State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To:	Loctn.:
To: Steve Smallwood	Loctn.: Tally
To:	Loctn.:
From: Victoria Martinez	Date: 5/22/78

TO: Al Townsend, Bob Kappelmann, Steve Smallwood and Frank Darabi

FROM: J. P. Subramani

DATE: May 22, 1978

SUBJECT: Florida Power Corporation BACT application for 4 stationary gas turbