific investigation is necessary within and around the cooling water reservoir in order to provide reasonable assurance that this reservoir will not induce or increase sinkhole potential or other such structural failure.

72. <u>11.7.8-Ground Water Monitoring Plan:</u> FDER-72

A. Monitored Parameters: The monitor wells shall be sampled and analyzed in accordance with Chapter 17-160, F.A.C.

The proposed parameters are not adequate due to the various effluent streams that are to be diluted and mixed within the cooling water reservoir. The required parameters, for quarterly sampling, shall include the Primary Drinking Water Standards, Fecal Coliform Bacteria, Vanadium, Beryllium, pH, Ra-226, Radium-228, Gross Alpha, Total Dissolved Solids, Turbidity, Copper, Chloride, and Sulfate, Fluoride, Iron Manganese, Specific Conductivity, Water Level, Temperature, Polyaromatic Hydrocarbons, Oil and Grease, and Tars. Temperature, Specific Conductivity, pH and water levels measurements shall be performed in the field during sampling activities.

Initial sampling of all monitor wells shall occur within 60 days of monitor well completion. Initial sampling of the monitor wells shall consist of the sampling of all ground water monitor wells for the Primary and Secondary Drinking Water parameters included in Chapter 17-550, F.A.C., Fecal Coliform Bacteria, EPA Method 608 to include the parameters included in the above paragraph. Thereafter this condition will be required every 5 years.

B. Monitor Locations: The proposed monitor well locations and construction design are acceptable for the monitoring of the unconfined aquifers, however, the intermediate and upper Floridan aquifer should also be monitored. Additional wells and well construction design should be proposed for the monitoring of the intermediate and upper Floridan aquifers.

All monitor wells must be constructed in accordance with plans on file in the southwest District office within 60 days of SCA approval. The wells shall be surveyed within 60 days of construction and shall be horizontally located by metes and bounds or equivalent surveying techniques.

Monitor well completion data shall be submitted within 30 days of construction, of each well, and shall include the following:

a. The completed FDER MONITOR WELL COMPLETION REPORT,

b. A copy of the Southwest Florida Water Management District (SWFWMD) APPLICATION TO CONSTRUCT, REPAIR, MODIFY OR ABANDON WELL (Form SF 306(3) REV. 4/90.), and

c. A copy of the SWFWMD WELL COMPLETION FORM (SF 25-18-5/83)

C. Monitoring Frequency: The monitoring frequency shall be quarterly and once every 5 years as described above.

73. TECO states that a 3.1 MGD discharge is required to prevent trace metals, solids and other potential constituents from accumulating in the cooling reservoir (Section 3.5.1-4). Please explain what "trace metals, solids and other potential constituents: are expected, and in what concentrations. FDER-73

74. Why does TECO need a Reverse Osmosis (R/O) unit for the facility, and does the concentrate from this R/O unit have anything to do with the accumulation of the above referenced "trace metals, solids, and other potential constituents" in the cooling reservoir? FDER-74

75. Please explain what the "Reclaimed lake" is, and whether or not it is currently considered "waters of the State". FDER-75

76. Will the thermal mixing zone encompass only the "Reclaimed Lake" or will it extend out into Little Payne Creek? FDER-76

77. In Section 5.2.3 TECO alluded to the possible use of biocides other than chlorine gas. What biocides other than chlorine gas might be used for cooling system protections? FDER-77

78. Please be advised that small creeks like Little Payne Creek normally have periods of "low flow" during the dry season. The biota in such systems are specifically adapted to seasonal fluctuations in water levels and velocities. Any constant discharge flow from the Polk Power facility would be disruptive to the natural wet/dry cycle of Little Payne Creek and its associated biota. Therefore, a continuous daily discharge of 3.1 MGD of effluent to Little Payne Creek is unacceptable. Furthermore, this discharge does not appear to be an optimum use of a valuable water resource. FDER-78

In Section 8.3.6-2 you stated that "a no discharge alternative" via berm up-sizing was possible but not pursued because of the difficulty in determining a design to contain all foreseen and unforeseen situations. Given the above comment, has TECO considered a berm design to contain only foreseen situations up to and including a 25-year, 24-hour storm event? If not, then please do so now.

79. According to Section 3.5.4-16, the IWT system will adjust process wastewater and contaminated stormwater to a pH range of 6.0 to 9.0, prior to discharge to the cooling reservoir. FDER-79

The pH range allowable by F.A.C. Rule 17-302.560(21) is from 6.0 to 8.5 units for discharges to predominantly fresh waters. Considering the fact the TECO does propose a surface water discharge to Little Payne Creek from the cooling reservoir, it would be advisable that the pH range of any water entering the cooling reservoir fall within the 6.0-8.5 range.

80. 11.7.6 and 11.7.7 - Ground Water Flow Modeling FDER-80

Please submit on 3.5 inch disks the data sets used to run each of the final MODFLOW simulations.

Waste Management

81. The desulfurization process will use and reclaim zinc titanate and form zinc sulfate. Are any of the by-products of this process considered hazardous at any stage of this process? Can upsets in this process cause a change in the chemical process allowing the formation of undesirable substances (see p. 3.1.1-29)? Will any of these products or waste be exposed to a situation where they would end up in wastewater or leach into groundwater? (Such as during cleaning of the system). What is the pH in this process? FDER-81

82. The Industrial Wastewater Treatment System (p. 3.1.4-4) will not be permitted to handle hazardous substances. When you refer to wastewater produced from chemical cleaning being trucked offsite "by a licensed contractor" do you mean a firm licensed to transport hazardous waste? What firm now does this at your other facilities? Does TECO do any of its own transporting and manifesting of hazardous waste? FDER-82

83. The reservoirs (i.e., 3.1.4.5) will require massive soil placement and compaction. What thickness lifts will be used during soil placement? What will be the required compaction? An example of the specification for the above would be a maximum of 10 inch lift thickness and 95% Modified Proctor density minimum. Will the basin be lined with a synthetic liner? If any existing phosphate facilities are used, please supply the QA/QC documents from their construction. Also supply lift thickness used in construction and density specifications. FDER-83

84. The slag storage area and stormwater run-off collection basin "will be lined with a synthetic material or other materials with similar low permeability characteristics". Please specify what is meant by "other material" on the top of page 3.1.4-8. FDER-84

85. What is the expected pH of the stormwater run-off from the concrete-lined sulfur storage area which will be routed to the IWT (p.3.1.4-8)? Also, that of the sulfuric acid storage area (p.3.1.4-9). Are these acceptable discharges under your NPDES? FDER-85

86. The stormwater management basins (p.3.1.4-10) are designed to handle only the first inch of run-off from the 25 year, 24 your storm event. Why only one inch and why is the 25 year storm event used and not the 100 year storm? The 25 year storm is repeatedly referred to, but isn't the 100 year storm FDER-86

typical engineering design criteria? See also p.3.3.1-7.

87. On p. 3.4.3-15, it refers to a description of SCR in appendix 11.1.3. I can not find this appendix as my book jumps from 9.5 in Vol. 4 to 11.2 in Vol. 5. FDER-87

88. What catalyst is used in SCR? I could not find chemical reaction in the SCA or SCR. FDER-88

89. The ammonia compounds and arsenic trioxide on pp. 3.4.3-16 to 3.4.3-17 are hazardous substances. What will be the methods of collection and disposal? FDER-89

90. You refer to vanadium pentoxide on the top of p. 3.4.3-18. What is your proposed method of disposal? If you propose speculative accumulation, please state a source you will sell this to and a schedule for use and recycling. RCRA has a specific timetable for storage for speculative accumulation. If you dispose of it, please state the firm you will have do it. FDER-90

91. Any cleaning of the systems that will use SCR will result in waste requiring hazardous material disposal. Please inform us of the firm you intend to use for disposal and the quantities of hazardous waste that will be generated in addition to all hazardous constituents. Will heavy metals be present? FDER-91

92. On p. 3.6.2-4, it states the cleaning solution waste will be "collected and transported offsite for appropriate treatment and disposal:. Who do you intend to use and what firm now does this at your other facilities? FDER-92

93. In paragraph 3.7.1.3, if refers to a brine disposal area. Is this lined with a synthetic liner? Is the liner system to be made consistent with RCRA hazardous waste regulations? What do they mean by a "temporary cover" (middle of the page)? A number of the trace elements listed are hazardous substances. It appears the brine will be RCRA regulated substance. Please respond. FDER-93

94. On the top of page 3.7.1-6, it refers to the EP Toxic test. This should be TCLP. In para. 3.7.2.1 the same mistake is made. This could change the results. FDER-94

95. In paragraph 3.7.1.8, it refers to reclamation of zinc oxide and titanium dioxide and disposal of zinc sulfide and titanium dioxide in a landfill. What other substances may be present in the materials to be disposed (specifically referring to RCRA regulated). Why are not both the sorbent fines and cyclone solids being reclaimed? FDER-95

96. TCLP should be performed on the brick described in para. 3.7.2.2. FDER-96

97. In para. 3.7.2.3, it refers to a catalyst. What is the catalyst? FDER-97

98. In para. 3.7.2.4, it refers to treating catalysts. Disposal in a landfill may be inappropriate. RCRA speculative accumulation regulations apply. Please respond. FDER-98

99. Provide a contingency plan with blanks in the places where names should be, if necessary. The current plan in the documents is not complete. All personnel must be able to reach the site within a shout period of time (i.e., 15 min. or less). FDER-99

Point Source Evaluation

100. TECO should provide an estimate for the 7Q10 low flow for Little Payne Creek. FDER-100

101. The data summary table for the monitoring program should list the applicable method detection limits (MDLs). TECO incorrectly set all values measured below the applicable MDL at zero. Values measured below the MDL should only be set at zero if all of the values for that parameter are below the MDL. A value of the one half of the MDL should be used in cases where the individual value is below the MDL, but other samples for that parameter are above detection. FDER-101

102. In their discussion of the monitoring data, TECO acknowledges that several samples did not meet applicable criteria for lead, silver, radium, and un-ionized ammonia. TECO should address why they believe the cooling reservoir will meet water quality criteria for these parameters when the existing "ambient" water quality does not. FDER-102

103. TECO should provide a more detailed characterization of all inputs to the cooling reservoir (Table 3.5.1-1), and should address how they derived each characterization. At a minimum, the characterization for the RO concentrate should include the metals listed in the table, combined radium, and gross alpha. The characterization of the domestic wastewater should include nutrients (ammonia nitrogen, nitrate plus nitrite nitrogen, organic nitrogen,and total phosphorus) and carbonaceous biochemical oxygen demand (CBOD). FDER-103

104. TECO should provide background information on the thermal model used to evaluate temperature effects of the project, and should provide text describing how model inputs (wind speed, cloud cover, radiation,and heat exchange coefficients) were determined. TECO should also provide model results of an existing reservoir in the area (the mine cuts or the reclaimed lake) and compare model results to measured temperatures(i.e. calibrate the model). FDER-104

105. Similarly, TECO should provide background information on the mixing zone modeling they conducted. TECO only provided the results of the mixing zone analysis. They should describe the calculations performed and all model inputs. FDER-105

106. The frequency of the proposed measurement program should be expanded to include daily monitoring of effluent flow and temperature. The parameter coverage will also need to be expanded, but specific parameter coverage will be dependent on the projected reservoir quality. Additional parameters would likely include nutrients, CBOD, and all metals near applicable water quality criteria. FDER-106

107. Given our previously stated concerns over this continuous discharge to a low flow creek, we were also concerned withe the brevity of the cooling reservoir discharge alternatives discussed in Chapter 8.3.6. No cost estimates were provided for the proposed alternatives, and no intermediate volume discharge alternatives were discussed. FDER-107

Wetland Resource

108. Please provide a time estimate on when a corridor for the natural gas pipeline might be proposed. FDER-108

109. Please clarify how dependent the proposed plant will be on receiving fuel oil from the proposed GATX pipeline. FDER-109

110. Please provide a set of good quality, recent 1:400 aerial photographs of the proposed transmission line corridor. The photographs should be labeled with the flight date, north arrow, and the corridor boundaries. FDER-110

111. Please provide justification for not proposing restrictive clearing for transmission line crossings in forested wetland areas. FDER-111

112. Please discuss the possibility of incorporating the following practices into the construction of transmission line access roads in wetlands: FDER-112

a. hauling in any required fill;
b. using temporary matting for access in the wetland;
c. constructing stabilized at-grade roads rather than fill roads.

113. The narrative stated that the only structures to be guyed would be the dead-end structures. Please clarify the need for a 75′ by 150′ filled maintenance pad at the structures in wetlands. FDER-113

114. Please discuss the use of alternate ROW maintenance FDER-114

techniques other than mowing and herbicide in the wetland areas crossed by the transmission line ROW.

115. Please provide a blue-line map showing the previously approved reclamation plan for the site and a copy of the document upon which the map is based. This information has been requested several times and is necessary to determine what the extent of the Department's Wetland Resource jurisdiction would have been on the site. FDER-115

116. Please provide a schedule for the restoration of wetlands required under DER permits for the site. FDER-116

If your have any questions please contact me at (904) 487-0472.

Sincerely,

Steven Palmer P.E.
Siting Coordination Office

SP/ah

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: Hamilton S. Oven
From: Max Linn MAL
Date: September 20, 1992
Subj: Sufficiency Comments on the Proposed TECO Polk Power Station (AIR QUALITY)

FDER-1 1. The applicant needs to supply the input and output files for the Bowman GEP program runs that were performed to determine the downwash parameters for the ISCST2 and ISCLT2 modeling runs.

FDER-2 2. Stack parameters and the emission rates for the various pollutants modeled need to be supplied for Source 14 (Flare).

FDER-3 3. Source 13 (Tail Gas Treating Unit Thermal Oxidizer) has a sulfur dioxide emission rate of 6.56 g/s in Table 2-4, but was modeled with an emission rate of 8.2 g/s. Which of these values is correct?

FDER-4 4. The carbon monoxide emission rates for IGCC Fugitive Sources 42 and 43 in Table 2-30 are listed as 0.0001 g/s (.1E-3 g/s), but these sources were modeled with an emission rate of .001 g/s (.1E-2). What is the correct emission rate for these sources?

FDER-5 5. AAQS Modeling for Sulfur Dioxide

a. Identify sources 101a and 101b.
b. Source 121n has a tabled emission rate of 87.00 g/s, but 42.87 g/s was modeled. Which of these values is correct?
c. Source 126h has a tabled stack height of 63.1 m, but was modeled at 67.1 m. Which of these values is correct?
d. Source 126g has a tabled stack exit velocity of 7.88 m/s, but 7.28 m/s was modeled. Which of these values is correct?
e. Source 127j has a tabled emission rate of 45.72 g/s, but was modeled at 41.96 g/s. Which of these values is correct?
f. Source 131i has a tabled exit temperature of 319 K, but was modeled at 314 K. Which of these values is correct?
g. Source 134a has a tabled emission rate of 25.40 g/s, but was modeled at 6.43 g/s. Which of these values is correct?
h. Sources 167 a and b have tabled exit temperatures of 441.3K and 449.7 K, respectively, but were modeled as a combined source with an exit temperature of 466.0 K. Please justify the modeled value.

FDER-6 6. AAQS Modeling for Nitrogen Oxides

a. The TECO CT's in simple cycle mode have a tabled emission rate of 4.87 g/s (Table 2-25), but were modeled at 4.74 g/s. Which of these values is correct?

b. The TECO CT's in combined cycle mode have a tabled emission rate of 9.42 g/s (Table 2-25), but were modeled at 9.07 g/s. Which of these values is correct? Note: The higher emission rates were used in the significant impact area analysis.

c. Source 100d was in the emission inventory, but was not modeled. Please explain.

d. Source 118g has a tabled stack diameter of 5.79 m, but was modeled at 1.83 m. Which of these values is correct?

e. Source 136a was in the emission inventory, but was not modeled. Please explain.

FDER-7 7. AAQS Modeling for Particulate Matter

a. Source 26's Y coordinate is out of the output range. It should be 3067366.0. Please explain why it is out of range.

b. Source 112a has a tabled emission rate of 1089.3 g/s, but was modeled at 89.3 g/s. Which value is correct?

c. Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which value is correct?

FDER-8 8. PSD Class I and II Modeling for Sulfur Dioxide

a. IMC Lonesome Mine Dry #1 and #2 were not modeled. Please explain this omission.

b. McKay Bay Refuse to Energy was not modeled. Please explain this omission.

c. Source 125 h has a tabled stack height of 38.35 m, but was modeled at 28.35 m. Which of these values is correct?

d. The applicant needs to justify the use of all negative (increment expanding) emissions used in the modeling.

FDER-9 9. PSD Class I and II Modeling for Nitrogen Oxides

a. Sources 6 through 11 were modeled with an emission rate of 4.74 g/s, but for the SIA they were modeled at 4.87 g/s (Table 2-25). Which of these values is correct for the increment modeling?

b. The nitrogen oxides emission inventory provided by the applicant includes the following sources: 113i, 113j, 129h, 129i, 148a, 151a, and 157b. None of these sources were included in the increment modeling. Please explain this omission.

FDER-10 10. PSD Class I and II Modeling for Particulate Matter

a. Source 26 has a Y coordinate that is out of the models output range. Please explain why.

b. Source 109d has a tabled emission rate of 13.26 g/s, but was modeled at 6.45 g/s. Which of these values is correct?

c. Source 125m has a tabled emission rate of 25.07 g/s, but was modeled at 12.61 g/s. Which of these values is correct?

d. Source 128f has a tabled emission rate of 4.22 g/s, but was modeled at 5.04 g/s. Which of these values is correct?

e. Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which of these values is correct?

f. Source 130h has a tabled emission rate of 17.73 g/s, but was modeled at 4.92 g/s. Which of these values is correct?

FDER-11 11. The applicant needs to supply a copy of the inputs and output from their VISCREEN program run.

FDER-12 12. EPA Modeling Guidelines require that ISCLT modeling be performed on an annual basis. The applicant performed the annual modeling runs using a composite of five years. The applicant needs to explain why they deviated from the modeling guidelines.

FDER-13 13. Any additional sulfur dioxide modeling must include the proposed Florida Power Corporation's Polk County facility and the Kissimmee Utility Cane Island facility. The applicant must also contact the Department with regard to emission changes at Orlando Utility's Stanton facility and Florida Power Corporation's Intercession City facility. Furthermore, since the TECO Hardee Power Plant was certified for four units, four units must be modeled. In the application only three units were modeled.

FDER-14 14. Beryllium Modeling

a. Where did the short-term emission rate for Source 1b come from?

b. Sources 6 through 11 have a tabled short-term emission rate of .0004 g/s (100% load at 20 F), but were modeled at .0003 g/s. Which of these values is correct?

c. The output for the 24-hour modeling for 1984 is missing.

FDER-15 15. Chromium Modeling

a. Source 1b has a tabled emission rate of .0026 g/s, but was modeled at .000052 g/s. Which of these values is correct?

b. Sources 2b through 5b have tabled emission rates of .0035 g/s, but were modeled at .000018 g/s. Which of these values is correct?

c. Sources 6 through 11 have tabled emission rates of .0013 g/s, but were modeled at .000007 g/s. Which of these values is correct?

d. Source 13 has a tabled emission rate of .0132 g/s, but was modeled at .000264 g/s. Which of these values is correct?

e. Source 15 has a tabled emission rate of .0066 g/s, but was modeled at .000132 g/s. Which of these values is correct?

FDER-16 16. H2SO4 Modeling

Sources 7 through 11 were modeled with an emission rate of 0.6305 g/s (100% Load, 90 F). Should these sources have been modeled at 0.7566 g/s (100% Load, 20 F)?

FDER-17 17. Fl~~ou~~uoride Modeling

Sources 7 through 11 were modeled with an emission rate of 0.0037 g/s (100% Load, 90 F). Should these sources have been modeled at 0.0045 g/s (100% Load, 20 F)?

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

RECEIVED

OCT 12 1992

ENVIRONMENTAL PLANNING

TO: Buck Oven

THRU: Clair Fancy
Preston Lewis

FROM: Syed Arif SA

DATE: September 22, 1992

SUBJECT: TECO Polk Power Station - PA92-32, Mod 8042
PSD-FL-194

The Bureau of Air Regulation finds the above referenced application package insufficient. Based on our initial review of their proposal, we have determined that additional information is needed in order to process the application. The following information is required:

FDER-18 1. The emission calculations for the criteria and non-criteria pollutants are not adequately shown in the application. All calculations affecting emissions should be shown in their entirety, and not just summarized in tabular form. This includes showing the equations used, assumptions made and any supporting documents used for emission calculations.

FDER-19 2. Please provide a maximum value for fuel bound nitrogen for both natural gas and fuel oil. Also, calculate the maximum NOx emissions based upon your maximum value for fuel bound nitrogen for the Integrated Coal Gasification Combined Cycle (IGCC), Combined Cycle (CC) and the Simple Cycle combustion turbines.

FDER-20 3. Please submit a detailed process flow diagram for the IGCC unit showing the volumetric air flow rates for each stream when burning fuel oil and the different scenarios for syngas combustion. Also, submit the same for the CC, Simple Cycle and the auxiliary boiler when burning natural gas and fuel oil.

FDER-21 4. What is the efficiency of the combustion turbine for the IGCC, CC and the Simple Cycle units? Calculate Y (refer to NSPS 40 CFR 60, Subpart GG) in kilojoules per watt hour, showing all the calculations.

FDER-22 5. Submit manufacturer's name, model number, generator name plate rating (gross MW), maximum steam production rate for the Heat Recovery Steam Generator (HRSG) for the IGCC and the CC units.

FDER-23 6. What is the maximum and nominal power (MW) output of the steam turbine generator for the IGCC and the CC units? What is the steam input to these turbines?

FDER-24 7. Please submit the manufacturer's design specification for the proposed IGCC General Electric 7F combustion turbine (CT), GE 7EA CTs and also for the auxiliary boiler.

FDER-25 8. What is the estimated annual throughput and the type of air pollution control for the fuel oil storage tanks? What are the estimated emissions?

FDER-26 9. Please submit a detailed listing of all the continuous emission monitoring systems (CEMs) required for this project. This should include the type of the CEM (in-situ or extractive), the make and model number, the pollutant it will monitor, and any associated data acquisition system.

FDER-27 10. What kind of control and monitoring equipment is proposed for continuously recording power generation, coal feed rate, fuel injection rate of syngas, natural gas and fuel oil, nitrogen and the water injection rate for the IGCC unit.

FDER-28 11. Please provide the names and addresses of all the manufacturers and suppliers that were contacted for budgetary quotations and engineering estimates in developing capital and annualized cost estimates for this project. Also, provide a summary of all the equipment, raw material and the fuel costs.

FDER-29 12. Does the applicant propose to do simultaneous fuel (natural gas and fuel oil) firing for the CC and Simple Cycle units? If so, provide details on how this will be accomplished.

FDER-30 13. Please submit the information requested in Rule 17-256.600(3) regarding Industrial, Commercial, Municipal, and Research Open Burning as it relates to this project.

FDER-31 14. Please quantify the nitrogen quantity in the soot blowing and purging process as outlined in the Air Separation Unit schematic of Figure 2-5, page 2-15 of Volume 4.

FDER-32 15. The uncondensed gas (tail gas) is routed either to the tail gas treating unit or to the thermal oxidizer depending on the tail gas sulfur content. What is the determining sulfur content and what is the maximum load (cfm) of tail gas that the thermal oxidizer can treat. Also, what is the efficiency of the thermal oxidizers for both the tail gas treating unit and the sulfuric acid plant?

FDER-33 16. The emission information provided for the IGCC, CC and the Simple Cycle combustion turbines different load conditions and ambient temperatures are based on which measurement methods? Please identify any differences between the measurement methods employed and the EPA test methods. Also, provide stack test information and data for each pollutant tested, and fuel analysis data for the fuel burned during the test.

FDER-34 17. Please provide more information on the flare, whether its steam assisted, air assisted or non-assisted. Also, submit the net heating value of the gas being combusted, the exit velocity of the flare and what device will be used to detect the presence of a flame.

FDER-35 18. Explain the basis for the stack exit temperature to be higher for Simple Cycle and CC CTs when firing natural gas compared to fuel oil as shown in Tables 2-26 to 2-29, pages 2-73 to 2-76 of Volume 4.

FDER-36 19. The hot gas clean up technology for the IGCC facility will improve overall efficiency as well as lower SO2 emissions in comparison to cold gas clean up controls as suggested by the applicant on page 4-3 of Volume 4. Table 2-8, page 2-53 of Volume 4 does not reflect lower SO2 emissions but a considerable increase in NOx emissions during the demonstration period. Please quantify the decrease in SO2 emissions as well as improvement in the overall efficiency in terms of increased power production.

FDER-37 20. Table 4-24, page 4-58 of Volume 4 gives a cost effectiveness figure of $5643/ton for a Simple Cycle CT with Oxidation catalyst. Please explain the steps in arriving at this figure.

FDER-38 21. In Appendix A.2 of Volume 4 which deals with particulate matter emissions from coal handling sources, the moisture content of the coal was assumed to be 15%. AP-42, Section 11.2.3 suggests a mean moisture content for the coal to be 4.5%. Please explain the deviation from this value.

FDER-39 22. Please re-submit the State permit application to operate/construct air pollution sources with all the items completely filled. The application included in Volume 5 has not been completely filled out and makes references to different sections of the Site Certification Application.

FDER-40 23. The 49.5 MMBtu/hr auxiliary boiler is not exempt from the permitting requirements unless it is fired exclusively by natural gas based on 17-2.210(3)(a). Please submit a state permit application for the auxiliary boiler.

FDER-41 24. The projected Maximum Individual Risk (MIR) is estimated to be 1.9 x 10-6 for the project. Please state how many people in the shaded area as shown in Figure 7-7, page 7-52 of Volume 4 are exposed to levels greater than 1.0 x 10-6.

SA:ch

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

RECEIVED

OCT 12 1992

ENVIRONMENTAL PLANNING

To: Steve Palmer, P.E.
Office of Siting Coordination, DER Tallahassee

From: Gary A. Maier, P.E., S.W. District Office G.M.

Date: September 25, 1992

Subject: TECO Site Certification Application

The Southwest District Office is pleased to submit the attached sufficiency review comments on the Tampa Electric Site Certification application. If we can provide any further information, please let me know. Please request Tampa Electric to submit 8 copies of its responses directly to the Southwest District.

Thank you for the opportunity to provide District input.

copies to: R. D. Garrity
J. H. Kerns w/o attachments
W. C. Thomas w/o attachments

Air Program

Please request Tampa Electric to submit responses to the following requests from the S.W. District Air Program.

FDER-42 1. Natural gas would be preferred to No. 2 fuel oil as a backup fuel for the GE 7F combustion turbine when syngas is not available. Please explain the choice of No. 2 fuel oil for backup. It appears that natural gas can be made available to the site since Tampa Electric proposed the use of natural gas in other sources.

FDER-43 2. Please describe the ultimate fate of all the mercury entering the IGCC. For example, for every 100 pounds of mercury entering the IGCC, please describe where all of it will end up, assuming the worst case emissions to the atmosphere. The total amount of mercury accounted for must add up to 100 pounds for every 100 pounds of mercury entering the IGCC.

FDER-44 3. Would NOx emissions be improved by combining conventional water injection with the proposed advanced dry low NOx burners? If not, then why not? If so, then please evaluate this option as an addendum to the proposed BACT analysis.

FDER-45 4. What chemical additives will be added to the coal slurry to adjust viscosity and pH? What will be the maximum quantity of chemical additives utilized, and the ultimate fate of the chemical additives?

FDER-46 5. Please provide some quantitative technical test data which demonstrates the effect on NOx emissions of various rates of pure nitrogen injection into combustion turbines.

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

RECEIVED
OCT 12 1992
ENVIRONMENTAL PLANNING

To: Hamilton S. Oven
From: Max Linn MYL
Date: September 16, 1992
Subj: Proposed TECO Polk Power Station's Class I Increment Violation

The applicant's modeling of sulfur dioxide in the Chassahowitzka National Wilderness Area indicates a violation of the 24-hour Class I increment. The modeling shows a predicted impact of 5.007 ug/m3, which is above the increment of 5 ug/m3. The TECO sources are significant contributors (0.395 ug/m3) to this violation.

Rule 17-2.500(1)(b), F.A.C. states: "Except as provided in Rule 17-2.500(3)(f) and (g), F.A.C., the Department shall not permit the construction or modification of any source or facility that would cause or contribute to an ambient concentration at any point within a baseline area that exceeds either the appropriate baseline concentration for the point plus the appropriate maximum allowable increase or the appropriate ambient air quality standard, whichever is less."

In conversations with Lew Nagler of EPA Region IV, the modeled impact of 5.007 ug/m3 was determined to be a violation of the increment. Consequently, the proposed sources cannot be permitted, as outlined in 17-2.500(1)(b), F.A.C., unless the applicant can get an exemption as defined in 17-2.500(3)(f) or (g).

TAMPA ELECTRIC COMPANY
POLK POWER STATION

Responses to Florida Department of
Environmental Regulation Sufficiency Comments

FDER--AIR

FDER-1

> The applicant needs to supply the input and output files for the Bowman GEP program runs that were performed to determine the downwash parameters for the ISCST2 and ISCLT2 modeling runs.

Response

The input and output files for the Bowman Good Engineering Practice (GEP) program runs were included on diskettes previously given to Florida Department of Environmental Regulation (FDER) with the Site Certification Application (SCA). Duplicate copies of these files in both computer printout and diskette formats are being submitted to FDER in conjunction with the updated Industrial Source Complex (ISC) and MESOPUFF files.

FDER-2

> Stack parameters and the emission rates for the various pollutants modeled need to be supplied for Source 14 (Flare).

Response

Nominal flare stack parameters used for modeling purposes were:

Stack height = 75 feet (ft) (22.9 meters [m]);

Stack exit temperature = 1,340 degrees Fahrenheit (°F) (1,000 Kelvin [K]);

Stack exit velocity = 65 feet per second (ft/sec) (20 meters per second [m/sec]); and

Stack diameter = 5 ft (1.5 m).

Nominal emission rates of 0.01 grams per second (g/sec) were used for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO) modeling, based on the fact that normal flare operations will involve only the pilot flame (see Section 2.2.1, Page 2-58 of the Prevention of Significant Deterioration (PSD) application, Appendix 11.1.3 of the SCA).

FDER-3

> Source 13 (Tail Gas Treating Unit Thermal Oxidizer) has a sulfur dioxide emission rate of 6.56 g/s in Table 2-4, but was modeled with an emission rate of 8.2 g/s. Which of these values is correct?

Response

The emission parameters for the tail gas treating unit (TGTU) thermal oxidizer were provided in Table 2-14, not Table 2-4, of the PSD permit application in Appendix 11.1.3 of the SCA. The larger emission rate of 8.2 g/sec, which was used in all modeling, was based on design information that was subsequently changed. The design change resulted in a lower rate of 6.56 g/sec, which was indicated in Table 2-14 of the SCA. The new design rate of 6.56 g/sec has been used in the updated ISC and MESOPUFF modeling analyses.

FDER-4

> The carbon monoxide emission rates for IGCC Fugitive Sources 42 and 43 in Table 2-30 are listed as 0.0001 g/s (.1E-3 g/s), but these sources were modeled with an emission rate of .001 g/s (.1E-2). What is the correct emission rate for these sources?

Response

The values given in Table 2-30 of the SCA (i.e., 0.0001 g/sec) are correct. The modeled emission rates of 0.001 g/sec were in error. The use of the larger values for modeling purposes was therefore conservative. Based on discussions with FDER staff, no additional modeling for CO is considered necessary since expected impacts due to emissions of CO from the Polk Power Station are well below significance levels.

FDER-5 AAQS Modeling for Sulfur Dioxide

FDER-5.a

Identify sources 101a and 101b.

Response

Sources 101a and 101b are duplicates of Sources 167a and 167b. Sources 101a and 101b have been eliminated from the emission tables and the model inputs in the updated ISC and MESOPUFF modeling analyses.

FDER-5.b

Source 121n has a tabled emission rate of 87.00 g/s, but 42.87 g/s was modeled. Which of these values is correct?

Response

The correct emission rate for Source 121n is 42.87 g/sec, which was modeled. The emission inventory table in Appendix B.1 of the PSD permit application in the SCA has been corrected accordingly, and a replacement table, Appendix B.1, Rev. 1, 11/25/92, is provided with this submission.

FDER-5.c

Source 126h has a tabled stack height of 63.1 m, but was modeled at 67.1 m. Which of these values is correct?

Response

The correct stack height for Source 126h is 67.1 m, which was modeled. The table has been corrected accordingly, and a replacement table, Appendix B.1, Rev. 1, 11/25/92, is provided with this submission.

FDER-5.d

Source 126g has a tabled stack exit velocity of 7.88 m/s, but 7.28 m/s was modeled. Which of these values is correct?

Response

The correct stack exit velocity for Source 126g is 7.28 m/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.1, Rev. 1, 11/25/92.

FDER-5.e

> Source 127j has a tabled emission rate of 45.72 g/s, but was modeled at 41.96 g/s. Which of these values is correct?

Response

The correct emission rate for Source 127j is 45.72 g/sec in the emission inventory table. The model input has been corrected accordingly in the updated ISC and MESOPUFF modeling analyses.

FDER-5.f

> Source 131i has a tabled exit temperature of 319 K, but was modeled at 314 K. Which of these values is correct?

Response

The correct exit temperature for Source 131i is 314.0 K, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.1, Rev. 1, 11/25/92.

FDER-5.g

> Source 134a has a tabled emission rate of 25.40 g/s, but was modeled at 6.43 g/s. Which of these values is correct?

Response

SO_2 emissions from Source 134a, the Auburndale cogeneration facility, were originally based on a fuel oil sulfur content of 0.2 percent in the facility's PSD permit application. The application was subsequently amended to reflect 0.05 percent sulfur (S) fuel oil. The modeled value of 6.43 g/sec is correct based on the amended application, and the table has been corrected accordingly in the replacement table, Appendix B.1, Rev. 1, 11/25/92.

FDER-5.h

> Sources 167 a and b have tabled exit temperatures of 441.3k and 449.7 K, respectively, but were modeled as a combined source with an exit temperature of 466.0 K. Please justify the modeled value.

<u>Response</u>

Sources 167a and 167b are tabled correctly. The model input has been corrected to include these two sources separately in the updated ISC and MESOPUFF modeling analyses.

FDER-6 AAQS Modeling for Nitrogen Oxides

FDER-6.a

> The TECO CT's in simple cycle mode have a tabled emission rate of 4.87 g/s (Table 2-25), but were modeled at 4.74 g/s. Which of these values is correct?

<u>Response</u>

The tabled emission rate of 4.87 g/sec is correct. The model input has been corrected accordingly in the updated ISC modeling analyses.

FDER-6.b

> The TECO CT's in combined cycle mode have a tabled emission rate of 9.42 g/s (Table 2-25), but were modeled at 9.07 g/s. Which of these values is correct? Note: The higher emission rates were used in the significant impact area analysis.

<u>Response</u>

The tabled emission rate of 9.42 g/sec is correct. The model input has been corrected accordingly in the updated ISC modeling analyses.

FDER-6.c

> Source 100d was in the emission inventory, but was not modeled. Please explain.

Response

Source 100d was mistakenly included in the emission inventory and has been removed.

FDER-6.d

> Source 118g has a tabled stack diameter of 5.79 m, but was modeled at 1.83 m. Which of these values is correct?

Response

The tabled stack diameter of 5.79 m is correct. The model input has been corrected accordingly in the updated ISC modeling analyses.

FDER-6.e

> Source 136a was in the emission inventory, but was not modeled. Please explain.

Response

Source 136a was inadvertently omitted from the model input. The source has been added to the input in the updated ISC modeling analyses.

FDER-7 AAQS Modeling for Particulate Matter

FDER-7.a

> Source 26's Y coordinate is out of the output range. It should be 3067366.0. Please explain why it is out of range.

Response

Source 26's Y coordinate was entered incorrectly into the long-term model input. The error has been corrected in the updated ISC modeling analyses.

FDER-7.b

Source 112a has a tabled emission rate of 1089.3 g/s, but was modeled at 89.3 g/s. Which value is correct?

Response

The correct emission rate for Source 112a is 1,089.3 g/sec in the table. The model input has been corrected accordingly in the updated ISC modeling analyses.

FDER-7.c

Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which value is correct?

Response

The correct emission rate for Source 128g is 3.92 g/sec, which was modeled. The table has been corrected accordingly in the replacement table Appendix B.7, Rev. 1, 11/25/92.

FDER-8 PSD Class I and II Modeling for Sulfur Dioxide

FDER-8.a

IMC Lonesome Mine Dry #1 and #2 were not modeled. Please explain this omission.

Response

As discussed on October 14, 1992, in a meeting with FDER staff (Max Linn and Cleve Holladay), it is appropriate and correct to have not included the IMC Fertilizer, Inc. (IMC), Lonesome Mine Dryer Nos. 1 and 2 since these facilities have been shut down.

FDER-8.b

McKay Bay Refuse to Energy was not modeled. Please explain this omission.

Response

The McKay Bay refuse to energy source should have been included in modeling analyses. This omission has been corrected in the updated ISC and MESOPUFF modeling analyses.

FDER-8.c

Source 125 h has a tabled stack height of 38.35 m, but was modeled at 28.35 m. Which of these values is correct?

Response

The correct stack height for Source 125h is 28.35 m, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.2, Rev. 1, 11/25/92.

FDER-8.d

The applicant needs to justify the use of all negative (increment expanding) emissions used in the modeling.

Response

The justification for all negative (increment expanding) emissions used in the updated ISC and MESOPUFF modeling is provided in Attachment FDER-A to these responses.

FDER-9 PSD Class I and II Modeling for Nitrogen Oxides

FDER-9.a

Sources 6 through 11 were modeled with an emission rate of 4.74 g/s, but for the SIA they were modeled at 4.87 g/s (Table 2-25). Which of these values is correct for the increment modeling?

Response

The correct emission rates for Sources 6 through 11 are 4.87 g/sec as in the table. The model input has been corrected accordingly in the updated ISC modeling analyses.

FDER-9.b

> The nitrogen oxides emission inventory provided by the applicant includes the following sources: 113i, 113j, 129h, 129i, 148a, 151a, and 157b. None of these sources were included in the increment modeling. Please explain this omission.

Response

Sources 113i, 113j, 129h, 129i, 148a, 151a, and 157b were inadvertently omitted from the model input. The modeling inputs have been corrected accordingly in the updated modeling analyses.

FDER-10 PSD Class I and II Modeling for Particulate Matter

FDER-10.a

> Source 26 has a Y coordinate that is out of the models output range. Please explain why.

Response

Source 26's Y coordinate was entered incorrectly into the long-term input. The error has been corrected in the updated ISC modeling analyses.

FDER-10.b

> Source 109d has a tabled emission rate of 13.26 g/s, but was modeled at 6.45 g/s. Which of these values is correct?

Response

The correct emission rate for Source 109d is 6.45 g/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.8, Rev. 1, 11/25/92, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-10.c

Source 125m has a tabled emission rate of 25.07 g/s, but was modeled at 12.61 g/s. Which of these values is correct?

Response

The correct emission rate for Source 125m is 12.61 g/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.8, Rev. 1, 11/25/92, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-10.d

Source 128f has a tabled emission rate of 4.22 g/s, but was modeled at 5.04 g/s. Which of these values is correct?

Response

The correct emission rate for Source 128f is 5.04 g/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.8, Rev. 1, 11/25/92, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-10.e

Source 128g has a tabled emission rate of 13.94 g/s, but was modeled at 3.92 g/s. Which of these values is correct?

Response

The correct emission rate for Source 128g is 3.92 g/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.8, Rev. 1, 11/25/92, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-10.f

Source 130h has a tabled emission rate of 17.73 g/s, but was modeled at 4.92 g/s. Which of these values is correct?

Response

The correct emission rate for Source 130h is 4.92 g/sec, which was modeled. The table has been corrected accordingly in the replacement table, Appendix B.8, Rev. 1, 11/25/92, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-11

The applicant needs to supply a copy of the inputs and output from their VISCREEN program run.

Response

A copy of the VISCREEN output file, which states all input assumptions and parameters, is provided to FDER under separate cover in conjunction with the sufficiency responses

FDER-12

EPA Modeling Guidelines require that ISCLT modeling be performed on an annual basis. The applicant performed the annual modeling runs using a composite of five years. The applicant needs to explain why they deviated from the modeling guidelines.

Response

Industrial Source Complex long-term (ISCLT) modeling on an annual basis has been completed for all parameters subject to long-term modeling, and the input and output files in both computer printout and diskette formats are being submitted to FDER under separate cover in conjunction with these sufficiency responses.

FDER-13

Any additional sulfur dioxide modeling must include the proposed Florida Power Corporation's Polk County facility and the Kissimmee Utility Cane Island facility. The applicant must also contact the Department with regard to emission changes at Orlando Utility's Stanton facility and Florida Power Corporation's Intercession City facility. Furthermore, since the TECO Hardee power Plant was certified for four units, four units must be modeled. In the application only three units were modeled.

Response

Based on the responses to the preceding comments, it was considered necessary to update the modeling analyses for SO_2, NO_x, and particulate matter (PM). Revisions of appropriate sections in the SCA and Sections 7.3, 7.4, and 9.2.2 in the PSD permit application describe the results of this updated modeling. These revised sections are provided in the replacement package for insertion in the SCA.

The PSD application for the proposed Florida Power Corporation (FPC) Polk County facility was submitted to FDER after the application for the Tampa Electric Company Polk Power Station. FDER has historically treated PSD applications on a *first-come-first-served* basis. At the request of FDER, emissions from the FPC sources were included in the updated modeling studies, although inclusion of these sources is inconsistent with the first-come-first-served policy of PSD increment assignment.

The Kissimmee Utility Cane Island facility has been included in the Class I inventories for SO_2, NO_x, and PM. However, since this facility is located more than 75 kilometers (km) from the Polk Power Station site, it was not included in modeling associated with ambient air quality standards (AAQS) or PSD Class II increments. The emission changes for the Orlando Utilities Commission Stanton facility and FPC's Intercession City facility have similarly been included in the appropriate inventories for the ISC and MESOPUFF modeling analyses.

Finally, the updated modeling continues to include three units for Hardee Power Station, consistent with the approved PSD permit and conditions for the project.

FDER-14 Beryllium Modeling

FDER-14.a

Where did the short-term emission rate for Source 1B come from?

Response

The *annual* beryllium emission rate for Source 1b was shown on Table 2-8 in the PSD permit application (Appendix 11.1.3 of the SCA). For *short-term* modeling, the emission rate consistent with the 50-percent load, 90°F scenario (see Table 2-15 of the PSD permit application, Appendix 11.1.3 of the SCA) was selected since the screening analysis for PM showed this scenario to produce the highest impacts.

FDER-14.b

> Sources 6 through 11 have a table short-term emission rate of .0004 g/s (100% load at 20 F), but were modeled at .0003 g/s. Which of these values is correct?

Response

The screening analysis showed the PM impacts for these sources to be at the maximum at 75-percent load, 90°F. The beryllium emission rate of 0.0003 g/sec used for modeling was consistent with the maximum impact load scenario.

FDER-14.c

> The output for the 24-hour modeling for 1984 is missing.

Response

The missing output is being provided to FDER under separate cover in conjunction with these sufficiency responses.

FDER-15 Chromium Modeling

FDER-15.a

> Source 1b has a tabled emission rate of .0026 g/s, but was modeled at .000052 g/s. Which of these values is correct?

Response

As stated in Section 7.0 of the PSD permit application (Appendix 11.1.3 of the SCA), *hexavalent* chromium was calculated to be 0.5 percent of total chromium for oil-fired sources, 2 percent for syngas, and 2 percent for syngas combustion. The modeled emission rates reflected these percentages since modeling for chromium was done to address possible cancer risk.

FDER-15.b

Sources 2b through 5b have table emission rates of .0035 g/s, but were modeled at .000018 g/s. Which of these values is correct?

Response

See response to Comment No. FDER-15.a.

FDER-15.c

Sources 6 through 11 have table emission rates of .0013 g/s, but were modeled at .000007 g/s. Which of these values is correct?

Response

See response to Comment No. FDER-15.a.

FDER-15.d

Source 13 has a tabled emission rate of .0132 g/s, but was modeled at .000264 g/s. Which of these values is correct?

Response

See response to Comment No. FDER-15.a.

FDER-15.e

Source 15 has a tabled emission rate of .0066 g/s, but was modeled at .000132 g/s. Which of these values is correct?

Response

See response to Comment No. FDER-15.a.

FDER-16 H_2SO_4 Modeling

Sources 7 through 11 were modeled with an emission rate of 0.6305 g/s (100% Load, 90 F). Should these sources have been modeled at 0.7566 g/s (100% Load, 20 F)?

Response

The modeled emission rate was correctly selected to reflect the worst-case emission scenario determined in the screening analysis.

FDER-17 Fluoride Modeling

Sources 7 through 11 were modeled with an emission rate of 0.0037 g/s (100% Load, 90 F). Should these sources have been modeled at 0.0045 g/s (100% Load, 20 F)?

Response

See response to Comment No. FDER-16.

FDER-18

The emission calculations for the criteria and non-criteria pollutants are not adequately shown in the application. All calculations affecting emissions should be shown in their entirety, and not just summarized in tabular form. This includes showing the equations used, assumptions made and any supporting documents used for emission calculations.

Response

Emission rates of criteria and noncriteria pollutants are summarized in Tables 2-2 through 2-8 (7F combustion turbine [CT]), Table 2-13 (auxiliary boiler), Table 2-14 (TGTU thermal oxidizer), Table 2-15 (sulfuric acid [H_2SO_4] plant thermal oxidizer), Table 2-16 (coal handling sources), Table 2-17 (integrated coal gasification combined cycle [IGCC] process vent sources), Table 2-18 (IGCC process vent and fugitive hydrogen sulfide [H_2S] sources), Table 2-19 (IGCC process vent and fugitive ammonia [NH_3] sources), Table 2-20 (IGCC fugitive CO sources), and Tables 2-21 through 2-25 (7EA CTs) in Appendix 11.1.3 (PSD permit application) of the SCA. The basis for these emission estimates and supporting calculations are contained in

Appendix A of the PSD permit application. The following Table FDER-18.1 provides a cross-reference of emission rate tables and supporting calculations. A discussion of each emission rate table follows.

Table 2-2. 7F CT Firing No. 2 Fuel Oil

As noted on Page A-1 of Appendix A.1 of the PSD permit application in the SCA, emissions of total suspended particulate (TSP)/particulate matter less than or equal 10 micrometers aerodynamic diameter (PM_{10}), SO_2, NO_x, CO, volatile organic compounds (VOCs), and H_2SO_4 in terms of pounds per hour (lb/hr) were based on vendor (General Electric Company [GE]) data. Copies of GE specification data (Polk Power Station, Emissions Data For Air Modeling forms) for the 7F CT fired with No. 2 distillate fuel oil for the three loads and ambient temperatures indicated in Table 2-2 are provided in Attachment FDER-B. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126.

The SO_2 emission rate data provided by GE were based on a fuel oil sulfur content of 0.3 weight percent. Fuel oil proposed for the Polk Power Station project will contain no more than 0.05 weight percent S. The GE emissions data for SO_2 was therefore multiplied by a factor of 0.1667 (0.05 divided by 0.3) to develop SO_2 emission rates for the 0.05 weight percent S fuel oil. An example of an SO_2 emission rate calculation follows:

Operating Scenario: 75-percent unit load, 59°F ambient temperature; and

SO_2 Emission Rate: 421 lb/hr, based on 0.3 weight percent S.

$$SO_2 = (421\ lb/hr) \times (0.1667)$$
$$= 70\ lb/hr,\ based\ on\ 0.05\ weight\ percent\ S$$

The TSP/PM_{10} emission data shown in Table 2-2 of the PSD permit application reflect GE emissions data for PM with the addition of H_2SO_4 mist. H_2SO_4 emission rates are also shown on the GE specification data sheets. Similar to SO_2 emission rates, the GE H_2SO_4 emissions data, which were based on a fuel oil S content of 0.3

Table FDER-18.1. Cross-Reference of Emission Rate Tables and Emission Rate Basis

Emission Source	Emission Rate Table	Emission Rate Basis
7F CT	Table 2-2, Page 2-47	Appendix A.1, Page A-1
7F CT	Table 2-3, Page 2-48	Appendix A.1, Page A-1
7F CT	Table 2-4, Page 2-49	Appendix A.1, Page A-1
7F CT	Table 2-5, Page 2-50	Appendix A.1, Page A-2
7F CT	Table 2-6, Page 2-51	Appendix A.1, Page A-2
7F CT	Table 2-7, Page 2-52	Appendix A.1, Page A-2
7F CT	Table 2-8, Page 2-53	Not applicable
Auxiliary boiler	Table 2-13, Page 2-59	Vendor data
TGTU thermal oxidizer	Table 2-14, Page 2-60	Vendor data
H_2SO_4 plant thermal oxidizer	Table 2-15, Page 2-61	Vendor data
Coal handling sources, PM	Table 2-16, Page 2-62	Appendix A.2, Pages A-3 through A-15
IGCC process vent sources, PM	Table 2-17, Page 2-63	Appendix A.3, Pages A-16 through A-19
IGCC process vent and fugitive sources, H_2S	Table 2-18, Page 2-64	Appendix A.4, Pages A-20 through A-26
IGCC process vent and fugitive sources, NH_3	Table 2-19, Page 2-65	Appendix A.4, Pages A-26 through A-28
IGCC fugitive sources, CO	Table 2-20, Page 2-66	Appendix A.4, Pages A-22 through A-26
7EA CT	Table 2-21, Page 2-68	Appendix A.5, Page A-29
7EA CT	Table 2-22, Page 2-69	Appendix A.5, Page A-29 and A-30
7EA CT	Table 2-23, Page 2-70	Appendix A.5, Page A-30
7EA CT	Table 2-24, Page 2-71	Appendix A.5, Page A-30
7EA CT	Table 2-25, Page 2-72	Not applicable

Source: ECT, 1992.

weight percent, were multiplied by a factor of 0.1667 to develop H_2SO_4 emission rates for the 0.05-weight-percent S fuel oil. The adjusted H_2SO_4 emission rates were then added to the GE PM rates to generate the TSP/PM_{10} emission rates shown on Table 2-2 of the PSD permit application. An example of an TSP/PM_{10} emission rate calculation follows:

Operating Scenario: 50-percent unit load, 20°F ambient temperature;
TSP/PM_{10} Emission Rate: 17 lb/hr, based on GE data; and
H_2SO_4 Emission Rate: 35 lb/hr, based on 0.3 weight percent S.

$$H_2SO_4 = (35\ lb/hr) \times (0.1667)$$
$$= 5.8\ lb/hr,\ based\ on\ 0.05\ weight\ percent\ S$$

$$TSP/PM_{10} = (17\ lb/hr) + (5.8\ lb/hr)$$
$$= 23\ lb/hr$$

Lead emission rates shown in Table 2-2 were calculated based on a fuel specification of 1 part per million (ppm) which is equivalent to 5.3×10^{-5} pounds per million British thermal units (lb/10^6 Btu) of lead heat input using the fuel higher heating value (HHV). Heat input rates (HHV) for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets. An example of a lead emission rate calculation follows:

Operating Scenario: 75-percent unit load, 59°F ambient temperature;
Heat Input (HHV): $1{,}452 \times 10^6$ British thermal units per hour (Btu/hr) based on GE data; and
Lead Emission Factor: 5.3×10^{-5} lb/10^6 Btu.

$$Lead = (1{,}452 \times 10^6\ Btu/hr) \times (5.3 \times 10^{-5}\ lb/10^6\ Btu)$$
$$= 0.077\ lb/hr$$

Tables 2-3 and 2-4. 7F CT Firing Syngas

As noted on Page A-1 of Appendix A.1 of the PSD permit application in the SCA, emissions from the 7F CT when fired with syngas were based on vendor (GE) data. Copies of GE specification data (Polk Power Station, Emissions Data For Air Modeling) for the 7F CT fired with syngas for the three loads and ambient temperatures indicated in Tables 2-3 and 2-4 are provided in Attachment FDER-B. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126.

Table 2-5. 7F CT Firing No. 2 Fuel Oil

Emission rates for noncriteria pollutants (fluorine, mercury, beryllium, arsenic, cadmium, and chromium) were calculated using the emission factors shown in Table A.1-1. of Appendix A.1 of the PSD permit application in the SCA. The emission factors, which are expressed in units of pounds per trillion British thermal units of pollutant, were multiplied by the HHV heat input rates for each operating load and ambient temperature indicated on Table 2-5. HHV heat input rates for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets included in Attachment FDER-B. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126. An example of a beryllium emission rate calculation follows:

Operating Scenario: 100-percent unit load, 90°F ambient temperature;
Heat Input (HHV): $1{,}619 \times 10^6$ Btu/hr based on GE data; and
Beryllium Emission Factor: 2.5×10^{-6} lb/10^6 Btu.

$$\begin{aligned} \textit{Beryllium} &= (1{,}619 \times 10^6\ \textit{Btu/hr}) \times (2.5 \times 10^{-6}\ \textit{lb}/10^6\ \textit{Btu}) \\ &= 0.0040\ \textit{lb/hr} \end{aligned}$$

Emissions of H_2SO_4 were calculated as described for Table 2-2; i.e., using the GE emission data for 0.3 weight percent S fuel oil multiplied by a factor of 0.1667 to reflect the use of 0.05 weight percent S fuel oil.

Tables 2-6 and 2-7. 7F CT Firing Syngas

As noted on Page A-1 of Appendix A.1 in the PSD permit application, emissions from the 7F CT when fired with syngas were based on vendor (GE) data. Copies of GE specification data (Polk Power Station, Emissions Data For Air Modeling) for the 7F CT fired with No. 2 distillate fuel oil for the three loads and ambient temperatures indicated in Table 2-2 are provided in Attachment FDER-C. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126.

Table 2-8. 7F CT

Table 2-8 contains annual emission rates, expressed in both tons per year (tpy) and grams per second, for the various 7F CT operating scenarios. The basis for the annual emission rates are indicated in the footnotes to Table 2-8. Annual emission rates in tons per year were converted to grams per second using a unit conversion factor of 0.0287. Examples of annual emission rate calculations follow:

Operating Scenario: Initial year, 7F CT fired with fuel oil, 10-percent maximum annual capacity factor; and

Maximum Hourly SO_2 Emission Rate: 56 lb/hr, from Table 2-2.

$$SO_2 = (56\ lb/hr) \times (8{,}760\ \textit{hours per year}\ [hr/yr]) \times (0.10/0.50) \times (1\ ton/2{,}000\ \textit{pounds}\ [lb]) = 49.1\ TPY$$

Operating Scenario: Demonstration period, 7F CT fired with syngas (50 percent cold gas cleanup [CGCU] and 50 percent hot gas cleanup [HGCU]) and fuel oil, 10-percent maximum annual capacity factor for fuel oil; and

Maximum Hourly NO_2 Syngas Emission Rate: 664 lb/hr, from Table 2-4.

$$NO_2 = \frac{(\ [664\ lb/hr] \times [8{,}760\ hr/yr]\ )}{2{,}000\ \textit{pounds per ton}\ (lb/ton)} = 2{,}908\ tpy$$

Operating Scenario: Postdemonstration period, 7F CT fired with syngas (100 percent CGCU) and fuel oil, 10-percent maximum annual capacity factor for fuel oil;

Maximum Hourly CO Syngas Emission Rate: 98 lb/hr, from Table 2-3; and

$$NO_2 = \frac{([98\ lb/hr] \times [8{,}760\ hr/yr])}{2{,}000\ lb/ton}$$

$$= 429\ tpy$$

Table 2-13. Auxiliary Boiler

Emissions from the auxiliary boiler were based on vendor (Texaco) data. A copy of the material provided by Texaco is included in Attachment FDER-C. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126. Annual emission rates in tons per year were based on 1,000-hr/yr operation for the auxiliary boiler. The hourly rates were therefore multiplied by a factor of 0.50 (1,000 hrs/yr/2,000 lb/ton) to determine annual rates in tons per year. Annual emission rates in tons per year were converted to grams per second using a unit conversion factor of 0.0287.

The SO_2 emission rate for the auxiliary boiler provided by Texaco was based on a fuel oil S content of 0.3 weight percent. Fuel oil proposed for the Polk Power Station project will contain no more than 0.05 weight percent S. The Texaco emission rate for SO_2 was therefore multiplied by a factor of 0.1667 (0.05 divided by 0.3) to develop SO_2 emission rates for the 0.05 weight percent S fuel oil.

Table 2-14. Tail Gas Treating Unit Thermal Oxidizer

Emissions from the TGTU thermal oxidizer were based on vendor (Texaco) data. A copy of the material provided by Texaco is included in Attachment FDER-C. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126. Annual emission rates in tons per year were based on 8,760-hr/yr operation for the TGTU thermal oxidizer. The hourly rates were therefore multiplied by a factor of 4.38

(8,760 hrs/yr/2000 lb/ton) to determine annual rates in tons per year. Annual emission rates in tons per year were converted to grams per second using a unit conversion factor of 0.0287.

Table 2-15. Sulfuric Acid Plant Thermal Oxidizer

Emissions from the H_2SO_4 plant thermal oxidizer were based on vendor (Texaco) data. A copy of the material provided by Texaco is included in Attachment FDER-C. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126. Annual emission rates in tons per year were based on 8,760-hr/yr operation for the TGTU thermal oxidizer. The hourly rates were therefore multiplied by a factor of 4.38 (8,760 hrs/yr/2000 lb/ton) to determine annual rates in tons per year. Annual emission rates in tons per year were converted to grams per second using a unit conversion factor of 0.0287.

Table 2-16. Coal Handling Sources

Detailed calculations for each PM emission rate shown on Table 2-16 are provided in Appendix A.2, Pages A-3 through A-15 of the PSD permit application in Appendix 11.1.3 of the SCA.

Table 2-17. IGCC Process Sources

Detailed calculations for each PM emission rate shown on Table 2-17 are provided in Appendix A.2, Pages A-16 through A-19 of the PSD permit application.

Table 2-18. IGCC Process Vents and Fugitive Sources

Detailed calculations for each H_2S emission rate shown on Table 2-18 are provided in Appendix A.4, Pages A-20 through A-21 (Process Vents) and Pages A-22 through A-26 (Fugitive Sources) of the PSD permit application.

Table 2-19. IGCC Process Vents and Fugitive Sources

Detailed calculations for each NH_3 emission rate shown on Table 2-19 are provided in Appendix A.4, Pages A-26 through A-28 (Process Vents) and Pages A-22 through A-26 (Fugitive Sources) of the PSD permit application.

Table 2-20. IGCC Fugitive Sources

Detailed calculations for each CO emission rate shown on Table 2-20 are provided in Appendix A.4, Pages A-22 through A-26 of the PSD permit application.

Table 2-21. 7EA CT Firing Natural Gas

As noted on Page A-29 of Appendix A.5 of the PSD permit application, emissions of TSP/PM_{10}, SO_2, NO_x, CO, VOC, and H_2SO_4 in terms of pounds per hour were based on vendor (GE) data. Copies of GE specification data (Polk Power Station, Emissions Data For Air Modeling) for the 7EA CT fired with natural gas for the three loads and ambient temperatures indicated in Table 2-21 are provided in Attachment FDER-B. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126.

The TSP/PM_{10} emission data shown in Table 2-21 reflect GE emissions data for PM with the addition H_2SO_4 mist. The H_2SO_4 emission rates are also shown on the GE specification data sheets. The H_2SO_4 emission rates were added to the GE PM rates to generate the TSP/PM_{10} emission rates shown on Table 2-21. An example of a TSP/PM_{10} emission rate calculation follows:

Operating Scenario: 75-percent unit load, 20°F ambient temperature;
TSP/PM_{10} Emission Rate: 7 lb/hr, based on GE data; and
H_2SO_4 Emission Rate: 3 lb/hr, based on GE data.

$$
\begin{aligned}
TSP/PM_{10} &= (7\ lb/hr) + (3\ lb/hr) \\
&= 10\ lb/hr
\end{aligned}
$$

Lead emission rates shown in Table 2-21 were calculated based on a emission factor of 12 × 10^{-6} lb/10^6 Btu of heat input using the fuel HHV. Heat input rates (HHV) for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets. An example of a lead emission rate calculation follows:

Operating Scenario: 75-percent unit load, 59°F ambient temperature;
Heat Input (HHV): 787.3 × 10^6 Btu/hr based on GE data; and
Lead Emission Factor: 12 × 10^{-6} lb/10^6 Btu.

$$\begin{aligned} Lead &= (787.3 \times 10^6\ Btu/hr) \times (12 \times 10^{-6}\ lb/10^6\ Btu) \\ &= 0.0095\ lb/hr \end{aligned}$$

<u>**Table 2-22. 7EA CT Firing No. 2 Fuel Oil**</u>

As noted on Page A-29 of Appendix A.5 of the PSD permit application, emissions of TSP/PM_{10}, SO_2, NO_x, CO, VOC, and H_2SO_4 in terms of pounds per hour were based on vendor (GE) data. Copies of GE specification data (Polk Power Station, Emissions Data For Air Modeling) for the 7EA CT fired with No. 2 distillate fuel oil for the three loads and ambient temperatures indicated in Table 2-22 are provided in Attachment FDER-B. Hourly emission rates in pounds per hour were converted to grams per second by multiplying the pound-per-hour values by a units conversion factor of 0.126.

The SO_2 emission rate data provided by GE were based on a fuel oil S content of 0.3 weight percent. Fuel oil proposed for the Polk Power Station project will contain no more than 0.05 weight percent S. The GE emissions data for SO_2 was therefore multiplied by a factor of 0.1667 (0.05 divided by 0.3) to develop SO_2 emission rates for the 0.05 weight percent S fuel oil. An example of an SO_2 emission rate calculation follows:

Operating Scenario: 100-percent unit load, 20°F ambient temperature; and
SO_2 Emission Rate: 316 lb/hr, based on 0.3 weight percent S.

$$SO_2 = (316\ lb/hr) \times (0.1667)$$
$$= 53\ lb/hr,\ based\ on\ 0.05\ weight\ percent\ S$$

The TSP/PM_{10} emission data shown in Table 2-22 of the PSD permit application reflect GE emissions data for PM with the addition H_2SO_4 mist. The H_2SO_4 emission rates are also shown on the GE specification data sheets. Similar to SO_2 emission rates, the GE H_2SO_4 emissions data, which was based on a fuel oil S content of 0.3 weight percent, was multiplied by a factor of 0.1667 to develop H_2SO_4 emission rates for the 0.05 weight percent S fuel oil. The adjusted H_2SO_4 emission rates were then added to the GE PM rates to generate the TSP/PM_{10} emission rates shown on Table 2-22. An example of a TSP/PM_{10} emission rate calculation follows:

Operating Scenario: 75-percent unit load, 90 °F ambient temperature;
TSP/PM_{10} Emission Rate: 15 lb/hr, based on GE data; and
H_2SO_4 Emission Rate: 22 lb/hr, based on 0.3 weight percent S.

$$H_2SO_4 = (22\ lb/hr) \times (0.1667)$$
$$= 3.7\ lb/hr,\ based\ on\ 0.05\ weight\ percent\ S$$

$$TSP/PM_{10} = (15\ lb/hr) + (3.7\ lb/hr)$$
$$= 19\ lb/hr$$

Lead emission rates shown in Table 2-22 were calculated based on a fuel specification of 1 ppm which is equivalent to 5.3×10^{-5} lb/10^6 Btu using the fuel HHV. Heat input rates (HHV) for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets. An example of a lead emission rate calculation follows:

Operating Scenario: 75-percent unit load, 59°F ambient temperature;
Heat Input (HHV): 812×10^6 Btu/hr based on GE data; and
Lead Emission Factor: 5.3×10^{-5} lb/10^6 Btu.

$$\mathit{Lead} = (812 \times 10^6\ \mathit{Btu/hr}) \times (5.3 \times 10^{-5}\ \mathit{lb}/10^6\ \mathit{Btu})$$
$$= 0.043\ \mathit{lb/hr}$$

__Table 2-23. 7EA CT Firing Natural Gas__

Emission rates for mercury were calculated using the emission factor shown on Appendix A.5, Page A-29 of the PSD permit application. The emission factor, which is expressed in units of pounds per trillion British thermal units of mercury, was multiplied by the heat input rates (HHV) for each operating load and ambient temperature indicated on Table 2-23. Heat input rates (HHV) for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets included in Attachment FDER-B. An example of a mercury emission rate calculation follows:

Operating Scenario: 100-percent unit load, 90°F ambient temperature;
Heat Input (HHV): 886.5 × 10^6 Btu/hr based on GE data; and
Mercury Emission Factor: 12 × 10^{-6} lb/10^6 Btu.

$$\mathit{Mercury} = (886.5 \times 10^6\ \mathit{Btu/hr}) \times (12 \times 10^{-6}\ \mathit{lb}/10^6\ \mathit{Btu})$$
$$= 0.010\ \mathit{lb/hr}$$

Emissions of H_2SO_4 were based on the GE emissions data shown on the Emissions Data For Air Modeling forms.

__Table 2-24. 7EA CT Firing No. 2 Fuel Oil__

Emission rates for noncriteria pollutants (fluoride, mercury, beryllium, arsenic, cadmium, and chromium) were calculated using the emission factors shown in Table A.1-1. of Appendix A.1, Page A-2 of the PSD permit application. The emission factors, which are expressed in units of pounds per trillion British thermal units of pollutant, were multiplied by the heat input rates (HHV) for each operating load and ambient temperature indicated on Table 2-24 of the PSD permit application. Heat input rates (HHV) for each of the three operating loads and ambient temperatures are shown on the GE performance data sheets included in Attachment FDER-B. An example of a beryllium emission rate calculation follows:

Operating Scenario: 100 percent-unit load, 20°F ambient temperature;

Heat Input (HHV): 1,114.8 × 10^6 Btu/hr based on GE data; and

Beryllium Emission Factor: 2.5 × 10^{-6} lb/10^6 Btu.

$$\mathit{Beryllium} = (1{,}114.8 \times 10^6\ \mathit{Btu/hr}) \times (2.5 \times 10^{-6}\ \mathit{lb}/10^6\ \mathit{Btu}) \\ = 0.0028\ \mathit{lb/hr}$$

Emissions of H_2SO_4 were calculated as described for Table 2-2; i.e., using the GE emission data for 0.3 weight percent S fuel oil multiplied by a factor of 0.1667 to reflect the use of 0.05 weight percent S fuel oil.

Table 2-25. 7EA CTs

Table 2-25 contains annual emission rates, expressed in both tons per year and grams per second, for the various 7EA CT operating scenarios. The basis for the annual emission rates are indicated in the footnotes to Table 2-25. Annual emission rates in tons per year were converted to grams per second using a unit conversion factor of 0.0287. Examples of annual emission rate calculations follow:

Operating Scenario: Simple-cycle, 50- and 10-percent maximum annual capacity factors for natural gas and fuel oil, respectively;

Maximum Hourly Natural Gas SO_2 Emission Rate: 29 lb/hr, from Table 2-21; and

Maximum Hourly Fuel Oil SO_2 Emission Rate: 42 lb/hr, from Table 2-22.

$$SO_2 = \frac{\left([29\ \mathit{lb/hr}] \times \left[\frac{0.5}{0.75} \times 8{,}760\ \mathit{hr/yr}\right]\right) + \left([42\ \mathit{lb/hr}] \times \left[\frac{0.1}{0.75} \times 8{,}760\ \mathit{hr/yr}\right]\right)}{2{,}000\ \mathit{lb/ton}}$$

$$= 109\ \mathit{tpy}$$

Operating Scenario: CC, 100- and 25-percent maximum annual capacity factors for natural gas and fuel oil, respectively;

Maximum Hourly CO Syngas Emission Rate: 59 lb/hr, from Table 2-21; and
Maximum Hourly CO Fuel Oil Emission Rate: 54 lb/hr, from Table 2-22.

$$CO = \frac{([59\ lb/hr] \times [0.75 \times 8{,}760\ hr/yr]) + \left([54\ lb/hr] \times \left[\frac{0.25}{0.75} \times 8{,}760\ hr/yr\right]\right)}{2{,}000\ lb/ton}$$

$$= 273\ tpy$$

FDER-19

Please provide a maximum value for fuel bound nitrogen for both natural gas and fuel oil. Also, calculate the maximum NOx emissions based upon your maximum value for fuel bound nitrogen for the Integrated Coal Gasification Combined Cycle (IGCC), Combined Cycle (CC) and the Simple Cycle combustion turbines.

Response

Distillate fuel oil planned for use at the Polk Power Station was premised to contain a maximum of 0.015 weight percent fuel bound nitrogen (FBN) for purposes of estimating NO_x emission rates. Natural gas does not contain any significant amount of FBN.

Depending on the catalyst employed, the petroleum refining process (hydrotreating) used to desulfurize petroleum products can also denitrogenate these products to obtain low FBN nitrogen levels. Based on information received from potential fuel suppliers, maximum FBN content for the low sulfur (0.05 weight percent S) distillate fuel oil planned for the Polk Power Station is expected to be 0.015 weight percent. However, it is possible that there will be brief periods when low sulfur distillate fuel oil with a FBN level of 0.015 weight percent or less is not available due to refining and/or fuel oil supply disruptions. This contingency is recognized in New Source Performance Standards (NSPS), Chapter 40, Code of Federal Regulations (CFR), Subpart GG, which contains a NO_x emission allowance for varying FBN levels.

FDER-20

Please submit a detailed process flow diagram for the IGCC unit showing the volumetric air flow rates for each stream when burning fuel oil and the different scenarios for syngas combustion. Also, submit the same for the CC, Simple Cycle and the auxiliary boiler when burning natural gas and fuel oil.

Response

IGCC 7F CT Unit

Air flow rates for the IGCC 7F CT unit at base load and 90°F are as follows:

Location	Volumetric Air Flow Rate (ft^3/hr)	
	Syngas	Distillate Fuel Oil
CT inlet	42.91×10^6	42.96×10^6
CT exhaust (HRSG inlet)	150.05×10^6	131.87×10^6
Stack outlet	70.98×10^6	62.58×10^6

Note: ft^3/hr = cubic feet per hour.
HRSG = heat recovery steam generator.

Simple Cycle 7EA CTs (Per CT)

Air flow rates for each simple cycle 7EA unit at base load and 90°F are as follows:

Location	Volumetric Air Flow Rate (ft^3/hr)	
	Natural Gas	Distillate Fuel Oil
CT inlet	29.58×10^6	30.06×10^6
CT exhaust	80.12×10^6	81.41×10^6
Stack outlet	80.12×10^6	81.41×10^6

Combined Cycle 7EA CT Units (Per CT/HRSG Unit)

Air flow rates for each CC 7EA unit at base load and 90°F are as follows:

Location	Volumetric Air Flow Rate (ft^3/hr)	
	Natural Gas	Distillate Fuel Oil
CT inlet	29.60×10^6	30.05×10^6
CT exhaust (HRSG inlet)	80.34×10^6	81.63×10^6
Stack outlet	40.08×10^6	40.83×10^6

Auxiliary Boiler

With the auxiliary boiler operating at design (maximum rated) conditions, there will be 9,240 cubic feet per minute (cfm) of air consumed at an ambient temperature of 85°F and 18,000 cfm of flue gas produced at 500°F. Assumptions used in determining these rates are as follows:

- Fuel = No. 2 fuel oil,
- Firing rate (HHV) = 49.5 million British thermal units per hour (MMBtu/hr),
- Excess air = 15 percent,
- Air temperature = 80°F, and
- Steam production = 35,000 lb/hr at 50 pounds per square inch gauge (psig).

FDER-21

What is the efficiency of the combustion turbine for the IGCC, CC and the Simple Cycle units? Calculate Y (refer to NSPS 40 CFR 50, Subpart GG) in kilojoules per watt hour, showing all the calculations?

Response

CT efficiencies at base load and 59°F ambient temperature, calculated pursuant to NSPS, 40 CFR GG, are summarized as follows:

CT	Fuel Type	Heat Consumption (MMBtu/hr)	Gross Power (kw)	Efficiency (Btu/kwh)	Efficiency (kJ/wh)
7F	Syngas	1,624.5	192,000	8,460.94	8.925
7F	Distillate oil	1,665.0	159,330	10,450.00	11.023
7EA	Natural gas	871.4	83,150	10,479.86	11.054
7EA	Distillate oil	946.7	86,300	10,969.87	11.571

Note: kw = kilowatt.
Btu/kwh = British thermal units per kilowatt-hour.
kJ/wh = kiloJoules per watt-hour.

NSPS Subpart GG is applicable to CTs only. Accordingly, the presence of an HRSG as part of a combined cycle (CC) unit has no bearing on the calculation of CT efficiency pursuant to NSPS Subpart GG.

FDER-22

Submit manufacturer's name, model number, generator name plate rating (gross MW), maximum steam production rate for the Heat Recovery Steam Generator (HRSG) for the IGCC and the CC units.

Response

IGCC Unit

The manufacturer of the HRSG has not been selected at this time. Model numbers and megawatt (MW) ratings are not applicable to HRSGs. The nominal amount of heat exchanged for the IGCC HRSG is 830 MMBtu/hr. Maximum steam production data (which will occur at 90°F ambient temperature) for the HRSG is summarized as follows:

Steam Type	Production Rate (lb/hr)	Temperature (°F)	Pressure (psig)
High pressure	703,800	996	1,500
Reheat	701,700	990	311

CC Units

The manufacturer's name, model number, generator name plant rating (gross megawatts) and maximum steam production rate for the HRSG for the CC units is currently unavailable. Procurement of this equipment has not been initiated as these units are not planned to be operational until the years 2001 and 2003.

Capacity projections have been made for the CC units based on configuration employing two GE 7EA CT generators, each of which is equipped with a two-pressure HRSG which generates high-pressure superheated steam and low-pressure saturated steam. The two steam sources are used to drive a nonreheat dual admission steam turbine (ST) generator. For this system, the expected maximum net cycle power available at the generator terminals is 92.9 MW for each CT generator and 79.5 MW for the ST generator. Maximum steam production rate for each HRSG is expected to be 290,200 lb/hr of high-pressure superheated steam and 46,600 lb/hr low-pressure saturated steam.

FDER-23

> What is the maximum and nominal power (MW) output for the steam turbine generator for the IGCC and the CC units? What is the steam input to these turbines?

Response

IGCC Unit

The IGCC ST has a nominal (design point) output of 123,655 kw and a maximum capability of 124,200 kw. Steam output at the design points are:

Steam Type	Production Rate (lb/hr)	Temperature (°F)	Pressure (psig)
High pressure	703,800	989	1,405
Reheat	717,400	987	305

CC Unit

The maximum and nominal power (megawatts) output of the ST generator for the CC units is estimated as 79.5 and 77, respectively. The steam input at maximum power output is expected to be 580,400 lb/hr high-pressure superheated steam, 93,200 lb/hr low-pressure saturated steam, and 566,200 lb/hr high-pressure superheated steam, 82,100 lb/hr low-pressure saturated steam at nominal power output.

FDER-24

Please submit the manufacturer's design specification for the proposed IGCC General Electric 7F combustion turbine (CT), GE 7EA CTs and also for the auxiliary boiler.

Response

The following vendor (GE) technical literature for the 7F and 7EA CTs is provided in Attachment FDER-D:

- 7F CT
  - -- MS7001F Gas Turbine Test and Performance Evaluation
  - -- MS7001FA Gas Turbine Design Evolution and Verification
- 7EA CT
  - -- MS7001EA Heavy-Duty Gas Turbine
  - -- MS7001EA Gas Turbine--Heavy-Duty 60 Hz Power Plant for Utility, Industrial and Cogeneration Applications

The technical specifications describing the auxiliary boiler from Texaco, Inc., are also provided in Attachment FDER-D.

FDER-25

What is the estimated annual throughput and the type of air pollution control for the fuel oil storage tanks? What are the estimated emissions?

Response

The estimated maximum annual throughput rate for each of the three oil storage tanks is 39,432,028 gallons per year. Emission controls for VOCs are not proposed for the distillate fuel oil storage tanks due to the low vapor pressure of distillate fuel oil; i.e., 0.012 pounds per square inch absolute (psia) at 80°F. Maximum annual VOC emission rate, using procedures found in AP-42, Section 4.3 (Storage of Organic Liquids), was calculated to be 2.16 tpy per tank. Storage tank VOC emission calculations are provided in Attachment FDER-E.

FDER-26

> Please submit a detailed listing of all the continuous emission monitoring systems (CEMs) required for this project. This should include the type of the CEM (in-situ or extractive), the make and model number, the pollutant it will monitor, and any associated data acquisition system.

Response

As an affected coal-fired unit under the Clean Air Act (CAA) Amendments of 1990, the Polk Power IGCC unit will be required to install a continuous emission monitoring system (CEMS) prior to commercial operation. The component parts of the CEMS as defined by U.S. Environmental Protection Agency (EPA) in their proposed rule 40 CFR 75.2 are as follows:

> "(1) Sulfur dioxide pollutant concentration monitor, (2) flow monitor, (3) nitrogen oxides pollutant concentration monitor, (4) diluent gas monitor (oxygen or carbon dioxide), and (5) data acquisition and handling system."

In addition, a continuous opacity monitoring system will also be required.

At this time, it is Tampa Electric Company's intent to install a dilution-type sampling system using a KVB Ecoprobe® or equivalent equipment. The monitors for the individual parameters are as follows:

Pollutant	Make/Model
SO_2	TECO 43H
NO_x	TECO 42
Carbon dioxide (CO_2)	Milton Roy 3300
Gas flow/temperature	United Sciences 100
Opacity	TECO 42B

The data acquisition system will be composed of an Allen Bradley SLC-500 program logic controller (PLC) feeding information to an ALR 486/33 computer using KVB software or equivalent system.

CC and simple cycle CTs will be equipped with monitoring systems as required by the final version of 40 CFR 75. At this point in time, it is likely that these units will require only NO_x and diluent monitors and a data acquisition system. The type of equipment described previously is the most likely type to be used at this time.

FDER-27

What kind of control and monitoring equipment is proposed for continuously recording power generation, coal feed rate, fuel injection rate of syngas, natural gas and fuel oil, nitrogen and the water injection rate for the IGCC unit.

Response

A distributed control system (DCS) will be used to provide control and monitoring of the overall IGCC facility. The DCS, in conjunction with supervisory computers, will provide historization, trending, and reporting for the items in this comment.

FDER-28

Please provide the names and addresses of all the manufacturers and suppliers that were contacted for budgetary quotations and engineering estimates in developing capital and annualized cost estimates for this project. Also, provide a summary of all the equipment, raw material and the fuel costs.

Response

Capital cost estimates for the two control technologies evaluated (NO_x selective catalytic reduction [SCR] and CO oxidation catalyst) were based on data developed for a recent CT cogeneration project. The major capital cost associated with both control technologies is the amount of catalyst required which, for systems having comparable control efficiencies, will vary primarily with exhaust gas flow rate. Capital costs for SCR and CO oxidation control systems for the Polk Power Station CTs were developed by ratioing the available cost data to account for larger flow rates. Factors used in estimating purchased equipment cost (PEC) were $2,700 and $1,275 per pound-second of exhaust flow for SCR and CO oxidation catalyst systems, respectively. Other direct and indirect capital costs were estimated using factors obtained from the Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual; reference Table 4-1, Page 4-2 of the PSD permit application in the SCA.

Costs used in developing the capital and annualized cost estimates are summarized in Table 4-19, Page 4-53 of the PSD permit application in the SCA. Data contained on Table 4-1 were provided by Tampa Electric Company, GE, and United Engineers and Constructors, Inc. (UE&C). Detailed CO oxidation catalyst capital and annual operating cost estimates for the CC 7EA CTs are shown on Tables 4-20 (Page 4-54) and 4-21 (Page 4-55) of the PSD permit application in the SCA. Detailed CO oxidation catalyst capital and annual operating cost estimates for the simple cycle 7EA CTs are shown on Tables 4-22 (Page 4-56) and 4-23 (Page 4-57) of the PSD permit application in the SCA. Further explanation of the CO oxidation catalyst capital and annual operating cost estimates for the simple cycle 7EA CTs is provided in the response to Comment No. FDER-37.

FDER-29

Does the applicant propose to do simultaneous fuel (natural gas and fuel oil) firing for the CC and Simple Cycle units? If so, provide details on how this will be accomplished.

Response

The 7EA CTs used for simple cycle and CC service are expected to have the ability to co-fire natural gas and distillate fuel oil simultaneously. Fuel flows are regulated automatically by the CT control system which adjusts the rate of fuel addition for each fuel so that the total required fuel input is not exceeded.

Continuous co-firing is not anticipated. Co-firing of natural gas and distillate fuel oil is expected to occur for only limited times during transient fuel switching from natural gas to back-up distillate fuel oil and vice versa.

FDER-30

Please submit the information requested in Rule 17-256.600(3) regarding Industrial, Commercial, Municipal, and Research Open Burning as it relates to this project.

Response

This rule applies to open burning in conjunction with ongoing operation of a facility. Rule 17-256.600(1), Florida Administrative Code (F.A.C.), generally prohibits open burning in connection with industrial, commercial, or municipal operations unless the open burning is determined by FDER to be the only feasible method of operation and prior approval is obtained from FDER. Requests for FDER approval of open burning in connection with industrial, commercial, or municipal operations are made by submitting an application containing the information specified in Rule 17-256.600(3), F.A.C.

Currently, Tampa Electric Company anticipates no need to conduct open burning in connection with industrial operations at the Polk Power Station. Should such a need arise in the future, Tampa Electric Company will submit an application to FDER containing the information specified in Rule 17-256.600(3), F.A.C., and will not conduct any open burning associated with industrial operations without prior FDER approval.

Also as discussed in Sections 4.1.1.3 and 4.5 of the SCA, Tampa Electric Company currently anticipates that certain combustible clearing and construction wastes will be burned onsite in accordance with applicable state and local requirements. Appropriate agency approvals will be obtained, as necessary, for these open burning activities during the construction activities.

FDER-31

> Please quantify the nitrogen quantity in the soot blowing and purging process as outlined in the Air Separation Unit schematic of Figure 2-5, page 2-15 of Volume 4.

Response

The total nitrogen purge rate is typically 2 to 4 tons per day (tpd). The syngas cooler soot-blowing stream is an internal stream which Texaco considers proprietary.

FDER-32

> The uncondensed gas (tail gas) is routed either to the tail gas treating unit or to the thermal oxidizer depending on the tail gas sulfur content. What is the determining sulfur content and what is the maximum load (cfm) of tail gas that the thermal oxidizer can treat. Also, what is the efficiency of the thermal oxidizers for both the tail gas treating unit and the sulfuric acid plant?

Response

The determining sulfur content is a function of several factors:

1. The quantity of sulfur species that must be converted in the downstream TGTU hydrogenation reactor to H_2S--These species include SO_2, carbon disulfide, carbonyl sulfide, uncondensed sulfur vapor, and possibly entrained sulfur liquid. These compounds will react with hydrogen in the hydrogenation reactor and heat will be liberated.
2. The current total gas mass flow from the sulfur recovery unit (SRU) to the TGTU--Higher sulfur levels in the tail gas at low unit flow rates can be tolerated than at maximum flow rates. At the lower flow rates, the reactor bed and downstream equipment will have a relatively high capacity for

heat absorption and the heat loss to the atmosphere will also be relatively higher.

3. The duration and frequency of the sulfur content increases in question--If the sulfur content is increased for a short period of time and returns rapidly to the normal level, little impact on operations is expected. On the other hand, frequent or prolonged increases in sulfur content will increase the probability of routing the tail gas to the thermal oxidizer.
4. The perceived temperature at the outlet of the TGTU reactor at which damage to equipment or the catalyst may occur--Typically, when the reactor outlet temperature or one of the bed temperature sensors reach 650°F, an alarm is issued. At 700 to 750°F, automatic shutdown of the TGTU occurs by routing tail gas to the thermal oxidizer.

At maximum design rates, we expect routing of tail gas to the thermal oxidizer may occur when sulfur content exceeds approximately 10,000 to 15,000 ppm.

The thermal oxidizer will be designed to handle all the tail gas from the SRU or the TGTU. The maximum load is estimated at approximately 8,400 standard cubic feet per minute (scfm).

The thermal oxidizer will be designed to combust all unoxidized sulfur species to SO_2 except for a residual H_2S content of 10 parts per million volumetric (vppm).

The TGTU is designed to handle a relatively wide range of feed gas compositions from the SRU. Tail gas from the SRU is routed directly to the thermal oxidizer, thereby bypassing the TGTU, only during SRU upsets that the TGTU cannot handle. It is expected that the frequency of such occurrences will be relatively rare and of short durations. During such events, the TGTU is normally kept in hot stand-by to permit a rapid switch-over back to normal processing of SRU feed gas once SRU operations are corrected and stabilized.

FDER-33

The emission information provided for the IGCC, CC and the Simple Cycle combustion turbines different load conditions and ambient temperatures are based on which measurement methods? Please identify any differences between the measurement methods employed and the EPA test methods. Also, provide stack test information and data for each pollutant tested, and fuel analysis data for the fuel burned during the test.

<u>Response</u>

Emissions data provided in the SCA for the 7F and 7EA CTs for varying fuel types, operating loads, and ambient temperatures are based on an extensive database of GE laboratory testing and field experience. The submitted emissions data represent expected CT performance using applicable EPA reference test methods.

FDER-34

Please provide more information on the flare, whether its steam assisted, air assisted or non-assisted. Also, submit the net heating value of the gas being combusted, the exit velocity of the flare and what device will be used to detect the presence of a flame.

<u>Response</u>

The flare will be nonassisted. The net heating value of the gas being flared will be 200 British thermal units per standard cubic foot (Btu/scf) or greater for normal operation. The flare is sized so that the exit velocity will not exceed 60 ft/sec for normal operation. A thermocouple will be provided at the flare tip to monitor the presence of a flame.

FDER-35

Explain the basis for the stack exit temperature to be higher for Simple Cycle and CC CTs when firing natural gas compared to fuel oil as shown in Tables 2-26 to 2-29, pages 2-73 to 2-76 of Volume 4.

Response

Gas turbine exhaust temperatures are slightly lower when firing distillate fuel oil in comparison to natural gas due to a change in CT firing temperature control employed to limit NO_x emissions when using distillate fuel oil.

FDER-36

> The hot gas clean up technology for the IGCC facility will improve overall efficiency as well as lower SO2 emissions in comparison to cold gas clean up controls as suggested by the applicant on page 4-3 of Volume 4. Table 2-8, page 2-53 of Volume 4 does not reflect lower SO2 emissions during the demonstration period. Please quantify the decrease in SO2 emissions as well as improvement in the overall efficiency in terms of increased power production.

Response

HGCU has the potential to reduce sulfur emissions by greater than 99 percent. The basis of this prediction is pilot plant performance at GE's Corporate Research and Development facility in Schenectady, New York, and efficiencies of commercially available, double effectiveness H_2SO_4 plants.

HGCU system performance levels for the start-up of the first commercial scale demonstration unit of this technology may be less than pilot plant experience. A principal objective of the 2-year demonstration period is to determine the performance of HGCU with respect to sulfur emissions. As noted in the PSD application (Appendix 11.1.3 of the SCA) on Page 4-4, continued operation of HGCU following the demonstration period (if found to be technically and economically viable) will be on the basis that emission rates using HGCU will be equivalent or less than those achieved by conventional CGCU for all regulated pollutants.

Studies have predicted an increase in overall power plant efficiencies in the order of 2 to 3 percent for HGCU as compared to CGCU. Since the Polk Power Station will use both HGCU and CGCU during the demonstration period, improvement in overall plant efficiency will be somewhat less.

FDER-37

Table 4-24, page 4-58 of Volume 4 gives a cost effectiveness figure of \$5643/ton for a Simple Cycle CT with Oxidation catalyst. Please explain the steps in arriving at this figure.

Response

A cost effectiveness of \$5,643 per ton of CO removed for the application of CO oxidation catalyst technology to the simple cycle CTs was developed using procedures obtained from the OAQPS Control Cost Manual.

Costs associated with Best Available Control Technology (BACT) determinations consists of two major components: capital costs and annual operating expenses. Detailed discussion of each of these costs for the simple cycle CT CO oxidation catalyst control technology evaluation follows.

Capital Costs

Capital costs are comprised of direct and indirect costs, and interest during construction. Direct costs include PEC, installation, and site preparation. Installation includes foundations and supports, handling and erection, electrical, piping, insulation for ductwork, and painting. Installation costs, per the OAQPS Cost Control Manual, are factored from the PEC. The OAQPS factors are summarized in Table 4-1, Page 4-2 of the PSD permit application in the SCA. The estimated PEC for CO oxidation control systems for six 7EA CTs is \$5,559,500, or \$926,583 per CT. Total installation cost, using the OAQPS factors, was calculated to be \$1,667,850. Site preparation for the six CTs was estimated to total \$150,000. Total direct capital costs (sum of purchased equipment, installation, and site preparation) is \$7,377,350. Details of the direct capital cost estimates are shown on Table 4-22, Page 4-56 of the PSD permit application in the SCA.

Indirect costs include engineering, construction and field expenses, contractor fees, startup, performance tests, and contingencies. Each of these indirect costs were factored from the PEC using the OAQPS recommended factors. Total indirect cost for the six 7EA CTs was calculated to be $2,946,535. Details of the indirect capital cost estimates are shown on Table 4-22, Page 4-56 of the PSD permit application in the SCA.

Interest during construction (financing of capital costs) was calculated, in accordance with guidance received from Mr. William M. Vatavuk, P.E. (author of the OAQPS Control Cost Manual), based on three payments made uniformly over a 1.5-year period with an interest rate of 10 percent. The 10-percent interest rate is applied to total capital costs (direct and indirect; $10,323,885) for 6 months, at which time a third of the borrowed funds are repaid, to two-thirds of the total capital costs for an additional 6 months when another third of the borrowed funds are repaid, and to one-third of the total capital costs for the final 6 months when the last third of the borrowed funds are repaid. This borrowing/repayment method is equivalent to paying the 10-percent interest rate on the total borrowed funds for one full year or $1,032,390.

Total capital investment (TCI), consisting of direct, indirect, and interest during construction, was calculated to be $11,356,275 as shown on Table 4-22, Page 4-56 of the PSD permit application in the SCA.

Annual Operating Costs

Annual operating costs include direct and indirect costs. Direct costs include operating labor and material, maintenance labor and material, catalyst expenses (periodic replacement and disposal), energy penalties (CT backpressure and downtime for catalyst replacement), and contingencies. Specific calculations for each of these items follows.

Operating Labor

Operator Labor Premises (Per CT): (a) $16.80-per-hour wage, (b) 0.25 hours labor per 8-hour shift, and (c) 4,380-hr/yr operation at 100-percent load.

Operator Labor = (\$16.80/hr) × (0.25 hr/8 hr) × (4,380 hr/yr) × (6)

Operator Labor = \$13,800 per year

Supervisor Labor = Operating Labor × OAQPS factor of 0.15

Supervisor Labor = \$13,800 × 0.15

Supervisor Labor = \$2,070 per year

Maintenance

Maintenance Labor Premises (Per CT): (a) \$12.50-per-hour wage, (b) 0.25 hours labor per 8-hour shift, and (c) 4,380-hr/yr operation at 100-percent load.

Maintenance Labor = (\$12.50/hr) × (0.25 hr/8 hr) × (4,380 hr/yr) × (6)

Maintenance Labor = \$10,265 per year

Maintenance Materials = Maintenance Labor × OAQPS Factor of 1.0

Maintenance Materials = \$10,265 × 1.0

Maintenance Materials = \$10,265 per year

Total Labor, Material & Maintenance Cost

= \$13,800 per year + \$2,070 per year + \$10,265 per year + \$10,265 per year

= \$36,400 per year

Catalyst Costs

1. Replacement (labor and materials)--Replacement frequency of oxidation catalyst is every 3 years of continuous operation. Estimated catalyst replacement cost (material and labor) is \$692,914 per CT, or \$4,157,484 for six CTs.
2. Disposal--Costs associated with transportation of spent catalyst is estimated to be \$20,000 per CT, or \$120,000 for six CTs.
3. Credit for Used Catalyst--Spent catalyst is typically returned to the oxidation catalyst vendor for reclamation and disposal. Value of used catalyst is estimated to be 15 percent of the catalyst replacement cost, or \$623,620.
4. Total Catalyst Costs

   = \$4,157,484 + \$120,000 - \$623,620

   = \$3,653,865 per replacement

5. Annualized Catalyst Cost--The total catalyst replacement cost of $3,653,865 will be incurred every 3 years assuming continuous operation at 100-percent load. Since the simple cycle CTs have a 50-percent capacity factor, catalyst replacement was premised to occur once every 6 years. The annualized cost of catalyst replacement, using procedures obtained from the OAQPS Cost Control Manual, is as follows:

Annualized Cost or Capital Recovery Cost (CRC)

$$CRC = CRF \times P$$

where: CRF = capital recovery factor, and
P = investment.

$$CRF = \frac{i \times (1 + i)^n}{(1 + i)^n - 1}$$

where: i = interest rate (10.06 percent), and
n = annualized period (6 years).

$$CRF = \frac{0.1006 \times (1 + 0.1006)^6}{(1 + 0.1006)^6 - 1}$$

$$= 0.230011$$

$$= 0.230011 \times \$3,653,865$$

$$= \$840,430 \textit{ per year}$$

Energy Penalties

1. Pressure drop across a CO oxidation catalyst system will increase backpressure on the CT. This backpressure reduces the power generating capacity of the

turbine. GE literature indicates that power output will be reduced by approximately 0.1 percent for each 1 inch of turbine backpressure. Specific calculations used to estimate the CO oxidation catalyst energy penalty are as follows:

Data:

a. Electricity cost: \$0.0428 per kilowatt hour (kwh);

b. Power production: 75,000 kw per CT (nominal);

c. Power loss due to backpressure: 0.2 percent (based on 2-inch pressure drop); and

d. Annual operating hours: 4,380 hr/yr.

Calculations:

Penalty = \$0.0428/kwh × 75,000 kw × 6 × 0.002 × 4,380 hr/yr

Penalty = \$168,718 per year

2. Periodic replacement of the oxidation catalyst will result in CT downtime and lost power revenues. Catalyst replacement is projected to take 4 days. Specific calculations used to estimate the annualized cost associated with CT downtime due to catalyst replacement follows:

Data:

a. Electricity revenue: \$0.02539 per kwh (includes adjustment for unburned fuels during downtime);

b. Duration of downtime: 4 days (96 hr/yr) once every 6 years;

c. Power production: 75,000 kw per CT (nominal); and

d. CRF: 0.230011 (based on 6-year period and 10.06-percent interest rate).

Calculations:

Penalty = \$0.02539/kwh × 75,000 kw × 6 × 96 hr/yr × 0.230011

Penalty = \$252,285 per year

3. Total energy penalty:

= \$168,718 per year + \$252,285 per year

= \$421,000 per year

Total Direct Costs (TDC)

= $36,400 per year + $840,430 per year + $421,000 per year

= $1,297,830 per year

Contingency

Contingency was estimated at 25 percent of TDC or $324,460 per year.

Indirect annual expenses include overhead, administrative charges, property taxes, insurance, and capital recovery. The first four items were calculated using recommended OAQPS factors. Capital recovery was calculated using the TCI estimate of $11,356,275, a control system life of 15 years, and an 10.06-percent annual interest rate. Specific indirect annual expense calculations follow

1. Overhead = total labor, materials, and maintenance cost multiplied by the OAQPS factor of 0.60.

   Overhead = $36,400 per year × 0.60

   Overhead = $21,840 per year

2. Administrative Charges = TCI multiplied by OAQPS factor of 0.02.

   Administrative Charges = $11,356,275 per year × 0.02

   Administrative Charges = $227,125 per year

3. Property Taxes = TCI multiplied by OAQPS factor of 0.01.

   Property Taxes = $11,356,275 per year × 0.01

   Property Taxes = $113,565 per year

4. Insurance = TCI multiplied by OAQPS factor of 0.01.

   Insurance = $11,356,275 per year × 0.01

   Insurance = $113,565 per year

5. Capital Recovery = TCI (minus initial catalyst charge to avoid *double-counting* of catalyst cost) multiplied by CRF of 0.131924. CRF based on 15-year period and 10.06-percent annual interest rate.

   Capital Recovery = ($11,356,275 - $4,157,485) × 0.131924

   Capital Recovery = $949,695 per year

6. TIC

= \$21,840 + \$227,125 + \$113,565 + \$113,565 + \$949,695

= \$1,425,790 per year

Total Annual Cost

= TDC + Contingency + TIC

= \$1,297,830 per year + \$324,460 per year + \$1,425,790 per year

= \$3,048,080 per year

Cost effectiveness, in terms of dollars per ton of pollutant removed, is calculated by dividing the total annual cost (in dollars per year) by the tons per year of pollutant removed. Tons per year of pollutant removed is determined by subtracting the annual emissions reflecting the use of CO oxidation control technology from annual baseline levels. Baseline CO emissions (based on the use of advanced dry low-NO_x combustors) are 25 and 30 parts per million by dry volume (ppmvd) CO for natural gas and distillate oil firing, respectively. Controlled emissions, consistent with the limit typically required for oxidation catalyst systems located in CO nonattainment areas, are assumed to be 10 ppmvd for both natural gas and distillate oil firing. Emission rates calculations are provided as follows:

1. Baseline emissions (at 100-percent load, 59°F ambient temperature):
   a. CO emission rate: 54 lb/hr per CT (natural gas);
   b. CO emission rate: 65 lb/hr per CT (distillate fuel oil);
   c. Capacity Factor: 0.5 or 4,370 hr/yr at 100-percent load (natural gas); and
   d. Capacity Factor: 0.1 or 876 hr/yr at 100-percent load (distillate oil).

$$\textit{Annual CO emissions} = \frac{[(54\ lb/hr \times 6 \times 4{,}380\ hr/yr) + (65\ lb/hr \times 6 \times 876\ hr/yr)]}{2{,}000\ lb/ton}$$

$$= 880.4\ tpy$$

2. Controlled emissions (at 100-percent load, 59°F ambient temperature):
   a. CO emission rate: 21.6 lb/hr per CT (natural gas);
   b. CO emission rate: 21.7 lb/hr per CT (distillate fuel oil);

c. Capacity Factor: 0.5 or 4,370 hr/yr at 100-percent load (natural gas); and

d. Capacity Factor: 0.1 or 876 hr/yr at 100-percent load (distillate oil).

$$\textit{Annual CO emissions} = \frac{[(21.6\ lb/hr \times 6 \times 4{,}380\ hr/yr) + (21.7\ lb/hr \times 6 \times 876\ hr/yr)]}{2{,}000\ lb/ton}$$

$$= 340.2\ tpy$$

3. Annual tons of CO removed:

= 880.4 tpy - 340.2 tpy

= 540.2 tpy

Cost effectiveness is calculated by dividing the total annual cost (in dollars per year) by the tons per year of pollutant removed as follows:

$$\textit{Cost effectiveness} = \frac{\$3{,}048{,}080\ \textit{per year}}{540.2\ tpy}$$

$$= \$5{,}643\ \textit{per ton CO removed}$$

In reviewing Tables 4-23 and 4-24 of the PSD permit application in the SCA which pertain to the simple cycle CT CO oxidation catalyst cost evaluation, it was noticed that there were a number of typographical errors and data entries that were inadvertently copied from the tables that pertain to the CC cost analysis. Revised Tables 4-23 and 4-24 (Rev. 1, 11/25/92) follow this response and are provided in the replacement package for insertion in the SCA.

The cost effectiveness calculation described previously is conservative (under-estimates actual cost effectiveness) for the simple cycle CTs since escalation for inflation was not applied as recommended by the OAQPS Cost Control Manual. Actual cost effectiveness for CO oxidation catalyst control systems when the simple cycle CTs will be installed (2002 through 2010) will be significantly higher.

Table 4-23. Annual Operating Costs for Oxidation Catalyst for Stand-Alone Simple-Cycle CTs

Item	$		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	13,800	(A)	
Supervisor	2,070		0.15 x A
Maintenance			
Labor	10,265	(B)	
Materials	10,265		1.00 x B
Subtotal Labor, Material, and Maintenance Costs	**36,400**	(C)	
Catalyst costs			
Replacement (materials and labor)	4,157,484		
Disposal	120,000		
Credit for used catalyst	-623,620		
Subtotal Catalyst Costs	3,653,865		
Annualized Catalyst Costs	**840,430**		
Energy Penalties			
Turbine backpressure	168,718		
Downtime for catalyst replacement (annualized)	252,285		
Subtotal Energy Penalties Costs	**421,000**		
Subtotal Direct Costs	**1,297,830**	(TDC)	
Contingency	324,460		0.25 x TDC
Indirect Costs			
Overhead	21,840		0.60 x C
Administrative charges	227,125		0.02 x TCI
Property taxes	113,565		0.01 x TCI
Insurance	113,565		0.01 x TCI
Capital recovery	949,695		
Subtotal Indirect Costs	**1,425,790**		
TOTAL ANNUAL COST	**3,048,080**		

Sources: GE, 1992.
ECT, 1992.

Table 4-24. Summary of CO BACT Analysis for Stand-Alone CC Units and CTs

	Emission Impacts			Economic Impacts			Energy Impact	Environmental Impacts	
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact?	Adverse Environmental Impact?
CC Units*									
Oxidation catalyst	86.3	377.8	616.5	7,549,185	3,179,695	5,158	19,882	Yes	Yes
Baseline	227.0	994.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Simple-Cycle CTs†									
Oxidation catalyst	77.7	340.2	540.2	11,356,275	3,048,080	5,643	14,912	Yes	Yes
Baseline	201.0	880.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A

*Basis: two CC units, 100-percent load, 59°F ambient temperature, 75 percent natural gas-firing annual capacity factor, 25 percent distillate fuel oil annual capacity factor.
†Basis: six simple cycle CTs, 100-percent load, 59°F ambient temperature, 50 percent natural gas-firing annual capacity factor, 10 percent distillate fuel oil annual capacity factor.

Source: ECT, 1992.

FDER-38

In Appendix A.2 of Volume 4 which deals with particulate matter emissions from coal handling sources, the moisture content of the coal was assumed to be 15%. AP-42, Section 11.2.3 suggests a mean moisture content for the coal to be 4.5%. Please explain the deviation from this value.

Response

The assumed moisture content of the coal of 15 percent represents the expected maximum moisture content based on available information on the characteristics of coals under consideration for the project. Also, based on available coal source information and Tampa Electric Company's extensive experience in receiving and using coal at its other existing power plant stations, the minimum moisture content of the coal is expected to be approximately 7 percent. Therefore, the moisture content of coal to be delivered and handled at the Polk Power Station is expected to range from 7 to 15 percent.

To provide a more conservative analysis of potential PM impacts for the Polk Power Station, estimates and modeling analyses of the PM emissions from coal handling sources have been revised based on the expected 7-percent minimum moisture content of the coal. The input and output files for the revised particulate modeling analyses in both computer printout and diskette formats are being submitted to FDER under separate cover in conjunction with these sufficiency responses. Appropriate sections and tables in the PSD permit application in Appendix 11.1.3 of the SCA have also been revised based on the revised modeling analyses and are provided in the replacement package for insertion in the SCA.

FDER-39

Please re-submit the State permit application to operate/construct air pollution sources with all the items completely filled. The application included in Volume 5 has not been completely filled out and makes references to different sections of the Site Certification Application.

Response

A completed FDER Application to Operate/Construct Air Pollution Sources for the Polk Power Station is provided in the replacement package for insertion in the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-40

The 49.5 MMBtu/hr auxiliary boiler is not exempt from the permitting requirements unless it is fired exclusively by natural gas based on 17-2.210(3)(a). Please submit a state permit application for the auxiliary boiler.

Response

The 49.5-MMBtu/hr auxiliary boiler will be fired with low sulfur distillate fuel oil. A completed FDER Application to Operate/Construct Air Pollution Sources is provided in the replacement package for insertion in the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-41

The projected Maximum Individual Risk (MIR) is estimated to be 1.9×10^{-6} for the project. Please state how many people in the shaded area as shown in Figure 7-7, page 7-52 of Volume 4 are exposed to levels greater than 1.0×10^{-6}.

Response

Two residences are located within this area. The exact number of people is unknown. It is emphasized that the approach used in the cancer risk assessment was conservative, as discussed in Section 7.5.2 of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-42

Natural gas would be preferred to No. 2 fuel oil as a backup fuel for the GE 7F combustion turbine when syngas is not available. Please explain the choice of No. 2 fuel oil for backup. It appears that natural gas can be made available to the site since Tampa Electric proposed the use of natural gas in other sources.

Response

For natural gas to be used as a backup fuel for the 7F CT when syngas is not available, it must be available at any time. At the current time, the quantities of natural gas required for the unit are unavailable in Florida based on the existing capacity of the gas transmission system, especially since a commitment to take the gas on a continuous basis cannot be made. Natural gas cannot be relied upon as a backup fuel in the near-term timeframe for the 7F CT and IGCC unit since the moment it is needed for backup, adequate capacity to provide the gas may not be available. Therefore, the choice of No. 2 fuel oil as the backup fuel source was made to ensure that there would always be a supply of fuel for the 7F CT.

Future units planned for the Polk Power Station site (i.e., 7EA CT and CC units) will use natural gas as their primary fuel. For these units, a commitment will be made to Florida Gas Transmission (FGT) or other suppliers for large quantities of gas on a continuous, firm basis. The suppliers will then be able to expand the capacity of the pipeline system into Florida to accommodate the large steady gas consumption. This is in contrast to the use of natural gas as a backup fuel. Even when the future units are using natural gas, pipeline capacity will not be adequate to supply the sudden surge in demand associated with natural gas as a backup fuel for the IGCC unit.

FDER-43

Please describe the ultimate fate of all the mercury entering the IGCC. For example, for every 100 pounds of mercury entering the IGCC, please describe where all of it will end up, assuming the worst case emissions to the atmosphere. The total amount of mercury accounted for must add up to 100 pounds for every 100 pounds of mercury entering the IGCC.

Response

The mercury balance is as follows:

Input	Mercury (lb/hr)
Coal	0.0584
Output (fate)	
Slag	0.0050
Fines	0.0484
HRSG stack	0.0030
Thermal oxidizer	0.0020
	0.0584

FDER-44

Would NOx emissions be improved by combining conventional water injection with the proposed advanced dry low NOx burners? If not, then why not? If so, then please evaluate this option as an addendum to the proposed BACT analysis.

Response

NO_x formation is a function of temperature in the combustion zone. Once a minimum stable flame temperature is attained by one NO_x control technology (in this case, advanced dry low-NO_x combustors), application of another control technology such as water injection to further reduce NO_x is not technically feasible since stable combustion could not be achieved.

FDER-45

What chemical additives will be added to the coal slurry to adjust viscosity and pH? What will be the maximum quantity of chemical additives utilized, and the ultimate fate of the chemical additives?

Response

Ammonium lignin sulfonate solution will be used to reduce slurry viscosity and anhydrous ammonia will be used to adjust slurry pH. The maximum consumption of the ammonium lignin sulfonate solution is 625 lb/hr. The maximum consumption of the anhydrous ammonia is 360 lb/hr. Both the ammonium lignin sulfonate and anhydrous ammonia will be sent to the gasifier with the slurry where they will be transformed into raw syngas. Most of the ammonia in the additives is converted to nitrogen and hydrogen in the gasifier. The remainder is processed by the SRU Claus reactor where it is also converted to nitrogen and hydrogen.

FDER-46

Please provide some quantitative technical test data which demonstrates the effect of NOx emissions of various rates of pure nitrogen injection into combustion turbines.

Response

Use of nitrogen addition as a diluent acts in the same fashion as water or steam injection to reduce NO_x formation. All three inert materials serve to lower combustion flame temperatures thereby reducing the formation of NO_x which is strongly temperature dependent. The injected nitrogen passes through the combustion process just as nitrogen present in the inlet combustion air (which is 79 percent by volume nitrogen) passes through the combustion process. Accordingly, the performance of nitrogen injection in reducing NO_x emissions will be comparable to that of water or steam injection.

There have been numerous tests run by GE with various syngas compositions, different diluents (steam, water, CO_2, and nitrogen), various syngas heating values, various firing temperatures, different locations for diluent addition, and different ratios of diluent to fuel gas. However, GE has not yet developed test data for the Polk Power Station IGCC unit specific operating parameters.

Based on GE's extensive combustion turbine design and operating experience and the massive amount of testing that has been performed on other combinations and configurations, GE has predicted and has guaranteed the NO_x emissions for the

IGCC unit at the Polk Power Station based on extrapolations from other configurations and their associated laboratory test data.

GE is currently planning to develop actual test data and formal reports for the Polk Power Station IGCC unit specific configuration in late 1993 and early 1994.

WATER FACILITIES (Industrial Waste)

FDER-47

> The proposed surface water monitoring plan for the effluent at Outfall 001 is not acceptable. A complete analyses of the wastewater in the cooling reservoir for the Primary and Secondary Drinking Water parameters and the following additional parameters must be submitted: BOD_5, Total Organic Carbon (TOC), total nitrogen, organic nitrogen, ammonia nitrogen, total phosphorus, ortho-phosphate, and dissolved oxygen.

Response

Protection of the environment was of paramount importance in Tampa Electric Company's conceptual design of the proposed Polk Power Station. Therefore, to ensure that the surface waters of the state are protected, Tampa Electric Company agrees that additional parameters may need to be periodically analyzed. However, Tampa Electric Company does not believe that all of the aforementioned parameters must be analyzed. According to Section 17-4.246, F.A.C.:

> "(1) The Department may require monitoring and sampling for pollutants that may violate criteria and for background or other conditions related to those pollutants or criteria, *only for pollutants reasonably expected to be generated by and contained in the permitted discharge or to result from the permitted activity* [emphasis added]."

This rule states clearly that only those parameters *reasonably expected* to be generated by the facility need be analyzed. It is apparent from the site-specific background groundwater quality data collected, and knowledge of the typical substances discharged as waste streams by power plants during their operation, that not all of the parameters listed in this comment need be analyzed.

Response

The reference on Page 3.4.3-15 of the SCA regarding descriptions of air emission control technologies is to the PSD permit application contained in Appendix 11.1.3 of the SCA. The PSD permit application comprises all of Volume 4. A description of SCR control technology is provided in Section 4.7.2, Pages 4-88 through 4-90, of the PSD permit application (Volume 4 of the SCA).

FDER-88

> What catalyst is used in SCR? I could not find chemical reaction in the SCA or SCR.

Response

Catalysts typically used in SCR NO_x control systems include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics. Of these, the metal oxide catalysts are the most common commercial SCR catalysts.

Specific SCR chemical reactions are shown in Section 4.7.2, Page 4-88, of the PSD permit application in Appendix 11.1.3 of the SCA.

FDER-89

> The ammonia compounds and arsenic trioxide on pp. 3.4.3-16 to 3.4.3-17 are hazardous substances. What will be the methods of collection and disposal?

Response

Arsenic is a trace metal found in coal and distillate fuel oil. Trace metals resulting from fossil fuel combustion are discharged in both a particulate and vapor phase (often as metal oxides, chlorides, and sulfates) due to the high temperatures occurring in the combustion process. As the combustion exhaust gases cool in the HRSG, vaporized metals will condense on PM present in the exhaust gases. The melting temperature of elemental arsenic is 1,503°F and therefore, this metal would be expected to be discharged from the HRSGs as PM.

Arsenic contained in the coal and distillate fuel oil will be discharged as a PM air emission. The magnitude of arsenic emissions during syngas and fuel oil-firing depends on the content of this metal in the fuels. Estimates of arsenic emission rates are provided in Section 2.2, Table 2-5 (7F CT firing fuel oil, Page 2-50), Table 2-6 (7F CT firing 100-percent CGCU syngas, Page 2-51), Table 2-7 (7F CT firing 50-percent CGCU/50-percent HGCU syngas), Table 2-14 (TGTU thermal oxidizer, Page 2-60), Table 2-15 (H_2SO_4 plant thermal oxidizer, Page 2-61), and Table 2-24 (7EA CT firing fuel oil, Page 2-71) of the PSD permit application in Appendix 11.1.3 of the SCA.

The ammonium compounds (ammonium bisulfate and ammonium sulfate) mentioned on Pages 3.4.3-16 and 3.4.3-17 form as a consequence of reacting ammonia used in a SCR NO_x control system with sulfur compounds present in the exhaust gases. Tampa Electric Company does *not* propose using SCR control systems for the Polk Power Station for the reasons listed in Section 4.7.2.4, Pages 4-107 through 4-109, of the PSD permit application. The reasons for not using SCR control technology include avoiding the generation and handling of toxic ammonia compounds.

FDER-90

> You refer to vanadium pentoxide on the top of p. 3.4.3-18. What is your proposed method of disposal? If you propose speculative accumulation, please state a source you will sell this to and a schedule for use and recycling. RCRA has a specific timetable for storage for speculative accumulation. If you dispose of it, please state the firm you will have do it.

Response

Vanadium pentoxide is a component of the catalyst typically used in SCR NO_x air emission control systems. The SCR catalyst serves as a site to react NO_x and ammonia to form elemental nitrogen and water. The SCR catalyst activity (NO_x conversion efficiency) declines over time and the catalyst must periodically be replaced with fresh catalyst. The catalyst remains in use (within the SCR control system) until it is replaced. Spent catalyst is typically returned to the SCR vendor for reclamation and disposal.

Tampa Electric Company does *not* propose using SCR control systems for the Polk Power Station for the reasons listed in Section 4.7.2.4, Pages 4-107 through 4-109, of the PSD permit application in Appendix 11.1.3 of the SCA. The reasons for not using SCR control technology include avoiding the generation and handling of potentially hazardous spent catalysts.

FDER-91

> Any cleaning of the systems that will use SCR will result in waste requiring hazardous material disposal. Please inform us of the firm you intend to use for disposal and the quantities of hazardous waste that will be generated in addition to all hazardous constituents. Will heavy metals be present?

Response

As previously noted in the response to Comment Nos. FDER-89 and FDER-90, Tampa Electric Company does *not* propose using SCR control systems for the Polk Power Station for the reasons listed in Section 4.7.2.4, Pages 4-107 through 4-109, of the PSD permit application in Appendix 11.1.3 of the SCA. The reasons for not using SCR control technology include avoiding the generation and handling of potentially hazardous materials such as ammonium compounds and spent catalysts.

FDER-92

> On p. 3.6.2-4, it states the cleaning solution waste will be "collected and transported offsite for appropriate treatment and disposal". Who do you intend to use and what firm now does this at your other facilities?

Response

At its existing power plant facilities, Tampa Electric Company has been contracting with Industrial Water Services, Inc., in Jacksonville, Florida, to dispose of chemical cleaning wastes in accordance with all county, state, and federal regulations. There are a number of firms that are fully qualified to perform these services. Selection of a firm to perform these services at the Polk Power Station in the future will be based on a competitive bidding process with qualified firms.

FDER-93

> In paragraph 3.7.1.3, it refers to a brine disposal area. Is this lined with a synthetic liner? Is the liner system to be made consistent with RCRA hazardous waste regulations? What do they mean by a "temporary cover" (middle of the page)? A number of the trace elements listed are hazardous substances. It appears the brine will be RCRA regulated substance. Please respond.

<u>Response</u>

The brine disposal area will consist of inactive and active cells. Inactive cells will be permanently capped brine solids storage areas. An active cell is defined as the brine solids storage cell which is in the process of being filled with brine solids and requires a temporary cover during a storm event. Only one active cell will be in use at any given time.

An impermeable synthetic liner will be placed under the entire brine disposal area. The liner will meet design considerations listed in 40 CFR 267, Subpart C §21 and Section 17-701.050, F.A.C.

The temporary cover will be an impermeable tarpaulin or similar device designed to minimize the amount of rainfall contacting the brine solids in the active cell. A permanent low permeable clay-like material will be used to cover the active cell after each is completely filled becoming an inactive cell.

The brine solids are not expected to be an Resource Conservation and Recovery Act (RCRA)-regulated substance. None of the brine solids constituents, including the trace elements mentioned on Page 3.7.1-2 of the SCA, are listed in 40 CFR 261, Subpart 33(f). Brine solids are not listed as a nonspecific or specific source as indicated in 40 CFR 261.31 and 261.32.

ATTACHMENT FDER-A

SO_2 PSD INCREMENT EXPANDING SOURCES BACKGROUND INFORMATION

SO_2 PSD INCREMENT EXPANDING SOURCES BACKGROUND INFORMATION

Background information is provided for sources identified by FDER included in the attached source inventory submitted to FDER on May 4, 1992.

SOURCES 400-450: CF BARTOW

Based on information from FDER's Tampa office files, the following emissions were reported by CF on July 29, 1975. An EPA Consent Order, dated November 14, 1975, required source compliance with emission limits which became effective on July 1, 1975 (after the SO_2 baseline date of January 6, 1975). It should be noted that prior to July 1, 1975, there were no emission limiting standards in Florida for sulfuric acid plants.

The appropriate baseline emissions for the CF Bartow Plant are estimated as follows:

Source No.	Acid Rate (TPD)	Reported Emission (lb/ton)	Emission in Inventory (lb/hr)	(g/s)
400	400	29	483.3	60.90
410	500	42	875.0	110.25
420	600	34	850.0	107.10
430	900	37	1387.5	174.83
440	900	48	1800.0	226.80
450	900	36	1350.0	170.10

Sample Calculation:

$$SO_2 = 400 \text{ tons/day} \times 29 \text{ lbs } SO_2\text{/ton acid} \times \text{day/24 hrs}$$
$$= 483.3 \text{ lbs/hr}$$
$$\times\ 0.126 \text{ g/s / lb/hr}$$
$$= 60.9 \text{ g/s}$$

SOURCE 640: USSAC FT. MEADE ROCK DRYER

This source has not been operated in several years. However, the company intends to keep the operation permit on the source current. As a result, the appropriate emission level in accordance with FDER protocol is zero, as the permit has not been surrendered.

SOURCE 650: USSAC FT. MEADE GTSP

Based on information from the FDER Tampa office files, the SO_2 emissions from the GTSP plant reported by USSAC on January 4, 1979, are as follows:

$$SO_2 = 72.5 \text{ lbs/hr} \times 2 \text{ trains}$$
$$= 145 \text{ lbs/hr}$$
$$\times\ 0.126 \text{ g/s / lb/hr}$$
$$= 18.27 \text{ g/s}$$

SOURCE 730: W.R. GRACE/SEMINOLE DRYER

Based on information from the FDER Tampa office files, the SO_2 emissions reduction from the two rock dryers at Seminole Fertilizer Corporation are based on the source operation for the past five years (and proposed future use) on natural gas. The dryers were previously operated on No. 6 fuel oil with a sulfur content of 2.4 percent. The SO_2 absorption of 40 percent is based on testing on similar units.

Dryer No. 1 - 120 MMBTU/hr

SO_2 = 120 x 10^6 BTU/hr x lb/18,300 BTU x 0.024 lb S/lb oil

x 2 lb SO_2/lb S x (1-0.4) SO_2 sorption

= 188.85 lbs/hr

x 0.126 g/s / lb/hr

= 23.80 g/s

Dryer No. 2 - 80 MMBTU/hr

SO_2 = 80 x 10^6 BTU/hr x lb/18,3000 BTU x 0.024 lb S/lb oil

x 2 lb SO_2/lb S x (1-0.4) SO_2 sorption

= 125.90 lbs/hr

x 0.126 g/s / lb/hr

= 15.86 g/s

As SO_2 emissions from natural gas firing are negligible, total SO_2 reduction from the two dryers combined are:

$$SO_2 \text{ total} = (23.80 + 15.86) \text{ g/s}$$
$$= 39.66 \text{ g/s}$$

SOURCE 960: AGRICO PIERCE DRYERS 1 AND 2

Based on information from the FDER Tampa office files, the following are the emissions for Dryers 1 and 2. The SO_2 absorption factor of 40 percent is based on testing on similar units. These dryers are no longer in existence.

$$SO_2 = 64 \times 10^6 \text{ BTU/hr} \times 2 \text{ units} \times \text{lb/18,300 BTU}$$
$$\times\ 0.023 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2\text{/lb S} \times (1-0.4)\ SO_2 \text{ sorption}$$
$$= 193.05 \text{ lbs/hr}$$
$$\times\ 0.126 \text{ g/s / lb/hr}$$
$$= 24.32 \text{ g/s}$$

SOURCE 970: AGRICO PIERCE DRYERS 3 AND 4

Based on information from the FDER Tampa office files, the following are the emissions for Dryers 3 and 4 (Permit No. A053-5031). The SO_2 absorption factor of 40 percent is based on testing on similar units. These dryers are no longer is existence.

SO_2 = 19,800 gals/day x day/24 hrs x 8 lb/gal x 0.023 lb S/lb oil x 2 lb SO_2/lb S x (1-0.4) SO_2 sorption

= 182.16 lbs/hr (for two dryers combined) x 0.126 g/s / lb/hr

= 22.95 g/s ~ 23.0 g/s

SOURCES 980 AND 990: BORDEN DRYERS

The SO_2 emission rates for Sources 980 and 999 are 5.29 and 6.48 g/s, respectively, based on the emission inventory compiled by Walk-Haydel (Sources 2a and 2b) in support of a permit application for Conserv (AC-53-42397, PSD-FL-076).

SOURCES 1000 AND 1010: DOLIME BOILER AND DRYER

The SO_2 emission rates for Sources 1000 and 1010 are 4.52 and 5.68 g/s, respectively, based on the emission inventory compiled by Walk-Haydel (Sources 4a and 4b) in support of a permit application for Conserv (AC-53-42397, PSD-FL-076).

SOURCE 1020: ESTECH/SWIFT SAP

Based on information from the FDER Tampa office files, the emission rate of this source is calculated from a sulfuric acid production rate of 610 tons/day (Permit No. A053-2103) and an emission rate of 29 lb/ton acid. This plant is no longer in existence.

SO_2 = 610 tons/day x 29 lbs/ton x day/24 hrs

= 737 lbs/hr

x 0.126 g/s / lb/hr

= 92.87 g/s

SOURCE 1030: ESTEC/SWIFT DRYER

Based on information from the FDER Tampa office files, the following is the emission rate of the dryer. The SO_2 absorption factor of 40 percent is based on testing on similar units. This dryer is no longer in existence.

SO_2 = 126 x 10^6 BTU/hr x lb/18,300 BTU x 0.023 lb S/lb oil

x 2 lb SO_2/lb S x (1-0.4) SO_2 sorption

= 190.03 lbs/hr

x 0.126 g/s / lb/hr

= 23.94 g/s

SOURCE 1040: ESTEC/SWIFT DRYER

Based on information from the FDER Tampa office files, the following is the emission rate of the dryer. The SO_2 absorption factor of 40 percent is based on testing on similar units. This dryer is no longer in existence.

$$SO_2 = 120 \times 10^6 \text{ BTU/hr} \times \text{lb}/18{,}300 \text{ BTU} \times 0.023 \text{ lb S/lb oil}$$

$$\times\ 2 \text{ lb } SO_2\text{/lb S} \times (1-0.4)\ SO_2 \text{ sorption}$$

$$= 180.98 \text{ lbs/hr}$$

$$\times\ 0.126 \text{ g/s / lb/hr}$$

$$= 22.8 \text{ g/s}$$

SOURCE 1050: USSAC BARTOW SAP

Based on information from the FDER Tampa office files, the following is the SO_2 emission rate from the SAP based on a production rate of 800 tons per day (Permit No. A053-59987) and an emission rate of 10 lbs/ton acid. This plant is no longer in existence.

$$SO_2 = 800 \text{ tons/day} \times 10 \text{ lbs/ton} \times \text{day}/24 \text{ hrs}$$

$$= 333.33 \text{ lbs/hr}$$

$$\times\ 0.126 \text{ g/s / lb/hr}$$

$$= 42.0 \text{ g/s}$$

SOURCE 1060: USSAC BARTOW DRYER

Based on the emission inventory compiled by Walk-Haydel (Source 14b, Conserv permit AC53-42397, PSD-FL-076), the emission rate of Source 1060 is 3.41 g/s. This dryer is no longer in existence.

SOURCES 1070 AND 1080: GENERAL PORTLAND CEMENT KILNS 4 AND 5

Based on the emission inventory compiled by Walk-Haydel (Source 24b and c, Conserv permit AC53-42397, PSD-FL-076), the emission rates of Sources 1070 and 1080 are 62.99 and 69.3 g/s, respectively. These kilns are no longer in existence.

SOURCE 1090: ELECTROPHOS 400 HP BOILER

(Note: All Electrophos sources (Sources 1090-1140) are no longer in existence.)

Based on information from the FDER Tampa office files, the following is the emission rate of the boiler.

$$
\begin{aligned}
SO_2 &= 135 \text{ gals/hr} \times 8 \text{ lbs/gal} \times 0.024 \text{ lb S/lb oil} \\
&\quad \times 2 \text{ lb } SO_2\text{/lb S} \\
&= 51.84 \text{ lbs/hr} \\
&\quad \times 0.126 \text{ g/s / lb/hr} \\
&= 6.53 \text{ g/s}
\end{aligned}
$$

SOURCE 1100: ELECTROPHOS 600 HP BOILER

Based on information from the FDER Tampa office files, the following is the emission rate of the boiler.

$$SO_2 = 30.4 \times 10^6 \text{ BTU/hr} \times \text{lb/18,300 BTU} \times 0.024 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2\text{/lb S}$$

$$= 79.7 \text{ lbs/hr} \times 0.126 \text{ g/s / lb/hr}$$

$$= 10.05 \text{ g/s}$$

SOURCE 1110: ELECTROPHOS FEED PREPARATION DRYER

Based on information in the FDER Tampa office files, the following is the emission rate of the feed prep. dryer.

$$SO_2 = 66.0 \times 10^6 \text{ BTU/hr} \times \text{lb/18,300 BTU} \times 0.024 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2\text{/lb S}$$

$$= 173.11 \text{ lbs/hr} \times 0.126 \text{ g/s / lb/hr}$$

$$= 21.81 \text{ g/s}$$

SOURCE 1120: ELECTROPHOS COKE DRYER

Based on information in the FDER Tampa office files, the following is the emission rate of the coke dryer.

$$SO_2 = 9.6 \times 10^6 \text{ BTU/hr} \times \text{lb/18,300 BTU} \times 0.024 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2\text{/lb S}$$

$$= 25.18 \text{ lbs/hr} \times 0.126 \text{ g/s / lb/hr}$$

$$= 3.17 \text{ g/s}$$

SOURCE 1130: ELECTROPHOS CALCINER

Based on information in the FDER Tampa office files, the following is the emission rate of the calciner.

$$
\begin{aligned}
SO_2 &= 21.5 \times 10^6 \text{ BTU/hr} \times \text{lb}/18{,}300 \text{ BTU} \times 0.024 \text{ lb S/lb oil} \\
&\quad \times 2 \text{ lb } SO_2/\text{lb S} \\
&= 56.39 \text{ lbs/hr} \\
&\quad \times 0.126 \text{ g/s / lb/hr} \\
&= 7.11 \text{ g/s}
\end{aligned}
$$

SOURCE 1140: ELECTROPHOS FURNACE

Based on information from the FDER Tampa office files, the following is the emission rate of the electric furnace which processes 62,500 pounds per hour of phosphate rock containing 0.3 percent sulfur.

$$
\begin{aligned}
SO_2 &= 62{,}500 \text{ lbs/hr} \times 0.003 \text{ lb S/lb rock} \times 2 \text{ lb } SO_2/\text{lb S} \\
&= 375.0 \text{ lbs/hr} \\
&\quad \times 0.126 \text{ g/s / lb/hr} \\
&= 47.25 \text{ g/s}
\end{aligned}
$$

SOURCE 1150: BREWSTER/IMPERIAL DRYER

Based on information from the FDER Tampa office files, the following is the emission rate for the dryer. The SO_2 absorption factor of 40 percent is based on testing on similar units. This dryer is no longer in existence.

$$SO_2 = 134 \times 10^6 \text{ BTU/hr} \times \text{lb}/18{,}300 \text{ BTU} \times 0.0174 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2/\text{lb S} \times (1-0.4)\ SO_2 \text{ sorption}$$

$$= 152.89 \text{ lbs/hr} \times 0.126 \text{ g/s / lb/hr}$$

$$= 19.26 \text{ g/s}$$

ADDITIONAL SO_2 PSD INCREMENTAL EXPANDING SOURCES

1. Mobil Nichols - Calciner

Based on information from the FDER Tampa office files, the following is the emission rate of the calciner (A053-136222). The permit was surrendered on May 4, 1992.

$$
\begin{aligned}
SO_2 &= 110.2 \text{ lbs/hr (permit limit)} \\
&\quad \times 0.126 \text{ g/s / lb/hr} \\
&= 13.89 \text{ g/s}
\end{aligned}
$$

2. Mobil Nichols - 75 HP Boiler

Based on the information from the FDER Tampa office files, the following is the emission rate of the boiler (A053-117006). The permit was surrendered on May 4, 1992.

$$
\begin{aligned}
SO_2 &= 75 \text{ HP} \times 3.352 \times 10^4 \text{ BTU/HP} \times \text{lb}/18{,}300 \text{ BTU} \\
&\quad \times 0.025 \text{ lb S/lb oil} \times 2 \text{ lb } SO_2\text{/lb S} \\
&= 6.87 \text{ lbs/hr} \\
&\quad \times 0.126 \text{ g/s / lb/hr} \\
&= 0.87 \text{ g/s}
\end{aligned}
$$

3. CF Industries - SAP A and B

These plants have been listed in many past permit application emission inventories, including a 1987 permit application by Central Phosphates, Inc. (now CF). The emission rates of Plant A and B were 52.5 g/s each; or a total of 105.0 g/s for the two plants combined. Prior to May 1988, they operated at 10 lbs/ton, 416.7 lbs/hr and 78 feet stack height. The plants subsequently operated at 8 lbs/ton, 350 lbs/hr and 110 feet stack height (see FDER permits AC29-146176 and 177).

4. IMC New Wales - Rock Dryer

This source has been listed in many past permit applications emission inventories, including a 1987 permit application by Central Phosphates, Inc. (CF). The emission rate of the dryer is 34.27 g/s.

The permit for this dryer was surrendered during the Third Train expansion in about 1980 (see attached).

SO2 PSD SOURCE INVENTORY 5/1/92

SOURCE NO.	EMIS (g/s)	UTM COORDINATES (km) EAST	UTM COORDINATES (km) NORTH	HT (m)	TEMP (K)	VEL (m/s)	DIAM (m)	BUILDING (m) HT	BUILDING (m) L	BUILDING (m) W	SOURCE DESCRIPTION
10	466.40	467.500	3197.200	15.24	819.8	56.21	4.21	11.8	17.1	17.1	FPC/DEBARY PROP TURBINES AT 20 DEG F
20	310.90	446.300	3126.000	15.24	819.8	56.21	4.21	11.8	17.1	17.1	FPC/INT. CITY PROP TURBINES/7EA AT 20 DEG F
30	276.10	446.300	3126.000	15.24	880.8	32.07	7.04	11.8	17.1	17.1	FPC/INT. CITY PROP TURBINES/7FA AT 20 DEG F
40	98.40	360.008	3162.398	97.60	442.0	23.23	4.88				FLORIDA CRUSHED STONE KILN 1
50	-50.40	388.000	3116.000	60.35	353.0	16.40	2.44				CF IND. BASELINE C
60	54.60	388.000	3116.000	60.35	353.0	17.77	2.44				CF IND. PROPOSED C
70	-50.40	388.000	3116.000	60.35	353.0	16.40	2.44				CF IND. BASELINE D
80	54.60	388.000	3116.000	60.35	353.0	17.77	2.44				CF IND. PROPOSED D
90	1.45	356.200	3169.900	27.40	470.2	7.48	4.88				FLORIDA MINING & MATERIALS KILN 2
100	654.70	361.900	3075.000	149.40	342.2	19.81	7.32				TECO BIG BEND UNIT 4
110	-2436.00	361.900	3075.000	149.40	422.0	28.65	7.32				TECO BIG BEND UNITS 1&2 (24-HR)
120	-1218.00	361.900	3075.000	149.40	418.0	14.33	7.32				TECO BIG BEND UNIT 3 (24-HR)
130	14.10	347.100	3139.200	83.82	394.3	15.70	3.05				PASCO COUNTY RRF
140	1008.80	334.200	3204.500	182.90	398.0	21.00	6.90				CRYSTAL RIVER 4
150	1008.00	334.200	3204.500	182.90	398.0	21.00	6.90				CRYSTAL RIVER 5
160	-314.00	334.200	3204.500	152.00	422.0	42.10	4.57				CRYSTAL RIVER 1
170	-1859.00	334.200	3204.500	153.00	422.0	42.10	4.88				CRYSTAL RIVER 2
180	105.40	483.500	3150.600	167.60	325.7	21.60	5.80				ORLANDO UTIL STANTON 1
190	242.40	483.500	3150.600	167.60	324.2	23.50	5.80				ORLANDO UTIL STANTON 2 (24-HR)
200	32.10	460.100	3129.300	18.30	422.0	38.00	3.66				KISSIMMEE UTIL EXIST
210	277.60	404.800	3057.400	22.90	389.0	23.90	4.88				HARDEE
220	-4.86	325.600	3116.700	7.32	464.0	3.23	0.91				STAUFFER BOILER
230	-7.36	325.600	3116.700	25.61	306.0	6.97	2.13				STAUFFER KILN
240	-0.45	325.600	3116.700	25.61	322.0	6.97	0.91				STAUFFER ROASTER
250	-1.50	325.600	3116.700	18.29	322.0	22.87	0.70				STAUFFER DRYER
260	-50.93	325.600	3116.700	49.00	335.0	3.60	1.20				STAUFFER FURNACE
270	500.10	408.500	3105.800	76.20	350.0	19.70	4.88				LAKELAND MCINTOSH 3
280	21.40	368.200	3092.700	50.00	491.0	18.30	1.80				HILLS. CO. RESOURCE RECOVERY
290	62.24	335.300	3084.400	49.10	522.0	27.72	2.74				PINELLAS
300	0.20	383.300	3135.800	12.30	466.2	9.20	0.40				EVANS PACKING
310	2.25	361.400	3168.400	8.50	357.4	10.95	1.08				ASPHALT PAVERS 4 (0700-1800)
320	2.25	359.900	3162.400	12.20	377.0	10.58	1.37				ASPHALT PAVERS 3 (0700-1800)
330	29.11	409.185	3102.754	30.48	783.2	28.22	5.79				LAKELAND UTILITIES CT
340	-146.00	396.600	3078.900	61.00	350.0	14.28	2.60				IMC SAP #1,2,3 BASELINE
350	189.00	396.600	3078.900	61.00	350.0	15.31	2.60				IMC SAP #1,2,3 (3 AT 3000 TPD)
360	126.00	396.600	3078.900	60.70	350.0	15.31	2.60				IMC SAP #4,5 (2 AT 3000 TPD)
370	5.54	396.600	3078.900	36.60	319.1	20.15	1.83				IMC DAP
380	5.04	385.600	3139.000	30.48	384.3	17.13	3.35	15.5	39.9	39.9	PASCO CO. COGEN. FACLITY PROPOSED
390	5.04	434.000	3198.800	30.48	384.3	17.13	3.35	15.5	39.9	39.9	LAKE CO. COGEN. FACILITY PROPOSED
400	-60.90	408.500	3082.500	30.49	350.0	12.20	1.37				CF BARTOW H2SO4 1 (400 TPD)
410	-110.25	408.500	3082.500	30.49	350.0	10.37	1.68				CF BARTOW H2SO4 2 (500 TPD)
420	-107.10	408.500	3082.500	30.49	364.0	4.27	2.74				CF BARTOW H2SO4 3 (600 TPD)
430	-174.83	408.500	3082.500	30.49	358.0	7.93	2.13				CF BARTOW H2SO4 4 (900 TPD)
440	-226.80	408.500	3082.500	63.41	358.0	10.67	2.13				CF BARTOW H2SO4 5 (900 TPD)
450	-170.10	408.500	3082.500	63.41	359.0	10.37	2.13				CF BARTOW H2SO4 6 (900 TPD)
460	42.00	408.500	3082.500	67.10	351.0	9.80	2.40				CF BARTOW H2SO4 7 (2000 TPD)
470	50.40	408.500	3082.500	63.41	361.0	10.88	2.13				CF BARTOW H2SO4 5 (2400 TPD)
480	50.40	408.500	3082.500	63.41	370.0	7.28	2.13				CF BARTOW H2SO4 6 (2400 TPD)
490	4.30	408.500	3082.500	9.10	450.0	22.50	0.70				CF BARTOW DAP
500	21.02	361.800	3088.300	30.00	375.0	20.00	0.61				CLM CHL
510	-54.60	398.400	3084.200	30.50	308.0	18.90	1.80				CONSERVE (2 @ 1300 TPD & 4 LB/TON)
520	42.00	398.400	3084.200	45.70	352.0	10.30	2.30				CONSERVE (2000 TPD @ 4 LB/TON)
530	-3.88	398.400	3084.200	24.40	339.0	12.90	1.52				CONSERVE ROCK DRYER
540	-83.98	409.500	3079.500	30.48	311.0	20.18	1.37				FARMLAND 1,2 H2SO4
550	67.16	409.500	3079.500	30.48	355.0	9.27	2.29				FARMALND 3,4 H2SO4

560	41.96	409.500	3079.500	45.72	355.0	9.65	2.44	FARMLAND 5 H2SO4
570	0.00	389.550	3067.930	38.10	339.0	10.13	2.90	IMC LONESOME MINE DRY 1 (SHUTDOWN 5/26/88)
580	0.00	389.550	3067.930	38.10	346.0	18.40	2.44	IMC LONESOME MINE DRY 2 (SHUTDOWN 5/26/88)
590	-152.71	406.700	3085.200	51.00	356.0	9.90	2.13	ROYSTER (1003 TPD @ 29 LB/TON)
600	35.70	406.700	3085.200	61.00	360.0	12.20	2.13	ROYSTER (1700 TPD @ 4 LB/TON)
610	63.00	416.120	3068.620	53.40	355.0	15.91	2.59	USSAC FT MEADE H2SO4 1
620	63.00	416.120	3068.620	53.40	355.0	15.91	2.59	USSAC FT MEADE H2SO4 2
630	-78.80	416.210	3068.740	29.00	314.0	6.77	3.02	USSAC FT MEADE H2SO4 (1500 TPD @ 10 LB/TON)
640	-15.79	416.000	3069.000	25.60	332.0	16.26	1.52	USSAC FT MEADE ROCK DRYER
650	-18.27	416.000	3069.000	28.35	330.0	17.60	1.52	USSAC FT MEADE GTSP
660	-108.00	409.770	3086.990	45.72	352.0	16.50	1.37	W.R. GRACE/SEMINOLE SAP #1
670	-108.00	409.770	3086.990	45.72	352.0	16.50	1.37	W.R. GRACE/SEMINOLE SAP #2
680	-52.50	409.770	3086.990	45.72	311.0	16.70	1.52	W.R. GRACE/SEMINOLE SAP #3
690	42.87	409.770	3086.990	45.72	311.0	16.70	1.52	W.R. GRACE/SEMINOLE SAP #3
700	40.32	409.770	3086.990	60.96	347.0	25.10	1.52	W.R. GRACE/SEMINOLE SAP #4
710	40.32	409.770	3086.990	60.96	347.0	25.10	1.52	W.R. GRACE/SEMINOLE SAP #5
720	40.32	409.770	3086.990	60.96	347.0	25.10	1.52	W.R. GRACE/SEMINOLE SAP #6
730	-39.41	409.770	3086.990	15.24	327.0	17.32	2.04	W.R. GRACE/SEMINOLE DRYER
740	52.50	363.400	3082.400	45.72	355.0	8.63	2.44	GARDINIER/CARGILL SAP #8
750	46.20	363.400	3082.400	45.72	355.0	9.20	2.29	GARDINIER/CARGILL SAP #7
760	-28.89	363.400	3082.400	20.73	310.0	13.12	1.07	GARDINIER/CARGILL DRYER
770	54.60	363.400	3082.400	45.72	344.0	12.50	2.74	GARDINIER/CARGILL SAP #9
780	-196.30	363.400	3082.400	22.60	322.0	19.51	1.52	GARDINIER/CARGILL SAP #4,5,6
790	-50.71	363.400	3082.400	45.72	355.0	9.20	2.29	GARDINIER/CARGILL SAP #7
800	0.60	394.800	3067.720	8.20	505.0	7.57	0.41	MOBIL BIG-4 BOILER
810	1.90	394.850	3069.770	30.50	334.0	7.26	1.82	MOBIL BIG-4 DRYER
820	2.44	398.290	3084.290	25.90	339.0	15.20	2.29	MOBIL NICHOLS #4 DRYER
830	2.99	382.200	3166.100	9.14	478.0	4.57	0.61	FDOC BOILER #3
840	0.82	386.700	3155.800	10.67	327.0	8.99	1.83	ER JAHNA (LIME DRYER)
850	2.09	359.800	3164.900	7.62	347.0	6.29	1.83	OMAN CONST (ASPHALT)
860	0.23	340.600	3119.200	12.20	339.0	6.47	3.05	DRIS PAVING (ASPHALT)
870	3.67	355.900	3143.700	9.14	408.0	16.00	1.30	OVERSTREET PAV. (ASPHALT)
880	0.06	331.200	3124.500	10.98	544.0	3.88	0.31	NEW PORT RICHEY HOSP BLR#1
890	0.03	331.200	3124.500	10.98	544.0	3.88	0.31	NEW PORT RICHEY HOSP BLR#2
900	0.08	333.400	3141.000	10.98	533.0	4.00	0.31	HOSP CORP OF AM BOILER #1
910	0.08	333.400	3141.000	10.98	533.0	4.00	0.31	HOSP CORP OF AM BOILER #2
920	7.25	340.700	3119.500	9.14	436.0	22.30	1.40	COUCH CONST-ODESSA (ASPHALT)
930	3.54	390.300	3129.400	6.10	422.0	21.00	1.38	COUCH CONST-ZEPHYRHILLS (ASPHALT)
940	-75.60	407.500	3071.300	45.73	350.0	26.40	1.60	AGRICO H2SO4 (2 @1800 TPD)
950	113.50	407.500	3071.300	45.73	350.0	39.06	1.60	AGRICO H2SO4 (2 @ 2700 TPD)
960	-24.32	404.100	3078.950	24.38	339.0	12.94	1.52	AGRICO PIERCE DRYERS 1,2
970	-23.00	404.100	3078.950	24.38	339.0	18.82	2.43	AGRICO PIERCE DRYERS 3,4
980	-5.29	414.500	3109.000	17.07	333.0	8.26	2.34	BORDEN DRYER
990	-6.48	394.800	3069.600	30.48	344.0	14.79	1.82	BORDEN DRYER
1000	-4.52	404.813	3069.548	27.43	494.1	7.25	0.61	DOLIME BOILER
1010	-5.68	404.813	3069.548	27.43	333.0	20.67	1.52	DOLIME DRYER
1020	-92.87	411.500	3074.200	30.79	358.0	3.90	2.13	ESTECH/SWIFT SAP (610 TPD & 29 LB/TON)
1030	-23.94	411.500	3074.200	18.29	339.0	8.47	2.95	ESTECH/SWIFT DRYER
1040	-22.80	411.500	3074.200	18.75	340.0	5.06	2.95	ESTECH/SWIFT DRYER
1050	-41.90	413.200	3086.300	28.96	305.0	7.50	2.12	USS AGRI-CHEM BARTOW SAP (800 TPD & 10 LB/TON)
1060	-4.99	413.200	3086.300	15.80	332.0	10.01	1.83	USS AGRI-CHEM BARTOW DRYER
1070	-62.99	358.000	3090.600	35.97	505.2	17.61	2.74	GEN. PORT. CEMENT KILN 4
1080	-69.30	358.000	3090.600	45.42	494.1	5.80	3.81	GEN. PORT. CEMENT KILN 5
1090	-6.53	405.600	3079.400	7.32	464.0	3.23	0.91	ELECTROPHOS 400HP BOILER
1100	-10.00	405.600	3079.400	6.10	464.0	7.71	0.91	ELECTROPHOS 600HP BOILER
1110	-20.90	405.600	3079.400	18.29	350.0	6.79	1.83	ELECTROPHOS ROCK DRYER
1120	-2.97	405.600	3079.400	18.29	322.0	22.87	0.70	ELECTROPHOS COKE DRYER
1130	-7.11	405.600	3079.400	25.61	306.0	6.97	2.13	ELECTROPHOS CALCINER
1140	-47.25	405.600	3079.400	29.27	314.0	8.52	2.13	ELECTROPHOS FURNACE (31.25 TPH ROCK @ 0.3% S)
1150	-19.60	404.800	3069.500	27.44	339.0	15.25	2.29	BREWSTER/IMPERIAL DRYER

PREVENTION OF SIGNIFICANT DETERIORATION REVIEW APPLICATION

AND

APPLICATION TO CONSTRUCT

PROPOSED SULFURIC ACID PLANT
POLK COUNTY, FLORIDA

CONSERV
NICHOLS, FLORIDA

VOLUME I

WH&A Job No. 2777
April 1981

WALK, HAYDEL & ASSOCIATES, INC.
ENGINEERS
NEW ORLEANS - MOBILE - BATON ROUGE

2) these angles were then used to obtain worst case days (high and second high) for major sectors in the desired directions for each year,

3) worst case days for each year for a particular case were then tabulated,

4) the critical direction (chosen by selecting the source complex closest to Conserv with the largest emissions output) in the interval of angles for a case was selected,

5) this critical angle was then used to compare the highest and second high concentrations for each of the five years of data - the higest concentration indicated the worst case meteorology for this direction out of the five years of data. This year of data and its high and second high days for all necessary angles was then selected for input to the ISC program.

8.3 Emissions Inventory

An inventory of emissions for all SO_2 sources (phosphate and non-phosphate) was compiled from records in the Tampa office of the Florida DER. Sources within 50 kilometers of Conserv were included in the inventory, and particularly large sources outside of 50 kilometers were included (e.g., Florida Power, Bartow plant).

The final inventory, Table 2 Appendix A, consists of sources whose emissions approached or exceeded a rate of 5.0 grams/second for sources greater than approximately 15 kilometers in distance from Conserv. For facilities that were close to Conserv (Mobil , Kaiser) all documented sources of SO_2 were included.

8.4 PSD Regulations

For the purpose of modeling (inclusion or exclusion of sources for a particular case), Federal PSD rules were followed per instructions of

TABLE 2
SOURCES AND PARAMETERS USED IN DISPERSION MODELING

	Name	I.D.	Emission Rate (g/s)	UTM Coordinates East	UTM Coordinates North	Height (m)	Temp. (°F)	Exit Velocity	Diameter (m)
1)	AGRICO CHEM.								
a)	Sulfuric Acid #10	01010	37.8	407.9	3071.0	45.72	360.	8.71	1.58
b)	SAP #11	01020	37.8	407.9	3071.0	45.72	57.	10.21	1.58
c)	R. Dryer 1	01030	11.09	407.9	3071.0	24.38	339.	12.94	1.52
d)	Dryers 3 & 4	01040	17.47	407.9	3071.0	24.38	339.	17.92	2.9
e)	SAP (New)	01050	42.0	407.6	3071.3	45.72	350.	9.54	2.9
f)	DAP (New)	01060	12.41	407.6	3071.3	38.1	327.	14.55	3.05
2)	BORDEN								
a)	Ph. Rock Dryer	02010	5.29	414.5	3109.0	17.07	333.	8.26	2.34
b)	Ph. Rock Dryer	02020	6.48	394.8	3069.6	30.48	344.	14.79	1.82
3)	C.F. CHEMICALS								
a)	SPA Plt. 1	03010	4.31	408.198	3082.678	9.14	355.	15.78	.433
b)	SAP No. 7	03020	41.99	408.198	3082.678	61.57	350.8	9.77	2.44
c)	SAP No. 2	03030	-110.6	408.198	3082.678	30.48	350.	4.6	1.68
d)	SAP No. 1	03040	114.66	408.198	3082.678	30.48	347.	7.27	1.68
e)	SAP No. 6	03050	25.19	408.198	3082.678	63.4	370.	7.28	2.13
f)	SAP No. 3	03060	42.0	408.198	3082.678	34.31	305.	18.9	1.24
g)	SAP No. 4	03070	55.18	408.198	3082.678	30.48	308.	20.2	1.22

TABLE 2
Continued

h) SAP No. 5	03080	63.0	408.198	3082.678	63.4	361.	10.88	2.13
4) DOLIME								
a) Boiler	04010	4.52	404.813	3069.548	27.43	494.1	7.25	.61
b) Dryer	04020	5.68	404.813	3069.548	27.43	333.	20.67	1.52
5) ELECTROPHOS								
a) Calciner	05010	6.24	405.6	3079.4	25.6	322.	8.01	2.13
6) FARMLAND INDUSTRIES								
a) SAP No. 4	06010	57.74	409.5	3079.5	30.48	305.	23.9	1.37
b) SAP No. 2	06020	41.99	409.5	3079.5	30.48	311.	22.3	1.37
c) SAP No. 1	06030	41.99	409.5	3079.5	30.48	311.	19.9	1.37
d) SAP No. 3	06040	63.0	409.5	3079.5	30.48	301.	24.1	1.37
e) Boiler	06050	4.58	409.5	3079.5	14.17	444.	12.66	1.22
7) GARDINIER								
a) R.Dryer	07010	17.6	415.3	3063.3	19.2	344.	8.96	2.89
b) SAP No. 8	07020	91.87	363.4	3082.4	45.72	355.	8.63	2.44
c) GTSP	07030	9.6	363.4	3082.4	38.4	328.	11.56	2.44
d) SAP No. 7	07040	36.75	363.4	3082.4	45.72	355.	9.20	2.29
e) Dryer	07050	28.89	363.4	3082.4	20.73	310.	13.12	1.07
f) Boiler	07060	10.08	363.4	3082.4	18.29	589.	6.99	2.54
g) Ph.A. Conc	07070	7.56	363.4	3082.4	23.77	345.	6.19	1.83
h) No. 7 PAC	07080	6.56	363.4	3082.4	23.77	343.	6.8	1.83
i) No. 8 PAC	07090	6.35	363.4	3082.4	23.77	343.	6.8	1.83
j) SAP No.9	07100	54.6	363.4	3082.4	45.72	344.	12.5	2.74
k) SAP 4,5,6	07110	-196.3	363.4	3082.4	22.6	322.	19.51	1.52
l) SAP No. 7	07041	-50.71	363.4	3082.4	45.72	355.	9.2	2.29
m) DAP P24	07120	4.29	363.4	3082.4	60.39	320	13.38	2.13

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TABLE 2
Continued

10)	KAISER								
a)	Dryer	10010	1.23	401.5	3086.5	18.29	333.	11.9	.27
b)	Dryer	10020	1.41	401.5	3086.5	21.34	311.	28.4	.46
11)	MOBIL								
a)	Calciner	11010	13.48	398.0	3085.3	30.48	366.	18.0	1.37
b)	No. 3 Dryer	11020	7.35	398.0	3085.3	30.48	355.	7.74	1.46
c)	No. 2 Dryer	11030	19.78	398.0	3085.3	25.9	346.	8.75	2.29
d)	No. 1 Dryer	11040	15.9	398.0	3085.3	25.9	346.	12.86	2.29
e)	No. 4 Dryer	11050	2.44	398.29	3084.29	25.9	339	16.05	2.29
12)	ROYSTER								
a)	SAP I	12010	63.5	406.7	3085.2	60.96	366.	9.93	2.13
b)	SAP I	12011	-257.25	406.7	3085.2	60.96	366.	9.93	2.13
c)	DAP Plt	12020	4.01	406.7	3085.2	31.09	316.	10.58	2.68
13)	SWIFT-AGRI CHEM.								
a)	SAP I	13010	32.2	411.5	3074.2	30.79	358.	3.9	2.13
b)	Dryer	13020	18.1	411.5	3074.2	18.29	339.	8.47	2.95
c)	Dryer	13030	33.4	411.5	3074.2	18.75	340.	5.06	2.95
14)	USS AGRI-CHEM.								
a)	SAP I	14010	41.9	413.2	3086.3	28.96	305.	7.5	2.12
b)	R. Dryer	14020	3.41	413.2	3086.3	15.8	332.	10.01	1.83
c)	DAP Plt	14030	3.93	413.2	3086.3	40.54	305.	12.69	2.13
d)	R. Dryer	14040	9.20	416.0	3069.0	25.6	332.	16.26	1.52
e)	R. Dryer	14050	9.20	416.0	3069.0	25.6	332.	16.26	1.52
f)	GTSP	14060	28.35	416.0	3069.0	28.35	330.	17.6	1.52
g)	SAP 2	14070	-73.5	416.0	3069.0	60.96	304	6.5	30.5
h)	New SAP	14080	92.40	416.0	3069.0	53.34	355	9.4	2.59

MA-1034

TABLE 2
Continued

20)	CAMDEN GRAIN								
	a) Furnace	20010	29.8	360.2	3102.5	30.18	344.	18.62	.66
	b) Furance	20020	10.48	360.2	3102.5	30.18	344.	18.1	.66
21)	CHLORIDE METALS								
	a) Furnace	21010	12.98	361.8	3088.3	30.17	397.4	22.86	.61
	b) Furnace	21020	8.04	361.8	3088.3	29.87	354.	17.2	.61
22)	CONCRETE PRODUCTS								
	a) Boiler	22010	5.9	362.8	3097.9	9.14	455.	5.39	.406
23)	DELMONTE	23010	4.22	359.6	3093.05	11.89	494.1	3.0	1.36
24)	GEN. PORT. CEMENT								
	a) Kiln No. 6	24010	100.8	358.0	3090.6	44.35	473.	6.6	4.72
	b) Kiln No. 4	24020	62.99	358.0	3090.6	35.97	505.2	17.61	2.74
	c) Kiln No. 5	24030	69.3	358.0	3090.6	45.42	494.1	5.8	3.81
25)	GULF COAST LEAD								
	a) Furance	25010	22.0	363.9	3093.85	30.48	350.	22.4	.61
26)	MACASPHALT								
	a) Heater	26010	17.83	363.5	3066.8	7.62	408.	15.06	1.52
	b) Plant	26020	11.05	423.13	3101.53	12.19	327.	2.26	3.05
27)	FLORIDA POWER & LIGHT								
	a) Station 1	27010	732.9	367.1	3053.8	152.1	425.	20.67	7.925
	b) Station 2	27020	732.9	367.1	3053.8	152.1	425.	20.67	7.925
28)	ADAMS PACKING								
	a) Dryer	28010	2.89	421.70	3104.2	28.04	347.	22.93	1.43

emission limitations on the basis of all similar units at a plant is recommended in order to avoid unequal application of this type of limitation to plants with the same total emission potential but different size units. Upon establishing the total mass limitation, individual source emissions will be determined by prorating the mass emission total on the basis of the percentage weight input to each source process.

(3) Fugitive Particulate – No person shall cause, let, permit, suffer or allow the emissions of particulate matter, from any source whatsoever, including but not limited to vehicular movement, transportation of materials, construction, alteration, demolition or wrecking, or industrially related activities such as loading, unloading, storing or handling, without taking reasonable precautions to prevent such emission, except particulate matter emitted in accordance with the weight process table (Table I), the visible emissions standards or specific source limiting standards specified in this chapter.

(4) Objectionable Odor Prohibited – No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor.

(5) Volatile organic compounds emissions or organic solvents emissions.

(a) No person shall store, pump, handle, process, load, unload or use in any process or installation volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

(b) All persons shall use reasonable care to avoid discharging, leaking, spilling, seeping, pouring, or dumping volatile organic compounds or organic solvents.

(6) Stationary sources – No person shall cause, let, permit, suffer, or allow to be discharged into the atmosphere emission from the following listed sources greater than any emission limiting standard given.

(a) Incinerators

1. The emission limiting standards for new incinerators with a charging rate of fifty or more tons per day are:

a. Particulate matter – 0.08 grains per standard cubic foot dry gas corrected to 50 percent excess air.

b. Odor – there shall be no objectionable odor.

2. The emission limiting standards for new incinerators with a charging rate of less than fifty tons per day are:

a. Visible emissions – no visible emissions except, visible emissions are allowable for up to three minutes in any hour at densities up to but not more than, a density of Ringelmann Number 1. (Opacity of 20 percent)

b. Odor – there shall be no objectionable odor.

3. As soon as possible, but not later than July 1, 1975, existing incinerators shall comply with the standards for new incinerators except that the particulate matter emission limiting standard for existing incinerators with a charging rate of fifty or more tons per day shall be 0.1 grains per standard cubic foot of dry gas corrected to 50 percent excess air.

(b) Sulfuric Acid Plants – the emission limiting standards for sulfuric acid plants are:

1. Existing Plants

a. Sulfur dioxide (SO_2) – ten pounds of SO_2 per ton of 100 percent H_2SO_4 produced, as expeditiously as possible but not later than July 1, 1975; in the Florida portion of the Jacksonville, Florida – Brunswick, Georgia, Interstate Air Quality Control Region as defined in 40 C.F.R. Section 81.91, twenty-nine pounds of SO_2 per ton of 100 percent H_2SO_4 produced as expeditiously as possible but not later than July 1, 1975.

b. A plume with visibility of no greater than 10 percent opacity.

2. New Plants

a. Sulfur dioxide – four pounds of SO_2 per ton of 100 percent H_2SO_4 produced.

b. Acid Mist – 0.15 pounds per ton of 100 percent acid produced.

c. A plume with visibility of no greater than 10 percent opacity.

(c) Phosphate Processing – the emission limiting standards for phosphate processing are:

1. Fluorides (water soluble or gaseous-atomic weight 19) the following quantities expressed as pounds of fluoride per ton of phosphatic materials input to the system, expressed as tons of P_2O_5 for:

a. New plants or plant sections:

a 1. Wet process phosphoric acid production, and auxiliary equipment – 0.02 pounds of F per ton of P_2O_5.

a 2. Run of pile triple super phosphate mixing belt and den and auxiliary equipment – 0.05 pounds of F per ton of P_2O_5.

a 3. Run of pile triple super phosphate curing or storage process and auxiliary equipment – 0.12 pounds of F per ton of P_2O_5.

a 4. Granular triple super phosphate production and auxiliary equipment.

i. Granular triple super phosphate made by granulating run-of-pile triple super phosphate 0.06 pounds of F per ton of P_2O_5.

ii. Granular triple super phosphate made from phosphoric acid and phosphate rock slurry – 0.15 pounds of F per ton of P_2O_5.

a 5. Granular triple super phosphate storage and auxiliary equipment – 0.05 pounds of F per ton of P_2O_5.

a 6. Di ammonium phosphate production and auxiliary equipment – 0.06 pounds of F per ton of P_2O_5.

a 7. Calcining or other thermal phosphate rock processing and auxiliary equipment excepting phosphate rock drying and defluorinating – 0.05 pounds of F per ton of P_2O_5.

a 8. Defluorinating phosphate rock by thermal processing and auxiliary equipment – 0.37 pounds of F per ton of P_2O_5.

a 9. All plants, plant sections or unit operations and auxiliary equipment not listed in a.1 to a.8 will comply with best technology pursuant to Section 2.03(1) of this rule.

b. Existing plants or plant sections. Emissions shall comply with above section, 17-2.04(6)(c) 1.a., for existing plants as expeditiously as possible but not later than July 1, 1975 or

b 1. Where a plant complex exists with an operating wet-process phosphoric acid section (including any items 17-2.04(6) 1., a., a.1. through a. 6. above) and other plant sections processing or handling phosphoric acid or products or phosphoric acid processing, the total emission of the entire complex may not exceed 0.4 pounds of F

FDER files - 1987

TABLE 5-1

AIR POLLUTION SOURCES INCLUDED IN AIR QUALITY MODELING

CENTRAL PHOSPHATES, INC.
HILLSBOROUGH COUNTY, FLORIDA

Description		ID	SO2 (g/s)	X-Coord (km)	Y-Coord (km)	Ht. (m)	Temp. (°K)	Vel. (m/s)	Dia. (m)
CPI	C H2SO4 (Exist)	623	37.80	388.155	3116.034	60.52	352.0	13.00	2.44
CPI	D H2SO4 (Exist)	624	37.80	388.211	3116.047	60.52	352.0	13.00	2.44
CPI	A H2SO4 (Exist)	611	-52.50	388.076	3116.011	18.75	316.0	18.75	1.52
CPI	B H2SO4 (Exist)	612	-52.50	388.085	3115.976	18.75	316.0	18.75	1.52
CPI	A H2SO4 (Prop)	621	35.83	388.076	3116.011	27.44	316.0	19.69	1.52
CPI	B H2SO4 (Prop)	622	35.83	388.085	3115.976	27.44	316.0	19.69	1.52
CPI	C H2SO4 (Exist)	633	-37.80	388.155	3116.034	60.52	352.0	13.00	2.44
CPI	D H2SO4 (Exist)	634	-37.80	388.211	3116.047	60.52	352.0	13.00	2.44
CPI	C H2SO4 (Prop)	643	50.40	388.155	3116.034	60.52	352.0	16.40	2.44
CPI	D H2SO4 (Prop)	644	50.40	388.211	3116.047	60.52	352.0	16.40	2.44
AGRICO	DAP	301	7.36	407.380	3071.700	38.10	328.0	14.60	3.10
AGRICO	#12 H2SO4	302	42.00	407.580	3071.340	45.70	350.0	9.50	2.90
AMAX	Big 4 - Rock Dryer	402	16.35	394.850	3069.770	30.50	334.0	7.26	1.82
BPI	Brewster (Composite)	501	13.40	389.500	3068.000	38.10	339.0	15.20	2.44
CF.Bartow	Ret. H2SO4	601	-110.60	408.500	3083.000	30.50	350.0	4.60	1.68
CF.Bartow	DAP	602	4.30	408.500	3083.000	9.10	450.0	22.50	0.70
CF.Bartow	#7 H2SO4	603	52.90	408.500	3083.000	67.10	351.0	9.80	2.40
CLM	Chloride Metals	701	21.02	361.800	3088.300	30.00	375.0	20.00	0.61
CONSERVE	Conserve	801	-15.20	398.400	3084.200	30.50	308.0	18.90	1.80
CONSERVE	Conserve	802	42.00	398.400	3084.200	45.70	352.0	10.30	2.30
EVANS	Dryer	1101	9.37	383.300	3135.800	25.90	346.0	17.30	1.00
FARMLAND	2 53 26 Farmland	1201	2.30	409.500	3079.500	14.00	444.0	12.70	1.20
FCS	Kiln and Power Plant	1301	98.41	360.008	3162.392	91.50	389.0	14.66	4.88
FPC	Crystal River	1401	2017.60	334.400	3204.510	182.90	398.0	27.40	6.90
FPC	Crystal River	1402	-2173.00	334.400	3204.510	152.40	420.0	45.60	4.60
FPC	Higgins Peak	1414	-121.84	336.500	3098.300	16.80	727.0	61.00	4.60
FPL	FPL Manatee (Comp)	1501	824.82	367.100	3053.800	152.10	425.0	14.90	7.90
GARDINIE	7/8 H2SO4	1602	5.81	363.200	3082.300	45.60	339.0	12.20	2.35
IMC	IMC Noralyn	1901	30.64	414.700	3080.300	13.70	330.0	40.40	1.22
LAKELAND	Lakeland Utilities	2001	393.60	408.500	3105.800	76.20	354.0	19.70	4.90
LAKELAND	Lakeland Utilities	2002	21.20	408.500	3105.800	47.70	389.0	11.70	3.10
MOBIL	Mobil	2201	2.40	398.000	3085.300	25.90	339.0	16.00	2.30
NEWWALES	#4 H2SO4	2301	63.00	396.560	3078.640	60.70	349.7	15.55	2.60
NEWWALES	AFI	2302	3.78	396.750	3079.350	52.40	321.9	13.00	2.40
NEWWALES	MULTIPHOS	2303	5.36	396.830	3079.430	52.40	319.1	7.10	2.40
NEWWALES	#2 DAP	2304	5.54	396.450	3079.150	36.60	319.1	20.80	1.80
NEWWALES	#5 H2SO4	2305	63.00	396.490	3078.640	60.70	349.7	15.55	2.60
NEWWALES	Rock Dryer	2306	-34.27	396.680	3078.860	21.04	347.0	18.56	2.13
NEWWALES	#1-3 H2SO4 Exist	2316	-146.00	396.530	3078.750	61.00	350.2	11.14	2.50
NEWWALES	#1-3 H2SO4 Mod	2318	189.00	396.530	3078.750	61.00	350.2	16.71	2.50

Florida Department of Environmental Regulation

Southwest District • 4520 Oak Fair Boulevard • Tampa, Florida 33610-7347 • 813-623-5561

Bob Martinez, Governor
Dale Twachtmann, Secretary
John Shearer, Assistant Secretary
Dr. Richard Garrity, Deputy Assistant Secretary

PERMITTEE:
Seminole Fertilizer Corporation
Bartow Plant
Post Office Box 471
Bartow, Florida 33830

PERMIT/CERTIFICATION
Permit No.: A053-176564
County: Polk
Expiration Date: 04-23-95
Project: Two Phosphate Rock Dryers

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

For the operation of two phosphate rock dryers, one rotary and one fluid bed. The dryers are fired on natural gas or fuel oil with a maximum of 2.4% sulfur. Particulate emissions are controlled by a series of dry cyclones for each dryer followed by one wet impingement scrubber for the fluid bed dryer and two wet impingement scrubbers for the rotary dryer. The exhaust from the wet scrubbers of each dryer is vented to a two unit MikroPul Division "Elekrofil" Wet Electrostatic Precipitator equipped with two stacks, R-1 (east), and R-2 (west).

Location: 3/4 mile north of State Road 60, 4 miles west of Bartow, Polk County

UTM: 17-409.8 E 3086.8 N

Neds No.: 0046

Point ID:
R-1 - 31
R-2 - 39

Replaces Permit No.: A053-99819

PERMITTEE:
Seminole Fertilizer Corporation
P.O. Box 471
Bartow, FL 33830

PERMIT/CERTIFICATION
Permit No: A053-176431
County: Polk
Expiration Date: 04/11/93
Project: Sulfuric Acid Plant #3

SPECIFIC CONDITIONS:

1. A part of this permit is the attached 15 General Conditions.

2. Visible Emissions shall not exceed 10% opacity.
[Rule 17-2.600(2)(a)2.a., F.A.C.].

3. Sulfur Dioxide emissions shall not exceed the lesser of
A. 10 pounds per ton of 100% acid produced, or
B. 460 pounds per hour.
[Rule 17-2.600(2)(a)2.b., F.A.C.].

During any time that Sulfuric Acid Plant #4, #5, or #6 exceeds a production rate of 70 tons per hour of 100% H_2SO_4, the sulfur dioxide emissions from Sulfuric Acid Plant #3 shall not exceed the lesser of
C. 7.4 pounds per ton of 100% acid produced, or
D. 340 pounds per hour.
[Reference previous permit and 1985 correspondence].

4. Acid Mist emissions shall not exceed the lesser of
A. 0.3 pounds per ton of 100% acid produced, or
B. 13.8 pounds per hour.
[Rule 17-2.600(2)(a)2.c., F.A.C.].

5. The maximum permitted production rate is 46 tons per hour of 100% H_2SO_4.

6. Test the emissions for the following pollutant(s) within 30 days of startup, and annually thereafter, and submit a copy of the test data to the Air Section of the Southwest District Office of the Department within 45 days of such testing [Rule 17-2.700(2), F.A.C.]:

(X) Opacity
(X) Sulfur Dioxide
(X) Acid Mist

7. Testing of emissions must be accomplished within $\pm$10% of the permitted maximum production rate of 46 tons per hour of 100% H_2SO_4. The actual production rate shall be specified in each test result. A compliance test submitted at a production rate less than 90% of the permitted maximum production rate will automatically constitute an amended permit at the lesser rate until another test showing compliance at a higher rate is submitted. Failure to submit the actual production rate and actual operating conditions may invalidate the test data and fail to provide reasonable assurance of compliance. [Rule 17-4.070(3), F.A.C.].

Mobil Mining and Minerals Company

P.O. BOX 311
NICHOLS, FLORIDA 33863-0311
TELEPHONE (813) 425-6200

CERTIFIED MAIL #P-426-330-819
RETURN RECEIPT REQUESTED

May 4, 1992

Mr. Scott Sheplak
Florida Department of Environmental Regulation
4520 Oak Fair Blvd.
Tampa, FL 33610-7347

Re: Non-Renewal of Air Emission
Sources for Mobil
Nichols Preparation Complex

Dear Mr. Sheplak:

Below is a list of the sources which Mobil will no longer use at Mobil's Nichols complex. They are or will be dismantled.

The sources which will not be renewed are outlined below:

(1)	Raymond Mills 1 and 2	AO-53-136223 ✓
(2)	Raymond Mills 3 and 4	AO-53-136224 ✓
(3)	Calciner Heat Recovery	AO-53-149844 ✓
(4)	Bin 35-A Baghouse *	AO-53-162166
(5)	Calciner	AO-53-136222 ✓
(6)	75 HP Titusville Boiler	AO-53-117006 ✓

-13.899/s
see attached

* The 35-A bin permit will be allowed to lapse as that bin is being incorporated into the Dry Rock Storage Building dust control system through a construction permit modification.

If you have any questions, please advise.

$75\ HP \times (3.352\times10^4)\ BTU/HR$
$\times 1/18300\ BTU/lb$
$\times (0.025\times2)\ lb\ SO_2/lb$
$\times 0.126$
$= \boxed{0.869\ lb/s}$

Sincerely,

T. L. Snyder

T. L. Snyder,
Environmental Engineer

mal/AIR-EMIS
encl.

A053-57099

PAID JUN 18 1982

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

D.E.R.
JUN 18 1982
SOUTHWEST DISTRICT
TAMPA

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Phosphate Rock Calciner [ ] New[1] [ ] Existing[1]

APPLICATION TYPE: [ ] Construction [xx] Operation [ ] Modification

COMPANY NAME: Mobil Chemical Company COUNTY: Polk

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peeking Unit No. 2, Gas Fired) No. 6 oil/natural gas fired, phosphate rock calciner with Venturi scrubber

SOURCE LOCATION: Street Highway 676 City Nichols, FL 33863

UTM: East 17-398.4 North 3085.3

Latitude ___ ° ___ ' ___ "N Longitude ___ ° ___ ' ___ "W

APPLICANT NAME AND TITLE: K. D. Fetrow, Manager of Manufacturing

APPLICANT ADDRESS: P. O. Box 311, Nichols, Florida 33863

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of MOBIL CHEMICAL COMPANY

I certify that the statements made in this application for a Operating - Renewal 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: R. E. Schulz for

K. D. Fetrow, Manager of Manufacturing
Name and Title (Please Type)

Date: 6/18/82 Telephone No. (813) 425-3011

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

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 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: [signature]

Robert W. McMaster
Name (Please Type)

(Affix Seal)

Mobil Chemical Company
Company Name (Please Type)

P. O. Box 311, Nichols, Florida 33863
Mailing Address (Please Type)

Florida Registration No. 17260 Date: 5/14/82 Telephone No. (813) 425-3011

[1]See Section 17-2.02(15) and (22), Florida Administrative Code, (F.A.C.)

MOBIL CHEMICAL COMPANY

PHOSPHATE ROCK CALCINER

PROCESS INPUT RATE:

Production from the Calciner is weighed by belt scales as it passes to storage. The output tons are approximately equal to input tons (Neglecting loss of weight in calcining and dusting).

EFFICIENCY ESTIMATION:

PARTICULATE: Past data shows what average particulate loading to the scrubber is 0.26 grains per ACFM.

$$\text{INLET} = \frac{0.26 \times 38.119 \times 60}{7000} = 85 \text{ lbs./hr.}$$

$$\text{OUTLET} = 10.68 \text{ lbs./hr.}$$

$$\text{EFFICIENCY} = 100 \times \frac{85.0 - 10.63}{85.} = 87.5\ \%$$

FLUORINE: Past data shows that average fluorine loading to the scrubber is 0.056 grains per ACFM

$$\text{INLET} = \frac{0.056 \times 38.119 \times 60}{7000} = 18.3 \text{ lbs./hr.}$$

$$\text{OUTLET} = 0.203 \text{ lbs./hr.}$$

$$\text{EFFICIENCY} = 100 \times \frac{18.3 - 0.203}{18.3} = 98.9\ \%$$

SO_2 :

on oil

$$\text{INLET} = 0.025 \times 4000 \times \frac{64}{32} = 200 \text{ lbs./hr.}$$

$$\text{OUTLET} = 110.2 \text{ lbs./hr.}$$

$$\text{EFFICIENCY} = 100 \times \frac{200 - 110.2}{200} = 44.9\ \%$$

September 24, 1980

USS Agri-Chemicals
Post Office Box 150
Bartow, Florida 33830

Attention: Mr. Basil Powell

Re: Evaluation of Ambient Sulfur Dioxide Concentrations Attributable to All USSAC Emission Sources After Proposed Modifications Are Completed

Gentlemen:

As requested by the Florida Department of Environmental Regulation, attached is a modeling evaluation of ambient sulufur dioxide concentrations resulting from simultaneous operation of the propoed new sulfuric acid plant and existing emission sources. Concentrations predicted are shown in comparison with applicable ambient air quality standards.

Please call if there are any questions regarding this report.

Yours very truly,

DAMES & MOORE

James W. Little

James W. Little
Senior Air Quality Analyst

JWL:ht

125.3 lb/h. Therefore, approximately 31 percent of the original sulfur present in the fuel was removed.

The rock drying rate during the test was 235 ton/h compared to the allowable rate of 250 ton/h. For modeling purposes, the measured SO_2 emission rate and the measured volumetric flow were scaled upward to reflect the amount of fuel oil which would be used at the allowable drying rate. Resulting emission characteristics are shown in Table 1. (It should be noted that 24-hour and annual modeling results based on allowable hourly drying rates are probably conservative because actual average drying rates are less than allowable and the dryer does not run 24 hours per day.)

Existing GTSP Plant

The existing GTSP plant includes dryers which use natural gas as a fuel when available and fuel oil otherwise. SO_2 emissions during fuel oil combustion can be calculated based on fuel sulfur content; but, as is the case with the rock dryer, this is not the most accurate method because sulfur removal is possible before combustion products are released to the atmosphere. Removal can occur through retention on the product being dryed and through absorption in the scrubber used for control of other emissions.

To determine sulfur removal efficiency, a recent test was run on one of the GTSP production trains. (The two trains are identical, so it is assumed that a test run on one train will be valid for both.) No. 6 fuel oil was burned at a rate of 3.1 gal/min during the test. This fuel contained 2.48 percent sulfur by weight and had a density of 8.155 lb/gal. If all the sulfur in the fuel had been emitted as SO_2, the resultant emission rate would have been 75.2 lb/h. The actual measured emission rate, however, was 72.5 lb/h, representing a sulfur removal efficiency of a little more than 3 percent. The large difference in sulfur removal efficiency between the GTSP plant and the rock dryer can be attributed primarily to differences in the pH of scrubber water. The GTSP plant scrubber uses recycled acid pond water with a pH of 4 or less, whereas the pH of rock dryer scrubber water is about 7.

GTSP
x 2 plants

ATTACHMENT FDER-B

GE EMISSIONS DATA FOR 7F AND 7EA CTs

POLK POWER STATION
EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 100%

Configuration: Combined cycle; 100% CGCU (Case 1)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 191,490 192,000 192,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	8,517	8,461	8,422
Fuel flow, 100 scf/hr	64,335	64,083	63,791
Heat input, mmBtu/hr (lhv)	1,631	1,624.5	1,617
Heat input, mmBtu/hr (hhv)	1,761.5	1,754.5	1,746.5
NO_x, ppmvd @ 15 percent O_2	25	25	25
NO_x, lb/hr	207	213	222.5
CO, ppmvd	25	25	25
CO, lb/hr	98	87	87.5
SO_2, lb/hr	516	518	496
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	2.2	2.0	2.0
H_2SO_4 mist, lb/hr	55	55	53
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	463,338	461,503	459,103

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 75%

Configuration: Combined cycle; 100% CGCU (Case 1)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 143,620 144,000 144,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	8,926	8,877	8,817
Fuel flow, 100 scf/hr	50,572	50,426	50,083
Heat input, mmBtu/hr (lhv)	1,282	1,278	1,270
Heat input, mmBtu/hr (hhv)	1,383.5	1,380	1,371.5
NO_x, ppmvd @ 15 percent O_2	25	25	25
NO_x, lb/hr	163	167.5	185
CO, ppmvd	25	25	25
CO, lb/hr	80	75	71
SO_2, lb/hr	405	403	394
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	1.8	1.8	1.6
H_2SO_4 mist, lb/hr	43	43	42
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	342,632	363,177	360,605

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 50%

Configuration: Combined cycle; 100% CGCU (Case 1)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 95,745 96,000 96,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	10,221	10,090	9,968
Fuel flow, 100 scf/hr	38,603	38,209	37,748
Heat input, mmBtu/hr (lhv)	979	969	957
Heat input, mmBtu/hr (hhv)	1,057	1,046.5	1,033.5
NO_x, ppmvd @ 15 percent O_2	25	25	25
NO_x, lb/hr	124	127	132
CO, ppmvd	25	25	25
CO, lb/hr	70	67	65
SO_2, lb/hr	310	305	294
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	1.6	1.6	1.5
H_2SO_4 mist, lb/hr	33	33	31
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	267,774	275,521	272,058

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 100%

Configuration: Combined cycle; 50% HGCU, 50% CGCU (Case 2)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 185,970 192,000 192,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	8,120	8,131	8,232
Fuel flow, 100 scf/hr	74,158	76,672	77,625
Heat input, mmBtu/hr (lhv)	1,510	1,561	1,581
Heat input, mmBtu/hr (hhv)	1,631	1,686	1,707.5
NO_x, ppmvd @ 15 percent O_2	81	78	73
NO_x, lb/hr	664	660	633
CO, ppmvd	25	25	25
CO, lb/hr	99	87	87
SO_2, lb/hr*	516	518	496
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	2.2	2.0	2.0
H_2SO_4 mist, lb/hr	55	55	53
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	440,059	454,167	459,382

*Assumed equal to 100 percent CGCU syngas SO_2 emission rates.

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 75%

Configuration: Combined cycle; 50% HGCU, 50% CGCU (Case 2)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 139,480 144,000 144,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	8,530	8,522	8,654
Fuel flow, 100 scf/hr	58,427	60,269	61,202
Heat input, mmBtu/hr (lhv)	1,190	1,227	1,246
Heat input, mmBtu/hr (hhv)	1,285	1,325	1,345.5
NO_x, ppmvd @ 15 percent O_2	81	78	73
NO_x, lb/hr	523	519	498
CO, ppmvd	25	25	25
CO, lb/hr	81	75	69
SO_2, lb/hr*	405	403	394
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	1.8	1.8	1.6
H_2SO_4 mist, lb/hr	43	43	42
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	346,800	357,168	362,196

*Assumed equal to 100 percent CGCU syngas SO_2 emission rates.

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 50%

Configuration: Combined cycle; 50% HGCU, 50% CGCU (Case 2)

Fuel: Modified Illinois No. 6 coal gas

Duct Firing: No KW 92,985 96,000 96,000

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	9,812	9,704	9,752
Fuel flow, 100 scf/hr	44,810	45,752	45,978
Heat input, mmBtu/hr (lhv)	912.5	931.6	936.2
Heat input, mmBtu/hr (hhv)	985.5	1,006	1,011
NO_x, ppmvd @ 15 percent O_2	81	78	73
NO_x, lb/hr	401	394	374
CO, ppmvd	25	25	25
CO, lb/hr	71	67.5	64
SO_2, lb/hr*	310	305	294
NM-HC, ppmvd	1.0	1.0	1.0
NM-HC, lb/hr	1.6	1.6	1.5
H_2SO_4 mist, lb/hr	33	33	31
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	263,742	271,076	272,542

*Assumed equal to 100 percent CGCU syngas SO_2 emission rates.

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 100%

Configuration: Simple cycle (Case 4)

Fuel: Distillate oil *

Duct Firing: NA	KW	175,500	159,330	141,710

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	10,250	10,450	10,780
Fuel flow, lb/hr	96,975	89,757	82,350
Heat input, mmBtu/hr (lhv)	1,799	1,665	1,528
Heat input, mmBtu/hr (hhv)	1,907	1,765	1,619
NO_x, ppmvd @ 15 percent O_2	42	42	42
NO_x, lb/hr	311	288	264
CO, ppmvd	25	25	25
CO, lb/hr	83	77	71
SO_2, lb/hr	553	512	469
NM-HC, ppmvd	5	5	5
NM-HC, lb/hr	11	10	9
H_2SO_4 mist, lb/hr	58	54	49
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	296,144	274,016	251,248

*Fuel assumptions: distillate oil--maximum 0.015 percent FBN, 0.3 percent S

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 75%

Configuration: Simple cycle (Case 4)

Fuel: Distillate oil *

Duct Firing: NA KW 130,080 118,800 107,840

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	11,280	11,530	11,840
Fuel flow, lb/hr	79,100	73,844	68,830
Heat input, mmBtu/hr (lhv)	1,467	1,370	1,277
Heat input, mmBtu/hr (hhv)	1,907	1,452	1,353
NO_x, ppmvd @ 15 percent O_2	42	42	42
NO_x, lb/hr	254	237	221
CO, ppmvd	25	25	25
CO, lb/hr	61	58	56
SO_2, lb/hr	451	421	392
NM-HC, ppmvd	7	7	7
NM-HC, lb/hr	11	11	10
H_2SO_4 mist, lb/hr	47	44	41
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	241,284	225,003	209,678

*Fuel assumptions: distillate oil--maximum 0.015 percent FBN, 0.3 percent S

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: IGCC (7F) Load: 50%

Configuration: Simple cycle (Case 4)

Fuel: Distillate oil *

Duct Firing: NA	KW	86,940	79,300	71,240

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	12,530	12,900	13,410
Fuel flow, lb/hr	58,728	55,148	51,499
Heat input, mmBtu/hr (lhv)	1,089	1,023	955
Heat input, mmBtu/hr (hhv)	1,155	1,084	1,013
NO_x, ppmvd @ 15 percent O_2	42	42	42
NO_x, lb/hr	188	177	165
CO, ppmvd	40	40	40
CO, lb/hr	99	93	88
SO_2, lb/hr	335	314	294
NM-HC, ppmvd	20	20	20
NM-HC, lb/hr	32	28	28
H_2SO_4 mist, lb/hr	35	33	31
TSP, lb/hr	17	17	17
PM_{10}, lb/hr	17	17	17
CO_2, lb/hr	179,455	168,533	157,095

*Fuel assumptions: distillate oil--maximum 0.015 percent FBN, 0.3 percent S

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: Stand-alone CT or CC (7EA) Load: 100%

Configuration: CT or CC with dry-low NO_x - 2

Fuel: Natural gas *

Duct Firing: NA

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	10,250	10,480	10,780
Fuel flow, lb/hr lhv	46,251	41,722	38,236
Heat input, mmBtu/hr (lhv)	966.0	871.4	798.6
Heat input, mmBtu/hr (hhv)	1,072.3	967.3	886.5
NO_x, ppmvd @ 15 percent O_2	9	9	9
NO_x, lb/hr	35	32	29
CO, ppmvd	25	25	25
CO, lb/hr	59	54	49
SO_2, lb/hr	36	33	30
NM-HC, ppmvd	7	7	7
NM-HC, lb/hr	10	9	9
H_2SO_4 mist, lb/hr	4	3	3
TSP, lb/hr	7	7	7
PM_{10}, lb/hr	7	7	7
CO_2, lb/hr	126,153	113,744	104,224

*Fuel assumptions: natural gas--maximum 10 gr S/100 scf

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: Stand-alone CT or CC (7EA)   Load: 75%

Configuration: CT or CC with dry-low NO_x - 2

Fuel: Natural gas *

Duct Firing: NA

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	11,020	11,400	11,820
Fuel flow, lb/hr lhv	37,312	33,961	31,409
Heat input, mmBtu/hr (lhv)	779.3	709.3	656.0
Heat input, mmBtu/hr (hhv)	865.0	787.3	728.2
NO_x, ppmvd @ 15 percent O_2	9	9	9
NO_x, lb/hr	28	25	24
CO, ppmvd	25	25	25
CO, lb/hr	45	42	39
SO_2, lb/hr	29	26	24
NM-HC, ppmvd	7	7	7
NM-HC, lb/hr	8	7	7
H_2SO_4 mist, lb/hr	3	3	3
TSP, lb/hr	7	7	7
PM_{10}, lb/hr	7	7	7
CO_2, lb/hr	100,886	91,771	84,814

*Fuel assumptions: natural gas--maximum 10 gr S/100 scf

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: Stand-alone CT or CC (7EA) Load: 100%

Configuration: CT or CC with dry-low NO_x - 2

Fuel: Distillate oil *

Duct Firing: NA

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	10,750	10,970	11,190
Fuel flow, lb/hr lhv	55,353	49,826	45,053
Heat input, mmBtu/hr (lhv)	1,051.7	946.7	856.0
Heat input, mmBtu/hr (hhv)	1,114.8	1,003.5	907.4
NO_x, ppmvd @ 15 percent O_2	42	42	42
NO_x, lb/hr	181	163	148
CO, ppmvd	30	30	30
CO, lb/hr	71	65	59
SO_2, lb/hr	316	284	257
NM-HC, ppmvd	7	7	7
NM-HC, lb/hr	10	9	9
H_2SO_4 mist, lb/hr	33	30	27
TSP, lb/hr	15	15	15
PM_{10}, lb/hr	15	15	15
CO_2, lb/hr	172,852	155,568	140,696

*Fuel assumptions: distillate oil--maximum 0.015 percent FBN, 0.3 percent S

POLK POWER STATION

EMISSIONS DATA FOR AIR MODELING

Unit: Stand-alone CT or CC (7EA) Load: 75%

Configuration: CT or CC with dry-low NO_x - 2

Fuel: Distillate oil *

Duct Firing: NA

Ambient Temperature (°F)	20	59	90
Heat rate, Btu/kwh lhv	11,510	11,870	12,190
Fuel flow, lb/hr lhv	44,505	40,316	36,879
Heat input, mmBtu/hr (lhv)	845.6	766.0	700.7
Heat input, mmBtu/hr (hhv)	896.3	812.0	742.7
NO_x, ppmvd @ 15 percent O_2	42	42	42
NO_x, lb/hr	145	131	120
CO, ppmvd	30	30	30
CO, lb/hr	54	50	47
SO_2, lb/hr	254	230	210
NM-HC, ppmvd	7	7	7
NM-HC, lb/hr	8	7	7
H_2SO_4 mist, lb/hr	27	24	22
TSP, lb/hr	15	15	15
PM_{10}, lb/hr	15	15	15
CO_2, lb/hr	137,576	124,771	114,109

*Fuel assumptions: distillate oil--maximum 0.015 percent FBN, 0.3 percent S

ATTACHMENT FDER-C

TEXACO EMISSIONS DATA FOR HRSG, AUXILIARY BOILER, AND THERMAL OXIDIZERS

HRSG Stack

Temperature, Deg F	265	
Stack Tip Diameter, ft	19	
Stack Height, ft	150	
Exit Veolocity, ft/sec	68	
TRACE ELEMENTS		lb/hr
Arsenic		0.0006
Beryllium		0.0001
Cadmium		0.0009
Chromium, total		0.0004
Lead		0.0035
Mercury		0.0034

Aux Boiler Stack

Temperature, Deg F	500	
Stack Tip Diameter, ft	3.0	
Stack Height, ft	20	
Exit Veolocity, ft/sec	43	
DUTY. MMbtu/hr (HHV)		49.50
Major Gases		
	vol%	lb/hr
Carbon Dioxide	12.12	8354
Moisture	10.39	2929
Nitrogen	74.90	32856
Oxygen	2.60	1302
	100	45441
MW (DRY)		30.3
	ppmv	lb/hr
SOx as SO2	174	15.6
UHC as methane	107	2.4
NOx as NO2	123	7.9
Particulates		3.0
Carbon Monoxide	108	4.3
TRACE ELEMENTS		
Lead	0.009	0.003

Thermal Oxidizer Stack

Temperature, Deg F		1400	
Stack Tip Diameter, ft		4.5	
Stack Height, ft		199	
Exit Veolocity, ft/sec		35	
DUTY. MMbtu/hr (HHV)			16.20
Major Gases			
		vol%	lb/hr
	Carbon Dioxide	23.26	14944
	Moisture	7.56	1986
	Nitrogen	66.28	27099
	Oxygen	2.45	1144
	Argon	0.46	266
		100	45438
	MW (DRY)		32
		ppmv	lb/hr
	SOx as SO2	602	52.0
	UHC as methane	37	0.8
	H2S	9	0.4
	NOx as NO2	42	2.6
	Particulates		13.1
	Carbon Monoxide	29	1.1
TRACE ELEMENTS			
	Arsenic	0.005	0.001
	Beryllium	0.0075	0.000
	Cadmium	0.002	0.000
	Chromium, total	1.500	0.105
	Lead	0.007	0.002
	Mercury	0.006	0.002

Acid Plant Stack

Temperature, Deg F		1400	
Stack Tip Diameter, ft		3.5	
Stack Height, ft		199	
Exit Veolocity, ft/sec		30	
DUTY. MMbtu/hr (HHV)			7.1
Major Gases			
		vol%	lb/hr
	Carbon Dioxide	4.73	1604
	Moisture	3.03	420
	Nitrogen	90.22	19468
	Oxygen	2.02	498
		100	21991
	MW (DRY)		28.9
		ppmv	lb/hr
	SOx as SO2	211	10.1
	UHC as methane	29	0.35
	H2S	9	0.23
	NOx as NO2	33	1.14
	Particulates		2.6
	Carbon Monoxide	29	0.61
	Ammonia		
TRACE ELEMENTS			
	Arsenic	0.005	0.000
	Beryllium	0.0067	0.0000
	Cadmium	0.002	0.000
	Chromium, total	1.3	0.052
	Lead	0.007	0.001
	Mercury	0.006	0.001

ATTACHMENT FDER-D

GE TECHNICAL LITERATURE FOR 7F AND 7EA CTs

GE Power Generation

MS7001F Gas Turbine Test and Performance Evaluation

G.A. (Tom) Cincotta
GE Company
Schenectady, New York

MS7001F GAS TURBINE TEST AND PERFORMANCE EVALUATION

G.A. (Tom) Cincotta
GE Company
Schenectady, New York

ABSTRACT

A review of the most thoroughly tested turbine in GE's history – the MS7001F – featuring results from both field testing at the customer site and production testing in Greenville. As the owner of the world's most advanced gas turbine, Virginia Power made history in the summer of 1990 with the commercial operation of the first heavy-duty gas turbine rated at 150 MW. It achieved over 50 percent fuel efficiency in combined-cycle operation. The field tests involved synchronization on oil and gas, full load, mechanical design, various configurations of water and steam injection, aeroperformance, modulated inlet guide vanes (IGV), and operating performance. Testing showed that the design is conservative and all components met or exceeded their design life expectations.

TEST DESCRIPTION

Following the completion of the prototype testing which was performed on the MS7001F prototype gas turbine in Greenville, in 1988, the machine was readied for shipment to Virginia Power Corporation's Chesterfield site. The machine left Greenville for Virginia Power via rail in November, 1988. The date of shipment was planned to permit the machine to be moved directly to the ready Turbine Building and to be placed on its foundation.

As is common knowledge, the machine had undergone testing in Greenville with a temporary M152 rotor. M152 was used for the rotor wheels because IN/706 wheel forgings were not available in time for testing at Greenville. The plan was to replace rotors at Virginia Power's Chesterfield site

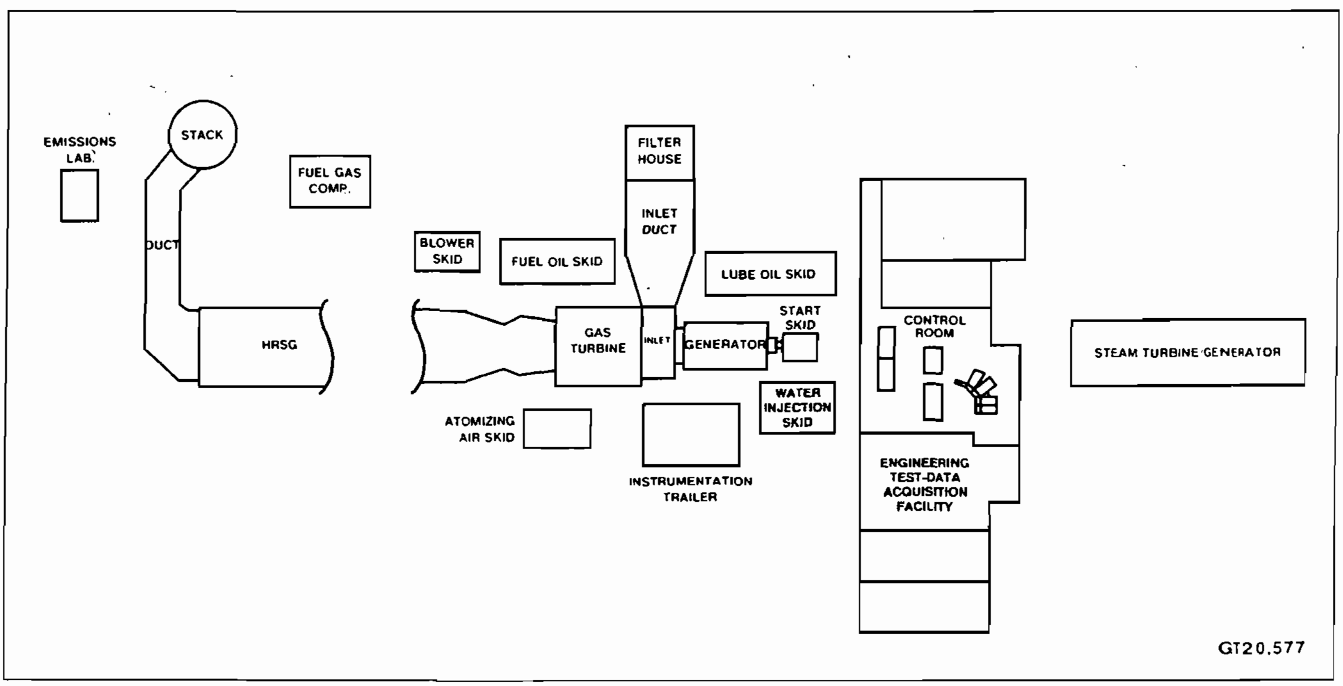

Figure 1. Virginia Power Chesterfield No. 7 – equipment layout

in 1989. Directionally Solidified (DS) first-stage buckets were added to the IN/706 rotor as a design improvement before the rotor was shipped to Virginia Power (VP) in October, 1989. The rotor change-out was completed as planned at the Chesterfield site before the end of October, 1989.

The MS7001F gas turbine was installed at Virginia Power as a part of a procured multishaft STAG™ (*STeam And Gas*) power plant to be designated as Chesterfield Unit No. 7. This unit is configured as a combined-cycle plant and can be operated on dual fuels (distillate and/or natural gas) with steam injection for NO_x control. The plant (Fig. 1) contains a gas turbine-generator, a steam turbine-generator, a two-pressure heat recovery steam generator (HRSG), and a number of accessory skids; and it shares a common stack with Chesterfield Unit No. 8 to be installed at a later date. A bypass damper was not included as a part of the Chesterfield No. 7 plant.

The absence of a bypass damper (Fig. 2) dictated that the plant be operated as a combined-cycle plant. Any time the gas turbine is fired, hot exhaust gases are directed into the HRSG. The HRSG is designed to bypass up to 40 percent of the steam directly to the condenser. If more than 40 percent steam is produced, the steam has to be directed to the steam turbine to produce power. Consequently, in order to test the gas turbine up to full-load (baseload) capacity, the principal objective, the entire combined-cycle plant had to be available and operating.

- NO BYPASS DAMPER
- LIMITED STEAM BYPASS CAPABILITY TO CONDENSER
- 6/1/90 CONTRACTUAL COD COMMITMENT TO VP

GT20.578

Figure 2. Test constraints – 7F engineering field test at VP

The engineering test plan included 30 days of testing to be performed prior to the pre-established commercial operation date (COD). These tests were performed during the period from January 10, 1990 through May 4, 1990 and, when possible, were made to coincide with the normal plant startup activities. The objectives of the test plan are described in Fig. 3. While the prototype MS7001F was extensively tested in the factory at Greenville, there were limitations to the extent of the testing which could be performed in the factory. The field engineering test was planned to fill these testing voids and to complete the evaluation of the prototype machine.

- EVALUATE PRODUCTION STARTING MEANS
- ESTABLISH MACHINE STARTUP PARAMETERS
- CONFIRM MECHANICAL DESIGN
  - AT BASE LOAD OPERATION
  - FOR IN/706 ROTOR
  - FOR DIRECTIONAL SOLIDIFIED (DS) FIRST STAGE BUCKETS
- CONFIRM AERO/THERMO PERFORMANCE
- CONFIRM COMBUSTOR EMISSIONS PERFORMANCE
  - OIL/GAS FUELS
  - WATER/STEAM DILUENT
- VERIFY OPERATION/PERFORMANCE OF TURBINE CONTROLS AND ACCESSORY SYSTEMS

GT20.576

Figure 3. Objectives – engineering test plan

The first objective was to evaluate the production starting means. The starting means which accompanied the gas turbine at VP Chesterfield Unit No. 7 had never been tested at the factory. The factory test starting configuration, as discussed in D.E. Brandt's paper, "MS7001F Prototype Test Results," was a special case to allow for the absence of a generator. In Greenville, a separate compressor was used as a load and this created a unique characteristic requiring a special starting means. The prototype starting means was built by Voith Engineering and assembled and tested as a skid at their York, Pennsylvania plant prior to delivery to the Chesterfield site.

The combination of a new starting means, a new IN/706 rotor, and the customer's combined-cycle plant configuration resulted in the necessity to re-examine the startup parameters as established from the Greenville testing. This was the second test objective.

The third objective was to confirm the mechanical design at baseload and with the new IN/706 rotor which also featured the latest DS first-stage buckets. Testing considerations at Greenville, while they simulated turbine gas path temperatures and pressures, were limited to about 60 percent output. This was our first opportunity to test at the full operating conditions, including the mechanical stress levels.

DESCRIPTION	T/C's	STATIC PRESS.	STRAIN GAGES	DYNAMIC PRESSURE	LOAD CELLS	VIBRATION
CASING	✓	✓	✓	✓		
BEARINGS	✓	✓			✓	✓
SHROUDS	✓	✓				
BUCKETS	✓					
NOZZLES	✓	✓				
COMPRESSOR	✓	✓	✓	✓		
WHEELS	✓					
COMBUSTORS	✓	✓	✓	✓		
	1,422	429	144	38	28	23

• 2,084 INDIVIDUAL PARAMETERS WERE MEASURED

GT20.580

Figure 4. Test instrumentation summary – VP engineering field test

QUANTITY	DESCRIPTION
1	7F DATA SYSTEM
8	ENGINEERING DATA DISPLAY TERMINALS
1	ROTOR INSTRUMENTATION TELEMETRY SYSTEM
2	480 PORT PRESSURE SCANNERS
16	14 CHANNEL FM INSTRUMENTATION TAPE RECORDERS
9	STRIP CHART RECORDERS
1	MULTI-CHANNEL DYNAMIC DATA ANALYSIS SYSTEM
224	MONITOR SCOPES AND SIGNAL CONDITIONING AMPLIFIERS
1	HIGH SPEED TELECOMMUNICATIONS LINK
MISC.	TRACKING FILTERS
1	EMISSION MONITORING LABORATORY
1	WATER INJECTION SKID
1	WATER TANKER TRUCK
	MISCELLANEOUS

GT20.579

Figure 5. Equipment list – data acquisition facility

The fourth objective, and perhaps the most important, was the confirmation of aerodynamic and thermodynamic performance of the gas turbine at and near baseload and at all anticipated combinations of operating parameters. These included both fuels (distillate and gas), both NO_x control diluents (water and steam), and a range of ambient temperatures, IGV angles, and part-load conditions.

Combustion emissions performance had been tested on a single combustor in the laboratory (Schenectady) and on the prototype machine during tests in the factory (Greenville). The prototype machine testing was limited to distillate fuel, water diluent, and 60 percent load. The fifth test objective was to extend the Greenville test results to the full operating range of the machine, fuels, and diluents.

Other objectives were defined which dealt with the operation of the turbine controls and accessory systems. These objectives were intended to evaluate the performance of these systems and to determine if, in the future, these systems could be simplified and/or eliminated. For example, the exhaust frame blower skid. The objective being to determine if this skid could be eliminated.

Instrumentation of the gas turbine included all instrumentation that was installed for the factory test and had survived that activity and was still functioning. Where it was possible to get to the sensor to effect a repair or replacement, it was done. The new IN/706 rotor was completely reinstrumented. As a result, the machine went into the field engineering test with approximately two thirds of the original instrumentation intact and functioning. Figure 4 indicates that 2084 individual parameters were instrumented, including 1422 temperatures, 429 static pressures, 144 strain gauges, 38 dynamic pressures, 28 load cells, and 23 vibration measurements.

The Data Acquisition System (DAS) for the engineering test was installed in the area set aside at Virginia Power for the future location of the Chesterfield Unit No. 8 control room. A temporary wall was constructed to separate the Unit No. 7 control room from the data acquisition facility. The proximity of the two areas was ideal for test control, communications, and transfer of standard machine data from the SPEEDTRONIC™ Mark IV panel to permanent storage in the DAS.

Thermocouple and strain gauge instrumentation were installed on rotating components and were brought off the rotor through the use of a telemetry system mounted on the aft end of the rotor. All rotor and stator data signals were routed to an instrumentation trailer which was located adjacent to the gas turbine. Pressure data were fed to multi-port pressure scanners and converted to digital signals. The digitized temperature and pressure data were then transmitted, via fiber optic cables, to the data acquisition facility and the 7F data system for processing and storage. Dynamic strain and pressure data signals from the telemetry system and from the stationary parts of the gas turbine were also sent to the data acquisition facility in analog form where they were recorded on magnetic tape and on strip chart recorders. Most dynamic data was also displayed on monitor scopes for real-time examination by the test engineers.

The data acquisition facility (Fig. 5) comprised three rooms. One room contained all the equipment for recording and displaying the dynamic data. This room contained 16 FM instrumentation tape recorders, (14 channels each), nine strip chart recorders, a multi-channel dynamic Data Analysis System, 224 monitoring scopes for real-time display, and miscellaneous equipment to support the process.

A second adjacent room contained all the equipment to record and store static data. This room contained the 7F data system and was the control center for the eight engineering data display terminals. All the static data and the calculations derived from that data were available for display and hard copy printing on these desktop work stations. Displays were refreshed every 30 seconds. In addition, a high-speed telecommunications link was provided to the GE engineering building in Schenectady, NY, for the convenience of the engineers working there.

The third room was a work area for the test engineers. It contained tables, chairs, personal computers, copier, phones, fax machine, and sundry office equipment.

There were several additional facilities used in the test program. A water injection skid and a water truck were located near the turbine and were used during the water injection emissions testing. This equipment was provided for the testing because the Virginia Power requisition had provision for only steam injection.

An emissions laboratory was located outdoors in the vicinity of the stack. This laboratory was installed in a trailer for mobility and was furnished and manned by Radian Corporation under a subcontract to GE.

CHRONOLOGY OF FIELD TEST EVENTS

Preparations for the engineering field test began early in 1989, shortly after the MS7001F gas turbine was shipped to Virginia Power. A test plan was prepared and negotiations with VP were undertaken, based on that plan, to reach accord on numerous critical issues of space, timing, support and procedures. Virginia Power was most cooperative. They were supportive and gracious hosts and deserve GE's heart-felt thanks.

The IN/706 rotor was instrumented with thermocouples and strain gauges at the factory in Greenville and shipped to the site in October, 1989. Rotor change-out was accomplished expeditiously on arrival. At the same time that the rotor was being installed, the telemetry system was added.

After the machine was closed, the process of connecting instrumentation leads from the sensors to the data acquisition equipment was initiated. The instrumentation trailer and the water injection skid were moved into the turbine building and their installation procedures begun. Construction and preparation of the space to house the data acquisition facility was also started.

Testing activities (Fig. 6) did not begin until January 10, 1990, at which time the MS7001F gas turbine was cranked for the first time at the VP Chesterfield site. By January 30, 1990, the HRSG was sufficiently complete that it could be filled with water and bottled up to support the first gas turbine start to full-speed/no-load (FSNL).

By March 14, 1990, the HRSG was ready to take on more energy from the gas turbine exhaust by dumping steam into the condenser. It was at this time that the starting tests were performed and the gas turbine generator was synchronized to the distribution line and loaded to low part-loads for the first time.

By March 27, 1990, the steam turbine was ready to be operated and loaded. Then, the gas turbine was started on distillate fuel and fired to baseload for the first time. At that point the plant was up and ready to accomplish the planned mechanical design testing at full load.

The fuel gas compressor was brought on line in early April. Water injection emissions testing was completed on April 13, 1990. The "Candy Cane" water injection configuration was tested over the complete operating load range and on both fuels (distillate and natural gas). The "pre-mixed" water/oil injection configuration was not tested in its entirety due to concerns about the schedule and our commitment to VP not to allow the testing schedule to interfere with the commercial operation date.

At this point, the testing was interrupted to restore the gas turbine into the Virginia Power steam-injected combustion configuration. This was an ideal time to perform a combustion inspection, a borescope inspection, and to water wash the compressor. These were accomplished on April 16, 17, and 24th respectively.

With the gas turbine configured for steam

EVENT	COMPLETION DATE
GAS TURBINE CRANKED	JAN. 10, 1990
FIRST GAS TURBINE START (FSNL)	JAN. 30, 1990
GAS TURBINE SYNCHRONIZED	MARCH 14, 1990
STARTING TESTS	MARCH 14, 1990
STEAM TURBINE SYNCHRONIZED	MARCH 15, 1990
FIRST TIME AT BASE LOAD	MARCH 27, 1990
MECHANICAL DESIGN TESTING	MARCH 28, 1990
WATER INJECTION EMISSIONS TEST	APRIL 13, 1990
COMBUSTION INSPECTION	APRIL 16, 1990
BORESCOPE INSPECTION	APRIL 17, 1990
COMPRESSOR WATER WASH	APRIL 24, 1990
PERFORMANCE (AERO/THERMO) TEST	APRIL 30, 1990
STEAM INJECTION EMISSION TEST	MAY 4, 1990
EXHAUST FRAME COOLING TESTS	MAY 4, 1990

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Figure 6. Chronology of key field test events

injection, the final phase of the engineering test was begun. Aerodynamic and thermodynamic performance testing was completed on April 30, 1990. Steam injection testing over the complete load range and on both fuels was completed by May 4, 1990. Exhaust frame cooling tests were conducted in parallel with the steam injection testing. This concluded the engineering field testing activities.

EVALUATION OF TEST RESULTS

Analysis of the data taken during the engineering field test is ongoing. A report summarizing the final results is expected early in the fourth quarter of 1990. The following section contains qualitative statements on the results available as of July 1990.

Prototype Starting Means

The prototype starting means includes a 40-hp pony motor, a 4700-hp cranking motor, and a hydraulic torque converter. The pony motor is used for keeping the gas turbine/generator on slow roll (75 - 100 rpm). The cranking motor is used for breaking the train free from a static condition, for purging prior to starting the gas turbine, and for starting the gas turbine (accelerating to self-sustaining speed).

All components of the starting means were tested individually and as a complete system. Operation was normal in all respects. The starting means performed all intended functions flawlessly, including slow roll. In 56 attempts to start the gas turbine at VP, it never faltered. GE is very enthusiastic about its operation and reliable performance.

The overall seismic vibration levels are moderately high during hydraulic transmission of power. Voith, the manufacturer of the torque converter, says this is to be expected. At all times, other than during hydraulic transmission of power, vibration levels are very low.

Maximum current drawn from the cranking motor was 900 amps during acceleration. Highest drain temperature recorded was 250 F. Normal bearing metal temperatures for the output shaft are in the 150-160 F range, which was expected for the design.

One recommendation that resulted from the testing is that it would be desirable for future modifications to have the ability to index the shafting system for balancing work or for borescoping the machine. Shaft indexing is currently accomplished through manual means.

Starting Parameters

The starting characteristics of the MS7001F gas turbine were expected to be affected by the changes in configuration since the factory prototype testing in Greenville. The principal configurational changes being the load change (generator instead of load compressor on the gas turbine shaft), the new IN/706 rotor with DS buckets, and the new Voith starting means.

The results of the testing (Fig. 7) show that the optimal starting characteristics do differ a little from those of the factory testing. The differences are small and in the direction of design simplicity.

The variable inlet guide vane (IGV) angle during start retains the same general profile as that used throughout the existing product line. Minimum IGV angle is set at 27 degrees and is held at this value until all evidence of compressor rotating stall has cleared. At 83.5 percent corrected speed, the IGV angle is opened rapidly to 54 degrees. This angle is held constant to full speed and is thereafter increased as required by the SPEEDTRONIC Mark IV Control curve for the gas turbine loading process. The torque converter is drained at 85 percent speed (3060 rpm), and the crank motor shut down after a five minute cooldown period.

The MS7001F gas turbine at VP has provisions for fifth and thirteenth stage compressor bleed. During the start up testing all possible combina-

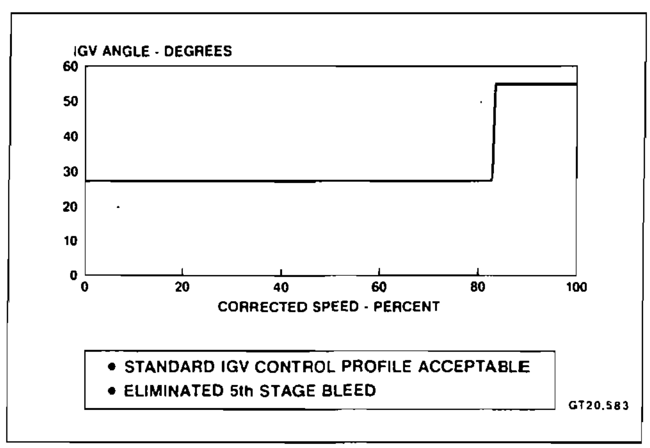

Figure 7. Start parameters

tions of bleed and IGV angles were examined for their effect on component stress. The result of this testing is the elimination of fifth-stage bleed as unnecessary. The compressor case currently contains four fifth-stage bleed ports. These ports were fitted with blanks for Virginia Power.

Future compressor casings will be manufactured without fifth-stage bleed provisions. In addition approximately 80 feet of piping, two control valves, and two shutoff valves will be deleted. This will simplify the design, improve reliability, and enhance maintainability.

Start, Loading, and Shut Down Transients

A typical start transient from the time that the fuel stroke reference (FSR) is initiated is shown in Fig. 8. Normally, the sequence of events is as follows. The gas turbine will have been on slow roll (75 - 100 rpm) for some time. The gas path

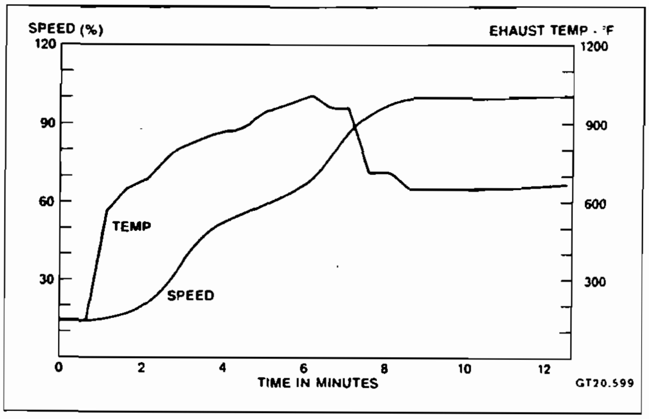

Figure 8. Typical MS7001F start transients

and the exhaust system (including the HRSG and stack) are then purged. This is accomplished by starting the crank motor, accelerating to 35 percent speed (1260 rpm), draining the torque converter and decelerating back down to firing speed (504 rpm). This takes about eight minutes. The torque converter is then refilled, fuel flow is initiated, and the machine is fired. After the presence of flame in the combustors is confirmed, the machine is held at firing speed for approximately one minute for warm up. At the expiration of the one-minute warm up, the starting means begins to accelerate the turbine-generator as fuel flow is increased. Acceleration rates and fuel flow are controlled to minimize turbine peak exhaust temperature. (Peak exhaust temperature, as measured in the testing, was on the order of 1000 F when the machine was at approximately 68 percent speed). At 83.5 percent speed, the IGV's

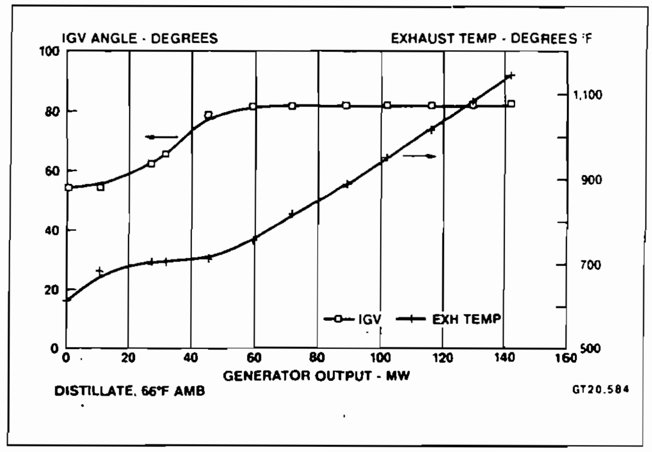

Figure 9. Typical MS7001F loading profile

begin to open and the exhaust temperature drops considerably due to the increased mass flow.

The start transient, from initiation of FSR to full-speed/no load (FSNL) takes a little over eight minutes. When added to the purge time, the total start transient from slow roll to FSNL takes 16 to 17 minutes.

One possible loading transient is shown in Fig. 9. As load is increased, the control system modulates IGV angle. At about 60 MW, the IGV's are fully opened (81 degrees). As load continues to increase from this point, with fully opened IGV's, the exhaust temperature increases more sharply.

The time to reach baseload from FSNL depends not on the MS7001F gas turbine, but on the ability of the HRSG and the steam turbine to follow the gas turbine. In simple-cycle mode, the time to baseload would be on the order of 30

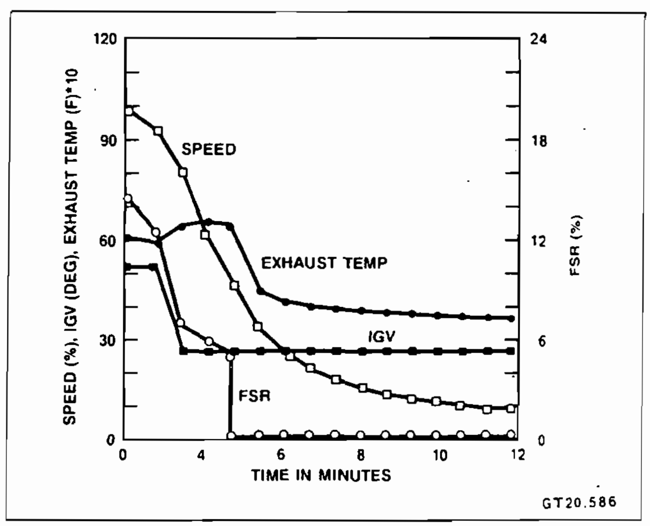

Figure 10. Typical MS7001F shutdown transients

CASINGS	• METAL TEMPERATURES WERE AS EXPECTED • UNIFORM CIRCUMFERENTIAL VARIATION
COMPRESSOR	• EXTENSIVELY TESTED IN GREENVILLE • VP RESULTS CONSISTENT WITH GVL RESULTS • DESIGN CONFIRMED
COMBUSTORS	• METAL TEMPERATURES AS EXPECTED (BELOW MS7E LEVELS) • DYNAMIC PRESSURES CONSISTENTLY LOW OVER ENTIRE OPERATING RANGE
STATIONARY SHROUDS	• STAGE 1 PERFORMED AS EXPECTED • STAGES 2, 3 WERE COOLER THAN EXPECTED
NOZZLES	• ALL STAGES PERFORMED AS EXPECTED
ROTOR	• METAL TEMPERATURES WELL WITHIN DESIGN LIMITS • WHEEL METAL TEMPS LOW RELATIVE TO WHEEL SPACE TEMPS, INDICATING ADDITIONAL DESIGN MARGIN
BUCKETS	• PERFORMED AS EXPECTED
WHEELSPACE	• 3rd AFT WHEELSPACE OVERCOOLED • POTENTIAL EXISTS FOR EXHAUST FRAME BLOWER ELIMINATION
BEARINGS	• JOURNAL/THRUST BEARING METAL TEMPS WELL WITHIN DESIGN LIMITS
VIBRATIONS	• UNIT OPERATES WITHIN DESIGN LIMITS AT BASE LOAD • MAX HORIZ. SEISMIC VIBS. (INCHES/SEC): #1 BRG .1, #2 BRG .3

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Figure 11. VP 7F test – mechanical design

minutes. In a combined cycle, the time would be in excess of one hour, depending on the condition of the steam side at the time.

A typical shutdown transient is shown in Fig. 10. The sequence would be as follows. First, the gas turbine would be unloaded and the breakers opened. In so doing, the IGV's would be closed to 54 degrees at FSNL. Next, the fuel flow would begin to decrease and the machine would respond by reducing speed proportionally. At about 86 percent corrected speed, the IGV's would close completely to the minimum setting (27 degrees). At about 50 percent speed, fuel flow goes to zero and the gas turbine-generator coasts down to about 100 rpm. At this point the pony motor is brought on line to hold the machine at slow roll speed for as long as required.

Mechanical Design Evaluation

The conclusions with respect to mechanical design performance are based on the results of all testing, including the operation at or above baseload. The analysis of the data is expected to continue through the third quarter of 1990. Quantitative results will be available then. At the present time the following qualitative conclusions (Fig. 11) can be reported.

Casings - All casing metal temperatures were in the range anticipated. The temperature variations as measured circumferentially around the casings were very uniform. This is significant in that excessive stresses are not present nor are any distortions that would contribute to rubbing.

Compressor - The compressor was extensively tested in the Greenville prototype test phase. The data measured during the engineering test at VP were very consistent with the results from Greenville. All design aspects of the new MS7001F compressor have been confirmed.

Shrouds - Measured data from the first-stage shroud indicate that it performed very much as expected. The second- and third-stage shrouds, however, were cooler than expected. This implies that the present shroud design could allow higher firing temperatures without redesign.

Nozzles - All three turbine nozzle stages performed as expected over the entire operating range.

Rotor - All metal temperatures measured on the new IN/706 rotor were well within the design limits. Wheel metal temperatures were low as compared to the measured wheelspace temperatures, indicating additional margin for the rotor design.

Combustors - All combustor metal temperatures were in the expected range. It is significant to note that these measured metal temperatures are below the levels experienced on the MS7001E combustors (Fig. 12). Dynamic pressures were consistently low over the entire operating range, including the cases with high diluent injection flows for NO_x abatement.

Buckets - All turbine bucket stages performed as expected, including the DS first-stage buckets.

Wheelspaces - The most important result is the confirmation that the third aft wheelspace continues to be overcooled. Tests were performed with the exhaust frame blowers turned off and the results are being examined for future elimination of these blowers.

Bearings - All bearing metal temperatures (journal/thrust) were well within their design limits.

Vibrations - The unit operates within the vibration design limits throughout the entire operating range. Maximum seismic vibration levels measured were on the horizontal seismics at base load and steady state. These were 0.1 and 0.3 inches per second on the No. 1 and No. 2 bearings respectively. The levels measured on the vertical seismics were lower.

Aerodynamic/Thermodynamic Performance

Testing was performed without diluent injection for the purpose of evaluating the performance potential of the advanced MS7001F gas turbine. A comprehensive test program was conducted in which a number of parameters were varied. These included fuel types, loading, IGV angle, firing temperatures, and ambient temperatures which fortuitously ranged between 40 and 92 F over the testing period. Testing was performed in combined cycle and the results adjusted for simple-cycle back pressure using industry-

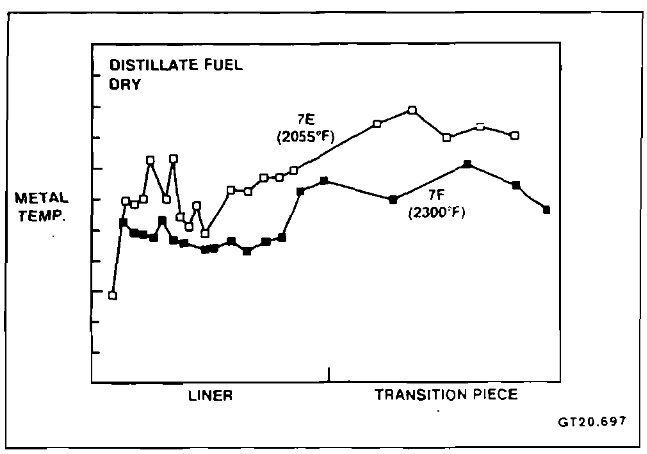

Figure 12. Combustor axial temperature distribution – 7E vs 7F

	RATINGS	TEST RESULTS
NATURAL GAS		
• OUTPUT	150 MW	BETTER THAN
• HEAT RATE (LHV)	9,880 BTU/KWHR	BETTER THAN
DISTILLATE		
• OUTPUT	147.2 MW	BETTER THAN
• HEAT RATE (LHV)	9,960 BTU/KWHR	BETTER THAN

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Figure 13. ISO performance – simple cycle, dry

EMISSION	DISTILLATE	NATURAL GAS
NO_X: (PPMVD AT 15% O_2)	65 PLUS CORRECTION FOR FUEL BOUND NITROGEN	42
CO: (PPMVD)	25	25
(LB/HR)	90	90
VOC: (LB/MBTU) - HHV AS METHANE	.0103	.0103
PARTICULATES: (LB/HR)	19	19
VISIBLE: (% OPACITY)	20	20

ALL REQUIREMENTS HAVE BEEN MET

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Figure 14. Emission requirements – baseload

acceptable techniques. The latest published simple-cycle ratings and the test results are shown in Fig. 13.

All combined-cycle performance guarantees to Virginia Power for the Chesterfield Unit No. 7 have been met.

Emissions

Testing was performed over the entire load range for both distillate and natural gas fuels. The capabilities of both water and steam diluents were examined.

The initial test plan included the thorough evaluation of several combustor hardware configurations for water injection. Due to plant schedule limitations, only the primary hardware configuration, the "Candy Cane" configuration was fully tested in the field. However, both the "Candy Cane" and the two "Mixer" configurations have been tested as a single-combustor can at the GE Gas Turbine Development Laboratory in Schenectady, so the relative performance of the configurations will have to be assessed from that data.

Figure 14 shows the requirements for emissions performance at base load. The water-injected "Candy Cane" configuration and the steam-injected configuration tested fully met all these requirements without qualifications. The diluent-to-fuel ratios to achieve 42 ppmvd NO_X on natural gas and 65 ppmvd NO_X on distillate at base load as determined from the testing are as follows:

Fuel	Diluent	Diluent/ Fuel ratio
Natural Gas	Steam	1.15
Natural Gas	Water	0.75
Distillate	Steam	1.45
Distillate	Water	0.85

Combustion and Borescope Inspections

The water injection emission testing was completed in mid-April. Testing was suspended at this time in order to change out the combustion configuration from the water-injected configuration to the steam-injected configuration. This process required the removal of all 14 combustor can end covers and the removal of instrumented transition pieces and liners from four cans. It required just a little more effort; to perform combustion and borescope inspections, so they were done at this point

By April 16, 1990, the gas turbine had accumulated 497 fired hours and 159 fired starts. This total includes the experience accumulated in Greenville.

On April 16-17, 1990, a full combustion inspection was performed by GE gas turbine engineering personnel. The findings are summarized in

PERFORMED APRIL 16-17, 1990

OPERATING TIME 497 FIRED HOURS
159 FIRED STARTS

RESULTS

- NONE OR MINIMAL DISTRESS (NO IMPACT ON OPERATION)
  - FORWARD BRACKET MOUNT
  - AFT BRACKETS
  - LINERS
  - HULA SEALS
  - CROSSFIRE TUBES
- MINIMAL WEAR NOTED ON TRANSITION PIECE SIDE SEALS
- SOME CARBON BUILDUP ON FUEL NOZZLES
- ALL CRITICAL DIMENSIONAL CLEARANCES WITHIN SPECIFICATION

CONCLUSION

- COMBUSTOR OPERATING AS EXPECTED
- NEXT TEST INSPECTION AT 3,000 FIRED HOURS

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Figure 15. Combustion inspection

Fig. 15. No distress was found on any of the combustion hardware. Only minimal wear was noted on the transition piece side seals. There was some carbon buildup on the fuel nozzles, but this is normal for operation on distillate fuel. The most recent testing before the inspection had been on distillate fuel. It was noted at other times during the test program that this carbon residue was removed as a result of operation on natural gas fuel.

The principal conclusions from the combustion inspection were:

a) The combustion system was performing as expected, and

b) The next formal combustion inspection should be scheduled at 3000 fired hours. As more experience is obtained on the MS7001F combustion system, the inspection interval will be increased to that for the gas turbine product line (8000 hours). We are taking a gradual approach on the first unit so that we may track and evaluate what is happening.

On April 17, 1990, an inspector from the GE Atlanta Service Shop performed a formal borescope inspection of the machine. These results are summarized in Fig. 16.

PERFORMED APRIL 17, 1990

OPERATING TIME 497 FIRED HOURS
159 FIRED STARTS

RESULTS
- NO DAMAGE OR UNUSUAL INDICATIONS FOUND
  - INLET
  - COMPRESSOR
  - TURBINE
  - EXHAUST DIFFUSER
- MINOR ACCUMULATION OF LIGHT TAN DEPOSIT ON COMPRESSOR BLADES/VANES AND TURBINE STAGES 1 AND 2

CONCLUSION
- THE MS7001F MACHINE AT VP CHESTERFIELD #7 IS JUDGED TO BE IN "LIKE NEW" CONDITION

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Figure 16. Borescope inspection

No damage or unusual indications of any sort were found anywhere in the inlet, compressor, turbine, or the exhaust diffuser. Minor accumulation of a light tan deposit was noted in the compressor and in the first two stages of the turbine. A report of the inspection has been issued.

As a result of the borescope inspection of the machine at VP Chesterfield Unit No. 7, the MS7001F gas turbine was judged to be in "like new," condition.

CONCLUSIONS

The MS7001F prototype gas turbine has successfully concluded the planned engineering field test program at the Virginia Power Chesterfield site (Fig. 17). All test and performance objectives have been achieved, including aero/thermo performance, emissions, design verification, etc.

- ALL TEST OBJECTIVES ACHIEVED
  - PERFORMANCE
  - EMISSIONS
  - DESIGN VERIFICATION
  - ETC.
- ANALYSIS TO DATA PROMISES EXCEPTIONAL PERFORMANCE
  - FINAL TEST REPORT TO BE RELEASED IN NOV. '90
- MOST EXTENSIVELY TESTED PROTOTYPE IN GE HISTORY

	HOURS	STARTS
- GVL FACTORY	387	134
- VP ENG'G FIELD	209	37
- PLANT ACCEPTANCE	244	19
	840	190

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Figure 17. Conclusions – 7F engineering field test

The MS7001F prototype has been the most extensively tested gas turbine prototype in GE history. When all the test times are accumulated, the totals include 840 fired hours and 190 fired starts.

At three PM on June 12, 1990, the MS7001F prototype gas turbine, as part of the Chesterfield Unit No. 7 combined-cycle power plant was accepted by Virginia Power Corporation and entered into commercial utility service.

ACKNOWLEDGMENTS

GE truly appreciates the cooperation, generosity, and confidence of Virginia Power Corporation in permitting GE the opportunity to perform this engineering test at their facility during the installation and startup phases of the Chesterfield Unit No. 7 plant.

GER-3633	Evolution in the Design of Utility Steam Turbine-Generators	GER-3647	Steam Turbine Long-Bucket Development
GER-3636	Experience with Compressed Air Cleaning of Main Steam Piping	GER-3648	Design Considerations for Gas Turbine Fuel Systems
GER-3642	Steam Turbine Cycle Optimization, Evaluation and Performance Testing Considerations	GER-3649	Designing for High Reliability – Gas Turbine Plant Performance and Its Importance in Purchasing Decisions
GER-3643	Emission Controls and Costs for Gas Turbine Applications	GER-3650	Gas Turbine Applications with Solid Fuels and IGCC
GER-3644	The Economics of Repowering Steam Turbines	GER-3651	GE Combined-Cycle Experience
GER-3645	MS70001F Gas Turbine Test and Performance Evaluation	GER-3658	SPEEDTRONIC™ Mark V Control System
GER-3646	Steam Turbines for Utility Applications	GER-3659	Control System Upgrades for Existing Gas Turbines in the 1990's

Turbine Technology Reference Library

GER-3424	Aircraft-Derivative Gas Turbine Maintenance Practices
GER-3425	GE LM5000 Aircraft-Derivative Gas Turbine Systems
GER-3430	Cogeneration Application Considerations
GER-3434	Gas Turbine Design Philosophy
GER-3456	Cogeneration Financial Incentives
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MS7001FA Gas Turbine Design Evolution and Verification

D.E. Brandt
GE Company
Schenectady, NY

MS7001FA GAS TURBINE DESIGN EVOLUTION AND VERIFICATION

D.E. Brandt
GE Company
Schenectady, NY

INTRODUCTION

The MS7001FA gas turbine is based on GE's heavy-duty gas turbine design philosophy, which stretches back through forty years of experience, and is derived from the MS7001A machine. This paper describes the MS7001FA gas turbine design, its features, the program of development, testing and review, and test and performance evaluation to ensure that the traditionally high reliability and availability standards achieved by GE's existing gas turbine designs have been maintained or improved.

The MS7001FA shares significant construction features, materials and aerodynamic similarities with the MS7001EA gas turbine and the same design life requirements responsible for the outstanding reliability of that product. The MS7001FA, therefore, represents an iteration of a reliable field-proven design with parts life design requirements consistent with its predecessors.

GE's confidence in the successful application of the MS7001FA gas turbine is derived from its extensive experience in designing heavy-duty gas turbines and the participation of GE's aircraft engine engineers in the design of the GE heavy-duty product line. This confidence also results from GE's practice of performing extensive and supportive developmental tests in conjunction with analytical efforts, and then field testing these concepts prior to application in new product line machines. The successful completion of two heavily instrumented prototype test series validates this confidence.

EVOLUTION OF THE MS7001FA

The aerodynamic, combustion and mechanical design of the MS7001FA is rooted in that of the MS7001EA. Figure 1 illustrates the retention of the classic GE constructional features in the MS7001FA. The rotor is made of bolted-disk and the shell is of single-wall construction, without the complication of inner barrels. The MS7001FA's rotor has been constructed to maintain critical speed margins in excess of 20 percent with respect to synchronous speed with the first bending critical speed above running speed. As the rotor accelerates from zero to full speed, there are no bending critical speeds through which the rotor must pass.

The MS7001FA's construction has been simplified by applying the two-bearing systems typical of GE's proven MS5001 and MS6001 designs. The elimination of the middle bearing permits greater accessibility to combustion components, offers a simpler construction, and eliminates the need for this bearing's maintenance.

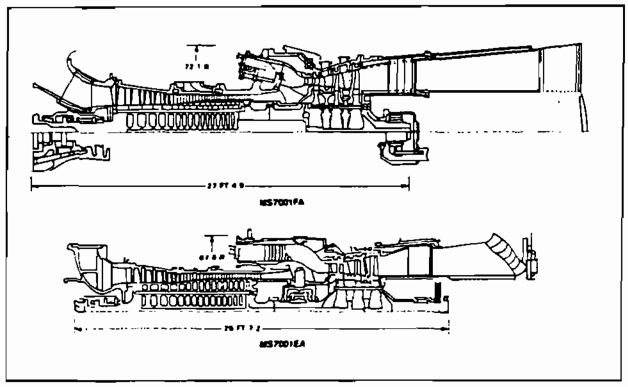

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Figure 1. MS7001FA vs MS7001EA

Figure 2 illustrates that the MS7001FA gas turbine has greater critical speed margin than either of the other two-bearing gas turbines — the MS5001 and MS6001 — operating successfully in the GE fleet. Figure 2 also illustrates that the unbalanced response of the MS7001FA gas turbine is superior to that of the MS5001 or MS6001, neither of which have experienced rotor vibration problems while operating in service.

The large-diameter bolt circle possessed by the compressor construction stiffens the rotor structure and allows for complete torque-carrying capability to be delivered to the load flange of the gas turbine while operating under full-load conditions, without placing the compressor bolts in shear. This

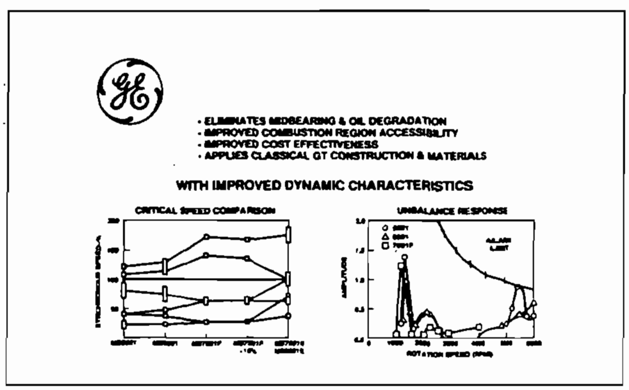

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Figure 2. Rotor construction - two bearings

particular requirement has been demonstrated as a successful and reliable means of construction in all GE gas turbines. The hollowing out of the shaft in the region of the load coupling is designed to reduce the overhung weight in that region of the rotor, improving its critical speed margin.

The relationship between the MS7001FA and MS7001EA machines is further illustrated in Figure 3. In this figure, the central solid lines represent the aerodynamic scaling of the compressor used to derive the MS6001 and MS9001 gas turbines from the MS7001 design. The dashed lines connecting this series of solid lines to those on the left represent incremental changes to earlier designs resulting in the MS7001E family. The dotted lines extending from the MS7001EA to the MS7001FA also represent incremental changes to the MS7001E design in creating the MS7001FA compressor.

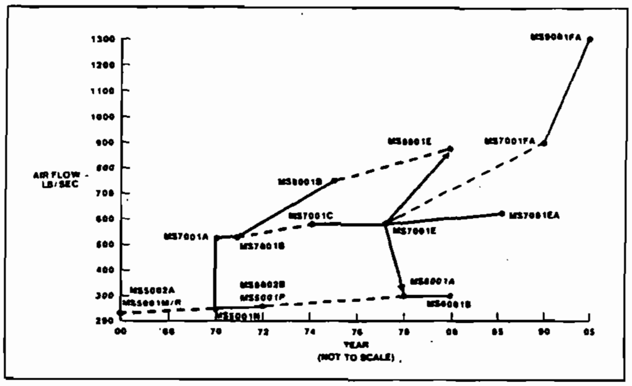

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Figure 3. Growth in compressor air flow (ISO conditions)

The last 16 stages of the MS7001EA and MS7001FA compressors use similar blading, except in length and in pitch diameter, with identical angles, which allows the MS7001FA to retain the ruggedness of the MS7001EA compressor. The redesign of the first stage of the MS7001EA compressor, together with the addition of the zero stage to form the MS7001FA compressor, has resulted in an increase in the MS7001FA's surge margin .

Like the MS7001EA, the combustion system of the MS7001FA uses 14-inch diameter liners. The MS7001FA liners, however, are shorter, of heavier construction, and possess six fuel nozzles. The MS7001FA combustion system contains 14 combustors to accommodate a higher flow, as compared with the 10 combustors in the MS7001EA. Each of these features represents an improvement in the reliability of the MS7001FA, resulting in more efficient cooling, improved strength, and lower combustion noise.

The design of the MS7001FA turbine follows the three-stage, high energy per stage design found in the MS6001/MS7001/MS9001 turbines. The same design life requirement, which has resulted in an absence of design related rupture or high cycle fatigue failures in the MS7001EA, was applied to the MS7001FA.

The higher firing temperature of the MS7001FA has required the application of advanced cooling concepts developed by GE for high-performance military and commercial aircraft engines. This application has resulted in lower metal temperatures in critical turbine components of the MS7001FA, as compared with the MS7001EA. Note that the internal cooling circuit of the MS7001EA has been retained in the MS7001FA, as shown in Figure 4.

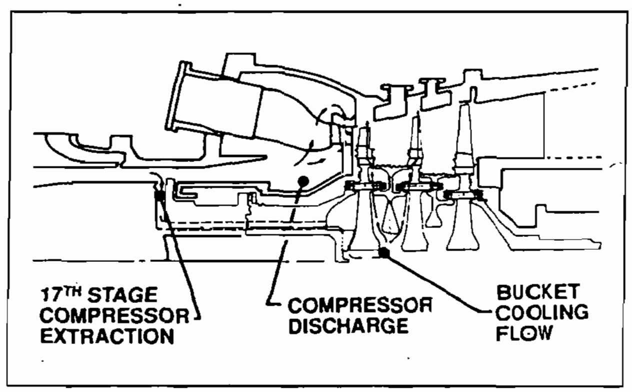

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Figure 4. MS9001F Internal cooling circuit

Since the MS7001FA possesses a front-end drive feature to more readily accommodate combined-cycle applications, the establishment of electric motor-driven accessory systems was required. The GE approach has been to design these systems consistent with our steam turbine practice, which ensures continuity with GE experience as well as the high reliability associated with GE steam turbine designs.

The GE practice of incremental improvements in product design also applies to the improvements in reliability of the GE product line. This is illustrated in Figure 5, which demonstrates the steady improvement in the availability of the MS7001 fleet as GE has moved progressively from one MS7001 model to the next.

The MS7001FA gas turbines are fully-qualified gas turbines as a result of the engineering tests performed on the first production unit. The testing at firing temperatures up to 2350° F (1288°C) has demonstrated that all design assumptions have been verified.

Figure 6 illustrates the substantial benefit of a GE-designed MS7001 gas turbine as compared with GE's competition. The data illustrated in Figure 6 is derived directly from the operating experience of domestic utilities reporting into the NERC database.

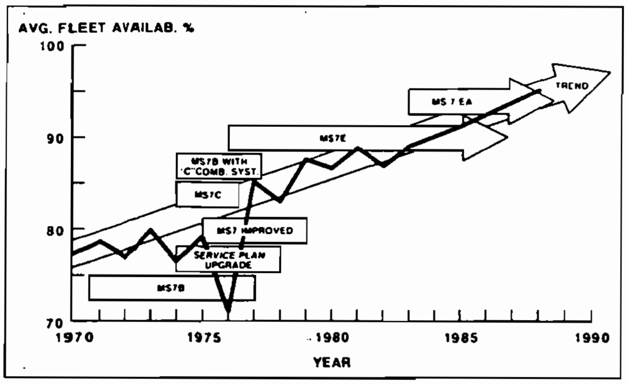

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Figure 5. Availability growth with GE developments and machine maturity

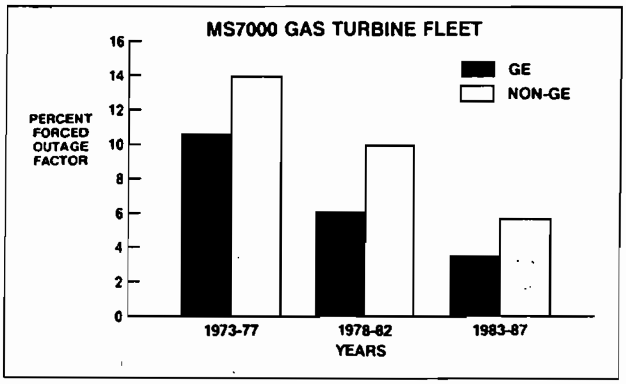

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Figure 6. Reliability improvement: GE vs non-GE (forced outage performance)

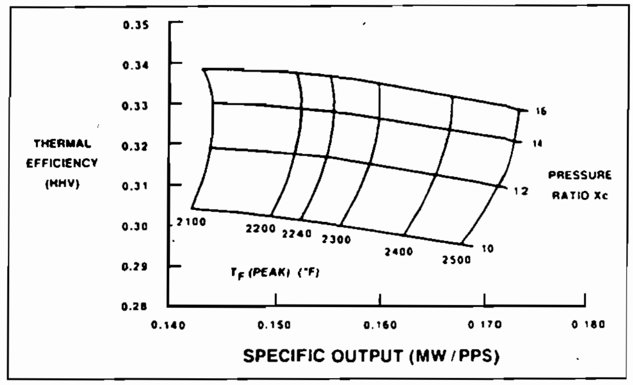

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Figure 7. Simple-cycle parameters (Left)

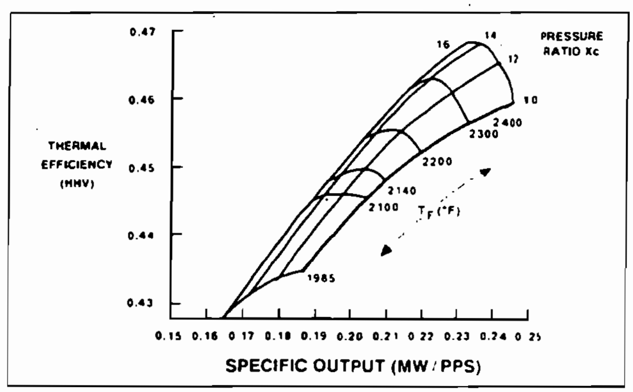

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Figure 8. Combined-cycle parameters (Right)

GE's heavy-duty gas turbine design philosophy benefits from incremental changes from model to model, the use of proven materials and construction methods, the highly reliable multiple combustion system, an extensive database of materials properties, component and prototype testing, and field testing and performance evaluation to verify design assumptions, which are described below.

CYCLE SELECTION

The gas turbine accommodates a broad range of power generation alternative applications, including simple-cycle, cogeneration, combined-cycle, heat recovery, and IGCC.

Initial studies over a range of firing temperatures indicated that a value of 2300° F (1260° C) represented a reasonable firing temperature consistent with long component lives, advanced cooling methods, material capabilities and effective corrosion protection coatings. Given the selection of the firing temperatures, it was necessary to select a cycle pressure ratio. Figures 7 and 8 illustrate the basis for selection of 15:1 as the pressure ratio for the MS7001FA and a firing temperature of 2300°F (1260°C) in the simple- and combined-cycle mode. The favorable prototype test results have permitted an uprating to 2350°F (1288°C) at a pressure ratio of 15:1.

When selecting cycle parameters for simple-cycle applications, it is important to provide as high a power density for the power plant as possible. The specific output is a significant measure; the greater the output per pound of air flow, the smaller the gas turbine. Figures 7 and 8 show the specific work peaks at approximately 15:1 for a firing temperature of 2350° F (1288°C). To satisfy both simple- and heat recovery-cycle requirements, the cycle's pressure ratio is balanced.

Combined-cycle applications require a cycle configuration that emphasizes thermal efficiency. With a firing temperature of 2350°F (1288°C), the highest efficiency is obtained at a pressure ratio of 15:1 in combined-cycle application.

With the firing temperature and pressure ratio established, optimal compressor flow can now be determined. One major consideration in this decision is the exit annulus area of the turbine. Once a successful design is conceptualized for the first turbine stage at a specific firing temperature, it becomes necessary to determine just how large a last-stage bucket can be and still maintain mechanical integrity and aerodynamic performance. The MS7001FA utilizes the alloy GTD-111, a derivative of René 80 with improved hot corrosion resistance, for all three turbine buckets, which allows a 50 percent improved stress capability and a 20 percent improvement in low cycle fatigue (LCF) capability over U-500. The strength of GTD-111, together with a new aerodynamic turbine design with a moderate exit Mach number, established the flow at 408 kg/sec (900 lb/sec). The net result is a turbine efficiency which is significantly higher than that of the MS7001EA turbine.

MS7001FA PROGRAM STRUCTURE AND DESIGN FEATURES

The MS7001FA program has been organized to utilize GE's resources, skills, experience and knowledge-base. To achieve our objectives, a Design Review Board was established. Design Review Board experts were drawn from GE's Corporate Executive Offices, the Corporate Research and Development Center, the Aircraft Engine businesses, and experts within the Power Generation operation. These Board members reviewed design progress on a monthly basis to ensure that the total GE experience-base was brought to bear on the MS7001FA program.

The review of design advancements by Corporate experts is a well established practice in the continued design iterations followed by the GE gas turbine business. More than 40 design reviews were held. Every specific design aspect, from assumptions through calculations and life prediction, was reviewed. These detailed reviews assured that experiences and technologies from other GE organizations were applied to the MS7001FA to enhance its reliability and performance.

Figure 9 lists the engineering test planning for the MS7001FA project. As has been standard throughout the evaluation of GE gas turbines, there are three phases of tests involved in the design of a new product. In Phase I, accessory systems are tested for performance and individual components are tested in support of design activities. In Phase II, the entire machine is tested to verify the design assumptions, and, finally, during Phase III, a full-load operating test is conducted on an electric utility system. Each design assumption and analytical boundary condition is thoroughly researched as the design progresses through the three-phase system to final verification.

PHASE I ACCESSORY SYSTEMS FUNCTIONAL TESTING

PHASE II FACTORY LOADED TEST VIA LOAD COMPRESSOR - 1 YEAR
(3,000+ CHANNELS OF INSTRUMENTATION)

- VERIFY STALL MARGIN - MAP COMPRESSOR
- VERIFY MACHINE AND COMPONENT PERFORMANCE
- VERIFY SYSTEM AND COMPONENT DYNAMIC BEHAVIOR
- VERIFY GAS PATH PROFILES
- VERIFY HEAT TRANSFER ASSUMPTIONS
- VERIFY COMBUSTOR PERFORMANCE
- VERIFY EMISSIONS PREDICTIONS

VERIFY COMPLETE GT SYSTEM COMPATIBILITY AND DESIGN
• GAS TURBINE • ACCESSORIES • CONTROLS

PHASE III FIELD PERFORMANCE TEST AT UTILITY SITE

- REFURBISHMENT OF CRITICAL STATOR/COMBUSTOR/ACCESSORY INSTRUMENTATION
- SIMILAR TO PHASE II BUT W/O COMPRESSOR MAPPING
- GENERATOR

LONG TERM DEMONSTRATION - MAINTAINABILITY/RELIABILITY/TRAINING

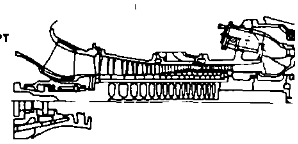
GT17423

Figure 9. MS7001F Engineering test plan

Compressor

GE was extremely fortunate to have an exceptionally reliable compressor on which to base the MS7001FA design. The compressor for the MS7001FA (Figure 10) is an axial-flow, 18-stage compressor with extraction provisions at stages 9 and 13. The prototype engineering test results have indicated that the flow stability of the MS7001FA was under excellent control. The compressor's aerodynamic and mechanical design follow that of the 17-stage MS7001EA (633 lb/sec, 3600 rpm), with an additional zero stage. Like its predecessor compressors, the MS7001FA is a bolted-disk design.

• PHILOSOPHY
- BUILDING BLOCK, SCALING CONCEPT
- MINIMUM RISK, COST, LOSS IN EFFICIENCY
- MAXIMUM RELIABILITY



• 7FA APPROACH
- BUILD ON 7EA CORE WITH WELL KNOWN CHARACTERISTICS, LARGE SURGE MARGIN, VERY HIGH EFFICIENCY
- USE ADVANCED ANALYSES TO CONFIRM DESIGN *UNDER AEBG GUIDANCE* (CUSTOM TAILORED RO AND RI)
- CONFIRM COMPRESSOR MAP ON PROTOTYPE TEST
- SCALE 7EA FOR CORE COMPRESSOR

"7FA SURGE MARGIN ≥ 7EA OVER FULL SPEED AND AMBIENT TEMPERATURE RANGES"

GT16723

Figure 10. 7FA Compressor design

The MS7001FA compressor was developed by applying a scale factor to the diameters of the MS7001EA, then increasing the annulus area an additional amount to achieve the desired flow, and, lastly, adding a zero stage. As a result, the MS7001FA is aerodynamically similar to the MS7001EA and blading for stages 2 through 17 is interchangeable with the MS7001E, except for length.

Stages 0 and 1 have been designed for operation in transonic flow using design practices applied by aircraft gas turbine designers for high bypass ratio aircraft engines. As a result of using this conservative design approach, variable stators, in addition to variable inlet guide vanes, are not required for surge control, thereby maintaining the simplicity and ruggedness of the MS7001EA compressor.

Like the MS7001EA, the MS7001FA's compressor surge control is accomplished through variable inlet guide vanes (VIGV) and selective bleed. At 100 percent speed, the VIGV are fully open for simple-cycle applications. For combined-cycle applications the VIGV are positioned at an intermediate setting and open as a function of load and exhaust temperature to maintain maximum thermal efficiency. The 9th and 13th stage bleed valves close during startup when the generator breaker closes.

The low stage loading, which has resulted in a very rugged MS7001EA compressor, has been retained and has resulted in a high level of compressor efficiency in the MS7001FA.

Higher strength alloys have been applied to accommodate the increased compressor blade stresses which naturally result from an increase in diameter. Custom 450 stainless steel has been selected for the VIGV and stages 0 through 8. A higher strength version of AISI 403 with columbium added is the alloy of choice in stages 9 through the exit guide vanes. The net result of the application of these higher strength alloys is that the applied stress/yield strength ratio is equivalent to that of the MS7001EA (Figure 11).

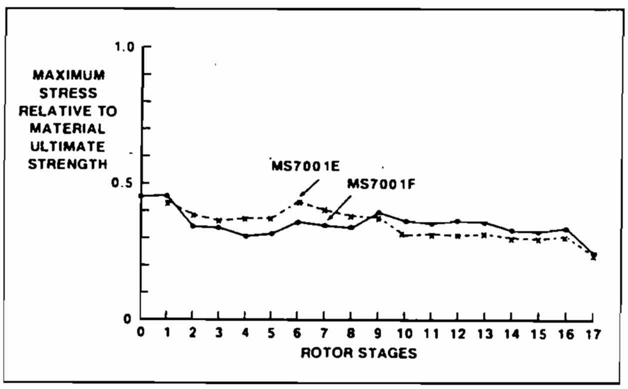


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Figure 11. MS7001E/MS7001F Compressor rotor blade relative stress comparison

The application of Custom 450 will have an additional benefit in corrosive environments. Field and laboratory testing of this alloy in acidic salt environments (pH = 4) has demonstrated that it can be applied without coatings for corrosion protection. In these tests, a variety of coatings were applied to AISI 403 and Custom 450 and compared with uncoated Custom 450. The field tests were performed on MS7001E machines operating in industrial environments that had proven to be very aggressive to front-end stages of NiCd-coated AISI 403. Uncoated Custom 450 demonstrated a clear superiority over any other non-Custom 450-based system, as well as coated Custom 450 (Figure 12). Those coated systems which appeared to be equivalent to bare Custom 450 in the laboratory tests (Figure 12) did not hold up in the field tests. (Erosion was the main cause of coating failure).

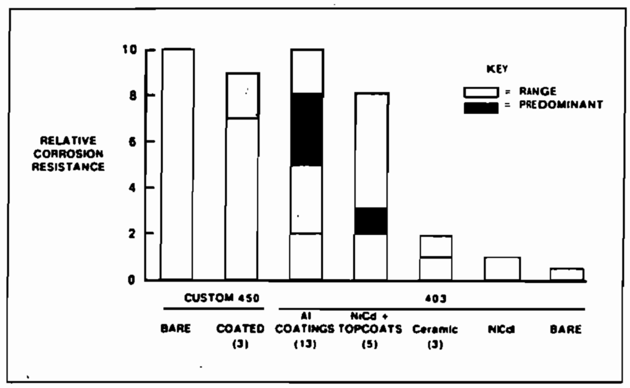

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Figure 12. Corrosion resistance acidic laboratory tests

The dynamic behavior of compressor blading is of great concern to the compressor designer. For this reason, full-scale wheelbox testing of the stage 0 blading was performed before the final design was committed to manufacturing. Testing was accomplished in GE's Gas Turbine Development Laboratory low-pressure wheelbox facility. Our facility permits the testing of fully-bladed, full-scale rotors up to 170-inch diameter at rated machine speeds and pressures as low as two psia. The blades are instrumented to determine their dynamic response while being excited by air jets as a dynamic stimulus.

Extensive efforts have been applied over the last decade to develop advanced computer-based predictive techniques that will accurately predict the dynamic response of complex unshrouded compressor and turbine blading. The results of these efforts are demonstrated in Figure 13, where the predicted and measured Campbell Diagrams are compared for the 0 stage compressor blading. Not only is the prediction exceptionally accurate, but it is clear that dynamic responses of the blade are well clear of the forcing functions of significance at operating speed.

Combustion System

The MS7001FA combustion system (Figure 14) consists of 14 combustion chambers with 14-inch nominal-diameter combustion liners. The net increase of four combustion chambers increased air flow capability. GE used the proven size and

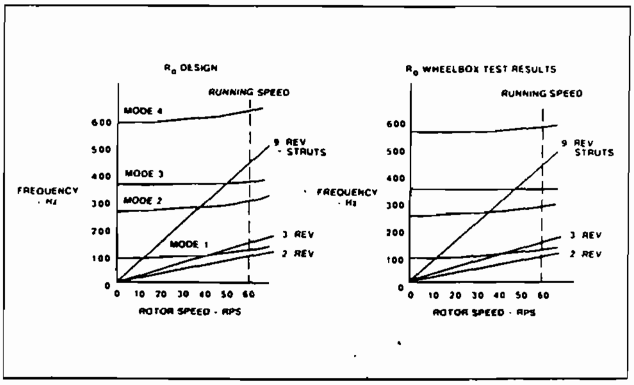

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Figure 13. Campbell diagram

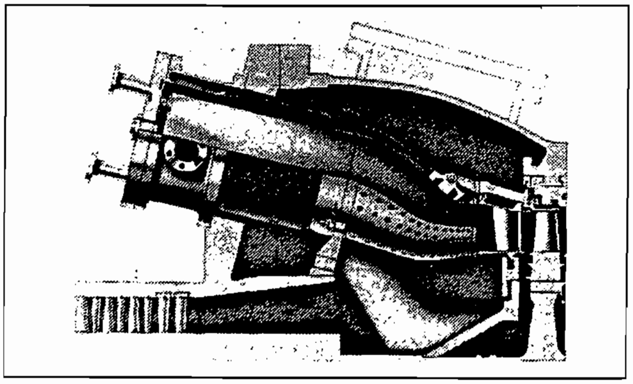

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Figure 14. MS7001FA Combustion system

configuration of the MS7001EA combustion system and merely increased the number of combustion chambers from 10 to 14. Transition pieces conduct the combustion gases to the first-stage nozzle.

The liners are constructed in a manner identical to the MS7001EA liners (Figure 15), but are 30 percent thicker and 213 mm. (8.4 in.) shorter. This design provides for extensive and effective film cooling of the liner wall, as well as penetrations for combustion and dilution air and for cross-fire tube connections.

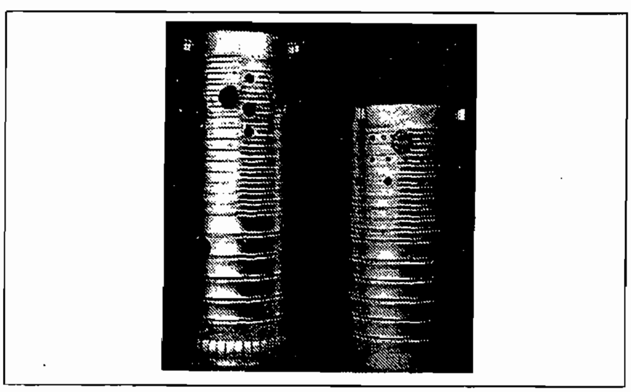

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Figure 15. MS7001F/MS7001EA Combustion liners

The MS7001FA liners are constructed of Hastelloy-X material, with the addition of HS-188 in the lower 282 mm (11.1 inch) portion and the application of thermal barrier coating to the internal surface. These additions provide for improved high-temperature strength and a reduction of metal temperatures and thermal gradients. A flow sleeve surrounds the liner to provide a controlled flow path for the combustion, dilution and cooling air, as in the MS7001EA unit.

The liner cap represents a field-proven improvement over the MS7001EA design. It provides for six fuel nozzles in lieu of one (Figure 16). This multi-fuel nozzle arrangement was selected as a result of superior field experience.

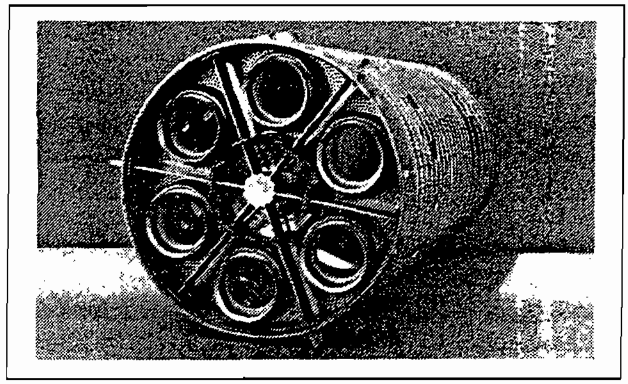

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Figure 16. MS7001F Combustion liner cap

A prototype multi-nozzle system was installed on an operating MS7001B gas turbine in utility service with water injection for NO_X control. This test, confirmed by extensive full-scale combustion tests in our Schenectady laboratory, clearly demonstrated the reduced combustion noise (dynamic pressure) level achieved when operating with multi-fuel nozzles, as opposed to operating with a single fuel nozzle system (Figure 17). This noise reduction reduced the combustion system wear to the point where combustion inspection intervals of the tested machine were extended by a factor of four. The design has proven so successful that it is available as a standard option on the MS7001EA machines, and several MS7001EA units are in operation with the same multi-nozzle quiet combustion system.

The application of the multi-nozzle also results in a shorter flame, so the MS7001FA combustion system is 583 mm (23 inches) shorter than the MS7001EA system. The six fuel nozzles are mounted directly on the combustion end cover so that no more piping connections are required than for a single fuel nozzle. This is accomplished through manifolding integral with the cover (Figure 18).

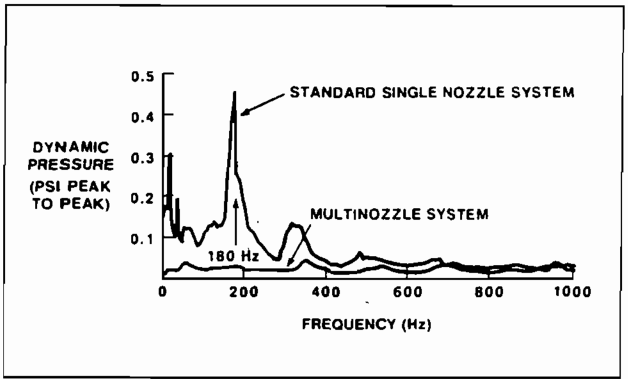

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Figure 17. Multi and single fuel nozzle combustion noise

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Figure 18. MS7001 Fuel nozzle

The transition piece is constructed of two major assemblies (Figure 19). The inner transition piece is surrounded by a perforated sleeve with the same general shape as the transition piece. This perforated sleeve forms an impingement cooling shell causing jets of compressor discharge air to be directed onto the transition piece body. The air, after impinging on the transition piece body, then flows forward in the space between the impingement sleeve and transition piece into the annulus between the flow sleeve and the combustion liner.

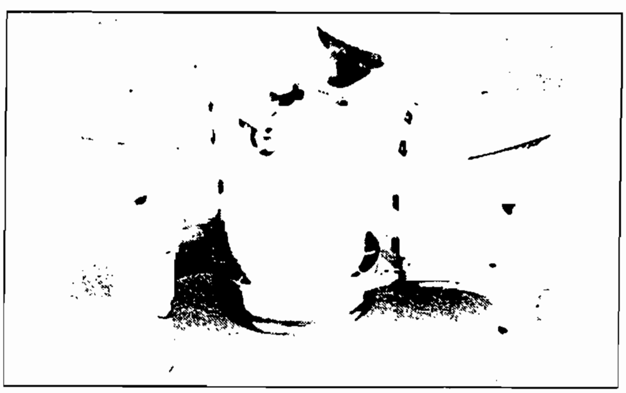

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Figure 19. MS7001F Transition piece

It then joins additional air flowing through bypass holes in the flow sleeve to provide the air for the combustion/cooling/ dilution processes.

The aft frame of the transition piece is cooled through the action of compressor discharge air flowing through drilled holes. These holes ensure that the air enters the main gas stream as a film on the inside surface of the aft frame.

Like the MS7001EA, the transition piece body is constructed of Nimonic 263, and the aft frame of cast FSX-414. The internal surface of the transition piece is coated with a thermal barrier to minimize metal temperatures and thermal gradients.

Full-scale tests of this advanced cooling system were performed on an operating MS6001 unit, and demonstrated a high degree of system reliability and compatibility. (See GE/EPRI reports AP3885, "High Reliability Gas Turbine Combustor Project," and AP5964, "Impingement-Cooled Transistor Piece.") These tests were so successful that the customer elected to purchase the test hardware for continued operation of his unit.

Turbine

The MS7001FA turbine is a three-stage design, with the first-stage blade unshrouded and the second- and third-stage blades equipped with integral Z form tip shrouds, as is the MS7001EA. Improvements in the aerodynamics have resulted in a turbine which is two percent higher in efficiency than the MS7001EA. As a result of this design approach, the turbine is capable of significant uprating to a firing temperature of 1370°C (2500°F). The MS7001FA turbine represents a new aerodynamic design with zero exit swirl at full load and a moderate exit Mach number.

Each of the three rotor stages consists of 92 investment-cast blades (the same as in MS7001 models A thru EA) of GTD-111 (Figure 20). The first-stage nozzle is constructed of investment-cast FSX-414 segments, and the second- and third-stage nozzles of investment-cast GTD-222 segments.

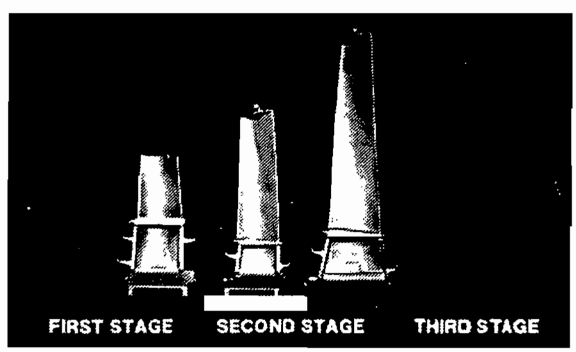

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Figure 20. MS7001F Buckets

The first- and second-stage blades and all three nozzle stages are air cooled. The first-stage blade is made of directionally solidified construction and convectively cooled via serpentine passages, with turbulence promoters formed by coring techniques during the casting process (Figure 21), a system proven in advanced aircraft engines operating at firing temperatures of 2600°F (1427°C). The cooling air leaves the blade through holes in the tip as well as in the trailing edge.

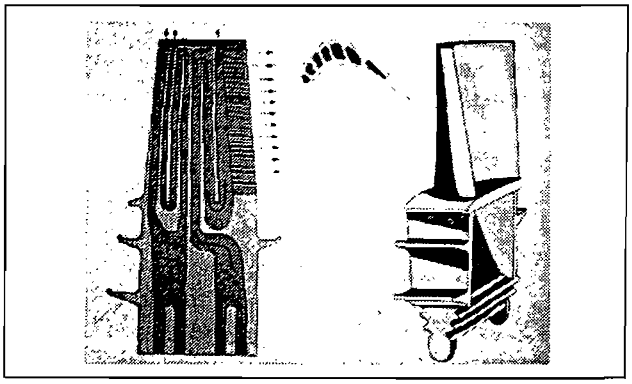

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Figure 21. First-stage bucket cooling passages

The second-stage blade is cooled by convective heat transfer using STEM – (Shaped Tube Electrode Machining) drilled radial holes, with all cooling air exiting through the tip like the MS7001EA.

The first-stage nozzle contains a forward and aft cavity in the vane, and is cooled by a combination of film, impingement and convection techniques (Figure 22) in both the vane and sidewall regions, similar to the MS7001EA. There are a total of 575 holes in each of the 24 segments.

The second-stage nozzle, as in the MS7001EA, is cooled by a combination of impingement and convection techniques, while the third-stage nozzle is cooled by convection only.

The efficient use of cooling air made possible by these advanced cooling methods is further enhanced by the reduced vane surface area of the first-stage nozzle, achieved by low solidity. The particular vane shape selected has also been developed for aircraft engines, and is illustrated in Figure 22.

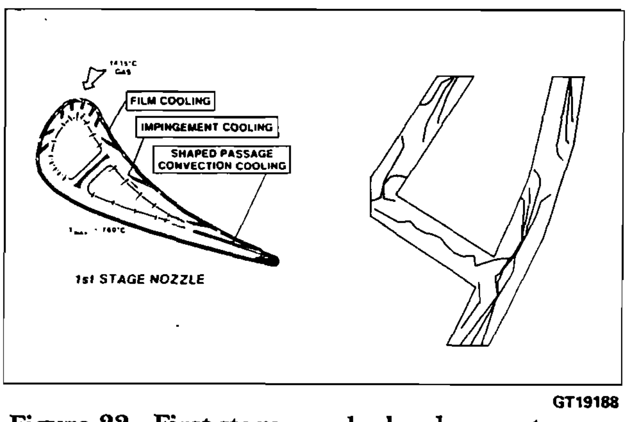

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Figure 22. First-stage nozzle development

In order to further enhance the excellent hot corrosion and oxidation resistance of GTD-111, all three stages of blades are coated. The first- and second-stage coating is a patented alloy of Co, Cr, Al and Y, applied by the PLASMAGUARD™ low-pressure plasma spray method, followed by an aluminide overcoat on external and internal surfaces. The third-stage blade is coated with a high Cr coating, which is applied by a pack process and subsequently receives a diffusion heat treatment.

The blades of all three stages are designed with long shanks and integral cover plates. These shanks provide for isolation of the gas path from the wheel rim and for mechanical damping of the system via seal/damping pins located under the platform and in the cover-plate edges. This system, in combination with the interlocking blade tip Z shrouds, has proven very effective and durable in similar designs found in the MS7001EA and other production machines. Careful attention has been given in designing the blade shank, especially the transition between the airfoil root and the dovetail, to ensure that high stresses are avoided due to structural discontinuities. This is a practice common to all GE blade designs.

The first- and second-stage stationary shrouds are two-piece designs. Here, the gas side inner shroud is separate from the supporting outer shroud to provide freedom for expansion/contraction for improved low cycle fatigue (LCF) life. The first-stage shroud is cooled by impingement, film, and convective means.

The cooling circuit for the turbine components consists of both internal and external circuits (see Figure 4). The first- and second-stage blades, the first-stage nozzle and the first-stage shroud are cooled by an internal cooling air circuit typical of the MS7001EA, while the second- and third-stage nozzles are cooled by an external cooling air circuit without the complexity of coolers or valves.

The internal circuit is supplied by the 17th stage and by compressor discharge air, and the external circuit by 13th stage extraction air. The first-stage nozzle and shroud cooling air is supplied from the compressor discharge plenum housing the combustion transition pieces. The blade cooling is supplied by air flowing radially inward at the 17th-stage compressor wheel, then through 15 holes drilled axially through the distance piece, and then over the forward face of the first-stage turbine wheel. The blade cooling air then flows through the bore of the first-stage turbine wheel into the chamber between the first- and second-stage wheels to the root of the first- and second-stage blades.

RELIABILITY EMPHASIS IN DESIGN

The MS7001FA was developed using advanced aircraft engine technologies in a manner to ensure high reliability, and with features that achieve low maintenance costs.

The approach used to ensure reliability involved a combination of approaches, all of which derived from the expressed desires of customers and the operating experience from a fleet of over 4,500 gas turbines. This approach involved customer interviews, assessment of operating experience, field trials of new concepts, Reliability Availability Maintainability (RAM) analysis for controls and accessories, extensive analysis and component tests, and extended machine engineering testing under load with copious instrumentation at factory and customer sites.

EPRI maintainability studies were done on the control system, the accessories, and other systems of the MS7001FA. (See GE/EPRI studies AP3875, "GT Microprocessor System: Reliability Test and Analysis," AP6823, "Controls and Accessory Reliability," and AP5822, "Improved Maintainability for Advanced Gas Turbines.") Full-scale wood mockups of the MS7001FA gas turbine structures and review of its design by a Users Maintainability Team provided input which has enhanced the maintainability of the MS7001FA. This review resulted in several customer-requested innovations, including the ability to service an individual combustor without disturbing adjacent combustors, and the ability to remove the first-stage nozzle without removing any stator casing.

Controls and Accessories Reliability

Studies performed by GE regarding gas turbine operating reliability indicate that the control and accessory systems have historically been a major cause of unreliability in gas turbine units. Specifically, these systems have been responsible for approximately 66 percent of the forced outages and approximately 33 percent of the forced outage time.

The methods used to ensure high reliability for controls and accessories systems, however, are different from those applied to ensure high reliability in the flange-to-flange gas turbine. This difference stems principally from the fact that redundancy is possible in the controls and accessories functions while it is not possible in the design of gas turbine components.

The methods used to ensure high reliability of the controls and accessories systems have included Reliability Block Diagram Analysis (RBDA), Fault Tree Analysis (FTA), and Failure Modes and Effects Analysis (FMEA). The selection of the appropriate analytical methods is a function of the configuration of the system being analyzed and the availability of reliability data for its components.

RBDA and FTA methods are "Top Down" approaches, which are used with systems for which an extensive system or component experience database exists.

GE has at its disposal two databases for the reliability of its gas turbines. The first, Operation Statistics Program (OPSTAT), maintains a record of the outages of all GE-manufactured gas turbines. The second, Operation Reliability Analysis Program (ORAP), maintains a more detailed operating record, reported on a weekly basis, which includes data from approximately eight million engine-period hours, two million fired hours, and 184 gas turbines.

The FMEA method is a "Bottom Up" approach, and is used for systems where extensive operating experience does not exist. In this case, the FMEA analytical method works from the assumption that the system is operating satisfactorily. It then searches for the various modes which could cause a system failure. This permits the addition of redundant or compensating components or systems to improve system reliability.

The method used to establish a reliable controls and accessories system design required first that system reliability goals be established (Table 1) consistent with the requirements for meeting the overall total combined-cycle plant reliability requirements (Table 2). Having established these reliability goals, the first step in the design process was to ensure that each system was as simple as possible in its concept. This ensured the elimination of unnecessary functions and, therefore, any influence these extraneous functions would have on the unreliability of the overall system.

This effort also resulted in the elimination of two systems which were included on the previous generation MS7001EA gas turbines. These systems were the accessory drive and the turning gear.

Having established the simplest system, it was then required that a reliability analysis be performed on each system to demonstrate that it met the requirements of Table 1. This analysis used RBDA, FTA or FMEA as appropriate to the given system, and used the operating database available for the system component. The method used is also indicated in Table 1. The engineer then compared the results of this analysis with the goals for the specific system to see if additional improvement was required to meet these goals.

In general, when improvement was required it was most readily accomplished by adding redundant components or functions within the system. This process was repeated until the overall gas turbine controls and accessories met the required reliability contained in Table 1.

Table 1

COMPRESSOR AND AUXILIARY RAM GOALS APPORTIONED FOR GAS FUEL

SYSTEM	FO /MFH	FO /YR	FOF (%)	UNAV (%)	SUR (%)	METHOD OF ANALYSIS
Auxiliary Power	7.3	0.044	0.05	0.05	0.04	FMEA
Clean/Wash	0	0	0.01	0.01	0	(1)
Control	27.8	0.167	0.22	0.22	0.64	RBD
Cooling & Sealing Air	5.1	0:03	0.03	0.03	0.11	RBD
Cooling Water	10.4	0.063	0.06	0.06	0.04	RBD
Enclosures	0	0	0.04	0.04	0.01	(1)
Exhaust	11.1	0.067	0.10	0.10	0.07	RBD
Fire Protection	11.5	0.069	0.03	0.03	0.04	RBD
Fuel Gas	8.0	0.048	0.01	0.01	0.02	RBD
Generator Control	18.0	0.108	0.14	0.14	0.09	FTA
Heating and Ventilation	1.7	0.01	0.01	0.01	0	RBD
Hydraulic Control/Trip	26.5	0.159	0.09	0.09	0.30	RBD
Inlet	3.3	0.02	0.01	0.01	0.02	RBD
Lube Oil	21.7	0.13	0.26	0.26	0.12	RBD
Steam/Water Injection	7.6	0.045	0.01	0.01	0.01	RBD
Starting	2.0	0.012	0.12	0.12	0.41	RBD
Total C&A	**162**	**0.972**	**1.19**	**1.19**	**1.92**	

NOTE: (1) These systems are passive during operation, but may inhibit start-up.

Table 2

RELIABILITY GOALS
SINGLE UNIT, SINGLE SHAFT,
COMBINED CYCLE PLANT

	PROJECTED TOTAL PLANT GOAL	GAS TURB. MIN. REQ.
MTBFO	3000 HR.	4400 HR.
FOF	5%	3.3%
AVAILABILITY	90%	95%
STARTING RELIABILITY	95%	96.7%

Table 3

RELIABILITY RESULTS

	MS7001E FLEET	MS7001FA GOAL	MS7001FA PREDICTED
FAILURE RATE	846	162	149
FORCED OUTAGE FACTOR	2.28	1.19	0.8
STARTING RELIABILITY	3.5	1.92	2.1

The result of this effort is shown in Table 3, which clearly indicates that the MS7001FA gas turbine has more than met the requirements for failure rate and forced outage factor. The starting reliability requires a modest improvement which should be achieved with the application of static (i.e. generator) starting.

Gas Turbine Engine Reliability

The various methods of reliability analysis for controls and accessories functions are not readily applicable to the design of the gas turbine engine proper. Since it is not possible to provide redundant components such as blades, extremely conservative design practices must be relied upon to ensure reliability. Design life margin takes the place of redundancy. The method and materials of construction are similar between these two generations of gas turbines.

GE's design approach uses statistical methods to ensure freedom from failure. One approach defines the failure mode active in judging the acceptability of each component. For example, one life criterion for the MS7001FA gas turbine blades (as well as for the MS7001EA) is based upon a given creep deformation, not rupture. Research performed by GE gas turbine materials engineers has shown that rupture time, such as that shown in Figure 23, is not sufficient in itself as a failure criterion. Figure 24 illustrates the degree of cracking developed in the cast

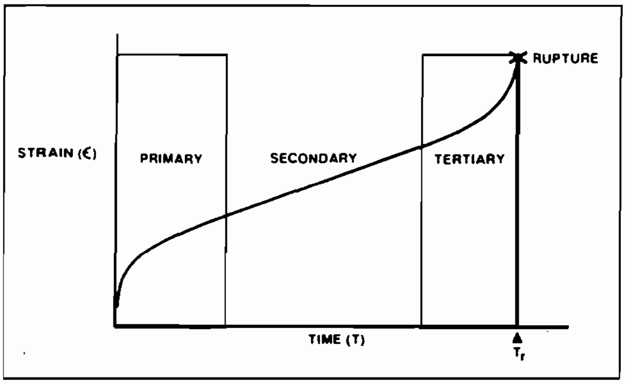

Figure 23. Strain accumulation during the standard creep test (with constant stress and temp.)

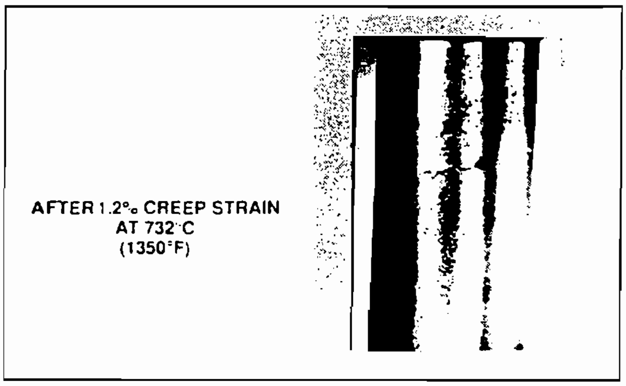

Figure 24. Surface cracking in IN-738

nickel-base superalloy IN-738 when it has accumulated 1.2 percent creep strain at 1350°F (732°C). This cracking developed well before actual rupture of the test specimen.

We have observed that creep cracking develops in nickel- and cobalt-base superalloys at approximately the onset of the tertiary stage of creep (see Figure 23). For this reason, a time-to-rupture criterion is not used when designing against failure. Instead, a creep strain criterion is chosen to avoid creep cracking.

In this regard, failure is defined as 1/2 percent creep strain accumulation in the required life of the blade, rather than rupture of that blade. The reason for selecting this percentage is that nickel-base superalloy structures start developing microcracks at approximately the transition from second stage to tertiary stage of creep. Cracking, therefore, becomes the definition of end of life, even though substantial time exists prior to rupture.

Since a material's response to stress, strain, temperature and environment is highly variable, it is necessary that sufficient testing over a broad range of conditions and characteristics be performed to create a statistically-dependable definition of the material's behavior (Figure 25).

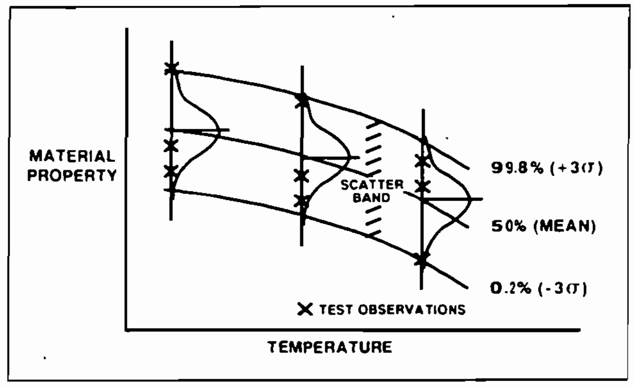

Figure 25. Statistical nature of material properties

Having established this statistically-significant material's property database, GE then selects the material characteristic for design to be at the minus four-standard deviation level to represent the material strength. Statistically, this results in one blade out of 100 operating gas turbines reaching its design life limit of 1/2 percent creep strain at or beyond the prescribed life criteria. All other buckets in these 100 gas turbines would have a greater life (i.e., lower creep strain) and none would have ruptured. The described life criteria used for the MS7001FA is the same as that applied to the MS7001EA.

The control functions provided with all GE gas turbines, including the MS7001FA, are set to limit the impact of the start/stop cycle. Light-off spikes are controlled so that the combination of duration and severity are such that only low strains are developed in turbine components without impeding light-off and cross-firing.

Acceleration and fired shutdown functions are also designed to have a minimum impact upon part life. Great effort has been expended to develop an understanding of the impact of start/stop cycles on cyclic life.

Field tests on an MS5002 unit and the first MS9001E unit incorporated a variety of start/stop characteristics to explore their impact upon cyclic life. Fully-instrumented hot-section components were incorporated to provide experimental correlation. The results of these efforts clearly demonstrated that the major deleterious cyclic effect is caused by machine trips, especially trips from full load. Figure 26 compares the impact upon strain range for a normal start/stop cycle with a cycle containing a full-load trip. Slowing the acceleration adds an additional 60 percent on the fatigue life of the nozzles and buckets.

Also essential to the conservative design of GE gas turbine components are well-established analytical programs which have been validated for the type of analysis for which they have been devel-

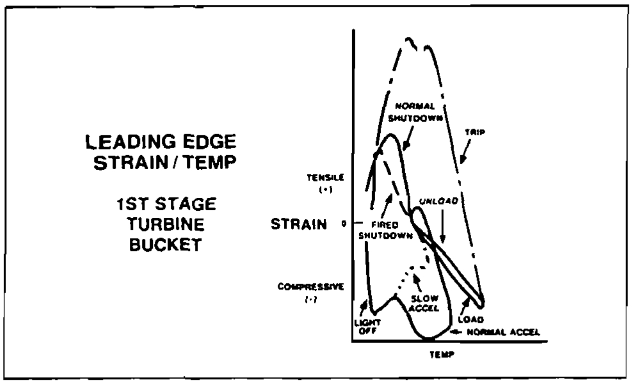

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Figure 26. Leading edge strain/temperature (first stage turbine bucket)

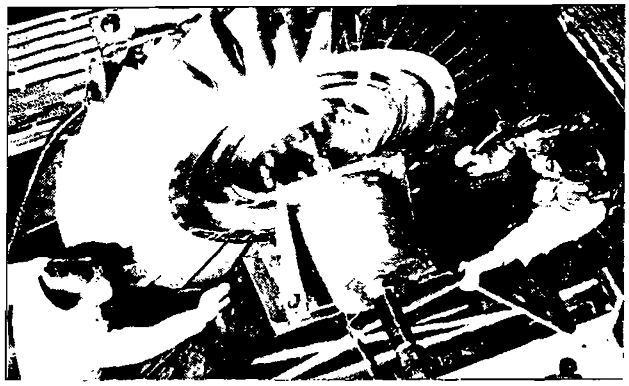

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Figure 27. Wheel box testing

oped. Due to the complex shape and elevated temperature environment of gas turbine components, these programs must be capable of three-dimensional, time-dependent, non-linear analysis.

Conservative life definition, detailed materials characterization, and accurate analytical capabilities have been combined with significant component and prototype testing in order to ensure that the conclusions reached in the design phase are accurately represented in the finished part.

Because of the critical role played by boundary layer heat transfer, a proper understanding of this phenomenon in the design of cooled components is essential. For this reason considerable heat transfer testing has been accomplished in support of the MS7001FA design process. This heat transfer testing included previous full-scale gas turbine prototype tests, hot cascade tests at GE's large aircraft engine facility, and liquid crystal thermography at GE's Corporate Research and Development laboratories.

Another important system that was subjected to considerable component testing was the combustion system. The development of the MS7001FA combustion system required more than 65 full-pressure, full- temperature, full-flow laboratory tests to qualify the final design.

Additional component tests included bench and wheelbox testing (Figure 27) of compressor and turbine blading to accurately establish their dynamic response characteristics and demonstrate freedom from excitation at natural frequencies.

The MS7001FA programs also made use of extensive field testing of materials and design concepts in order to validate these features prior to commitment. Examples of this are found in the extensive field testing of N263 as a combustion transition piece alloy, and that associated with the demonstration of the aerodynamic characteristics of the impingement-cooled transition piece. In the latter example, an operating MS6001 was equipped with a full complement of combustion components which duplicated the impingement-cooled design in the MS7001FA combustion system. The results demonstrated that the design could be released for MS7001FA application.

The most extensive example of design validation testing is found in the test program for the first production MS7001FA unit. Testing was performed in order to compare each component with those predictions made by the design engineer with respect to the design requirements. It was not a life test. In this regard, strain, temperatures and pressure are measured throughout the gas turbine in order to characterize the performance of each part.

In the case of the first production MS7001FA unit, more than 3,000 pieces of instrumentation (Figure 28) were applied to the unit for loaded factory testing in Greenville, S.C. at the full firing temperature of 2300°F (1260°C). The form of the test facility was such that the gas turbine compressor could be back-pressured in order to search for the actual stall line of the compressor. An additional fully-instrumented, full-load test was performed at the customer's site using more than 2,000 pieces of instrumentation (Figure 29).

DESCRIPTION	THERMOCOUPLES	PRESSURE TRANSDUCERS	STRAIN GAGES	DYNAMIC PRESSURES	LOAD CELLS	VIBRATION SENSORS	TOTALS
CASINGS	348	204	26	16	–	–	594
BEARINGS	58	14	–	–	14	12	98
SHROUDS							
STG 1	151	35					186
STG 2	33	4					37
STG 3	33	7					40
BUCKETS							
STG 1	49	–	4	3	–	·	56
STG 2	16	–	6	–			22
STG 3	8	–	18	–	–		26
NOZZLES							
STG 1	198	64					262
STG 2	243	60					303
STG 3	143	37					180
COMPRESSOR							
STATOR BLADES	114	108	94				316
ROTOR BLADES	6	–	40				46
WHEELS							
COMPRESSOR	65	3					68
TURBINE	169	6					175
COMBUSTORS	200	151	20	24	–	–	395
MISCELLANEOUS	94	121	–	–	–	18	233
TOTAL INSTRUMENTATION	1,928	814	208	43	14	30	3,037

GT19746

Figure 28. MS7001FA Prototype factory test instrumentation summary

DESCRIPTION	T/C's	STATIC PRESS.	STRAIN GAGES	DYNAMIC PRESSURE	LOAD CELLS	VIBRATION
CASING	✓	✓	✓	✓		
BEARINGS	✓	✓			✓	✓
SHROUDS	✓	✓				
BUCKETS	✓					
NOZZLES	✓	✓				
COMPRESSOR	✓	✓	✓	✓		
WHEELS	✓					
COMBUSTORS	✓	✓	✓	✓		
	1,422	429	144	38	28	23

• 2,084 INDIVIDUAL PARAMETERS WERE MEASURED

GT20580

Figure 29. Virginia Power FA test instrumentation summary

TEST RESULTS HAVE VALIDATED THE MS7001FA DESIGN

Figure 9 defines two prototype tests, a factory (Phase II) and a field (Phase III) fully instrumented test series. The factory test had as its principal focus the mapping of the compressor, necessitating a variable speed load. The field test focused on performance and utilized its generator as the load device. The testing of the first production MS7001FA unit with a full complement of instrumentation represents a long-standing practice in the validation of GE design practices. This testing is performed whenever an iteration occurs in a gas turbine design. For example, the first production units have been tested with full instrumentation for each MS7001 model and include testing on the MS7001A, MS7001B, MS7001C, MS7001E, MS7001EA, and now the MS7001FA. (No MS7001D gas turbine was produced.)

During the past twenty years, the GE heavy-duty gas turbine business has performed more than ten prototype tests on fully-instrumented units. It is this testing of instrumented production units which serves to improve and validate the analytical methods used in the design of GE heavy-duty gas turbines. Although several minor changes were implemented in some components, no significant design changes to the basic MS7001FA were required in order for it to be fully qualified for unlimited operation on electric utility systems. The conclusions drawn from this testing indicate that the design is conservative and all components will meet or exceed their design life expectations. The results of these two prototype tests (factory and field) were so favorable, including tests at 2350°F (1288°C), that the MS7001FA was uprated to the present 2350°F (1288°C) 157 MW rating.

Compressor Performance

During factory prototype testing, the optimum condition for starting the MS7001FA gas turbine was achieved by keeping the 5th-stage extraction closed while venting the 13th-stage extraction to the atmosphere. The gas turbine is started with the VIGV at an angle of 27°, increasing it to 54° at approximately 84 percent speed. Full-speed operation of the gas turbine is then maintained with the VIGV at 81°.

The compressor was fully mapped and, in addition, the pressure ratio limit was determined at corrected speeds of 90, 100 and 105 percent. On two occasions, the compressor was intentionally surged while searching for the surge line, without damage. A total of 77 test points were obtained during the compressor surge test phase, including the two intentional surges.

The conclusion from this test is that the MS7001FA compressor has exceptional efficiency in spite of the transonic nature of the zero and first-stage blading. This verifies the value of applying advanced aircraft fan blade aerodynamic design methods. Information from this test was used to confirm the need for the ninth-stage bleed during MS7001FA start-up.

The flow was more than three percent higher than predicted and the surge margin (the percent by which the mass-flow-to-pressure ratio fraction at surge exceeds that at full load under ISO conditions) is eight percentage points better than that of the MS7001EA compressor at operating speed. No in-service surge has ever occurred on an MS7001EA gas turbine. The superior surge margin of the MS7001FA is considered to be more than adequate for all service conditions.

Machine Performance

With the three percent improvement in airflow noted earlier, plus a turbine efficiency which projects to be some two percent higher than originally predicted, it has been possible to commit to a new rating on the MS7001FA machine at 2350°F (1288°C). This rating, which goes beyond the conservative rating originally projected, is 157 MW output and 10,144 KJ/kwh (9615 BTU/kwh) LHV heat rate on natural gas.

Dynamic Behavior

The maximum rotor vibration during all testing, except that associated with surge test, was 0.22 inches/second. During most of the test, however, the rotor vibration was on the order of 0.12 inches/second. The closest rigid rotor critical speed was determined to be at 72 percent of synchronous speed.

The shaft mode at this speed is a rigid-body mode referred to as a conical or rock mode. This mode is highly damped within the bearings and, with little energy in the rotor, does not result in uncontrolled responses. The first bending critical is calculated to be at 125 percent of synchronous speed.

The vibratory stress levels of the MS7001FA compressor and turbine blading are well within GE's successful experience on the more than 400 MS7001E/EA machines in service.

Gas Path Profiles

Nine thermocouples were included in each of 21 thermocouple rakes in the turbine section. Nine rakes were located aft of the first-stage blades, seven aft of the second stage, and five aft of the third stage. Twenty thermocouples were also located in each of the exits of two transition pieces. Additionally, gas temperatures were measured upstream of the nozzles. Included were six-thermocouple rake upstream of a first-stage vane leading edge; two four-thermocouple rakes upstream of second-stage vanes; and two five-thermocouple rakes upstream of third-stage vanes. These measurements allow a thorough understanding of the temperature profiles within the turbine.

Figure 30 illustrates the interstage gas path profile results. It can be seen from this figure that the first-stage profile is cooler and flatter than predicted, while the second-stage profile conforms almost precisely to that predicted at 60 percent span and less, and the third-stage profile is hotter and flatter than predicted. These results support the conclusion that GE's minimum hot gas path component life design requirement will be readily met in the MS7001FA gas turbine. This conclusion is supported by Figure 31, where it is shown that a 50° F (10°C) margin exists for the stage one blade, a 30°F (–1.1°C) margin for stage two, and a 40°F (4.4°C) margin for stage three for the MS7001FA.

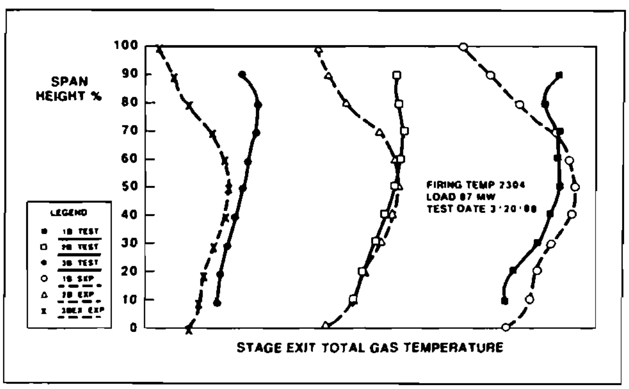

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Figure 30. MS7001FA prototype load test turbine gas path profile

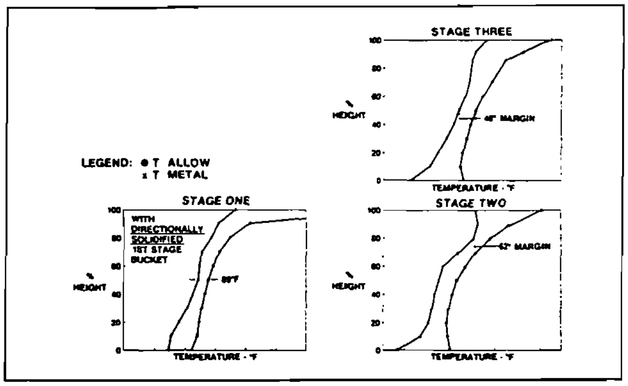

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Figure 31. Life margins at design point (MS7001FA buckets)

Component Temperatures

A considerable amount of effort was applied during the design phase of the MS7001FA regarding the determination of heat transfer coefficients to be used in the design of the hot section turbine parts. These tests included the use of water table, hot cascade and liquid crystal techniques so that the advanced cooling methods utilized in the MS7001FA could be most effective in reducing metal temperature and smoothing thermal gradients. The results of previous tests on first production units were also used.

The net result of this component and configurational testing during the design phase has resulted in congruency between metal temperature predictions and those actually realized on the first unit test. All metal temperatures in blades, nozzles and combustion hardware are at or below the design values. Figure 32 illustrates a typical comparison between measured temperatures and predicted temperatures at the first- and second-stage blade pitchline sections as determined during the factory test at 2300°F (1260°C).

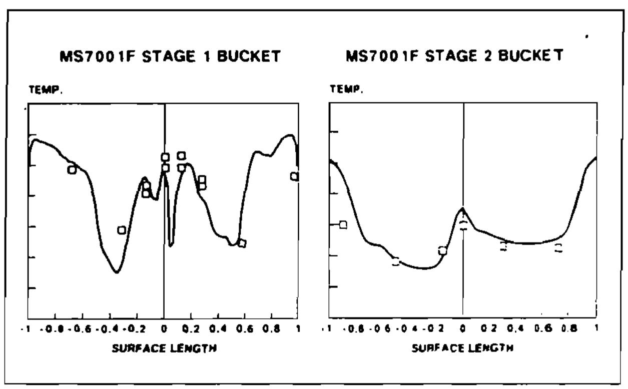

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Figure 32. Calculated versus measured surface temperatures

Combustion Performance

The combustion system lights off at 15 percent speed as predicted, with cross-firing of all 14 combustion chambers within eight seconds from ignition.

The multi-nozzle combustion system (see Figure 16) has resulted in very low dynamic pressures during all phases of combustion tests. The overall dynamic level was 2 psi p-p max versus a 3.5 psi p-p design limit. The discrete dynamic values were at 0.2 psi p-p max versus a design limit of 0.35 psi p-p. These low levels of dynamic response within the combustion system were maintained even with very high water-to-fuel ratios (from 0 to 2 lbs. of water per pound of fuel) during emissions abatement tests.

The metal temperatures for both liner and transition piece are as predicted. Figure 33 compares these measured temperatures with those of the MS7001EA. This comparison clearly indicates the result of the improved cooling used in the MS7001FA, since both temperatures and thermal gradients are lower in the MS7001FA.

The combustion system was free of any indications of wear. The only indication of distress was minor spalling of the thermal barrier coating in a highly localized area on some of the combustion liner caps. The metal surface being protected by the thermal barrier coating was not exposed.

Emissions testing was performed over the entire load range for both distillate and natural gas fuels during the field test. The capabilities of both water and steam diluents were examined. These systems met the installation's emissions performance requirements at base load, without qualifications.

The test confirmed the diluent required to achieve 42 ppmvd NO_X (on natural gas) and 65 ppmvd NOx (on distillate) at base load (see Table 4.)

The field test emissions test results are shown in Table V.

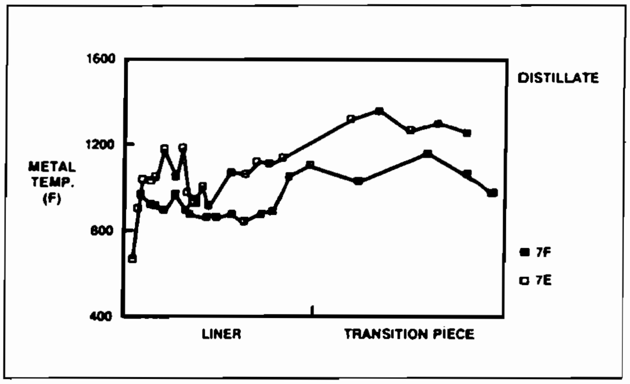

Figure 33. Combustion system temperatures

Table 4

Fuel	Diluent	Diluent/ Fuel Ratio
Natural Gas	Steam	1.15
Natural Gas	Water	0.75
Distillate	Steam	1.45
Distillate	Water	0.85

Table 5
VIRGINIA POWER 7F TEST EMISSION REQUIREMENTS BASE LOAD

EMISSION	DISTILLATE	NATURAL GAS
NOx: (PPMVD AT 15% O_2)	65 PLUS CORRECTION FOR FUEL BOUND NITROGEN	42
CO: (PPMVD)	← 25 →	← 25 →
(LB/HR)	← 90 →	← 90 →
VOC: (LB/MBTU) - HHV AS METHANE	← .0103 →	← .0103 →
PARTICULATES: (LB/HR)	← 19 →	← 19 →
VISIBLE: (% OPACITY)	← 20 →	← 20 →

ALL REQUIREMENTS HAVE BEEN MET

GT20593

Dry Low NO_X Combustors

During the 1970s, GE's research into low emission combustion systems developed the concept of pre-mixed and fuel-staged combustion as an optimum means by which gas turbine combustion systems could be operated with low NO_X emissions. This system was particularly chosen in order to avoid the complexity of moving parts within the combustor proper required by air-staged combustion. Both fuel- and air-staged combustion systems seek to provide lean combustion and hence low combustion temperatures, which naturally result in low NO_X emissions (Figure 34). In this figure, equivalence ratio and lean/rich combustion are directly related. An equivalence ratio of 1 is equal to stoichiometric combustion with lower equivalence ratios equivalent to lean combustion.

In order to accommodate the fuel/air ratios required to support combustion over the full operating range from light-off to full load, it was necessary to develop combustion systems which depended upon technology beyond simple operation with lean fuel/air mixtures. GE's response to this was to add pre-mixing of the fuel to ensure an intimate mixture between the fuel and the air at higher loads under very lean combustion characteristics. Figure 35 illustrates this combustor.

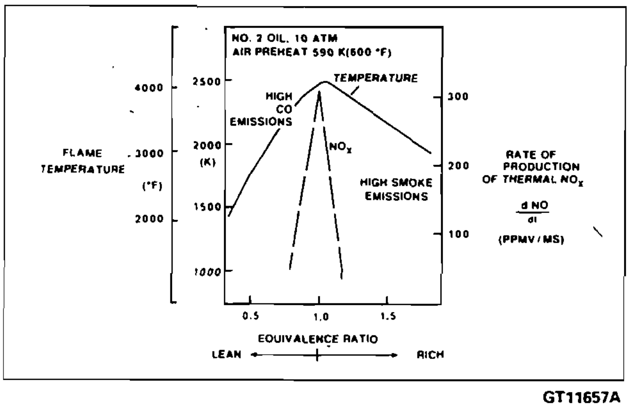

Figure 34. NO_X production rate

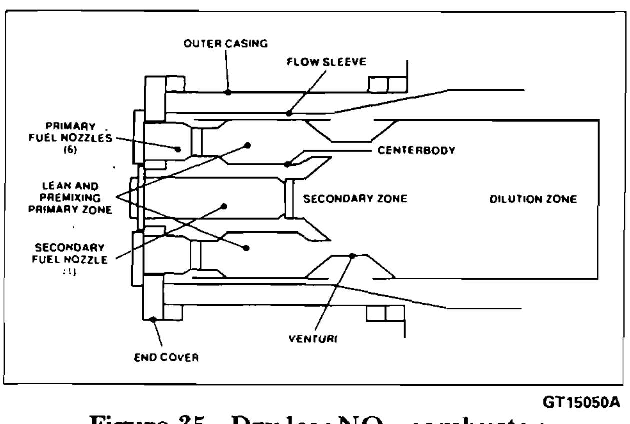

Figure 35. Dry low NO_X combustor

In this combustor, the primary zone features of six fuel nozzles as in the standard MS7001FA combustor. A seventh fuel nozzle protrudes down the axis of the combustor and is located at the throat of the venturi. During low loads, combustion takes place in the primary zone fed by the six fuel nozzles under lean operating fuel/air ratios. As the load is increased, fuel is introduced into the secondary fuel nozzle at the center of the venturi, where lean combustion also takes place to support the increased load. As the load is further increased, the fuel is cut off to the six fuel nozzles in the primary zone in order to extinguish the flame in this part of the combustor. Simultaneously, fuel is added into the secondary zone to support the load during this transfer function.

Within approximately 30 seconds, the flame in the primary zone has been extinguished so that fuel can be readmitted to the primary zone, where it is intimately mixed with the combustion air without combustion taking place in the primary zone. This premixed fuel/air mixture then flows through the venturi section where it is ignited by a pilot flame in the secondary fuel nozzle. The combustion of this pre-mixed fuel/air mixture is possessed of low NO_X emissions resulting from the thorough mixing of the fuel and the air, such that rich pockets are eliminated and hence the source of elevated NO_X.

Upon completion of the conceptual design of this system, full-scale machine-grade hardware was constructed for a field engineering test on an operating MS7001 machine in 1981. This test was so successful from an operating flexibility and a NO_X reduction standpoint that continued refinement of the design was undertaken.

The existence of a dedicated combustion test facility at GE's Gas Turbine Development Laboratory in Schenectady, New York, together with the nature of the GE heavy-duty gas turbine combustion system, has permitted full-machine-condition development to proceed on the dry low NO_X system developed by GE. This development used full-pressure, full-flow and full-firing temperature conditions typically found in the MS7001EA, the MS9001E, the MS6001B, the MS7001FA and the MS9001FA machines.

GE's development of this dry low NO_X system has emphasized the MS9001E due to the intense interest shown by Tokyo Electric Power (TEPCO) in this particular combustion system.

The MS7001FA dry low NO_X combustor has been undergoing qualification testing in GE's combustion laboratory facilities with the same rigor, but at a later schedule than that for the other current production machines. This testing, which has resulted in the extremely reliable and effective GE combustion systems presently in operation on all of our gas turbines, will permit the full qualification of the MS7001FA dry low NO_X system. Figure 36 illustrates GE's dry low NO_X combustion hardware components.

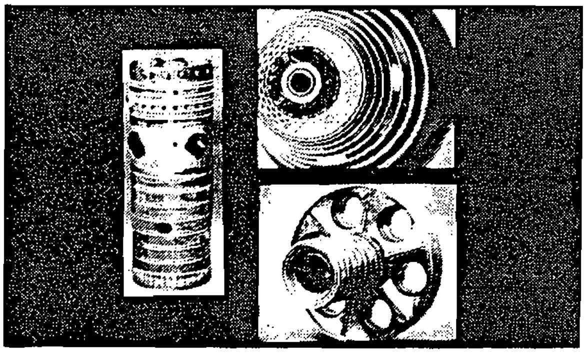

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Figure 36. MS7001 Dry low NO_X combustor

TEST PERFORMANCE AND EVALUATION

Since its introduction four years ago, GE's advanced-technology MS7001FA gas turbine has undergone the most thorough test and performance evaluation program of any gas turbine in the company's history. Prototype testing at the company's manufacturing facility in Greenville, South Carolina, plus field testing and plant acceptance testing at the unit's lead installation (Virginia Power Corporation's Chesterfield No. 7 power station), culminated with its first commercial operation at over 150 MW output. Combined with a Vogt two-stage heat recovery steam generator and a GE steam turbine-generator as part of a GE STAG (steam and gas) power plant, the unit achieved over 50% fuel efficiency in combined-cycle operation.

The unit at Chesterfield No. 7 is configured as a combined-cycle plant and can be operated on dual fuel (distillate and/or natural gas) with steam injection for NO_X control. The absence of a bypass damper in this installation means that the plant must always be operated in combined-cycle mode. Consequently, testing of the gas turbine at full, base load capacity (a principal objective of the test program), had to wait until the entire combined-cycle plant was available and operating.

The engineering test plan included 30 days of testing to be performed prior to the pre-established commercial operation date (COD). These tests were performed from January 10, 1990 through May 4, 1990 and, when possible, were made to coincide with the normal plant startup activities. While the prototype unit was extensively tested in the factory, there were limits to what could be performed there. The field engineering test was planned to fill these testing voids and to complete the evaluation of the machine in its production configuration.

Test objectives included evaluating the production starting means, re-evaluating the start-up parameters, and confirming the mechanical design of the unit at base load with the new IN/706 rotor and DS first-stage buckets. Perhaps the most important objective, however, was to confirm the aerodynamic and thermodynamic performance of the gas turbine at and near base load, and at all anticipated combinations of operating parameters. These included both fuels (distillate and gas), both NO_X control diluents (water and steam), and a range of ambient temperatures, IGV angles, and part-load conditions. In addition, testing at firing temperatures up to 2350°F (1288°C) confirmed the design adequacy for the new MS7001FA rating.

Other objectives were defined that dealt with the operation of the turbine controls and accessory systems. These objectives were intended to evaluate the performance of these systems and to decide if, in the future, these systems could be simplified and/or eliminated.

Among the notable findings on individual components from the field test were:

Shrouds – The second- and third-stage shrouds were cooler than expected, indicating that the present shroud design could allow higher firing temperatures without redesign.

Rotor – Wheel metal temperatures were low compared to the measured wheelspace temperatures, indicating additional margin for the rotor design.

Combustors – All combustor metal temperatures were in the expected range. It is significant to note that these measured metal temperatures are below the levels experienced on the well-proven MS7001E combustors. Dynamic pressures were consistently low over the entire operating range, including the cases with high diluent injection flows from NO_X abatement.

Wheelspaces – The most important result is the confirmation that the third aft wheelspace continues to be over-cooled. Tests were performed with the exhaust frame blowers turned off and the results are being examined for future elimination of these blowers.

Vibrations – The unit operates within the vibration design limits throughout the operating range. Maximum seismic vibration levels measured were on the horizontal seismic planes at base load and steady state. These were 2.5 and 7.6 mm/s on the No. 1 and No. 2 bearings respectively. The levels measured on the vertical seismic planes were lower.

CONCLUSION

Testing

The first MS7001FA production gas turbine has successfully concluded all engineering test programs wherein all performance objectives have been met or exceeded. Its performance has allowed an uprate and full qualification for utility service without limit. The test results support the conservative design methods applied to GE gas turbines, as well as the practice of reliance upon component tests and aircraft engine technology during the design phase. The MS7001FA will prove to be as reliable as its predecessors in the MS7001 product line.

The superiority of GE's design method in producing reliable gas turbines has been instrumentation in the evaluation process by the world's leading utilities, who have ordered more than 50 MS7001F/FA/MS9001F/FA gas turbines as major additions to their system capacity.

In the first nine months of commercial operation, the MS7001FA has achieved 4000 fired hours with 99 percent average reliability and starting reliability at 100 percent. Based on commercial operation to date, the MS7001FA will meet or exceed our expectations.

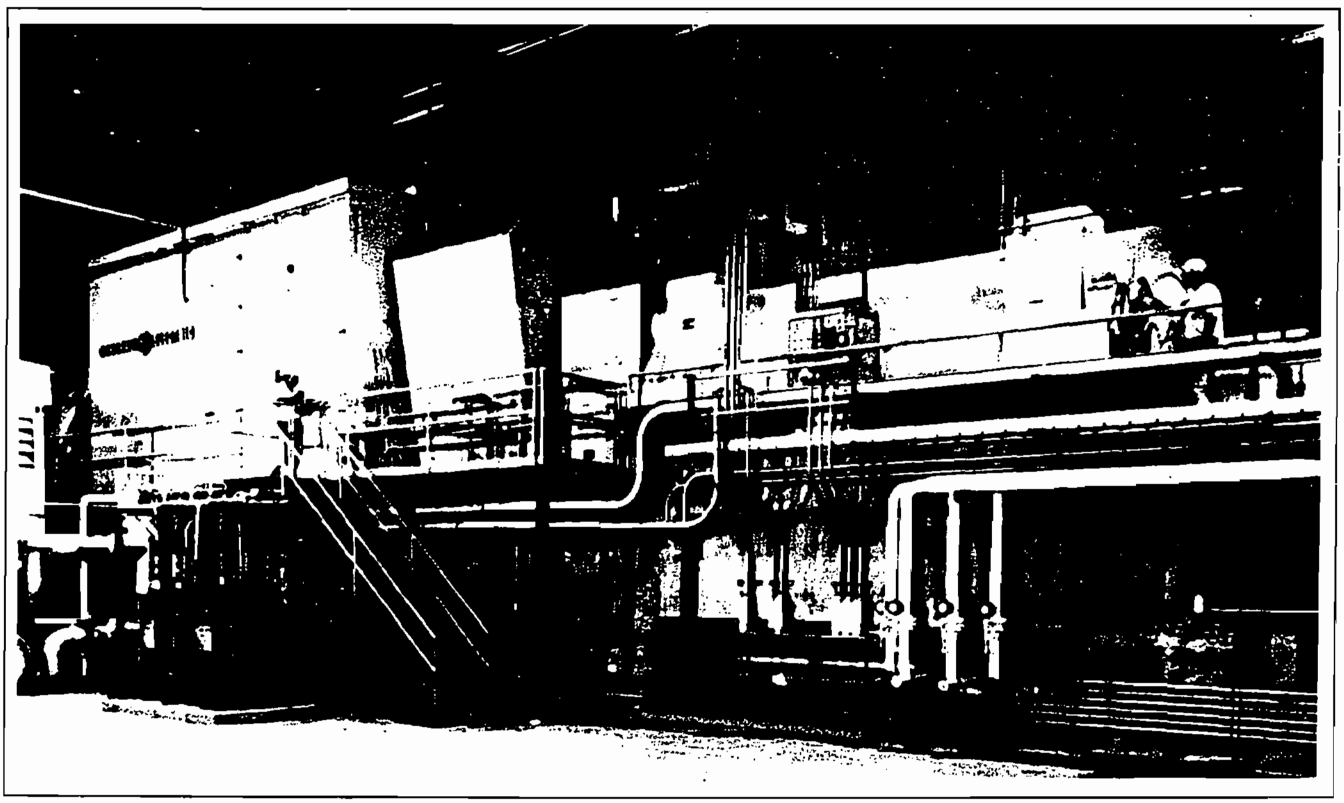
Commercial Operation

At its one-year anniversary of commercial operation at Virginia Power's Chesterfield Power Station, the MS7001Fgas turbine leads the industry in high reliability, availability and maintainability (RAM).

For the first nine months of commercial operation for the Chesterfield 7 MS7001Fgas turbine-generator, it recorded an average reliability of 99.1 percent. The 7F has recorded a starting reliability of 100 percent over more than 100 starts, while operating for more than 4,000 fired hours.The Chesterfield 7 STAG™ 107Fcombined-cycle unit, consisting of the 7F and a 64-megawatt GEsteam turbine, is rated at 214 megawatts but tested at 227 megawatts.

The 7F's RAMdata for the first five months of commercial operation was consistently higher than the latest comparable North American Electric Reliability Council/Generation Availability Data System (NERC/GADS)figures.

For that five-month period, the 7F showed a reliability of 98.5 percent, compared to a NERC/GADS figure of 95.55 percent. Availability for the 7Fwas rated at 98.3 percent, compared to a NERC/GADS figure of 89.54 percent. Starting reliability was 100 percent, compared to a NERC/GADSfigure of 91.57 percent.



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The Chesterfield 7 STAG™ 107F Combined-Cycle Unit Consists of the GE MS7001F gas turbine and a 64-megawatt GE steam turbine

The MS7001Fand its scaled up, 50-hertz derivative – the 212-megawatt MS9001F – are the result of a 10-year development program, utilizing technology developments from GEAircraft Engines and the GEResearch and Development Center. This strategy has allowed GEPowerGeneration to apply advanced cooling techniques and new materials to its "F" technology gas turbines.

GE has been able to fine-tune its technology as a result of operational experience and factory testing conducted on the MS7001F.That operational experience and testing have shown sufficient temperature margin in the directionally solidified (DS)buckets to increase the firing temperature by 50° to 2,350°F (10°Cto 1,287.8°C). By also modifying the first-stage nozzle, GE is able to achieve greater output and a lower heat rate while maintaining inlet air flow.

GE recently increased the output rating of the MS7001F gas turbine from 150 megawatts to 159 megawatts while reducing the heat rate from 9,880 Btu/kWh to 9,500 Btu/kWh.

The Chesterfield 7 combined-cycle unit is the most efficient large thermal power plant in the U.S. and the 7F is the only heavy-duty gas turbine firing at 2,300°F(1,260°C)in daily commercial operation. GE-designed "F" technology gas turbines have been ordered by utilities worldwide.

The 7F, like all other current GEproduction gas turbines, benefits from the worldwide operational experience of more than 4,500 installed units.

GER-3422B

GE Power Generation

MS7001EA Heavy-Duty Gas Turbine

E.D. Alderson
GE Company
Schenectady, New York

GE TURBINE REFERENCE LIBRARY

GE MS7001EA HEAVY-DUTY GAS TURBINE

INTRODUCTION

The MS7001EA is a single-shaft gas turbine designed specifically for 60 Hz power generation. The shaft speed of 3600 rpm provides direct drive of a 60 Hz generator. It is available worldwide as a packaged power plant for electric utility applications, or as an industrial power generating unit. As a simple-cycle unit it has a base-load rating of 83.5 MW with a thermal efficiency of 32 percent. * In a STAG** combined steam and gas turbine cycle, thermal efficiencies in excess of 45 percent can be obtained.

The MS7001E has been the technology leader of the General Electric gas turbine line of heavy-duty gas turbines, incorporating the latest materials and cooling technology, and the most advanced compressor, combustor, and turbine designs.

The first three MS7001E units were factory tested and shipped in 1976, entering commercial service in 1977 at Western Farmers Electric Cooperative, Anadarko, Oklahoma, USA. As of December 1989, a total of 128 MS7001E's and 38 MS-7001EA's had been shipped, with the 141 units in commercial service having accumulated over 3 MM operating hours.

The MS7001E design capitalizes on the experience gained from over 2,000 MS5001 units produced starting in 1957, and 250 earlier model MS7001 gas turbines shipped between 1970 and 1979. The most recent model, the MS7001EA, was introduced in 1985.

MS7001 Evolution

The first MS7001 design originated in 1966, with the MS5001M as the starting point (Fig. 1). At that time there was a burgeoning demand in the United States for gas turbines for peak load power generation, and there was a need for large blocks of power. This resulted in some installations with as many as 16 MS5001 units at a single site. Thus, a primary objective of the MS7001 program was to develop a gas turbine for power generation that would have a significantly higher output than the MS5001 and still be shippable in factory-assembled modules, like the MS5001. The result was a new gas turbine model, with a 17-stage compressor and a three-stage turbine, operating at 3600 rpm. The 3600 rpm shaft speed eliminated the need for a gear between the gas turbine and 60 Hz generator, as is necessary on the MS5001 units which operate at 5100 rpm.

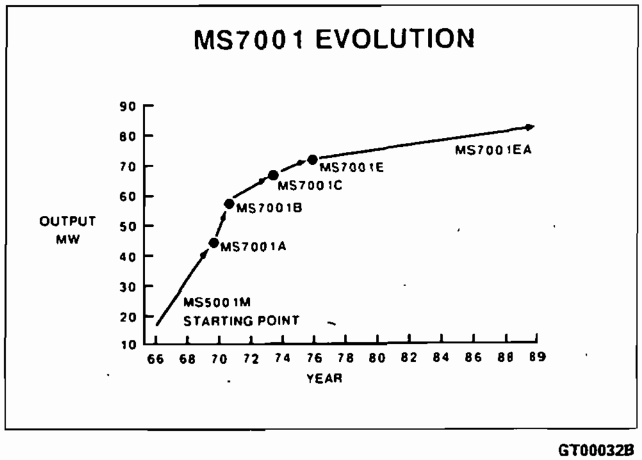

Figure 1

The compressor aerodynamic design was derived from the MS5001M by adding a stage at the compressor inlet, and scaling to the MS7001 size. Adding the zero stage served to increase the compressor air flow and the pressure ratio capability. This same compressor aerodynamic change was the genesis of the MS5001N and the current MS5001P.

The first MS7001A was factory tested and shipped in 1970 and started commercial operation in July 1971. The MS7001A had a base-load rating of 47MW at a turbine inlet temperature of 1650 F (899 C). The stage-one turbine nozzle had internal air cooling, but there was no bucket cooling.

In parallel with the MS7001A development, an air-cooled stage-one turbine bucket was developed. The addition of this feature to the MS7001A, along with additional stage-one nozzle cooling, resulted in the MS7001B. These turbine cooling changes allowed a turbine inlet temperature increase of 190

*Unless otherwise noted, all ratings given in this paper are net generator terminal output at ISO conditions of 59 F (15C) and 14.7 psia (1.013 bar), with natural gas and inlet and exhaust pressure drop. Thermal efficiencies are on a lower heating value basis.

**Trademark of General Electric Co., USA

F (106 C) to 1840 F (1004 C) and increased the gas turbine rated output to 60 MW.

As a consequence of the early development of the MS7001B configuration, only two MS7001A units were built. Both of these units are in electric utility peaking service.

The first MS7001B was shipped in 1971 and started commercial operation in January 1972. 243 MS7001B units have been shipped. 9 of these gas turbines are for industrial power generation.

Development of the MS7001C began in 1972. The major new features of this model were a change in the compressor aerodynamic design, to increase the airflow and to improve efficiency, and a change to an air-cooled stage-two turbine nozzle and bucket. The compressor changes resulted in an airflow increase of 12 percent, and the additional turbine cooling allowed a 110 F (61 C) increase in base-load firing temperature, to 1950 F (1066 C). The MS7001C rating was 68 MW, or 13 percent higher than the MS7001B. A total of 12 MS7001C units were shipped, beginning in September 1974 and ending in 1976.

The MS7001E development began in 1973, with the primary objective of increasing the gas turbine thermal efficiency. The changes from the MS7001C were: eight percent increase in cycle pressure ratio, turbine inlet temperature increase of 35°F (19°C), new stage-one turbine nozzle, and new stage-three turbine bucket. These changes increased the thermal efficiency by 3.8 percent and the output by 6.9 percent. The MS7001EA was introduced in 1985 with a 3.6 percent flow increase which raised the output by 3 percent. The current MS7001EA ratings are shown in Table I.

The letter "D" is missing from the above chronology because in 1972 a program was started to develop an MS7001D that would be capable of accepting large quantities of steam injected into the combustion system, to increase the output. However, the program was terminated when it became apparent that the market for this type of gas turbine was very limited.

MS7001EA Gas Turbine

Figure 2 is a cross section of the MS7001EA mounted on the turbine base and with the external piping in place. Air enters the 17-stage, axial-flow compressor, at the left, and is discharged at about 12 atmospheres into the cavity at the center of the unit. The air then flows to the left into the annular space around each of the 10 combustion chamber discharges into a transition duct that conveys the hot combustion products from the liner to a sector of the turbine inlet. The hot gas expands

MS7001EA CROSS SECTION

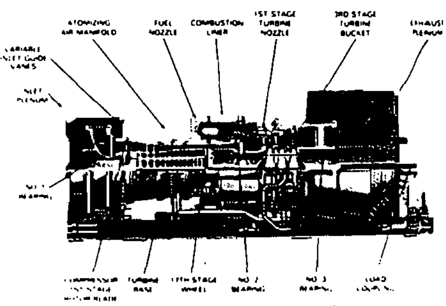

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Figure 2

from the 12-atmosphere pressure level down to atmospheric pressure through a three-stage, axial-flow turbine, and exhausts through the annular diffuser and exit turning-vanes to the exhaust stack.

The compressor is fitted with variable inlet guide vanes which direct the air flow into the stage-one rotor passages. Each vane has a shaft protruding through the casing, with a spur gear that meshes with a circumferential rack. The position of the rack is automatically set by the gas turbine control system. For startup, the guide vanes are placed in a closed position to limit flow through the compressor and thereby avoid pulsation during the starting cycle. As the shaft speed increases, the guide vanes

TABLE I
MS7001EA PACKAGE POWER PLANT RATED PERFORMANCE

	Base Load	Peak Load
Air Flow:		
lb/sec.	641	641
Kg/sec.	291	291
Compressor Ratio	12.4	12.6
Turbine Inlet Temperature:		
°F	2020	2120
°C	1104	1160
Exhaust Temperature:		
°F	986	1049
°C	530	563
Generator Output – MW	83.5	90.2
Heat Rate (LHV):		
Btu/kW-hr.	10480	10450
Kj/kW-hr	11054	11024

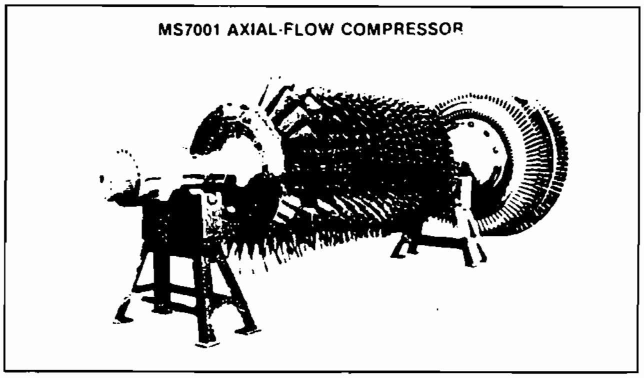

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Figure 3

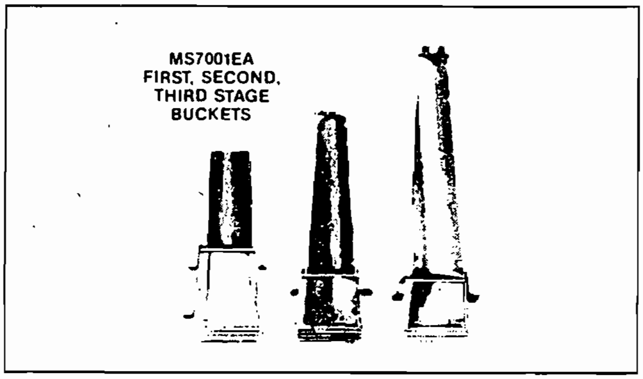

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Figure 4

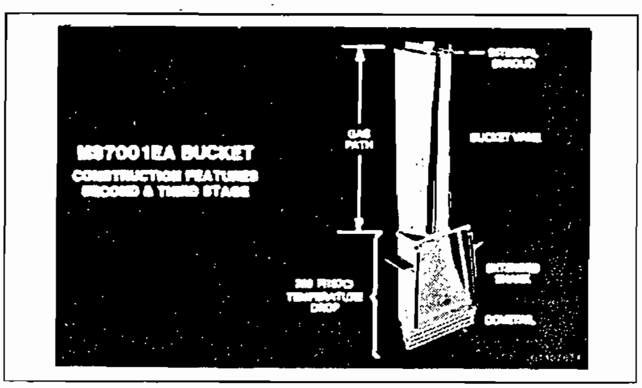

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Figure 5

are rotated until they are fully open to obtain maximum air flow. For STAG combined-cycle systems and other applications with heat recovery boilers the guide vanes are used to reduce air flow at part load conditions. This raises the gas turbine exhaust temperature and increases the cycle thermal efficiency.

The rotor is supported by three pressure-lubricated journal bearings. The self-equalizing tilting-pad thrust bearing is located at the compressor inlet end, in the same housing as the No. 1 journal bearing.

The compressor rotor construction is the same as used in all General Electric gas turbine designs, with individual rotor discs (wheels) for each stage. Sixteen through-bolts clamp the rotor discs between the forward and aft stub-shafts. The stage-one rotor blades are mounted on the wheel portion of the forward stubshaft, and the aft stubshaft carries the stage 17-blades.

The turbine rotor is also of through-bolted construction, consisting of the forward wheelshaft, stage-one wheel; stage one-two spacer, stage-two wheel, stage two-three spacer, stage-three wheel, and the aft wheelshaft. The turbine rotor assembled with the compressor rotor is shown in Fig. 3.

All three turbine stages have precision-investment-cast, long-shank buckets (Fig. 4). This construction effectively shields the wheel rim and the bucket root fastenings from the high temperatures in the main gas stream. In addition, the long-shank construction aids in damping bucket vibrations. As a further control against vibration, the stage-two and stage-three buckets have interlocking shrouds at the bucket tips. Figure 5 depicts these features.

In addition to providing vibration damping, the stage-two and stage-three bucket tip shrouds increase the turbine efficiency by minimizing tip leakage. Radial teeth on the bucket shrouds combine with mating teeth on the stator to provide a labyrinth seal against gas leakage past the bucket tips.

As shown in Fig. 6, passages inside the rotor convey air from compressor stage 16 to the base of the stage-one and stage-two bucket dovetails. The cooling air is extracted where there are a minimum of dust particles, because the spiral path of the compressor air flow centrifuges any solids to the outer diameter. This ensures that the cooling air holes in the buckets will not be obstructed by dirt deposits.

After flowing radially inward between the stage 16 and stage 17 compressor wheels, the cooling air passes through the shaft bore to the turbine, and then radially outward between the stage-one and stage-two wheels. Air enters the shank of the buckets and flows outward through radial holes in the

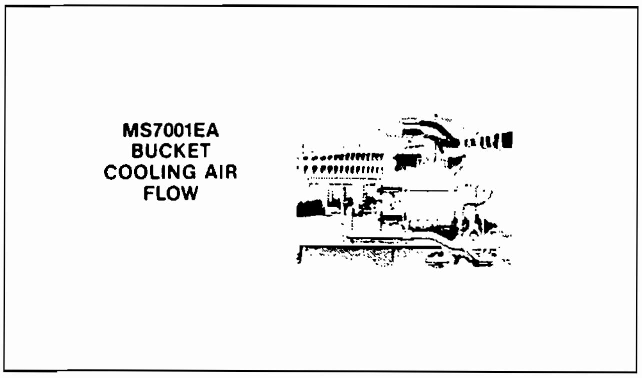

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Figure 6

bucket vanes, discharging into the gas path at the bucket tips. Figure 7 shows a cross section of the first-stage bucket through a cooling hole, and Fig. 8 is a view of the bucket tips. The stage-two bucket cooling air path is shown in Fig. 9. The air enters a cavity in the bucket shank, and flows radially outward from there through the holes in the vane.

All three turbine stages utilize precision-investment-cast, segmented nozzles. The stage-one nozzle segments are held in place by a cylindrical retaining ring at the outer circumference of the segments. This ring is centerline-supported and is positioned axially by contact with the first-stage turbine stationary shroud. The first-stage shroud is supported from the turbine shell (outer casing) and forms the outer boundary of the hot gas path, over the stage-one buckets.

The stationary shrouds over the second- and third-stage buckets are supported by the turbine shell in the same manner as the stage-one shroud. The stage-two and stage-three nozzle segments are in turn supported by the stationary shrouds, as shown in Fig. 10.

Both the stage-one and stage-two nozzle vanes are air cooled by a combination of internal

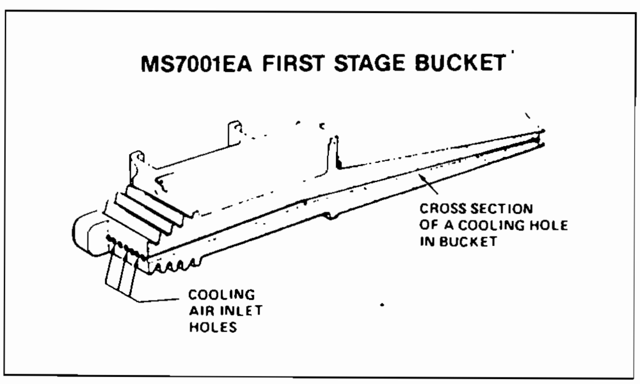

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Figure 7

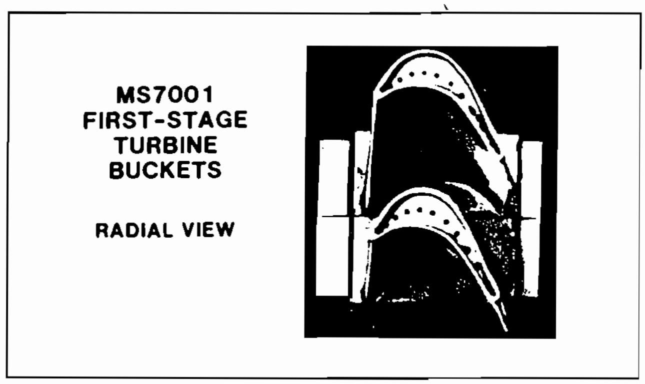

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Figure 8

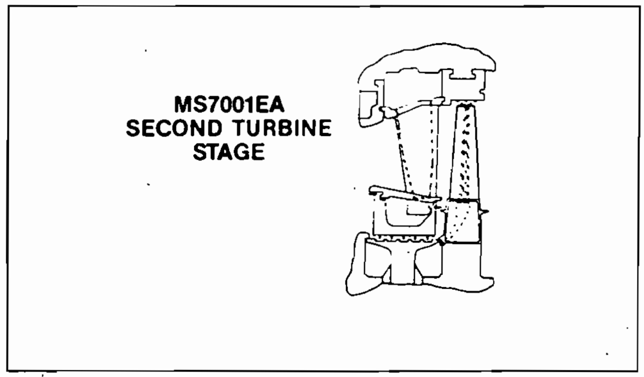

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Figure 9

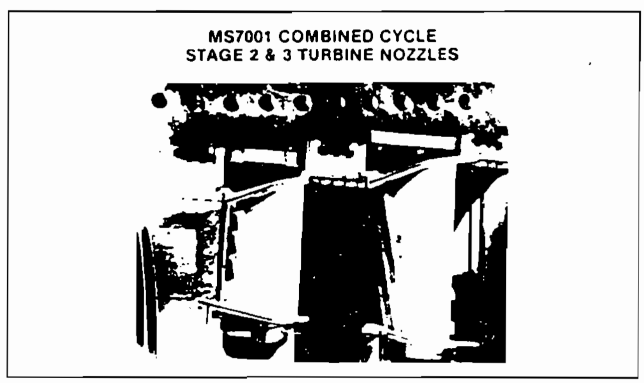

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Figure 10

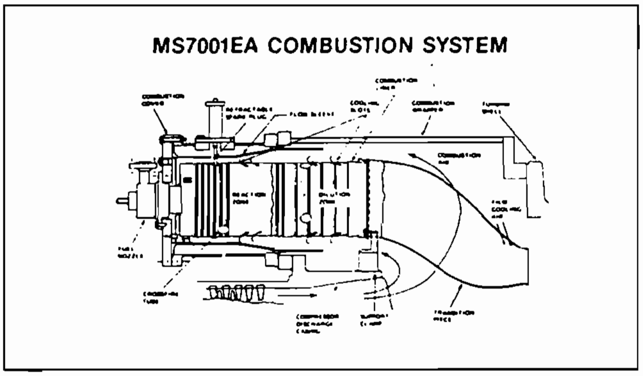

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Figure 11

impingement and external film cooling. The vanes are hollow with an internal sheet metal core plug (Fig. 9). Compressor discharge air feeds into the inside of the core plug and then discharges through a multiplicity of small holes in the core plug wall, impinging against the inside of the vane wall. From this space, the air flows around the core plug and exits to the gas path through holes in the vane wall, which provide external film cooling.

The combustion system utilizes ten 14-inch (356 mm) diameter combustors (Fig. 11). Cross-fire tubes connect adjacent liners, ensuring that flame in one chamber will ignite all of the other chambers. For redundancy, two chambers have spark plugs, which initiate the combustion process during gas turbine startup. Two other chambers have flame detectors, which signal the control system that flame has been established and is being maintained.

Each combustor has a fuel nozzle, which can utilize either oil or gas fuel. When oil is used, the fuel is atomized by pressurized air to ensure fine atomization and avoid formation.

The liners are slot-cooled and Thermal Barrier

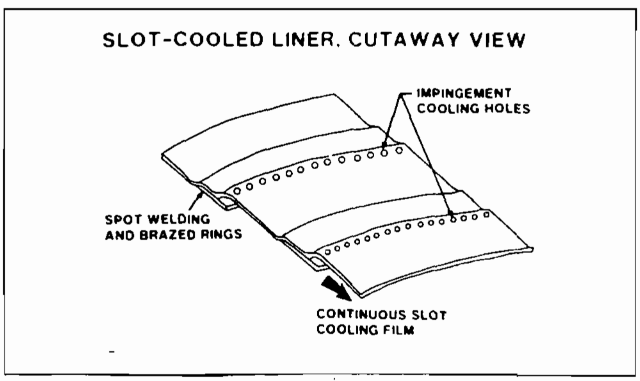

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Figure 12

Coated (TBC) to protect the liner metal walls from the combustion zone gas temperatures, which exceed 3000 F (1649 C). As shown in Fig. 12, compressor discharge air on the outside of the liner flows through holes and impinges against a ring that is attached to the inside of the liner. The air jets are deflected by the ring to form a continuous air film that flows downstream along the inside of the liner wall. There are 20 of these slots along the length of the liner.

The MS7001EA has provisions for internal inspection of the gas turbine without removing the outer casings. Openings are provided in the compressor, turbine, and combustion casings, that allow insertion of a borescope for visual inspection of compressor blades, turbine nozzles and buckets, combustion liners and transition pieces, and other critical parts. Figure 13 shows the borescope access holes in the turbine area. The same openings can be used to insert eddy-current probes for inspection of the turbine buckets and vanes and to provide access for measuring turbine nozzle deflection.

The materials and processes used in the MS7001EA are the same as those currently used on the-other gas turbines in the Power Generation product line. The materials for the major components are:

Compressor Blades: 12 Cr Steel	Turbine Nozzles: FSX-414
Compressor Wheels: Ni-Cr-Mo-V (stages 1-15) Cr-Mo-V (stages 16 and 17)	Turbine Buckets: GTDIII (Stage 1) IN738 (Stage 2) U500 (Stage 3)
Compressor Casings: Grey Cast Iron	Turbine Wheels: Cr-Mo-V Forging
Combustion Liner: Hastelloy-X	Turbine Shell: Ductile Cast Iron
Transition Piece: Nimonic-263	

The first-stage turbine buckets are VPS coated to provide protection against oxidation and corrosion.

Performance

The standard MS7001EA package power plant performance at ISO ambient conditions is listed in Table I. These ratings include the effect of 4 inches (102 mmm) of water inlet pressure drop and 5.5 inches (140 mm) of water exhaust system pressure loss, plus deduction for excitation loss.

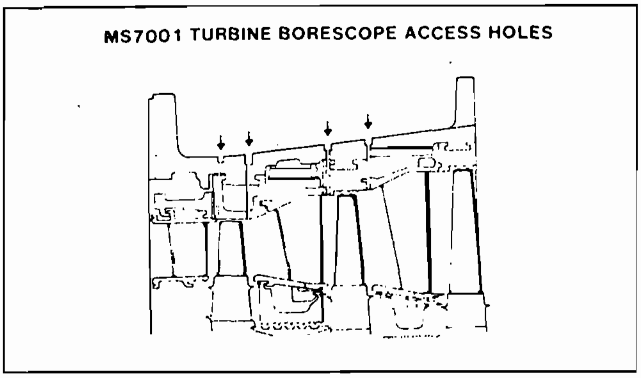

Figure 13

Controls

The MS7001EA startup time is 7.5 minutes from the start signal to synchronization. The loading cycle can be varied, depending on the circumstances, but the normal, automatic loading time is 12 minutes. The loading cycle can be reduced to six minutes by a manual override, or for emergency situations, an automatic fast loading cycle of 1.5 minutes can be used. The faster loading modes should be used sparingly since they cause more severe thermal stresses in the turbine parts than the 12-minute cycle.

For normal shutdown, the gas turbine fuel is not tripped until the load has been shed and the unit speed reduced to 40-50 percent of full speed. This "fired shutdown" procedure is used to reduce thermal stresses in the turbine, increasing the turbine nozzle and bucket life.

This control system is based on the use of distributed, high speed, 16 bit microprocessors. Each of three microprocessors performs both control and protective functions, with improved reliability achieved through redundant, two-out-of-three voting on all critical functions. Multiple sensors are divided among the three control microprocessors, and each computer drives one coil of a three-coil servovalve. Online diagnostics will locate a faulty section, which is then isolated from the good sections. While the turbine continues to run on these sections, the faulty electronics card is located and replaced. The repaired section is then self-tested and returned to service.

A fourth microprocessor performs all communication functions between the three control sections, the operator interface, and any other peripheral interfacing equipment. This communication section also performs all non-critical functions, such as auxiliary system monitoring, combustion monitoring, non-critical auxiliary sequencing, and data logging.

The operator interface is modern, with carefully human engineered design. The operator receives information from the CRT which normally gives a broad overview of the current operating condition. The operator can easily select appropriate detailed displays to investigate particular conditions that are of current interest. Operator inputs are accomplished through industrial grade membrane switches, requiring two operations, select and execute, to eliminate inadvertent action. The shielded emergency stop button is an exception. Backup readout capability is also provided in the event of a CRT or communication section failure while running.

The SPEEDTRONIC* Mark IV control system (Fig. 14) includes all standard options, and has substantial flexibility for meeting special requirements and for interfacing with industrial process computers. The CRT and membrane panel can be remoted over a simple serial cable with line drivers, and installed up to 2000 feet away and retains full capability. Centralized control of many turbines from a single station are available over multiplexed cable utilizing the GE "Smart Remote" terminal.

Accessories

The gas turbine accessories are mounted on a separate base that fits in-line with the turbine base (Fig. 15). The lubricating oil reservoir that supplies both the gas turbine and generator bearings is located in this base.

Mounted on the base is the accessory drive gear which is driven from the gas turbine compressor shaft by the accessory coupling. Mounted on and driven by the accessory gear are: 1) fuel oil pump, 2) fuel atomizing air compressor, 3) main lube oil pump, 4) hydraulic oil pump, and 5) cooling water pump.

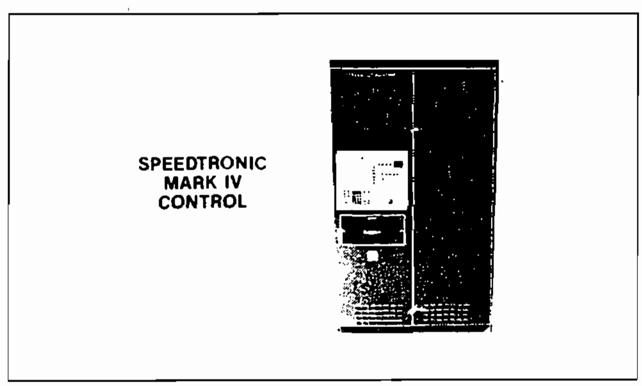

Figure 14

*Trademark of General Electric Company, USA

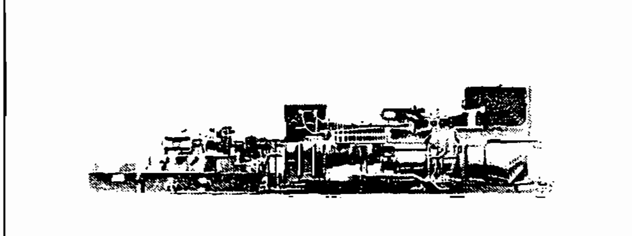

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Figure 15

For starting, an 800 hp electric motor drives a torque converter which connects to the main shaft of the accessory gear. After the gas turbine reaches self-sustaining speed (about 60 percent of full speed), the motor is shut down and the torque converter drained.

Other major equipment located on the accessory base includes: 1) fuel oil flow divider, 2) fuel oil filters, and 3) lube oil filters and coolers.

Power Plant Arrangement

For electric utility applications there is a standard package power plant arrangement that fits most sites (Fig. 16). For industrial power generation applications some of the standard package components can be used, but the overall arrangement is tailored to the specific customer installation.

The standard package power plant is comprised of the following components:

- Turbine Compartment
- Accessory Compartment
- Control Compartment
- Power Control Compartment
- Generator Compartment
- Generator Collector Compartment
- Generator Auxiliaries Compartment
- Cooling Water Skid
- Inlet-air System
- Exhaust System
- Auxiliary Power Transformer
- CO_2 Supply for Fire Protection
- Fuel Conditioner Skids

After connection to a fuel supply and an electrical grid, this equipment constitutes a completely self-sufficient power plant.

Turbine Compartment

The turbine compartment consists of the equipment shown in Fig. 2 plus a weatherproof enclosure. The compartment is ventilated by a motor-driven fan. A CO_2 fire protection system is provided.

Accessory Compartment

The accessory compartment equipment is housed in a weatherproof enclosure. It is ventilated and has fire protection, the same as the turbine compartment.

Control Compartment

The control compartment is located in line with the accessory compartment and contains the following:

- Turbine Control Panel
- Generator Control Panel
- Supervisory Control Panel (optional)
- Batteries and Charger

Generator Compartment

The MS7001EA is available with either an open-ventilated, air-cooled generator as shown in Fig. 17, or a hydrogen-cooled generator. The power plant in Fig. 16 shows the air-cooled generator arrangement. Both generators are shipped assembled, with the rotor in place. The generator frames are designed for mounting on the same foundation level as the gas turbine, with no separate base structure required.

The MS7001EA generators employ the Class F insulation system for stator windings, and Vetrolam insulation for the rotor windings. These insulation systems are designed to operate at higher temperatures than conventional insulating materials, and at the same time accept the thermal cycling required in peaking power applications.

MS7001EA PACKAGE POWER PLANT

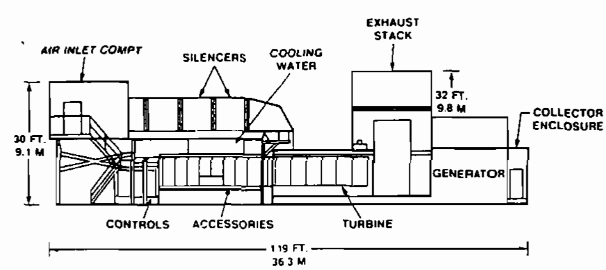

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Figure 16

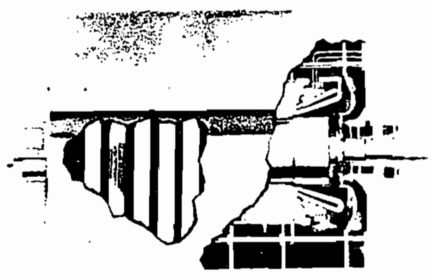

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Figure 17

Both the air-cooled and hydrogen-cooled generators utilize conductor cooling in the rotor windings. In conventionally cooled rotors, the cooling air flows through ventilating ducts machined in the rotor teeth. Thus the heat transfer path is from the copper conductor, through the slot insulation and through the rotor steel to the ventilating duct. With conductor cooling, the air flows through radial holes in the windings, so the cooling air is in direct contact with the copper. This provides much more effective cooling of the windings by eliminating the thermal resistance of the insulation and steel.

In the air-cooled design, the air inlet and discharge ducts include silencing sections, and acoustic panels are mounted on the sides of the frame to provide sound attenuation. The air inlets incorporate filtration equipment to prevent dust and dirt from entering the cooling air passages. The air is circulated by fans mounted directly on the generator rotor.

In the hydrogen-cooled design, the hydrogen is circulated in a closed system with heat removed from the hydrogen in gas-to-water heat exchangers, mounted in the generator frame. The heat absorbed by the water can be rejected either to the atmosphere in water-to-cooling modules, or to a separate source of cooling water.

Generator Auxiliaries Compartment (GAC)

The MS7001EA generators utilize a static excitation system. Excitation is provided by a static, hybrid thyristor and silicon diode bridge using a power potential transformer connected directly to the generator output leads. The GAC also houses the generator breaker, lightning arrestors, potential and current transformers, and the customer power take-off. These components plus the neutral grounding equipment are mounted in the generator auxiliaries compartment.

Cooling Water Modules

Cooling for lube oil and generator cooling medium where used, is provided by an off-base packaged cooling skid. Electric motor-driven fans duct ambient air over finned tubes. Corrosion inhibited water is circulated by motor-driven pumps. Both fans and pumps can be supplied with backup capability.

Inlet Air System

The standard inlet air system consists of a self-cleaning, high-efficiency filter and inlet silencing sufficient to meet overall package power plant sound level of 58 dBA at 400 feet (122 meters). The inlet house is mounted above and forward of the control compartment with the silencers located in the ducting above the control and accessory compartments. If more stringent silencing is required, additional silencer length can be added.

No. 1 Unit Testing

The first MS7001E gas turbine was installed in the load test facility at our Greenville, South Carolina Plant and commenced operation in June 1976. In this facility an MS7001E compressor (Fig. 18) is used to absorb the gas turbine output. Load on the gas turbine can be varied by throttling the compressor inlet and discharge.

The initial testing concentrated on measuring performance and critical design parameters. The gas turbine contained over one-thousand sensors, including one-hundred mounted on the rotor. Signals from the rotor sensors were transmitted to the data recording equipment via sliprings. The sensors included: thermocouples, static pressure transducers, dynamic pressure gages, strain gages, vibration sensors, clearanceometers, and load cells.

After the initial test period, the No. 1 unit was used as a test bed for proving out design improvements in the compressor, combustion, turbine and

MS7001 LOAD TEST
AXIAL-FLOW COMPRESSOR

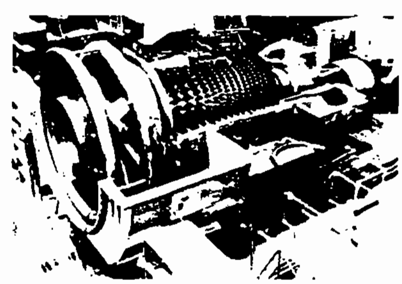

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Figure 18

accessory systems. A major portion of this testing was with new combustion hardware that was designed to lower nitrogen oxide emissions.

The MS7001E testing operation continued until June 1979, during which time the gas turbine was started 300 times and accumulated 450 fired hours.

Field Operation

The lead machines of the MS7001E design are three STAG 107E power plants at Western Farmers Electric Cooperative, Anandarko, Oklahoma, USA. In the STAG 100 combined-cycle configuration, the gas turbine exhausts to a heat recovery steam generator (HRSG) which supplies a steam turbine. The gas turbine and steam turbine are directly connected to opposite ends of the generator. At Western Farmers (Fig. 19) all of the equipment except the air inlet compartments and HRSG's is installed within a 140 ft. (42.7 m) by 300 Ft. (91.4 m) building.

The Western Farmers installation is designed for operation on either natural gas or distillate oil, but almost all of the operation has been with natural gas. The STAG 107E combined-cycle rating at the Western Farmers site with natural gas is 91.4 MW base load and 100.1 MW peak load.* The corresponding heat rates on a higher heating value basis are 8410 and 8270 Btu/kWh (2119 and 2084 Kcal/kWh).

Since the start of commercial service in the fall of 1977, the three gas turbines have accumulated a total of 203,870 operating hours with 1925 starts (Table II).

Table III shows the "RAM" (Reliability/Availability/Maintainability) performance of the WEFAR gas turbines/generators for the most recent full year (1989) of operation.

Changes were incorporated in the MS7001E to

GT01487

Figure 19

TABLE II
MS7001E STAG 100 COMBINED-CYCLE POWER PLANTS
WESTERN FARMERS ELECTRIC COOPERATIVE

As of Dec., 1989

Unit	Started Commercial Operation	Total Operating Hours	Total Starts
1	Sept. 1977	73,274	641
2	Oct. 1977	64,690	727
3	Nov. 1977	65,906	557
	Total	203,870	1,925

correct the combustion hardware life problem. These changes included increasing the thickness of the transition piece, and changing its shape and means of attachment. Installation of these new thick wall transition pieces started in March 1978 and modification of all three units was complete by June 1978. After June 1978, all load restrictions were removed and all units were placed on a 1500 hour inspection interval. In August 1978, the inspection interval was increased to 3000 hours, and following continued favorable experience, the inspection interval was extended to 5000 hours in March 1979. It is currently at 6500 hrs with a further increase to 8,000 hrs. planned for 1990.

TABLE III
THREE MS7001E STAG 100 COMBINED-CYCLE POWER PLANTS
WESTERN FARMERS ELECTRIC COOPERATIVE
1989

	Gas Turbine, Accessories Controls
Reliability	98.3%
Availability	96.1%
Starting Rel.	96.8%
Service Factor	63.7%

*At 27 C (80 F) and 0.972 bar (14.1 psia)

SUMMARY

The MS7001EA is the latest model 3600-rpm, single-shaft gas turbine in the General Electric heavy-duty product line. The MS7001EA has higher output and thermal efficiency than the previous models, and incorporates all of the design improvements developed in earlier models. With 141 7E/EA, units in commercial service and over 3 MM operating hours accumulated as of 12/89, the MS7001EA has proven that it meets performance guarantees and is a highly reliable gas turbine, an experience base which is now available in the improved MS7001EA.

CONVERSION FACTORS

The following is a list of conversion factors most commonly used for gas turbine performance.

To Convert	To	Multiply By
acres	hectares	4.047×10^{-1}
atm	kg/cm^2	1.0333
atm	lb/in.^{2}	1.47×10^{1}
bars	atm	9.869×10^{-1}
bars	lb/in.^{2}	1.45×10^{1}
Btu	J (joules)	1.055×10^{3}
Btu	kcal	2.52×10^{-1}
Btu/h	kcal/h	2.520 x 10–1
Btu/h	kJ/h	1.0548
Btu/h	W (watts)	2.931×10^{-1}
Btu/hp-h	kcal/kWh	3.379×10^{-1}
Btu/hp-h	kJ/kWh	1.4148
Btu/kWh	kcal/kWh	2.5198×10^{-1}
Btu/kWh	kJ/kWh	1.0548
Btu/lb	kcal/kg	5.555 x 10–1
Btu/lb	kJ/kg	2.3256
°C	°F	(°C x 9/5) + 32
°C	K	°C + 273.18
cm^3	ft^3	3.531×10^{-5}
cm^3	in.^{3}	6.102×10^{-2}
°F	°C	(°F – 32) x 5/9
ft	m	3.048×10^{-1}
ft^2	m^2	9.29×10^{-2}
ft^3	I (liters)	2.832×10^{1}
ft^3	m^3	2.832×10^{-2}
ft-lb	Btu	1.286×10^{-3}
ft-lb	kg-m	1.383×10^{-1}
ft/min	km/h	1.8288×10^{-2}
ft^3/min	I/s	4.720×10^{-1}
ft^3/min	m^3/min	2.832×10^{-2}
gal	m^3	3.785×10^{-3}
gal/min	I/s	6.308×10^{-2}
hectares	acres	2.471
hp (U.S.)	kW	7.457×10^{-1}
hp (U.S.)	hp (metric)	1.014

To Convert	To	Multiply By
in.	cm	2.540
in.	mm	2.54×10^{1}
in^2	mm^2	6.452×10^{2}
in. of mercury	kg/cm^{-2}	3.453×10^{-2}
in. of water (at 4 °C)	kg/cm^2	2.54×10^{-3}
in. of water (at 4 °C)	lb/in.^{2}	3.613×10^{-2}
J	Btu	9.486×10^{-4}
kg	lb	2.2046
kg/cm^2	lb/in.^{2}	1.422×10^{1}
kg-m	ft-lb	7.233
kg/m^3	lb/ft^3	6.243×10^{-2}
km	miles (statute)	6.214×10^{-1}
kW	hp	1.341
I	ft^3	3.531×10^{-2}
lb	kg	4.536×10^{-1}
lb/in.^{2}	kg/cm^2	7.03×10^{-2}
lb/in.^{2}	Pa	6.8948×10^{3}
lb-ft^2	kg-m^2	4.214×10^{-1}
l/min	ft^3/s	5.886×10^{-4}
I/min	gal/s	4.403×10^{-3}
m	ft	3.281
m^2	ft^2	1.076×10^{1}
m^3	ft^3	3.531×10^{1}
mile (statute)	km	1.6093
tons (metric)	kg	1.0×10^{3}
tons (metric)	lb	2.205×10^{3}
W	Btu/h	3.4129
W	Btu/min	5.688×10^{-2}
W	ft-lb/s	7.378×10^{-1}
W	hp	1.341×10^{-3}

Turbine Technology Reference Library

GER-3424	Aircraft-Derivative Gas Turbine Maintenance Practices
GER-3425	GE LM5000 Aircraft-Derivative Gas Turbine Systems
GER-3430	Cogeneration Application Considerations
GER-3434	Gas Turbine Design Philosophy
GER-3456	Cogeneration Financial Incentives
GER-3478	Reducing Solid Particle Erosion Damage in Large Steam Turbines
GER-3507	Technical Challenges in Replacing Large Generators for Utility Power Plants: An Update
GER-3541	SPEEDTRONIC Mark IV Control System
GER-3551	Development of the GE Quiet Combustor and Other Design Changes to Benefit Air Quality
GER-3558	New Developments in Steam Turbines for Cogeneration Systems
GER-3567	Gas Turbine Performance Characteristics
GER-3568	Dry Low NO_x Combustion for GE Heavy-Duty Gas Turbines
GER-3569	Advanced Gas Turbine Materials and Coatings
GER-3570	Gas Turbine Standardization for Better Value
GER-3571	Performance and Reliability Improvements for Heavy-Duty Gas Turbines
GER-3572	Aeroderivative Gas Turbine Performance, Emissions, and STIG
GER-3573	TEPCO 2000-MW Combined-Cycle Power Plant: Design, Construction and Operation
GER-3574	Combined-Cycle Product Line and Performance
GER-3575	Legislation and Regulations Affecting Power Generation Systems
GER-3576	Steam Turbine Digital Control and Monitoring (DCM) Systems
GER-3577	An Update on Steam Turbine Redesigns for Efficiency and Availability
GER-3578	Generators for Small and Mid-Size Fossil Fuel Plants
GER-3579	Improved Generators for Gas and Small Steam Turbine Drives
GER-3580	Generator Parameters and Characteristics
GER-3581	Generator Excitation Systems – the Right Product for Each Application
GER-3582	Steam Turbines for Combined-Cycle Power Systems
GER-3583	Power Plant Upgrading: An Increasingly Attractive Alternative
GER-3584	Combined Cycle Economics
GER-3585	GE Combined-Cycle Experience
GER-3590	Continuously-Coupled 40-Inch Titanium Last-Stage Bucket Development
GER-3614	Steam Turbines for Industrial and Cogeneration Applications
GER-3615	Steam Turbine Controls and Their Integration into Power Plants
GER-3616	Extending the Useful Life of Industrial Steam Turbines
GER-3617	Recent Advances in Mechanical Drive Turbine Technology
GER-3618	Recent Advances in Centrifugal Compressors
GER-3619	Generator Inspection and Maintenance
GER-3620	Gas Turbine Operating and Maintenance Considerations
GER-3621	Steam Turbine-Generator Maintainability – A Means to Improve Unit Availability
GER-3622	MS7001F Gas Turbine Design Evolution and Verification
GER-3623	Positive Pressure Variable Clearance Packing
GER-3624	A Technical Assessment of Turbine-Generator Upgrading
GER-3631	Steam Turbine Controls and Their Integration Into Power Plants
GER-3633	Evolution in the Design of Utility Steam Turbine-Generators
GER-3636	Experience With Compressed Air Cleaning of Main Steam Piping

For further information, contact your assigned GE Field Sales Engineer or write to Turbine Marketing Operations

GE Power Generation

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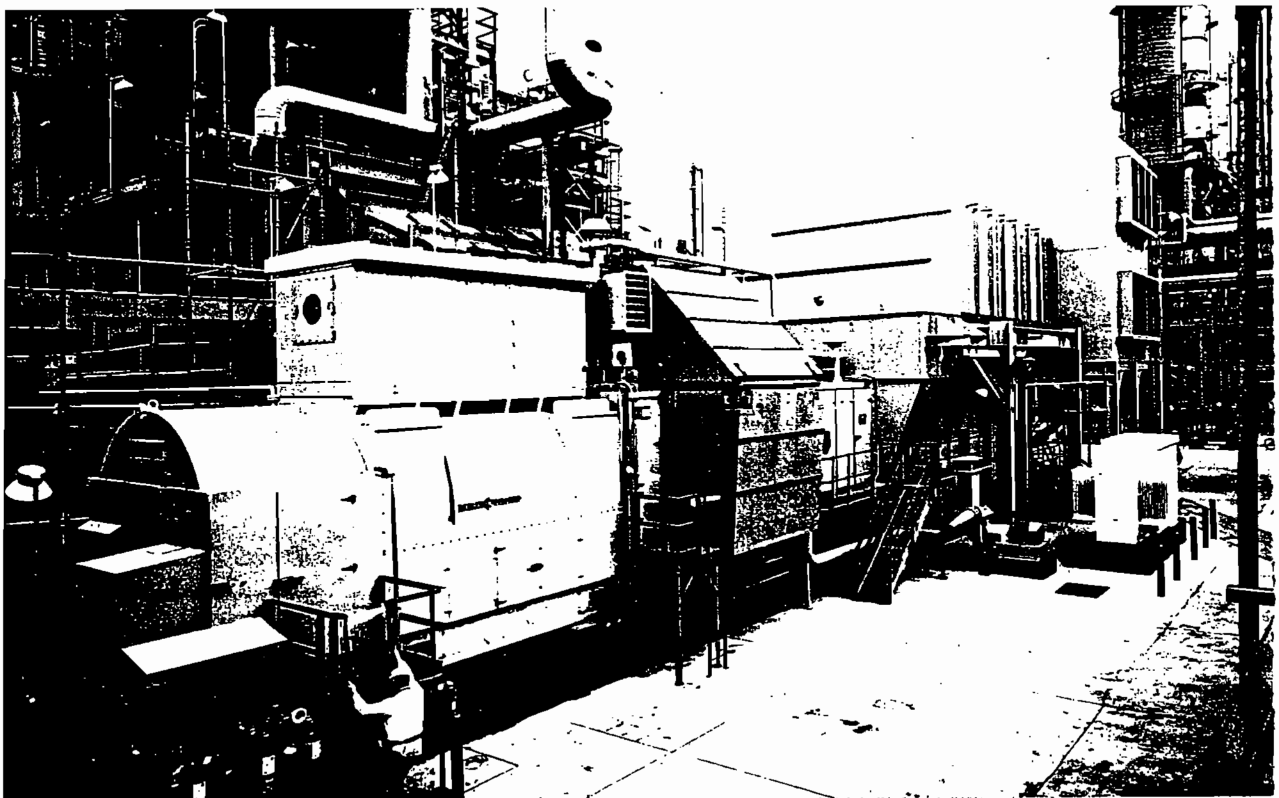
GE Power Generation



MS7001EA GAS TURBINE

Heavy-Duty 60 Hz Power Plant for Utility, Industrial and Cogeneration Applications.

CONTENTS

Cover Photo: RDC26178-1-5

MS7001 Gas Turbine

PROVEN RELIABILITY/ MAINTAINABILITY — THE RESULTS OF GE'S EVOLUTIONARY DESIGN PROCESS

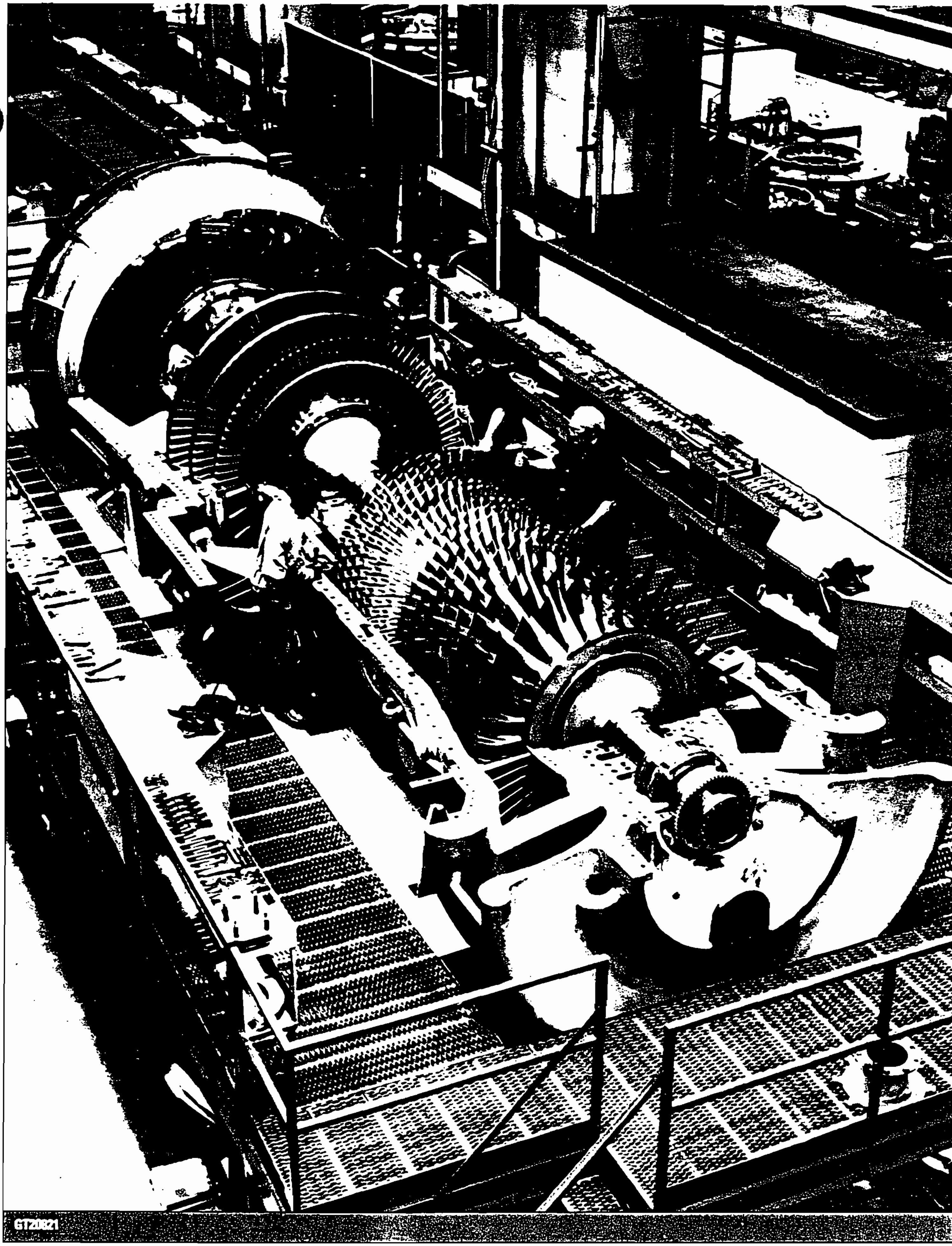
During the past 40 years, GE has dedicated itself to the needs of the gas turbine market, earning a reputation for excellence in design. The research and development efforts which sparked this reputation paid off again in the development of the MS7001 in 1968.

Of the nearly 4600 gas turbines now in operation, 500 are MS7001 units with 150 of those operating at current firing temperatures in peak and base-load applications. The unit has been uprated and improved using information accumulated from thousands of unit years of operation in utilities and industrial companies in climates ranging from desert heat to tropical humidity and arctic cold. Today, it is the most proven gas turbine of its size in the market and one of the most efficient.

Whether in 60 Hz simple-cycle or combined-cycle application, all MS7001 gas turbine-generators are completely engineered and integrated systems that include controls, auxiliaries, ducting and silencing — all designed for easy maintenance. Additionally, since each MS7001 features gas path cooling systems and materials, they are able to run at higher cycle temperatures, promoting fuel efficiencies and long-product life.

The axial-flow compressor performs at high levels with GE's basic inlet configuration, which has been successfully used across the entire GE gas turbine product line, providing low, uniform air-flow velocities and minimum entrance losses.

Recent statistics compiled by the North American Electric Reliability Council comparing all gas turbines over 50 MW testify to the reliability of the MS7001, which is consistently above 95% – far better than the average for all turbines in that size range.



▲ The MS7001 gas turbine, the fuel-flexible workhorse of the gas turbine industry since the early 1970's, provides reliable 60 Hz power generation.

ADVANCED FEATURES TO BENEFIT YOUR APPLICATION REQUIREMENTS

The MS7001 is designed for:

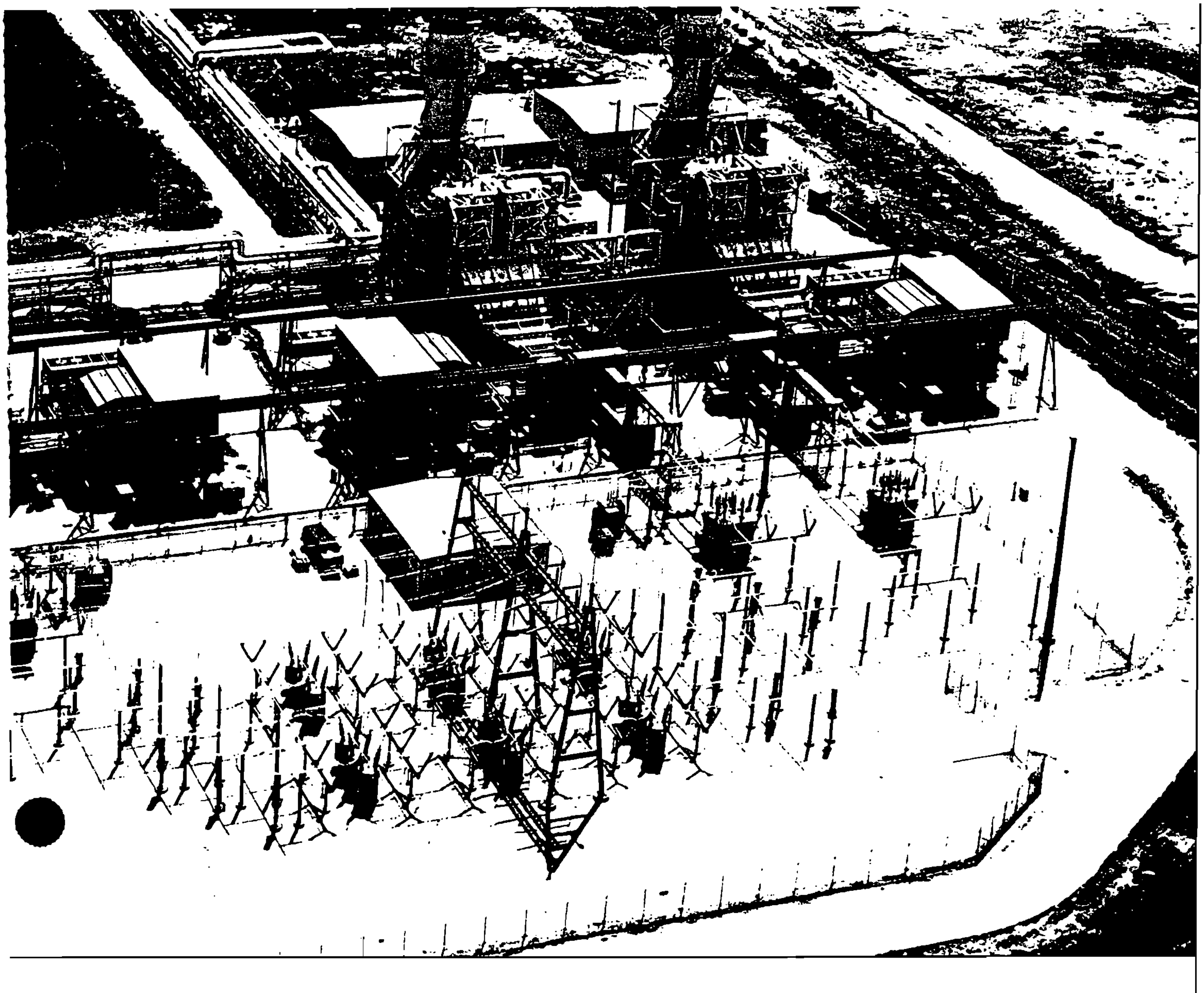
- 60 Hz power generation
- 83.5 MW output (ISO, gas fuel) at generator terminals
- 3600 rpm operation
- Excellent thermal efficiency: simple cycle in excess of 32%; combined cycle, 50%
- Fuel flexibility, including crude and residual oil capability and the ability to convert to coal-derived fuels without turbine modification
- On-line fuel switching capability
- Starting reliability consistently above 95%
- Availability above 95%
- Environmental acceptability — first unit to reach 25 ppm (NO_x)
- On-site maintenance capability
- Short order-to-operation time
- Low installed costs
- No station cooling water required

PERFORMANCE SPECIFICATIONS	
Performance (ISO, Natural Gas Fuel) At Generator Terminals	Model No. MS7001EA
Output	83.5 MW
Heat Rate (LHV)	10,480 Btu/kWh
Exhaust Flow	640 pps
Exhaust Temperature	986°F/536°C

MS7001EA Gas Turbine

Uncomplicated, Yet Versatile, Offers Flexibility In Fuel And Plant Layout Needs

Like its predecessors, the MS7001EA is uncomplicated and versatile; its medium-sized design lends itself to flexibility in plant layout and the easy addition of increments of power when a phased capacity expansion is required. A predecessor of GE's MS7001F, the world's most advanced gas turbine, the MS7001EA is ideal for those plants which require high efficiency along with the back-up power only multiple units can provide.



This GE turnkey plant employs four MS7001 gas turbines to produce 340 MW of power.

Fuel Flexibility

With state-of-the-art fuel handling and metering equipment, advanced bucket cooling, corrosion-resistant coatings and anti-erosion, dual-fuel nozzles, the MS7001EA accommodates a wide variety of fuels. These include natural gas, light and heavy distillate oil, naphtha, crude oil and residual oil. Over four million hours of operation have been accumulated using crude and residual oils. The MS7001EA is also designed with the demonstrated ability (27,000 hours of operation at the Cool Water IGCC Project) to convert to coal-derived fuels without turbine modifications.

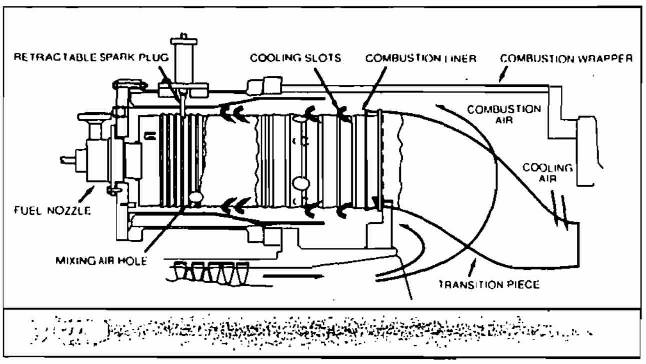
Since MS7001EA units are designed for dual-fuel operation, transferring from one fuel to another can occur while the turbine is running under load or during shut-down. Many utilities and industrial companies, where mid-range, combined-cycle and cogeneration applications of the MS7001EA can be used, benefit from this fuel flexibility and have realized significant cost savings.

A FLEXIBLE COMBUSTION DESIGN TO ACHIEVE YOUR EMISSION GOALS

In the search for improved designs that achieve reduced emissions, GE combustion engineers have developed a range of designs which allow a plant to comply with low NO_x requirements in several ways.

Small-diameter, high-mixing combustors, such as those employed in GE gas turbines, emit lower levels of nitric oxides (NO_x) than other systems for a given average combustor exit temperature. This means that additional NO_x abatement can be achieved more easily, whether through lean combustion or diluent injection.

Diluents, steam or water can be injected into the standard combustor to reduce NO_x emissions to 42 ppmvd (ref. 15% oxygen) without shortened inspection intervals. To date, 124 GE-designed units have been shipped that meet this emissions level. Several units employing GE's "Quiet Combustor" are routinely operating at 25 ppmvd (15% O_2). A dry low NO_x system is also available.



Reverse flow combustion system is designed for easy maintainability, longer intervals between inspections.

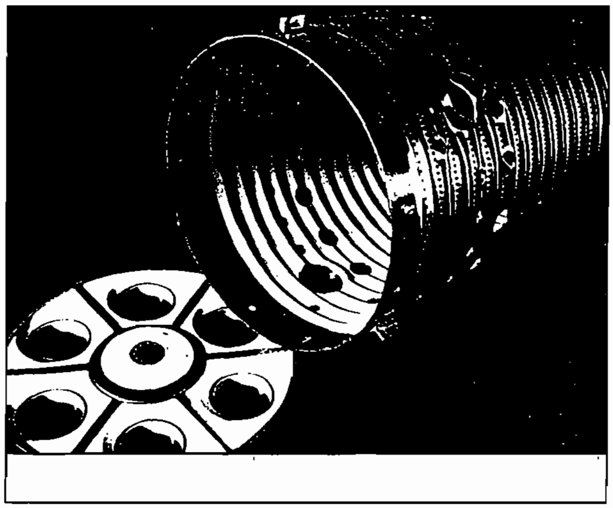
PROPRIETARY MATERIALS, THE KEY INGREDIENT FOR LONG COMPONENT LIFE

Unique GE resources — at the Corporate Research and Development Center, in GE's Aircraft Engine business and in GE Power Generation's own labs — have made possible the development of new materials to meet the high-temperature operating needs of the gas turbines and aircraft engines of tomorrow. These patented alloys, coatings and processes — unavailable from any other manufacturer — result in longer maintenance intervals, lower maintenance costs and longer component life.

A PROVEN COMBUSTION SYSTEM DESIGNED FOR EASIER MAINTENANCE, LONGER INSPECTION INTERVALS

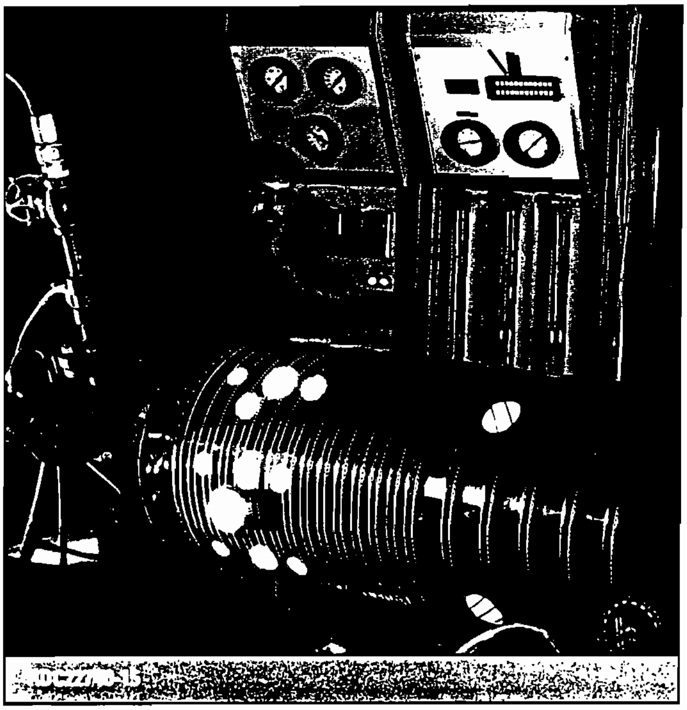
Combustion System

The MS7001EA combustion system features can-annular combustion, the optimal type of combustion system for the higher firing temperatures which are the key to producing combined-cycle efficiencies in the 50% class. Design control over temperature profile reduces the cooling air requirement, increasing efficiency and extending parts life. Reduced fuel residence time in the flame zone results in lower NO_x production. The can-annular configuration allows factory assembly and testing, which ensures the turbine's integrity at the time of delivery and reduces installation costs.

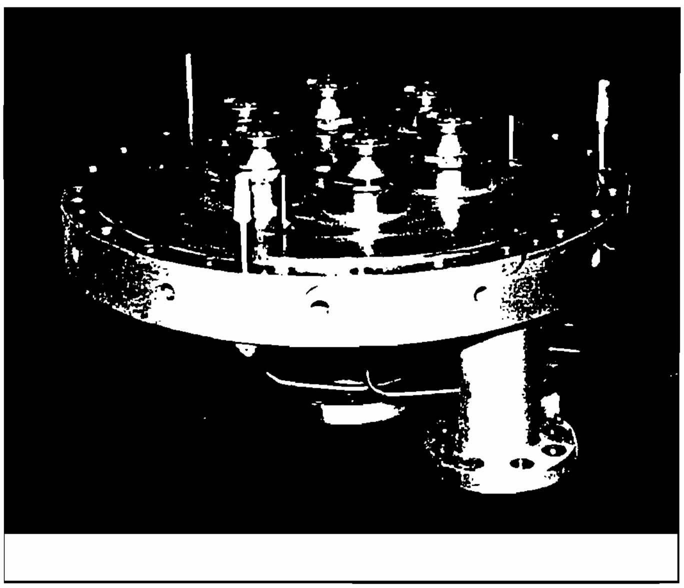


Multi-nozzle lean combustor achieves high efficiency, low emissions, and excellent temperature control. It utilizes special GE thermal-barrier coatings for longer part life.

▲ Dry low NO_x combustor is aimed at meeting siting requirements efficiently with normal maintenance.



▲ Lab tests show that shorter flame zone residence time results in lower NO_x production.



GE's multi-nozzle "Quiet Combustor" has demonstrated normal maintenance intervals while meeting 25 ppmvd NO_x requirements at 15% O_2 in several installations over thousands of operating hours with steam injection.

Transition Piece Design

The transition piece, featuring a positive curvature inner panel with a reinforcing rib and thermal barrier coating, significantly improves reliability, durability and performance. Field tests have proven that this design allows inspection intervals of 8000 hours for MS7001EA units in base load service, or 800 starts for peaking units.

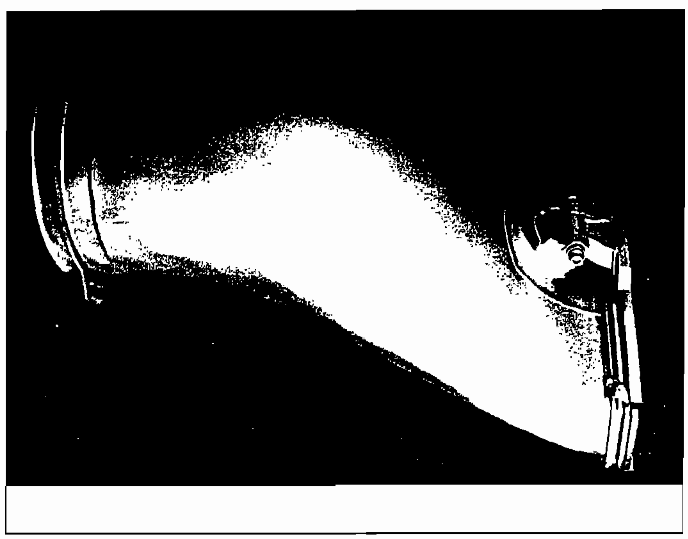
Low-Pressure Air Atomizing System

A low-pressure air atomizing fuel system allows the MS7001EA to burn distillate fuels with a clear stack. Recent field experience with the MS7001EA demonstrates that air atomization provides improved fuel inlet temperature distribution which reduces maintenance of hot-gas-path components.

Longer Inspection Intervals And Reduced Maintenance

The combustion system's slot-cooled liner cools more effectively for lower and more uniform liner metal temperatures. This results in extended inspection intervals, reduced maintenance and greatly improved reliability. Maintenance and inspection costs are further reduced since a crane is not required to remove the smaller parts used in the can-annular design.

▲ Lightweight combustion parts are easy to assemble by hand.



The 7EA transition piece is now made of Nimonic 263, a precipitation-strengthened, nickel-based alloy which has substantial deflection capability.

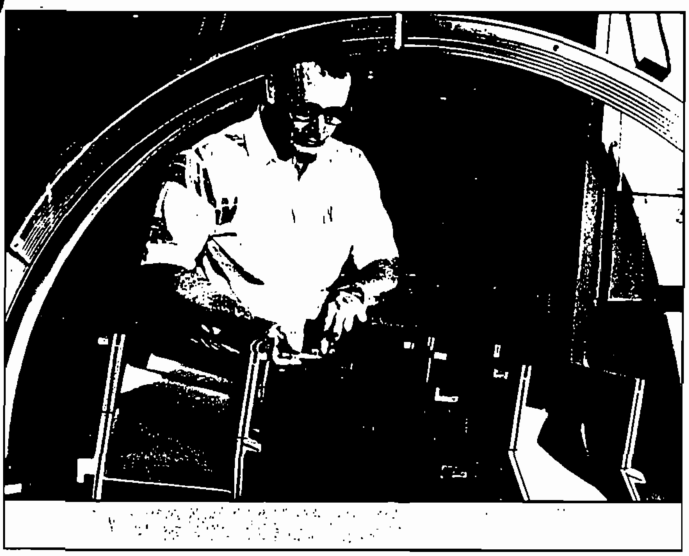
HIGH-QUALITY COMPONENTS DESIGNED AND ENGINEERED FOR EFFICIENT PERFORMANCE AND LONG LIFE

High-Efficiency Nozzles

All three nozzle stages on the MS7001EA are segmented and precision-cast from corrosion-resistant superalloys for strength, maximum dimensional control and excellent mechanical stability, as well as an improved finish on gas-path surfaces. This particular nozzle design eliminates high-cycle fatigue as a nozzle failure mode. In addition, multiple segment construction provides lower mechanical stresses and low cooling flow with attendant fuel savings. It also provides fewer leakage paths, which leads to enhanced efficiency and fuel savings.

Stage-one and stage-two nozzles are air cooled. Nozzles for the first stage are cast from FSX-414 alloy. Second- and third-stage nozzles are made of GTD-222 alloy.

Trailing edge cooling in the turbine nozzle reduces temperature by passing cooling air through small holes in the trailing edge. Factory inspection check assures correct dimensions.



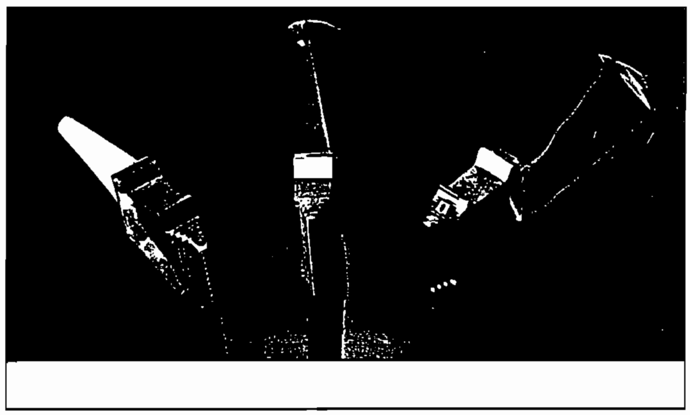
Buckets And Wheels

The MS7001EA turbine buckets are investment castings of a corrosion-resistant, nickel-base superalloy. First-stage buckets are cast from GTD-111, a proprietary superalloy designed specifically for this purpose and coated to protect against corrosion from sulfidation, significantly increasing bucket life. Additionally, the first-stage buckets are vacuum plasma spray-coated to further improve bucket life.

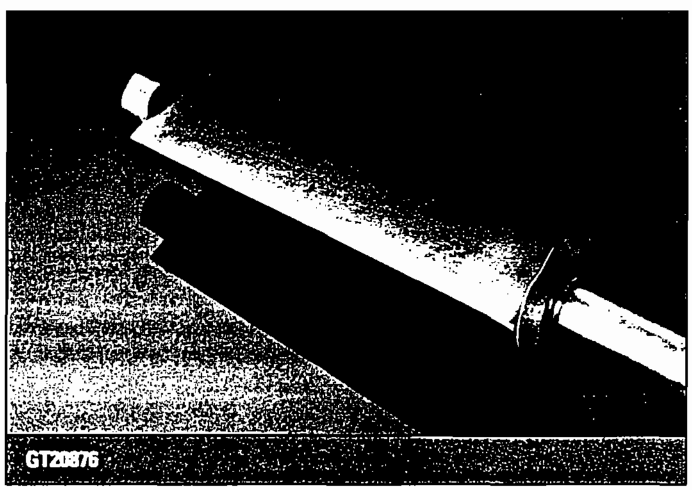
Second- and third-stage buckets have integral tip shrouds which control vibration without the use of a tie wire. Integral shrouds also improve stage efficiency through tip flow control.

The buckets on the MS7001EA gas turbine feature long shanks, which isolate the wheel rim from the gas path to reduce temperatures in the dovetail and wheel rim region. Increased length is the key to controlling vibration since axial pins located at the vane platform dampen bucket motion.

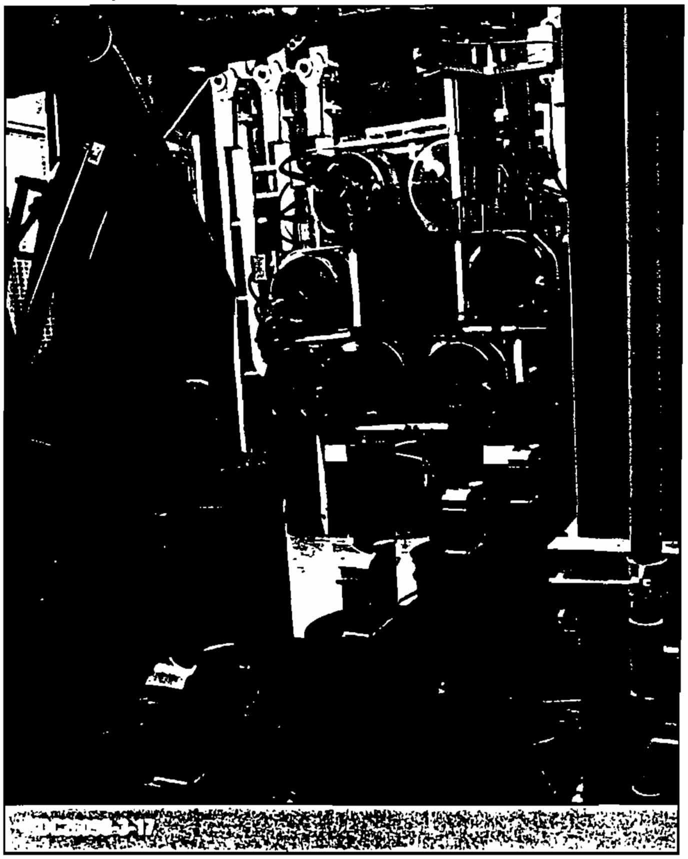
Holes through the vanes of the first- and second-stage buckets provide convective air cooling to maintain low metal temperatures. This cooling method is so effective that operating gas temperatures entering the turbine can be 200°F (93°C) higher than with non-air-cooled bucket designs.



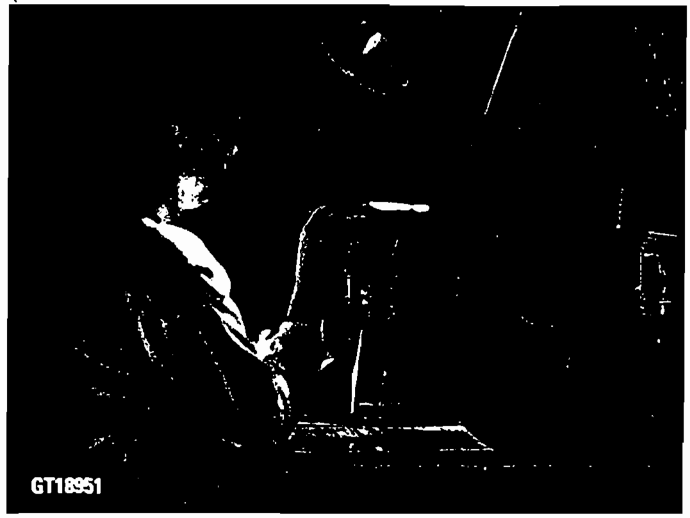
First- and second-stage turbine buckets feature convection air cooling — provided by holes through the vanes — to maintain low operating metal temperatures. Second- and third-stage buckets have integral tip shrouds which control vibration without the use of a tie wire.



The new GTD 450 composition of GE's inlet guide vane ▶ significantly improves corrosion resistance and strength with the redesigned reduced-camber airfoil also enhancing performance. In combined cycle applications, modulation of the vanes is used to maximize the exhaust temperature increasing efficiency at part-load operation.



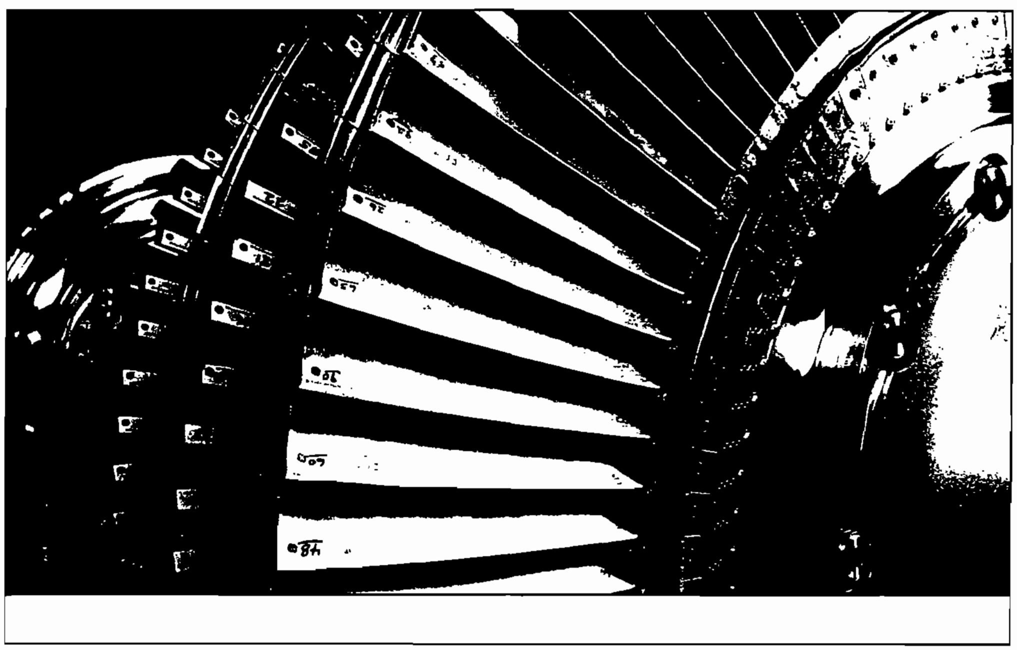
Robotic equipment is utilized to apply vacuum plasma spray-coating to first-stage bucket airfoils, using patented GTD-29 Plus coating with a unique process developed by GE's Corporate Research Center.



▲ As part of our stringent quality assurance program, each bucket is inspected with fluorescent penetrant prior to installation.

The precise moment weight of each bucket is determined by computer.

Moment-weighed buckets are assembled on wheel in positions assigned by computer to ensure easy balancing (above). If bucket replacement is required, GE records show details of exact bucket needed for optimum balance.

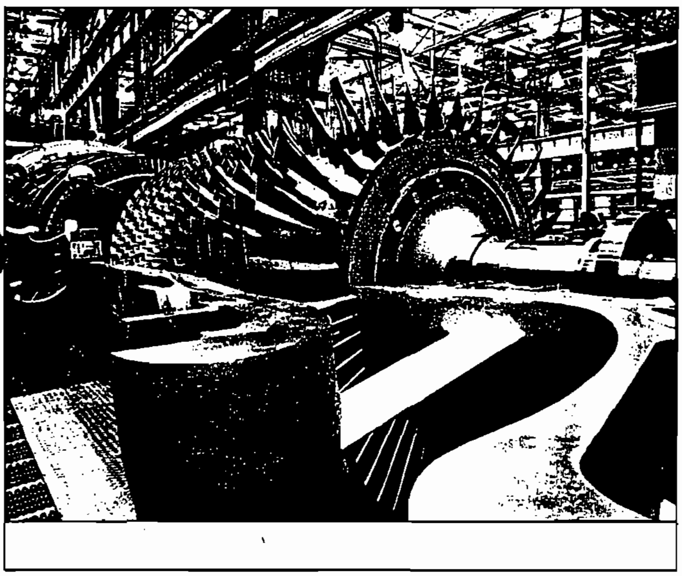


HIGH-QUALITY COMPONENTS (Continued)

Rotor

The compressor rotor has individual disks for each stage. Through-bolts connect the disks to the forward and aft stub shafts. The turbine rotor is similarly constructed, with spacer pieces clamped between the first- and second-stage wheels, as well as the second- and third-stage wheels.

Large blades are moment-weighed and arranged around the wheels through computer placement. Individual wheels are precision-balanced before assembly. The compressor and turbine rotor assemblies are aligned before assembly into the unit. This proven assembly technique eliminates rotor dynamics problems, resulting in years of trouble-free operation. Operating speed is below all bending critical speeds.



Assembly experts measure clearances of rotor during final assembly mating of rotor and stationary components.

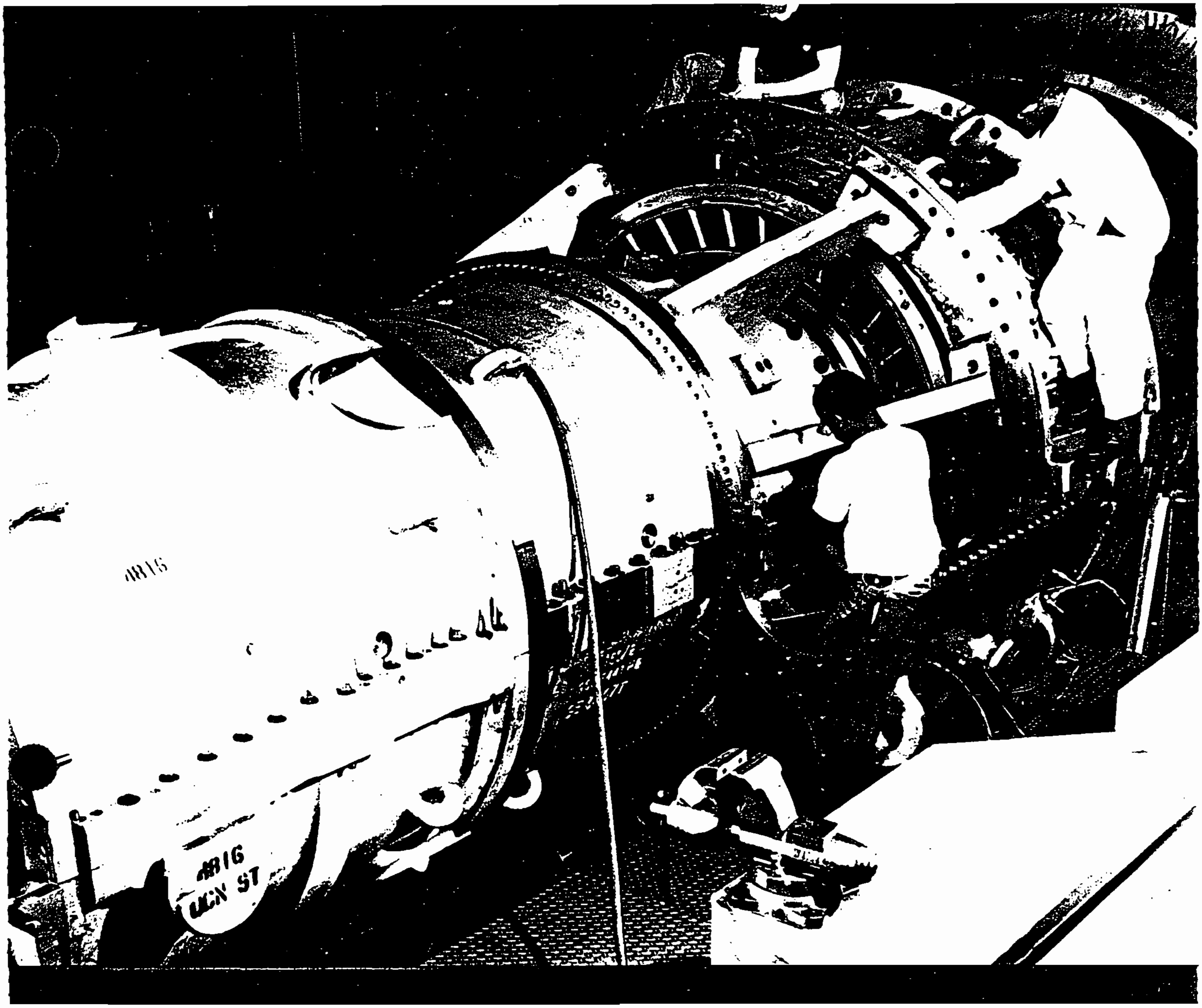
▲ The stator incorporates six major sections, split in half for easy maintenance.

Bearing System

The rotor is supported by three pressure-lubricated, long-life bearings to ensure that critical rotor speeds are positioned well out of operating speed range. The first and second bearings are elliptical types. The third bearing is a tilting pad thrust type. For compact power plant designs, the power take-off at the rotor's turbine end allows for compressor-end, turbine-driven accessories.

Casings

MS7001EA compressor and turbine casings are flanged at the horizontal centerline, permitting convenient access to the rotor and gas path for maintenance. Casing alignment is maintained through the use of dowels in the vertical flanges. All compressor and turbine casings are designed for long life. Openings in the casings permit boroscope inspection of critical internal parts without removing any outer casings.



Stator

The stator consists of six principle sections: the inlet casing, the compressor casing, the compressor discharge casing, the combustion wrapper, the turbine shell and the exhaust frame. All sections are sized for easy removal with a mobile crane.

The **inlet casing** uniformly directs air into the compressor and supports the No. 1 bearing. The **compressor casing**, which contains the stator blades, transfers the structural loads to the forward support. It provides air extraction for cooling and sealing functions, as well as start-up and shut-down surge control. The **compressor discharge casing** forms the inner and outer walls of the compressor diffuser, and supports the No. 2 bearing. The separate **combustion wrapper** contains the compressor discharge air. The **turbine shell**, which extends forward and attaches to the outer flange of the compressor discharge casing, contains the three turbine nozzles. The **exhaust frame** completes the stator section and contains the exhaust diffuser and No. 3 bearing support.

GE'S MS7001EA GENERATORS – MATCHED TO THE PACKAGED POWER PLANT

Optimal System Performance

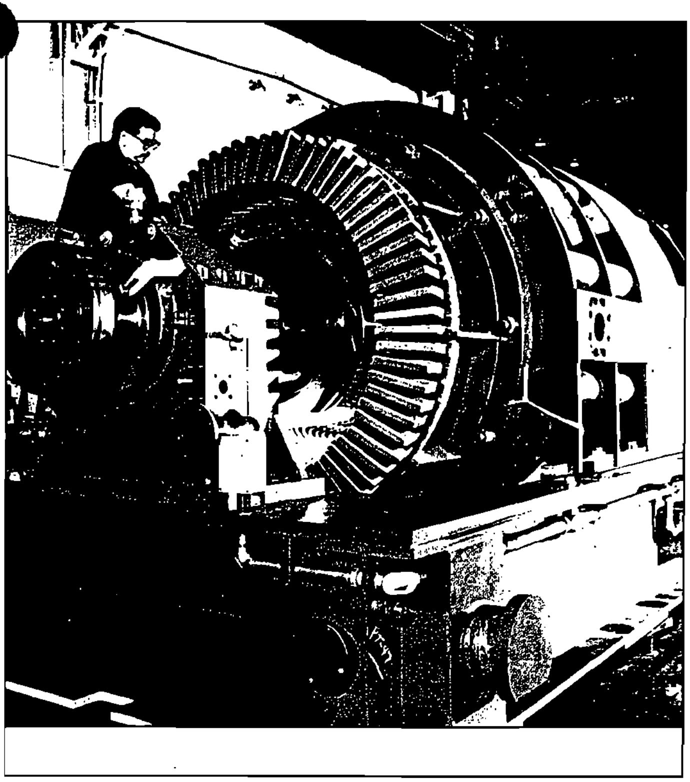
The MS7001EA generator is designed and manufactured by GE to meet high standards and high product quality. It features maximum packaging and proven reliability for low installation and maintenance costs.

Air-Cooled Design

The MS7001EA open-ventilated generator has increased output capability at lower ambient temperature that matches or exceeds the turbine's increased output capacity at low inlet air temperatures.

The air-cooling circuit includes inlet and discharge silencers and self-cleaning filters that are identical to those provided on the turbine. The rotor, stator and collector house are assembled as a package at the factory and shipped complete for simplified field installation.

GE's new 7A6 air-cooled generator, shown here during assembly in Schenectady, NY, uses Class F Micapal HT™ insulation, while the field winding contains direct-cooled conductor for reduced thermal stress.



Rugged Construction

Pedestal-type, tilting pad and elliptical-type bearings produce a rugged, stable rotor support system. A vacuum extraction system provides high bearing seal performance.

The stator frame minimizes vibration and sound transmission by incorporating a welded plate casing that is reinforced internally with bracing in both the radial and axial direction. Spring bars affix the key bars to the stator frame through web plates.

The stator core utilizes high-quality, grain-oriented silicon steel punchings for minimum electrical loss and reduced generator weight. Both the MS7001EA air- and hydrogen-cooled generators use direct conductor cooling. Cooling gas from the sub-slot flows out through radial holes in the rotor winding.

A Class F Micapal HT™ ground insulating system developed by GE provides insulating properties that meet or exceed ANSI and IEC Standards for thermal cycling conditions that occur in actual generator use. Micapal insulation, a strong, homogenous, high-dielectric material, consists of pure mica, a modified thermosetting resin binder and glass cloth. It has a proven record of long life with thousands of unit years of operation. The air-cooled generator is designed to meet Class B temperature rises at base load operation.

Sophisticated, Proven Excitation Systems

The proven and easy-to-maintain GE static excitation system provides reliable performance. It features a static, hybrid thyristor and silicon diode bridge that uses a power potential transformer directly connected to the generator output leads.

An automatic voltage regulator (AVR) holds the generator terminal voltage within narrow limits as the generator load changes. The system's high initial response minimizes voltage fluctuations during system disturbances. The AVR, in conjunction with the SPEEDTRONIC™ Mark V Control System, can optionally provide either automatic VAR or power factor control.

An optional, self-ventilated, overhung brushless rotating rectifier exciter system is also available. Redundant parallel diodes, each with a fuse in series, are sized to allow full generator output with one diode out of service. A static voltage regulator, with both an AC (automatic) and DC (manual) control mode, is included.

SPEEDTRONIC™ MARK V CONTROL SYSTEM IS DESIGNED FOR EASY OPERATOR INTERFACE AND MAXIMUM RELIABILITY

The SPEEDTRONIC Mark V Control System is the newest member of GE's electronic controls, featuring digital control loops improving speed range, response time and speed setting accuracy and reducing set point drift.

The SPEEDTRONIC Mark V uses three independent digital controllers to achieve the reliability benefits of triple modular redundancy. A fourth computer handles noncritical control and monitoring tasks and provides a protected link to a local and/or remote operator interface station.

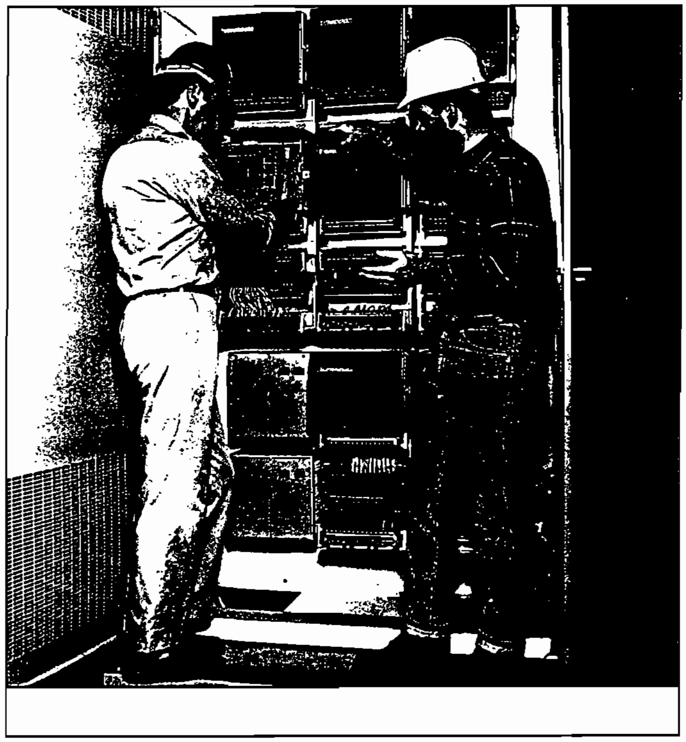
Redundant sensors are included in the system. They increase control system reliability for turbines in applications where sensor failures are more likely and where replacement may not be possible while the turbine is operational.

On-line diagnostics locate and identify faults, which can then be isolated and repaired without disruption to turbine operation. Failure rates have been measurably cut by decreasing the number of electronic components that directly control the turbine. Most failures can be serviced on-line without the system being upset, shut down or tripped.

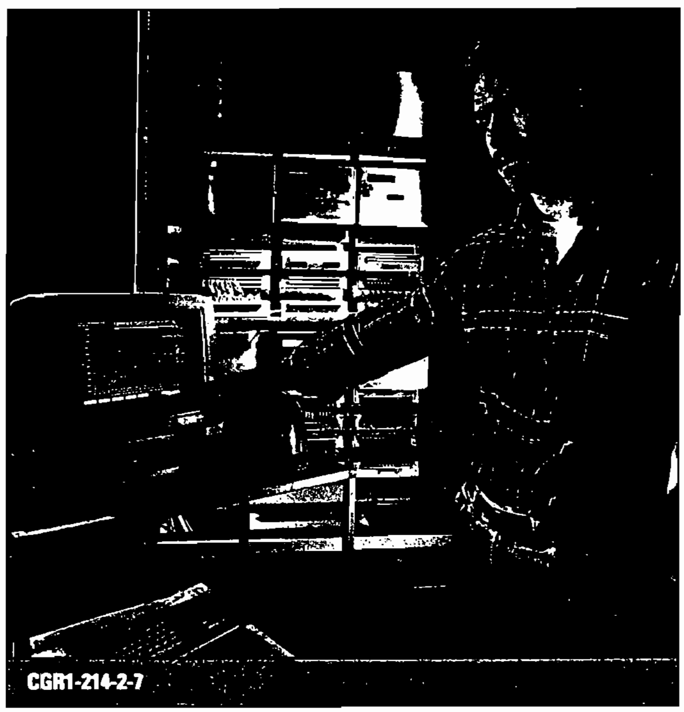
The 16-bit microprocessors used in the SPEEDTRONIC Mark V Control System have significantly reduced the large, complex, expensive and less reliable systems previously needed for three-channel redundancy.

The Smart Remote System is a remotely locatable operator interface for control and monitoring of up to eight gas turbine generators. Configured as a desk-top terminal, it incorporates color graphics capabilities, and can display up to four independent operating windows in addition to an alarm window that is always present. The system has access to all information in the Mark V system database, and can trend any point against time or against any other point. Optional historical data logging, archiving and manipulation capabilities are extensive. Performance analysis and monitoring capabilities are also optionally available for power generation installations.

The four processors, in combination with the equipment and human interfacing devices, form an integrated system that is specifically designed to perform the tasks of controlling, sequencing, monitoring and protecting a gas turbine, generator and its auxiliary and support systems in the most reliable fashion available today.



More than 150 displays can be called up from the SPEEDTRONIC Mark V Control System's memory. A drawer-mounted printer produces hard copy of any display. A CRT in the operator interface gives a clear overview of operating conditions. A switch on a central pad lets the operator run the turbine, and select detailed graphic displays that look into specific operating conditions.



▲ The Smart Remote System, in combination with four processors and human interfacing devices, form an integrated system that is specifically designed to perform the tasks of controlling, sequencing, monitoring and protecting a gas turbine and its auxiliary and support systems.

A COMPACT POWER PLANT PACKAGE DESIGNED FOR FLEXIBLE APPLICATION AND LOW MAINTENANCE

GE's packaged power plant emphasizes standardization, factory assembly and testing for ease of installation and start-up which help keep the cost per installed kilowatt low and reliability high. Because the basic plant layout represents a major portion of the total installed cost, many of the expenses generally incurred in complicated station layouts, plant design, and construction are eliminated.

Maximum packaging of the MS7001EA gas turbines makes them easy to site. The compact, fully integrated systems can be located virtually anywhere, since they do not require cooling water. They can be arranged in a variety of layouts to accommodate most terrains. Relatively small sites may be usable, and it is easy to make these sites attractive and to locate them close to consumers to eliminate long transmission lines.

The MS7001EA's many benefits — low investment costs, unattended remote-control operation, dispatch ease and loading flexibility — make it ideal for applications such as peak and bulk load, emergency stand-by, cogeneration and industrial self-generation. Its high specific work makes it a good choice for heat recovery applications, too.

The MS7001EA packaged power plant is a compact, self-contained gas turbine generating station consisting of five major components including gas turbine, accessories, controls, generator and switchgear.

The five components are housed in trim, all-weather enclosures designed to simplify maintenance and provide adequate thermal and acoustical insulation. Various acoustical arrangements can be supplied to meet a variety of sound levels from 64 dBA to 49 dBA at 400 feet for a single, simple-cycle packaged power plant.

Gas Turbine

The Turbine — Simple-cycle, single-shaft, three-bearing machine with can-annular combustion. The compressor and turbine casings are split horizontally throughout for easy accessibility and maintenance, including provisions for on-line and off-line compressor washing. The compressor and turbine rotor are solidly connected and supported on three pressure-lubricated journal bearings.

The basic air inlet duct arrangement is designed to incorporate silencing equipment for flexible acoustical requirements. The overhead inlet system permits close centerline spacing of units for a compact, unobstructive, functional site.

Accessories

Air Systems — Atomizing air; bearing seals; rotor cooling; stator cooling; bucket cooling; nozzle cooling.

Starting System — 800 HP induction motor.

Inlet Filtration — Field-proven self-cleaning inlet air filtration systems for gas turbine and generator.

Lube Oil System — Main shaft drive pumps; hydraulic system; single or duplex lube and hydraulic system filters and coolers; AC motor-driven auxiliary pumps; DC motor-driven emergency lube pumps; stainless steel piping.

Cooling Water System — Turbine/generator lube oil; turbine support legs; atomizing air.

Fuel Systems — Fuel oil pump; stop valve (fuel oil); fuel oil flow divider; atomizing air compressor; control valve (fuel oil).

Controls

Control Compartment — SPEEDTRONIC turbine control panel; generator control panel; space for optional supervisory and remote-control cable systems.

Smart Remote System — An optional, remotely locatable operator interface for control and monitoring of up to eight gas turbine generators. The system has access to all information in the Mark V system database.

Generator

Advanced Air-Cooled Design — Open-ventilated, air-cooled system is standard. Hydrogen cooling is optional. Meets Class B temperature rises at base load, Class F operating temperatures.

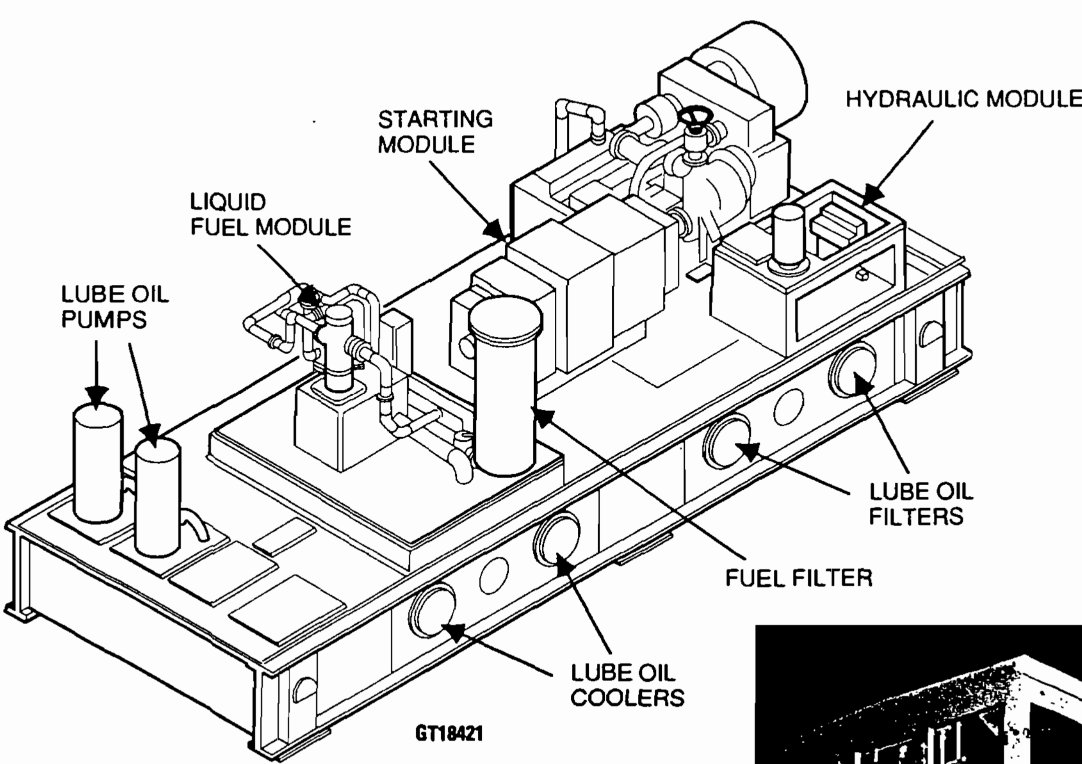
Hydrogen-Cooled Design — Optional for use with combined-cycle and other selected applications. Completely enclosed for operation with hydrogen gas as the cooling medium. The ventilation system is completely self-contained, including gas-to-water coolers and fans.

Base-Mounted Unit — Static or brushless excitation; pedestal-mounted tilting pad and elliptical bearings; simplified rotor and retaining ring design.

Generator Auxiliaries Compartment — Base-mounted, weatherproofed and installed in-line with (and close-coupled to) the generator compartment. Contains static excitation, disconnect link for auxiliary feeder, generator breaker, potential and current transformers and customer power take-off.

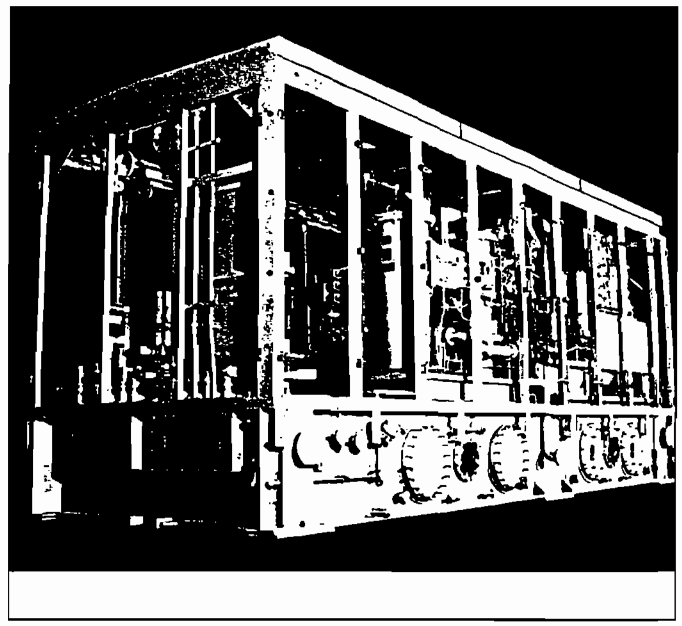
Switchgear

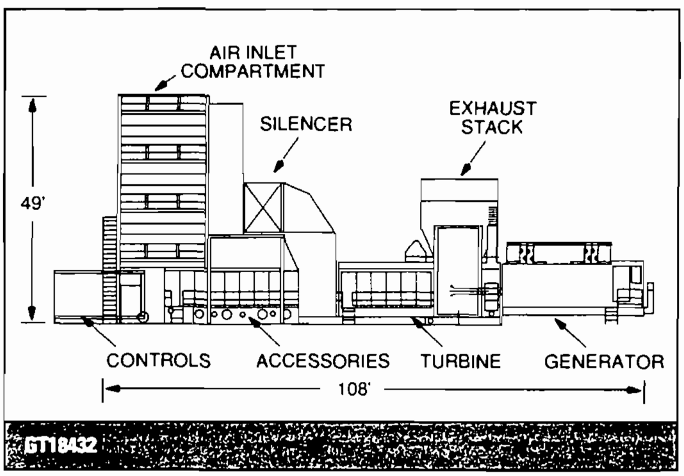
This compartment houses the generator breaker, lightning arresters, potential and current transformers, and the customer's power take-off.



◀ Accessory base arrangement.

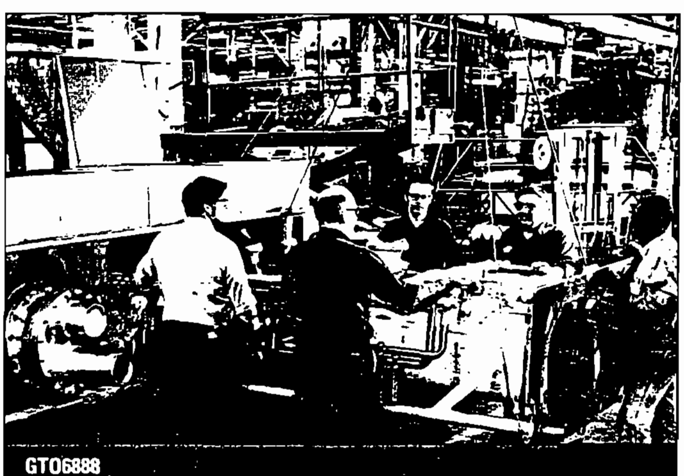
Improved "split base" packaging brings standardization to modularized accessory systems.



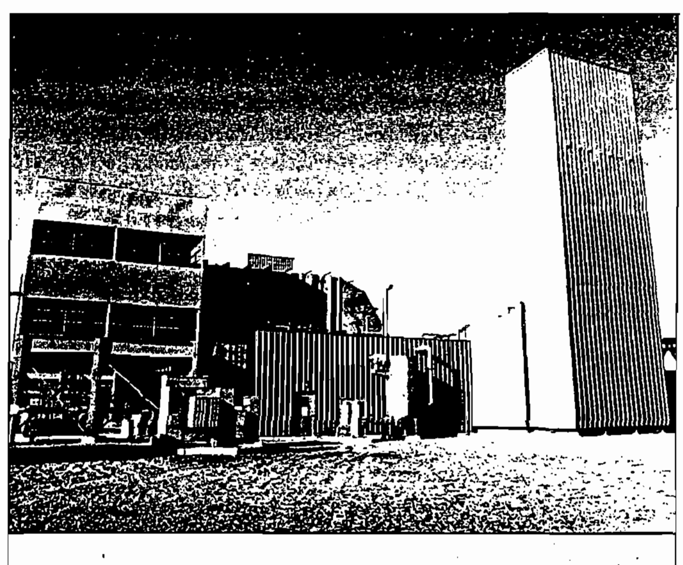


▲ Typical packaged power plant layout with dimensions.

▼ "Works-in-a-drawer" piping concept permits fast interconnection of one base at your job site for lube oil and other accessory equipment.



▼ Clean, attractive appearance is a feature of the MS7001EA packaged power plant. Standardization in this eastern U.S. plant also made possible the installation and operation of the four units a month ahead of schedule.



MANY OPTIONS TO SUIT ANY APPLICATION NEED

Many frequently requested former options that provide added benefits are now standard. However, several options on MS7001EA gas turbine are designed to provide greater control over wide-ranging situations.

- Water or steam injection for reduced NO_x emissions.
- Dry low NO_x* combustor meeting 25 ppmvd (15% O_2) U.S. Codes.
- Combinations of acoustical treatments to suit specific site requirements.
- Evaporative cooling for increased power output at high ambient temperatures (with low relative humidities).
- Built-in flexibility allowing for the use of distillate oil, natural gas, process gas, crude oil and residual oil — alone or in any combination. Demonstrated ability to convert to coal-derived fuels.
- Dual-fuel system for fast fuel changeover under load automatically or semi-automatically.
- Packaged liquid fuel-forwarding skid includes full-size AC and DC motor-driven pumps, fuel heater, and flow meter for supplying fuel to the main pump located in the turbine compartment.
- Smart Remote control systems for control and monitoring diagnostics trending.
- Diverse electrical relaying and monitoring accessories to suit user requirements.
- High-efficiency media inlet air filtration.
- Off-line compressor water wash system for thorough washing of entire compressor when the unit is down. For base-load continuous operation users, an on-line compressor water wash system can also be supplied.

*Available on units shipped in late 1991.

TOTALLY INTEGRATED PACKAGED POWER PLANTS UTILIZE THE VERSATILITY OF THE MS7001EA

Packaged Power Plant

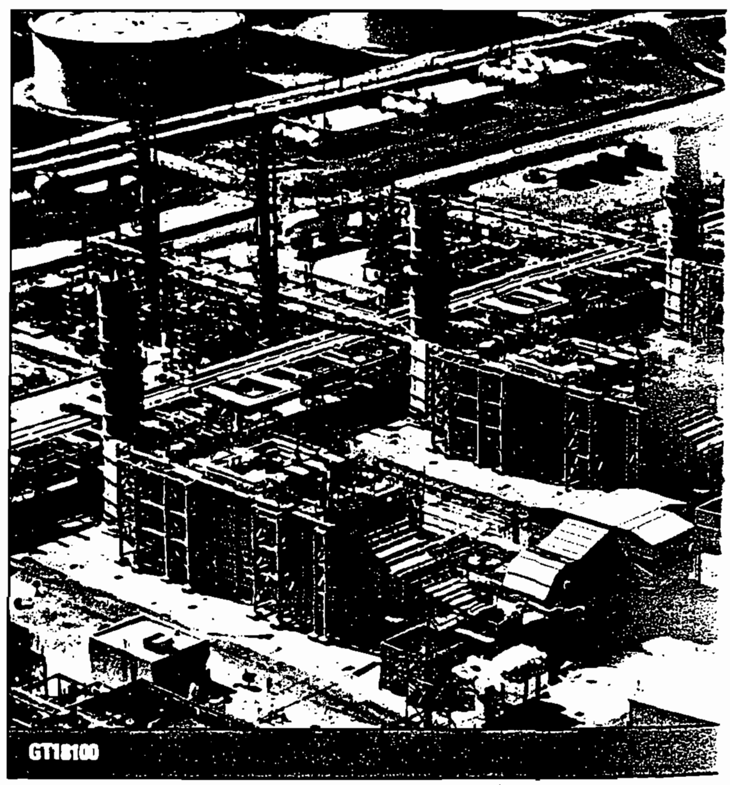
MS7001EA packaged power plants are totally integrated systems, including controls, auxiliaries, ducting and silencing. Their attractive appearance, coupled with the fact that they require absolutely no external cooling water, enhances their appeal where siting is a problem. Factory pre-packaging means a low installed cost. Plus, it allows the units to be put on-line quickly.

Optimal Efficiencies Via Cogeneration

Cogeneration can play a critical role in controlling high energy costs through effective integration of power generation and process utilization. The fuel effectiveness of a typical GE cogeneration plant is approximately 84%.

GE is the world's most experienced supplier of cogeneration power equipment. More than 400 cogeneration plants using GE turbine-generators are now in operation, each designed to meet specific operating requirements where both steam supply and reliable electrical output is critical.

GE gas turbines used in cogeneration plants offer the flexibility of tailoring the installation to meet site-specific technical needs, special testing standards and local requirements.



Industrial Generation

The MS7001EA gas turbine often provides the best solution for industrial power generation requirements where low maintenance, as well as economical and reliable power are needed. In addition to generating electrical power, the high-temperature exhaust of the gas turbine allows several functions in an industrial energy system to be performed simultaneously.

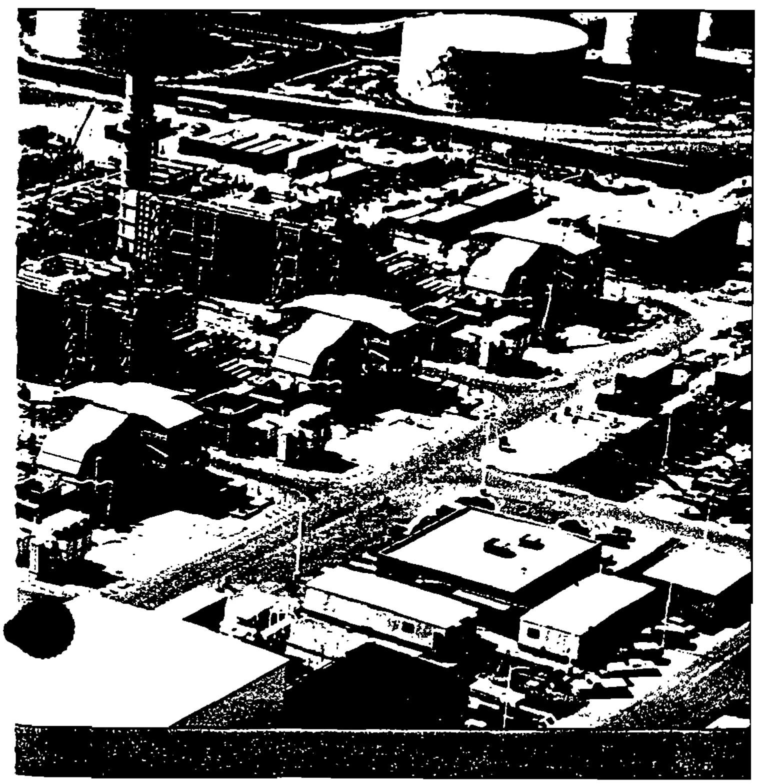
MS7001EA heavy-duty gas turbines are frequently used with heat recovery steam generators and are especially attractive to users with large requirements for electrical power and other process heat needs.

STAG™ Combined-Cycle Efficiency

STAG combined-cycle power plants, which use pre-engineered modules of GE MS7001EA gas turbines, GE steam turbines and heat recovery steam generators, blend the best of gas and steam-generating technologies, and offer outstanding base load efficiencies and mid-range daily start-and-stop service.

In the single-shaft arrangement—the simplest of all STAG configurations—the gas turbine, generator and steam turbine are situated in tandem on a single shaft. This arrangement is particularly suitable for multiple-unit station sizes in the 120 to 500 MW rating range.

▼ This 390 MW cogeneration plant in an oil field in Carson, CA, uses four MS7001 gas turbines to provide steam for oil recovery enhancement and electric power to the local utility.

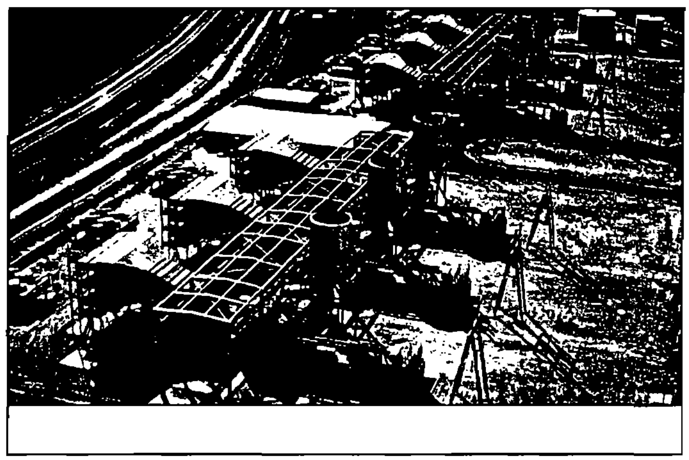


In the multi-shaft arrangement, multiple gas turbine-generators and heat recovery steam generators are teamed with a single steam turbine-generator. This arrangement provides a large block of economical, mid-range power generation, plus the ability to operate the gas turbines separately from the steam turbine through the use of the exhaust gas bypass stacks.

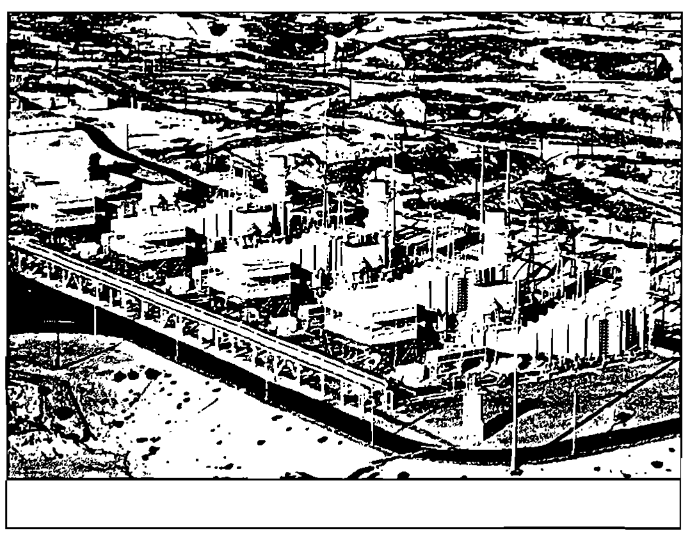
Two-Phase Flexibility Conserves Capital

To meet immediate peaking needs, the MS7001EA gas turbine can initially be installed as a simple-cycle unit. When requirements change, steam-side equipment can be added to configure to combined-cycle plant. Combined-cycle plants have proven to provide better heat rates than those obtainable from fossil-fired steam plants, at a substantially lower capital cost.

GE's packaged power plant emphasizes standardization, factory assembly and testing, and ease of installation which keeps the cost per kilowatt low in peaking applications like this. Its six MS7000 gas turbines saw 393 starts with availability of 99.3% and reliability of 99.9%.



This 300 MW cogeneration facility in a southwestern U.S. oil field provides 1.4 million lbs./hr. steam for enhanced oil recovery and excess electric power to the local utility with an availability of 95.7% over five years, reliability in excess of 98.7% after 160,000 fired hours.



FACTORS AFFECTING MAINTENANCE PLANNING

Minimizing maintenance costs and maximizing availability are the equipment owner's key concerns when planning a maintenance program. For a maintenance program to be effective, the owner must develop a general understanding of the relationship between his operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and the manufacturer's recommendations regarding the number and types of inspections, spare parts planning and the major factors affecting component life and proper operation of the equipment.

Maintenance Planning

The MS7001EA heavy-duty gas turbine is designed to withstand severe duty and to be maintained on-site, with off-site repair required only on certain hot-gas-path parts and rotor assemblies needing specialized shop service. The following features are designed into MS7001EA gas turbines to facilitate on-site maintenance:

- All casings, shells and frames are split on machine horizontal centerline. Upper halves may be lifted individually for access to internal parts.
- With upper half compressor casings removed, all stator vanes can be slid circumferentially out of the casings for inspection or replacement without rotor removal. Inlet guide vanes (IGVs) can be removed radially with the upper half of the inlet casing removed.
- With upper half of the turbine shell lifted, each half of the Stage I nozzle assembly can be removed for inspection, repair or replacement without rotor removal. Upper-half, later-stage nozzle assemblies are lifted with the turbine shell, also allowing inspection and/or removal of the turbine buckets.
- All turbine buckets are moment-weighed and computer-charted in sets for rotor spool assembly so that they can be replaced without the need to remove or rebalance the rotor assembly.
- All bearing housings and liners are split on the horizontal centerline so that they can be inspected and replaced when necessary. The lower half of the bearing liner can be removed without removing the rotor.
- All seals are separate from the main bearing housings and casing structures and can be readily removed and replaced.
- Fuel nozzles, combustion liners and flow sleeves can be removed for inspection, maintenance or replacement without lifting any casings or removing combustion cans.
- All major accessories, including filters and coolers, are separate assemblies that are readily accessible for inspection or maintenance. They can also be individually replaced as necessary.

The gas turbine parts requiring the most careful attention are those associated with the combustion process and those exposed to high temperatures from the hot gases discharged from the combustion system.

The basic design and recommended maintenance of MS7001EA gas turbines are oriented toward:

- Maximum periods of operation between inspections and overhauls.
- In-place, on-site inspection and maintenance.
- Use of local trade skills to disassemble, inspect and re-assemble.

MORE THAN 80 YEARS OF EXPERIENCE SERVICING POWER EQUIPMENT MAKES GE THE BEST CHOICE

There's more to operating a turbine than mere start-up. Service and maintenance costs must be carefully considered. Long-range considerations should be evaluated to obtain reliable service from the equipment.

Our global service and special programs can help improve gas turbine operation. Programs include installation, training, maintenance, repair and parts support. GE support programs are continually expanded and updated. On-line turbine operating data are collected and analyzed to help GE understand where future development work and programs should be focused.

Operating And Maintenance Support

The inspection and repair requirements outlined in the Maintenance and Instructions Manual provided to each owner lend themselves to establishing a pattern of inspections. Disassembly inspections start with very minor work, increase in magnitude to a major inspection (overhaul), and then repeat the cycle. The recommendations are generally tailored for a unit operating in base-load, continuous duty with natural gas fuel. Each user needs to generate a maintenance program around these recommendations based upon intended use, fuel type, duty cycle, etc., if it differs from the basic considerations.

A system of Technical Information Letters (TILs) is maintained by GE to provide rapid and formal dissemination of supplementary information to equipment owners and GE field service engineers necessary to assure optimum installation, operation and maintenance of the turbine.

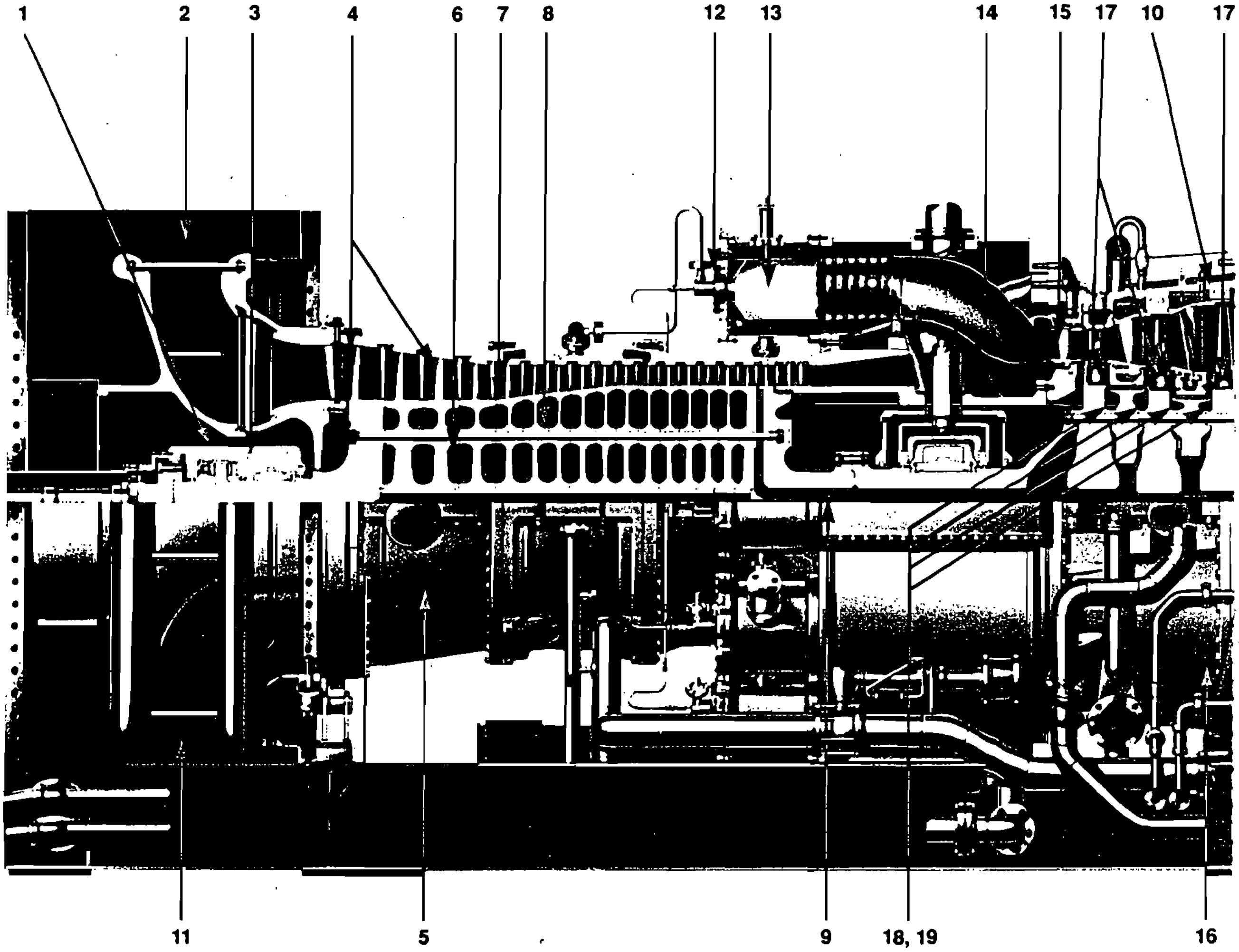
Product Service Support

Integrated services for each individual customer ensure the highest level of support. Solutions to specific needs are analyzed, coordinated, and implemented. Maintenance planning support is provided on a lifetime basis in cooperation with all GE service facilities.

Spare Parts Support

GE maintains a large inventory of parts to support short delivery cycles. Programs also include initial stock recommendations, maintenance parts recommendations, an exchange

THE MS7001EA SIMPLE-CYCLE, SINGLE-SHAFT, HEAVY-DUTY GAS TURBINE



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Compressor

(1) THRUST AND JOURNAL BEARING ASSEMBLY— Main thrust bearing is tilting pad type. All bearings are steel-backed, tin babbitted and pressure-lubricated.

(2) RADIAL INLET CASING — Provides uniform inlet flow to compressor.

(3) MODULATING INLET GUIDE VANES — Primary function to protect compressor from surge during start-up. Also used to maintain high exhaust temperature at part load in heat recovery applications.

(4) COMPRESSOR BLADING — Large chord, sub-sonic compressor blading of stainless steel material provides rugged air path design with wide operating limits.

(5) AXIAL-FLOW COMPRESSOR — Experience-proven 17-stage compressor designed for long life in varied types of service and environments.

(6) WHEEL CONSTRUCTION — Wheels of individual contour forgings are machined to constant stress a cross section and provide maximum material homogeneity.

(7) WHEEL RIM CLEARANCE — Protects rotor from distortion during abnormal operating conditions.

(8) THROUGH-BOLT CONSTRUCTION — Eliminates balance and thermal bowing problems and strengthens the rotor.

Stator Casings

(9) HORIZONTALLY SPLIT — On centerline to facilitate maintenance.

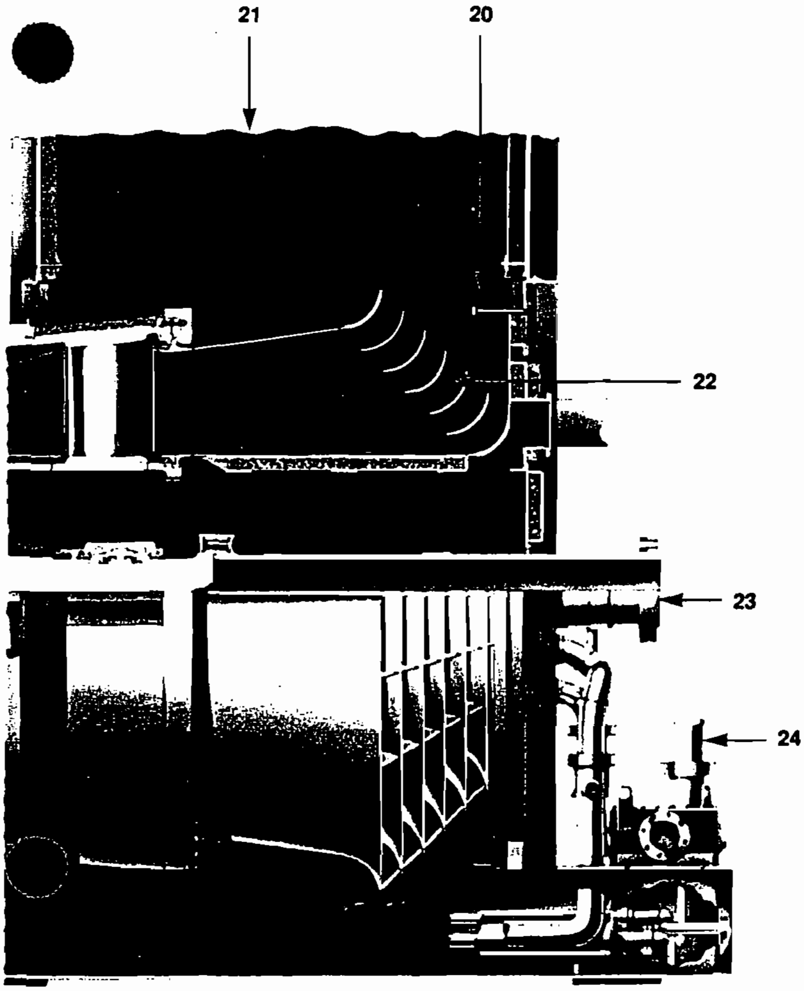
(10) SHELL COOLING — Provides dimensional stability to maintain close rotor clearances for optimum long-term performance.

(11) INLET ORIENTATION — Side or overhead arrangement available.

Combustion System

(12) FUEL NOZZLE — Gas, oil, dual-fuel and air-atomizing liquid fuel nozzles available for greater operational flexibility.

(13) REVERSE-FLOW COMBUSTION SYSTEM — Designed for improved life, ease of maintenance and efficient operation.



The Following Previously Optional Features Are Now Standard On The MS7001EA Gas Turbine:

- Modulating inlet guide vanes of C450 corrosion-resistant, high-strength material.
- Provisions for both off-line and on-line compressor wash.
- Dual oil-to-coolant heat exchangers with transfer valve.
- Stainless steel lube oil feed, fuel gas, fuel oil and atomizing air piping with TIG welding of the root pass.
- Piping in accordance with ANSI B31.3 including ASME welding requirements by GE-certified welders.
- Stainless steel valve trim throughout the lubrication system.
- GE "Energy Saver," TEFC, severe-duty motors with high-temperature insulation and anti-fungus coating.
- Third-party certification (UL/FM/ETL) of electrical devices and components.
- Terminal boxes, wiring, and conduit in accordance with the NEC including Class I, Group D, Division 2 requirements.
- Proximity-type vibration sensors and bearing metal thermocouples.
- Off-base cooling water heat exchanger module.
- Self-cleaning-type air filter for turbine and air-cooled generator.
- Enlarged exhaust frame cooling air fans.

(14) TRANSITION PIECE CONFIGURATION — Distributes combustor discharge gases to ensure that only gases of uniform temperature enter the turbine, extending nozzle and bucket life.

Turbine

(15) NOZZLE DESIGN — Increases nozzle life by passing cooling air through the body of individual nozzle partitions. Segmented construction permits stress-free nozzle expansion.

(16) THREE-STAGE TURBINE ROTOR ASSEMBLY — Designed for high-efficiency operation, with conservative metal temperatures in rotating components.

(17) LONG SHANK BUCKETS — Isolate wheel rim from hot gas path to reduce wheel temperatures and damp vibration.

(18) WHEEL COOLING — Turbine wheel and bucket cooling accomplished by compression flow extraction.

(19) WHEEL SPACE THERMOCOUPLES — Measure wheel space cooling temperature to provide continuous monitoring for additional safety and reliability.

Exhaust

(20) TEMPERATURE MEASUREMENT — Two separate exhaust control systems with thermocouples provide constant monitoring and protective alarm and trip functions.

(21) EXHAUST ORIENTATION — Side or overhead arrangements available.

(22) EXHAUST DIFFUSER

Other

(23) LOAD COUPLING — Rigid coupling and coupling guard.

(24) GUARDED OIL PIPING — For maximum safety, high-pressure oil lines use rigid steel piping that is located inside oil return lines or inside oil tank where possible.

plan, a repair and return plan, interchangeability reports, design improvements, modifications, upratings and conversions, and customized parts containerization.

Maintenance Scheduling

It is important to develop a schedule of inspection intervals and maintenance procedures based on the utilization of the equipment and the experience accumulated during its operation. The table below lists recommended combustion, hot-gas-path and major inspection intervals based on engineering judgment and operating experience gained with MS7001EA gas turbine units.

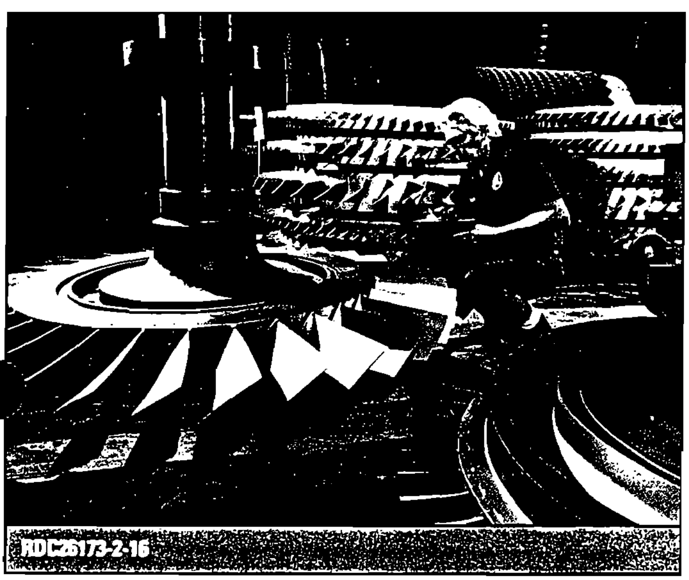
INSPECTION TYPE	FUEL TYPE	MS7001EA FIRED HOURS
COMBUSTION	GAS	8,000**
	DISTILLATE	8,000**
HOT-GAS-PATH	GAS	24,000
	DISTILLATE	24,000
MAJOR	GAS	48,000
	DISTILLATE	48,000

** May be impacted by amount of water or steam injection for NO_x control or power augmentation.

The MS7001EA gas turbines normally reach 24,000 real operating hours before hot-gas-path inspection and 48,000 real operating hours before a major inspection, reducing maintenance costs by 30%.

Diagnostic And Expert Systems

GE's Gas Turbine Technology Department and the GE Corporate Research and Development Center have developed a program for Diagnostics and Expert Systems to assist plant engineers in determining the on-line health of turbine generators. The systems utilize state-of-the-art sensors and control monitoring panels connected to a personal computer for data retrieval, archiving and analysis. Both thermal and mechanical performance are monitored. These systems enable maintenance personnel to better plan maintenance outages and spare parts. Predictive performance will also help determine the most economic operating profile of the equipment.



Field Service

GE offers maintenance including field engineering help. In addition, we offer total project responsibility—from supplying craft labor to overall project management. GE field engineers have the complete technical resources of GE at their disposal.

Service Shop Support

In the U.S., 19 service shops perform minor repairs on GE gas turbines. Two service shops—in Cincinnati and Houston—handle major inspections, overhauls or emergency repairs. Six overseas service shops are fully qualified for GE gas turbine repair. Each shop is staffed by experienced technicians, factory-trained to perform diverse repairs. An annual audit of each facility ensures that personnel and equipment standards remain high.

Area Service Concept

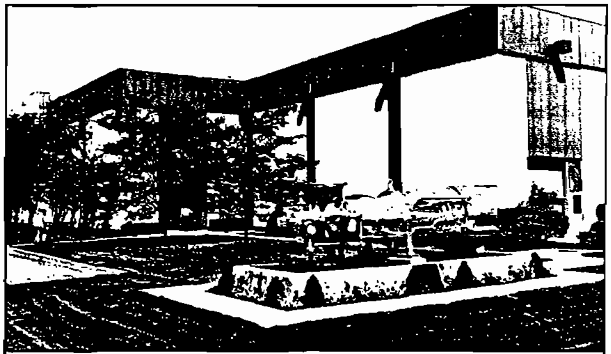
The application of GE gas turbines globally has resulted in the formation of integrated, localized service support centers. Field engineering, on-site repairs, contract maintenance support and personnel training are now conducted at single-area service centers around the world, such as the one in Saudi Arabia.

Updated files are maintained on each turbine in a service center area. GE experts bring together customer maintenance managers, engineers and foremen for discussions and instruction in new industry practices and techniques at Gas Turbine Maintenance Seminars.

Field-experienced GE engineers can provide hands-on training for your plant operation and maintenance personnel, tailored to the specific characteristics and requirements of your equipment.

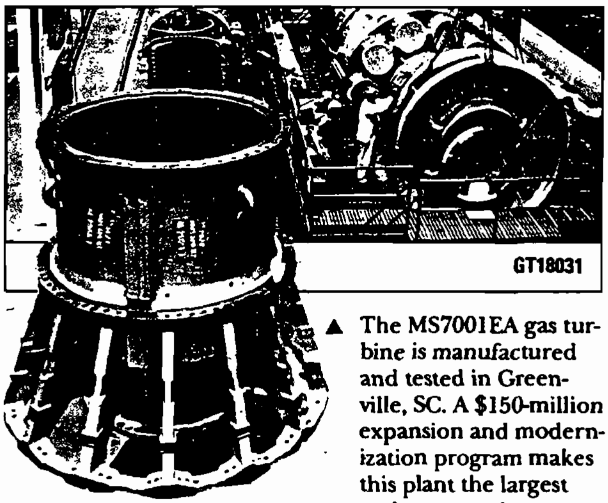
Whether for routine maintenance or emergency repairs, spare parts are available from GE warehouses in Schenectady, NY, and around the world.

◄ GE provides complete support services through a worldwide repair facilities network staffed with expert field engineers and technicians using state-of-the-art equipment and methods.



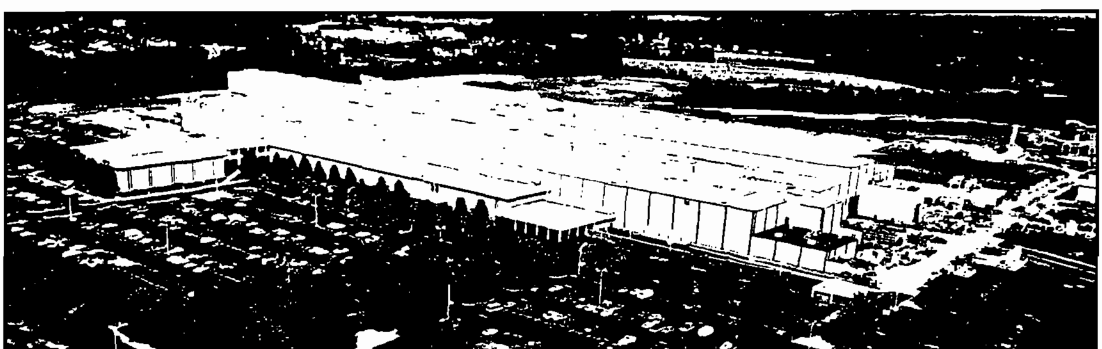
RDC25115-12-4

▲ Many of the evolutionary upgrading improvements made to the MS7001 gas turbine were completed in the Gas Turbine Development Laboratory located in Schenectady, NY.



GT18031

▲ The MS7001EA gas turbine is manufactured and tested in Greenville, SC. A $150-million expansion and modernization program makes this plant the largest and most modern gas turbine manufacturing facility in the world. ▼



RDC26175-15

GE–A SINGLE SOURCE FOR ANSWERS TO ALL YOUR POWER GENERATION NEEDS

The MS7001EA gas turbine is only one example of GE leadership in turbine technology. With a history of innovation and nearly 4600 combustion turbines operating successfully around the globe, GE is committed to providing a continuing standard of excellence.

- The industry's broadest selection of high-performance steam and gas turbine designs.
- Cogeneration expertise.
- High-technology upgrade programs.
- Pre-engineered parts and components.
- Worldwide locations and total service support.

For the technology and commitment to meet power generation needs in the '90s and beyond, you have a valuable resource in GE.

GE Power Generation

GEA-9680G 1/91 (10M) RTB Printed in USA.

General Electric Company
One River Road
Building 2, Room 101A
Schenectady, NY 12345

DUTY SPECIFICATION

DESIGN STANDARDS

The design, material and workmanship of all pressure parts shall be in strict conformity with the rules and regulations in effect at the date of contract as required by:

1. The A.S.M.E. BOILER AND PRESSURE VESSEL CODE, SECTION I.
2. The laws of the State of Florida.
3. Requirements of the ____________ Steam Boiler Inspection and Insurance Company, under whose inspection the pressure parts of each unit shall be constructed.

This boiler will be used for intermittent service, generally for plant black-start following maintenance shutdowns. It shall be designed for starting and continuous operation without extended utilities except as listed below (fuel and boiler feedwater).

DESIGN AND OPERATING CONDITIONS

Design Steam Capacity	________	Lb/Hr.
Maximum Continuous Load Steam Capacity	35,000	Lb/Hr.
Design Pressure	________	PSIA
Operating Pressure	65.0	PSIA
Steam Temperature	298	°F
Feedwater Supply Temperature	60	°F

BOILER FEEDWATER

Source	Boiler Feedwater Treating Plant	
Treatment	Demineralized (for high pres. boilers)	
Pressure	150	PSIG
Temperature	40-200	°F
Typical Analysis:		
Conductivity	0.1	uMHO/cm
Total Dissolved Solids	0.005	PPM(Na)
SiO_2	0.010	mg/l
pH	6-8	

FUEL ANALYSIS

Type		No. 2 Fuel Oil	
Pressure at Burner		45	PSIA
Temperature at Burner,	min	40	°F
	max	100	°F
Specific Gravity		0.876	
Flash Point		100	°F
Pour Point		20	°F
Minimum Heating Value:			
LHV		129,811	Btu/gal
HHV		137,600	Btu/gal

ATTACHMENT FDER-E

STORAGE TANK EMISSIONS CALCULATIONS

STORAGE TANK EMISSION CALCULATIONS

1. Per AP-42, Section 4.3, annual breathing losses from fixed roof tanks are calculated as follows:

$$L_B = (2.26 \times 10^{-2})\ M_V \left(\frac{P}{P_A - P}\right)^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_P C K_C$$

where: L_B = fixed roof breathing loss (lb/yr).
M_V = molecular weight of vapor in storage tank (lb/lb mole) = 130.
P_A = average atmospheric pressure at tank location (psia) = 14.76.
P = true vapor pressure at bulk liquid conditions (psia) = 0.012 at 80°F.
D = tank diameter (ft) = 128.
H = average vapor space height, including roof volume correction (ft) = 16.
ΔT = average ambient diurnal temperature change (°F) = 23.1.
F_P = paint factor (dimensionless) = 1.40 (medium grey tank color).
C = adjustment factor for small diameter tanks (dimensionless) = 1.0.
K_C = product factor (dimensionless) = 1.0.

Therefore, for each tank:

$$L_B = (2.26 \times 10^{-2}) \times 130 \times \left(\frac{0.012}{[14.76 - 0.012]}\right)^{0.68}$$
$$\times\ 128^{1.73} \times 16^{0.51} \times 23.1^{0.50} \times 1.40 \times 1.0 \times 1.0$$
$$= 2{,}849\ lb/yr$$

L_B = 1.42 tons/yr

2. Per AP-42, Section 4.3, annual working losses from fixed roof tanks are calculated as follows:

$$L_W = (2.40 \times 10^{-5})\ M_V P V N K_N K_C$$

where: L_W = fixed roof working loss (lb/yr).
M_V = molecular weight of vapor in storage tank (lb/lb mole) = 130.
P = true vapor pressure at bulk liquid temperature (psia) = 0.012 at 80°F.

V = tank capacity (gal) = 3,000,000.
N = number of turnovers per year (dimensionless):

$$N = \frac{\textit{Total throughput per year (gal)}}{\textit{Tank capacity, V (gal)}}$$

Oil Usage:

a. 7F CT (1 CT) operating 876 hours per year at 100% load, 20 °F ambient temperature:

$$\begin{aligned} \textit{Oil usage} &= (96{,}975\ lb/hr) \times (gal/7.3\ lb) \times (876\ hr/yr) \\ &= 11{,}637{,}000\ gal/yr \end{aligned}$$

b. 7EA simple-cycle CT (6 CTs) operating 876 hours per year at 100% load, 20 °F ambient temperature:

$$\begin{aligned} \textit{Oil usage} &= 6 \times (55{,}353\ lb/hr) \times (gal/7.3\ lb) \times (876\ hr/yr) \\ &= 39{,}854{,}160\ gal/yr \end{aligned}$$

c. 7EA combined-cycle CT (4 CTs) operating 2,190 hours per year at 100% load, 20 °F ambient temperature:

$$\begin{aligned} \textit{Oil usage} &= 4 \times (55{,}353\ lb/hr) \times (gal/7.3\ lb) \times (2{,}190\ hr/yr) \\ &= 66{,}423{,}600\ gal/yr \end{aligned}$$

d. Auxiliary boiler operating 1,000 hours per year at 100 percent load:

$$\begin{aligned} \textit{Oil usage} &= \frac{(49.5 \times 10^6\ Btu/hr) \times (1{,}000\ hr/yr)}{(129{,}811\ Btu/gal)} \\ &= 381{,}324\ gal/yr \end{aligned}$$

e. Total oil usage:

$$\begin{aligned} \textit{Oil usage} &= (11{,}637{,}000\ gal/yr) + (39{,}854{,}160\ gal/yr) \\ &\quad + (66{,}423{,}600\ gal/yr) + (381{,}324\ gal/yr) \\ &= 118{,}296{,}084\ gal/yr\ (total) \\ &= 39{,}432{,}028\ gal/yr\ (per\ tank) \end{aligned}$$

$$N = \frac{39.43 \times 10^6}{3 \times 10^6} = 13.14$$

K_N = turnover factor (dimensionless) = 1.0.
K_C = product factor (dimensionless) = 1.0.

Therefore, for each tank:

$$L_W = (2.40 \times 10^{-5}) \times 130 \times 0.012 \times (3 \times 10^{-6}) \times 13.10 \times 1.0 \times 1.0$$
$$= 1{,}462 \ lb/yr$$

$$\boxed{L_W = 0.74 \text{ tons/yr}}$$

Thus, for three storage tanks, maximum *total* annual VOC emissions would be:

$$Total\ VOC = 3 \times (L_B + L_W)$$
$$= 3 \times (1.42 + 0.74)$$
$$\approx 6.5 \ tons/yr$$

$$\boxed{\text{Total VOC} = 6.5 \text{ tons/yr}}$$

ATTACHMENT FDER-F

CURRENT CONCEPTUAL RECLAMATION PLAN FOR AGRICO FORT GREEN MINE (AGR-CP-F)

PROPOSED PROPERTY BOUNDARY
TEC POLK POWER PLANT

MINED / DISTURBED
OR TO BE MINED / DISTURBED

PERMIT AREAS

SCALE
2000' 0 1000' 3000'

MAP #2

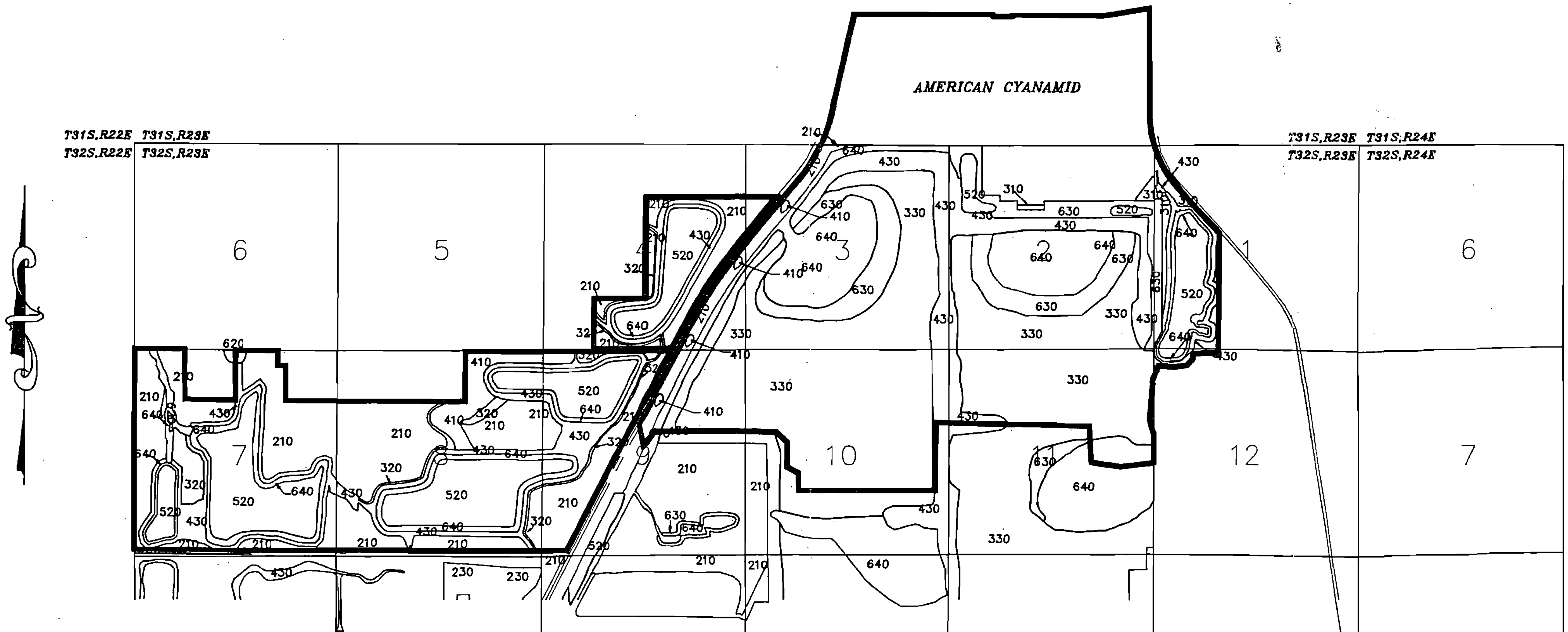
NO.	DATE	DESCRIPTION	BY	CHK	APP
REVISIONS					

AGRICO
Division of Freeport-McMoRan Resource Partners

FORT GREEN MINE
MINED, DISTURBED & PERMIT AREAS
AGR-FC-CPF

DRAWN R. PHILLIPS DATE 6/19/92 SCALE 1"=2000'
APPROVED DATE USE DIMENSIONS ONLY

DRAWING NO. FG MP 00 06



Legend

APRIL,1976 FLUCCS
LAND USE & COVER

140	TRANSPORTATION
210	CROPLAND & PASTURELAND
230	CITRUS GROVES
310	GRASSLAND
320	SHRUB & BRUSHLAND
330	MIXED RANGELAND
410	UPLAND CONIFEROUS FOREST
420	UPLAND HARDWOOD FOREST
430	UPLAND MIXED FOREST
520	LAKES
610	WETLAND CONIFEROUS FOREST
620	WETLAND HARDWOOD FOREST
630	WETLAND MIXED FORESTED
640	WETLAND VEGETATED NON-FORESTED WETLANDS

PROPOSED PROPERTY BOUNDARY
TEC POLK POWER PLANT

SCALE

2000' 0 1000' 3000'

MAP # 8

NO.	DATE	DESCRIPTION	BY	CHK	APP
3	8/5/92	REVISED SFG DRI LAND USE	JES		
2	7/6/92	REVISED SEC. 34(FG) L.U. D.E.R. REQ.	FDF		
1	6/19/92	REVISED SEC. 34(FG) L.U.	FDF		

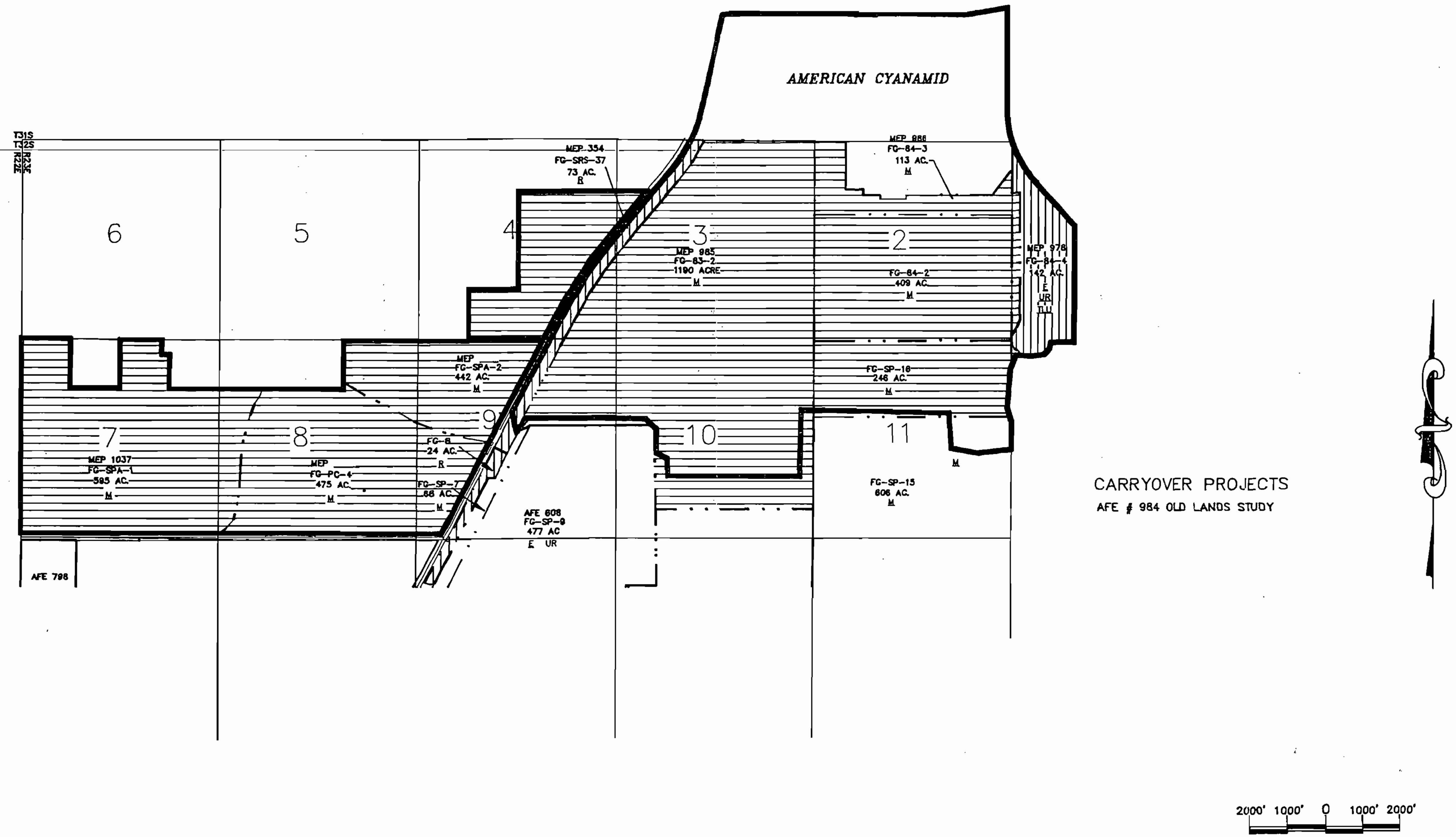
REVISIONS

AGRICO
Division of Freeport-McMoRan Resource Partners

FORT GREEN MINE
POSTRECLAMATION LAND USE
AGR-FG-CPF

DRAWN J. SCREWS DATE 1/19/91
APPROVED DATE
SCALE 1"=2000'
USE DIMENSIONS ONLY

DRAWING NO. FG OA LU 02



WORK COMPLETED

WORK TO BE SCHEDULED FOR FUTURE

R= RELEASED
UR= UPLAND RELEASED
A= ACTIVE RECLAMATION
E= ESTABLISHMENT
M= MINING OR MINING OPER.
I= INACTIVE
NM= NONMANDATORY
TLU= TEMPORARY LAND USE

PROPOSED PROPERTY BOUNDARY
TEC POLK POWER PLANT

AGRICO PROGRAM BOUNDARIES

NO.	DATE	DESCRIPTION	BY	CHK	APP

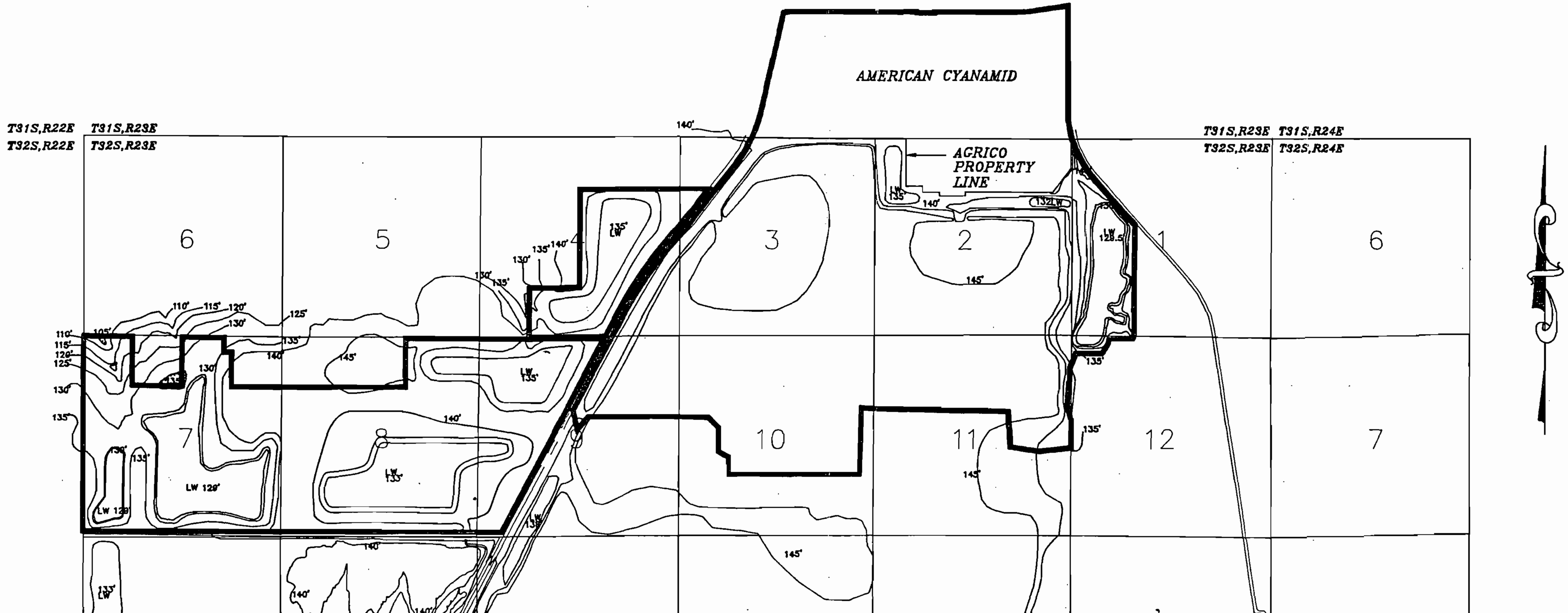
REVISIONS

AGRICO
Division of Freeport-McMoRan Resource Partners

FORT GREEN & SOUTH FORT GREEN
RECLAMATION STATUS

DRAWN R.PHILLIPS DATE 10/15/92 SCALE 1"=2000'
APPROVED DATE USE DIMENSIONS ONLY

DRAWING NO. LO CO 00 51



MAP # 7

NO.	DATE	DESCRIPTION	BY	CHK	APP
3	8/5/92	REVISED SFG DRI TOPOGRAPHY	JES		
2	7/8/92	UPDATE CONTOURS SEC. 4/5 HARDEE	FDF		
1	6/22/92	UPDATED SEC. 34 CONTOURS	FDF		

REVISIONS

AGRICO
Division of Freeport-McMoRan Resource Partners

FORT GREEN MINE
POSTRECLAMATION TOPOGRAPHY
AGR-FG-CPF

DRAWN J. SCREWS DATE 2/20/92
APPROVED ______ DATE ______
SCALE 1"=2000'
USE DIMENSIONS ONLY

DRAWING NO. FG OA CO 12

LEGEND

PROPOSED PROPERTY BOUNDARY
TEC POLK POWER PLANT

SCALE
2000' 0 1000' 3000'

PROPOSED AGR-FG-CPF
PREMINING LAND USE
REVISED 09/04/92

PROGRAM	ACRES	140	210	220	230	310	320	330	410	420	430	560	610	620	630	640
FG-1	239						93		28		37				39	42
FG-2	72		26				23				15				5	3
FG-3	190		64			20	89								9	8
FG-5	86		62			12										12
FG-8	24						1		23							
FG-9	38						29				6					3
FG-10	327		11				239				22					55
FG-11	64						50		10							4
FG-12	186						146								3	37
FG-13	366					276	26				31				13	20
FG-83(1)	151						30		54		50				7	10
FG-83(2)	1190		104				557		8		345					176
FG-83(3)	117						5				95					17
FG-83(4)	8						5		3							
FG-84(1)	738						65		74		542				23	34
FG-84(2)	409		114								90				174	31
FG-84(3)	113		4			4					66				24	15
FG-84(4)	142						56				59				21	6
FG-84(5)	398		83				217		5		11				65	17
FG-84(6)	330		36				207									87
FG-84(8)	65						38				21				3	3
FG-GSB-1	71		71													
FG-GSB-2	472		329		33				76						4	30
FG-GSB-3	479		59				305								17	98
FG-GSB-4	714		32				424							15	23	220
FG-GSB-5	711		76				423		32	16				24	37	103
FG-GSB-6	508		75				100		202	12				14	1	104
FG-GSB-7	430		247				61		64		24			5		29
FG-GSB-8	654		212				60	3	127	23				5		224
FG-GSB-9	331		211				8			46				32		34
FG-HC-1	172		130								3					39
FG-HC-2	669		122			190	106	73	6	38				12		122
FG-HC-3	963		69			3	154	394	24	175	3			27		114
FG-HC-4	716		107			71	403	1		6				5	1	122
FG-HC-5	205		17			15		116		14	6				2	35
FG-HC-6	56							50		5						1
FG-HC-7	310		25						191	4	11			54		25
FG-HC-8	394		298				6		25	26				3		36
FG-HC-9	614		416				6		95	5				60		32
FG-HC-10	383		54				1		212	32				29		55
FG-HC-11	763		603				47	4		70	1	2		9		27
FG-HC-12	321		42				129		84	25	8			12		21
FG-HC-13	349						183		17	148				1		
FG-HC-14	400		132			10	121	29	13	88				5		2
FG-PC-1	639		413				12		99		89			22	4	
FG-PC-2	1437		661			55	382				18		14		106	201
FG-PC-3	609		167				276		6		23				57	80
FG-PC-4	475		135				64		256		7					13
FG-PC-5	336		12			44	171		12		46				48	3
FG-SP-1	157		21		6		44		65						4	17
FG-SP-2	56		16				13		17						2	8
FG-SP-3	105								80		8					17
FG-SP-4	260		28				11		115		93					13
FG-SP-5	131		61				56								10	4
FG-SP-6	339		58			189	37								12	43
FG-SP-7	68		1				20		39		3				1	4
FG-SP-8	555					98	269		90		28				11	59
FG-SP-9	477		127				160		156						7	27
FG-SP-11	696		213						300		24				7	152
FG-SP-12	613		44			22	380		47		65				29	26

PROPOSED AGR-FG-CPF
PREMINING LAND USE
REVISED 09/04/92

PROGRAM	ACRES	140	210	220	230	310	320	330	410	420	430	560	610	620	630	640
FG-SP-13	103		1			7	37		13		35				3	7
FG-SP-14	587		4				425		82		17				10	49
FG-SP-15	606		53				335		118		16				17	67
FG-SP-16	246		4				76				132				30	4
FG-SP-17	636					121	355				2				48	110
FG-SP-18	645		87			20	434		2						17	85
FG-SP-19	60						51								7	2
FG-SPA-1	595		263		53	20	123		90		33			12		1
FG-SPA-2	442	3	113				102		91		126				4	3
FG-SRS37	73						33		10		26					4
FG-WFHC-1	544		508													36
FG-WFHC-2	854		436				43	277		9				4		85
FG-WFHC-3	731		122				279	87		169				7		67
NON-MANDATORY	1280		35			135	611		10		255				95	139
NON-DISTURBED	1889	100	66			4	147	1	147	67	136			528	402	291
	32182	103	7480	0	92	1316	9359	1035	3218	978	2628	2	14	885	1402	3670

FG-HC-2 includes acreage also included in FG-84-6 as follows:

	210	310	320
	18	2	10

FG-GSB-4 & FG-GSB-5 include acreage also included in the following programs:

	320	630	640
FG-12	146	3	37
FG-SP-19	51	7	2

****

TOTAL PREMINING LAND USE

	ACRES	140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
TOTAL	31906	103	7462	0	92	1314	9152	1035	3218	978	2628	2	14	885	1392	3631

PROPOSED AGR-FG-CPF
POSTRECLAMATION LAND USE
REVISED 08/03/92

PROGRAM	ACRES	140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
FG-1	239		200						39							
FG-2	72		12						60							
FG-3	190		150								40					
FG-5	86								86							
FG-8	24		24													
FG-9	38		8						30							
FG-10	327		114		80	115						11				7
FG-11	64		50								14					
FG-12	186		28								28	111			10	9
FG-13	366		200									16			60	90
FG-83(1)	151		127								17				7	
FG-83(2)	1190		1					744			172				88	185
FG-83(3)	117		39								10	50			2	16
FG-83(4)	8		7								1					
FG-84(1)	738		458		119	21	8				67	12			25	28
FG-84(2)	409							126			71				100	112
FG-84(3)	113					4					23	21			65	
FG-84(4)	142					47					11	63				21
FG-84(5)	398		91								48	123			46	90
FG-84(6)	330		165				9				43					113
FG-84(8)	65					22					10	22				11
FG-GSB-1	71		50								21					
FG-GSB-2	472		228						100						52	92
FG-GSB-3	479		124			7			44		57				45	202
FG-GSB-4	714		639							71	4					
FG-GSB-5	711		639							72						
FG-GSB-6	508					91	110	25		6	34			49		193
FG-GSB-7	430					71		72	146	5	19			22	38	57
FG-GSB-8	654					133	76	55		153	25			25		187
FG-GSB-9	331					280					8			4		39
FG-HC-1	172		124								16					32
FG-HC-2	669					274		55		91	2.00	110		11		126
FG-HC-3	963					252	84	42		168	49	97		33		238
FG-HC-4	716		639							77						
FG-HC-5	205					76	54			36						39
FG-HC-6	56						54									2
FG-HC-7	310						191		7	56	9			38		9
FG-HC-8	394					209	10			27	74			24		50
FG-HC-9	614		532							82						
FG-HC-10	383		3			40	29		137	28				126		20
FG-HC-11	763					360		12		88		203				100
FG-HC-12	321		9			214		9	7	29				40		13
FG-HC-13	349						182		17	149				1		
FG-HC-14	400					130	56	44	36	79				28		27
FG-PC-1	639		173			8			8		59	191		33	102	65
FG-PC-2	1437		643				293				144		15		141	201
FG-PC-3	609		71			16	199		134		41				57	91
FG-PC-4	475		231				14		22		44	123				41
FG-PC-5	336		25			207	3				52				49	
FG-SP-1	157			47	6	14			90							
FG-SP-2	56					38					7					11
FG-SP-3	105		94								11					
FG-SP-4	260		233								26				1	
FG-SP-5	131		73						8			29				21
FG-SP-6	339		146			8	37		63		14	7	9		12	43
FG-SP-7	68											16				52
FG-SP-8	555							345			38				70	102
FG-SP-9	477		287					131			46				4	9
FG-SP-11	696							517			59					120
FG-SP-12	613							444			51					118

PROPOSED AGR-FG-CPF
POSTRECLAMATION LAND USE
REVISED 08/03/92

PROGRAM	ACRES	140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
FG-SP-13	103															103
FG-SP-14	587							470			52					65
FG-SP-15	606							407			45				20	134
FG-SP-16	246							221			25					
FG-SP-17	636		444								66				29	97
FG-SP-18	645		402			43					48					152
FG-SP-19	60										49					11
FG-SPA-1	595		282				23				68	154		15		53
FG-SPA-2	442	3	146				18		31		76	123			4	41
FG-SRS37	73		65						8							
FG-WPHC-1	544		406			66				72						
FG-WPHC-2	854		9			227			292	44		199				83
FG-WPHC-3	731					167			92	73		280				119
NON-MANDATORY	1280		597			182	81		121		109				95	95
NON-DISTURBED	1889	100	66			4	147	1	147	67	136			528	402	291
	32182	103	9054	47	205	3326	1678	3720	1725	1473	2139	1961	24	977	1524	4226

FG-HC-2 includes acreage previously reclaimed in FG-84-6 as follows:

	140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
		18				10				2					

FG-GSB-4 & FG-GSB-5 include acreage previously reclaimed in the following programs:

	140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
FG-12		28								28	111			10	9
FG-SP-19										49					11

****

TOTAL POSTRECLAMATION LAND USE

LAND USE		140	210	220	230	310	320	330	410	420	430	520	610	620	630	640
TOTALS	31906	103	9008	47	205	3326	1668	3720	1725	1473	2060	1850	24	977	1514	4206

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

OCT - 9 1992

4APT-AEB

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: Tampa Electric Company, Polk County, Florida
(PSD-FL-194)

Dear Mr. Fancy:

This is to acknowledge receipt of an application for a Prevention of Significant Deterioration (PSD) permit for the above referenced facility by your letter dated August 27, 1992. Tampa Electric Company (TECO) proposes to construct a new electric generating power plant at the above referenced location. TECO's new facility will be known as the Polk Power Station. As discussed between Mr. Syed Arif of your staff and Mr. Stan Kukier of my staff on September 15, 1992, we have reviewed the application as submitted and have the following comments related to the air quality analysis:

1. In the modeling analysis, a composite five year meteorological period was used for <u>annual</u> SO_2, PM, and NO_x modeling, as well as for the quarterly lead modeling. It is suggested that the applicant review the "Guideline on Air Quality Models" which recommends annual modeling for SO_2, PM, and NO_x using five individual years of meteorological data, and quarterly modeling for lead using twenty quarters of meteorological data. Composite meteorological data sets can not be used for regulatory analysis. We suggest the source perform the annual and quarterly analyses using the individual years/quarters of meteorological data. As an alternative, the annual values for SO_2, PM, and NO_x may be taken directly from the short term modeling which has already been prepared. EPA-1

2. The ISCST2 modeling using the 1982 to 1986 meteorological data set shows modeled exceedances of the Class I 3-hour and 24-hour increments in all five years. Our review shows that only the predicted exceedances in 1986 were remodeled with the MESOPUFF II long range transport model. We recommend that the MESOPUFF II model be used to model the exceedances that were predicted with the 1982 to 1985 meteorological data. The application was not clear as to what steps would be taken to resolve any exceedance issues.

EPA-2

Thank you for the opportunity to comment on this application. If you have any questions concerning modeling or monitoring, please contact Mr. Lew Nagler of my staff at (404) 347-5014. Any other questions may be directed to Mr. Stan Kukier of my staff also at (404) 347-5014.

Sincerely yours,

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

cc: [illegible]

TAMPA ELECTRIC COMPANY
POLK POWER STATION

Responses to U.S. Environmental Protection Agency
Sufficiency Responses

EPA-1

In the modeling analysis, a composite five year meteorological period was used for <u>annual</u> SO_2, PM, and NO_x modeling, as well as for the quarterly lead modeling. It is suggested that the applicant review the "Guideline on Air Quality Models" which recommends annual modeling for SO_2, PM, and NO_x using five individual years of meteorological data, and quarterly modeling for lead using twenty quarters of meteorological data. Composite meteorological data sets can not be used for regulatory analysis. We suggest the source perform the annual and quarterly analyses using the individual years/quarters of meteorological data. As an alternative, the annual values for SO_2, PM, and NO_x may be taken directly from the short term modeling which has already been prepared.

<u>Response</u>

The modeling analyses for sulfur dioxide (SO_2) particulate matter (PM), and nitrogen oxides (NO_x) have been revised using five individual years of meteorological data, and the modeling analysis for lead has been revised using twenty quarters of meteorological data. The results of these modeling analyses are provided in the revised Section 7.0 of the PSD permit application in Appendix 11.1.3 of the Site Certification Application (SCA).

EPA-2

The ISCST2 modeling using the 1982 to 1986 meteorological data set shows modeled exceedances of the Class I 3-hour and 24-hour increments in all five years. Our review shows that only the predicted exceedances in 1986 were remodeled with the MESOPUFF II long range transport model. We recommend that the MESOPUFF II model be used to model the exceedances that were predicted with the 1982 to 1985 meteorological data. The application was not clear as to what steps would be taken to resolve any exceedance issues.

Response

The MESOPUFF II long-range transport modeling analysis has been revised using the 1982 through 1986 meteorological data. The results of this analysis are presented in the revised Section 9.0 of the PSD permit application in Appendix 11.1.3 of the SCA which is provided in conjunction with the sufficiency response documents.

PR 47.9.1

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 7, 1993

Ms. Diane K. Kiesling
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

RECEIVED JAN 1 1 1993

Re: Tampa Electric Company Polk County Project,
DOAH Case No. 92-4896EPP, PA 92-32

Dear Ms. Kiesling:

The Florida Department of Environmental Regulation has reviewed the responses for sufficiency from Tampa Electric Company (TECO) for their Polk County Site application pursuant to Section 403.5067, F.S. The Department in conjunction with reviewing agencies finds the application to still be insufficient in a number of areas. The sufficiency comments from the Department of Natural Resources are attached and incorporated herein. Polk County has obtained the consent of TECO to file their remaining insufficiency comments on January 12. The Southwest Florida Water Management District has obtained the consent of Tampa Electric Company to file their sufficiency comments at a later time in January.

The DER finds that TECO failed to adequately respond to the following comments included in our October 5, 1992 letter on sufficiency: comments #20, #36, #49, #50, #54, #63, #64, #71, #73, #75, #78, #99, #110, #115, and #116. For sake of clarification, I am attaching copies of the internal memoranda describing our concerns as Attachment A.

FDER-20, 36, 49, 50, 54, 63, 64, 71, 73, 75, 78, 99, 11[illegible], 115 AND 11[illegible]

Additionally, [the revised Figure 6.1.3-1, page 6.1.3-2 does not include the vertical dimension between the ground wire and the top conductors for the vertical configurations. It appears to scale out at approximately 16 feet. Is this the correct dimension? It is not consistent with dimensions depicted in Section 6.1-10. Please supply the design details of the neutralization tank. Will drawdown in the Floridan aquifer induce salt water intrusion?] In reference to FDER #99, please see the attached "Contingency Plan Guidance". Thank you for replacing the original copies of DER Forms 17.1202(1) signed by Mr. Autry and sealed by Thomas W. Davis. In the future, it would be desirable to have the amended areas of replacement pages highlighted by underlining or by sidebars.

FDER-A,B,C

Pursuant to Section 403.5067, F.S., the Department hereby finds that the application was not made sufficient in a timely fashion. We suggest that the time schedule for processing be modified to that shown on Attachment B to allow the agencies an adequate amount of time to review a complete and sufficient application prior to preparing the reports required by Section 403,507, F.S.

Sincerely,

Hamilton S. Oven

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

Attach:

cc: All Parties

TAMPA ELECTRIC COMPANY
POLK POWER STATION

RESPONSES TO SUFFICIENCY COMMENTS FROM
FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

FDER-20 Why the higher air flow rates for the syngas combustion scenario versus fuel oil combustion scenario for the IGCC 7F CT unit?

Reference Memorandum: David Zell, Air Permit Engineer to Michael S. Hickey, S.W. District Power Plant Siting Coordinator, December 24, 1992

Response

When the IGCC 7F CT is fired on syngas, the exhaust air flow includes, beside the inlet ambient air, the products of combustion and the nitrogen used as a diluent to control NO_x formation and for power augmentation by increasing fuel mass flow. There is no power augmentation (i.e., nitrogen addition) when the 7F CT is fired on the backup fuel oil. Section 3.1.1.2 (Pages 3.1.1-6 and 3.1.1-7) of the SCA provide a further explanation of the use of nitrogen in the unit.

FDER-36 TECO's response to our comment #36 is insufficient. Why are there higher sulfur dioxide emissions when HGCU (hot gas cleanup) and CGCU (cold gas cleanup) is used as opposed to CGCU alone. According to the site certification application, HGCU produces less sulfur dioxide emissions than CGCU. The sulfur dioxide emissions from HGCU are of particular concern, since it involves 50% of the coal gas flow.

Reference Memorandum: Mark Halverstadt, Engineer IV BAR to Buck Oven, January 4, 1993

Response

There was apparently some misinterpretation of data presented on sulfur dioxide (SO_2) emissions for cold gas cleanup (CGCU) alone versus the CGCU/hot gas cleanup (HGCU) operating scenario. The best summaries of emissions comparing the two configurations are provided in Tables 2-8 and 4-31 of the Prevention of Significant Deterioration (PSD) Application in Volume 4 of the SCA (see Pages 2-53 and 4-81, respectively). These summaries show that SO_2 emissions when using HGCU will be no greater than SO_2 emissions when operating on CGCU alone.

FDER-49 Please be advised that Rule 17-302.520(6)(b), F.A.C., refers to blowdown discharges for existing sources. Tampa Electric Company must address in detail the criteria used to calculate the 200 feet mixing zone and the effect that will cause the heated water discharge in the RWB during the worst case scenario.

<u>Reference Memorandum</u>: Yanisa G. Angulo, Industrial Waste Permitting, S.W. District to Robert K. Vanderslice, P.E., Supervisor Industrial Waste Permitting, S.W. District, December 29, 1992

<u>Response</u>

The thermal criteria used to calculate the thermal mixing zone in the receiving water body (RWB) is that the water temperature at the boundary of the thermal mixing zone will not exceed the temperature limitations specified by Rule 17-302.520(5)(b), Florida Administrative Code (F.A.C.). The criteria applied to freshwater streams and lakes in the Florida peninsula, as in the case of Polk Power Station, are described as follows:

1. For streams:
   a. The maximum temperature will not exceed 92 degrees Fahrenheit (°F), and
   b. The temperature will not exceed ambient temperature by more than 5°F.
2. For lakes:
   a. The maximum temperature will not exceed 92°F, and
   b. The water temperature will not exceed ambient temperature by more than 3°F.

The RWB is a reclaimed lake to the east of the cooling reservoir, therefore the temperature limitation for lakes in the peninsula was used as the thermal mixing zone criteria.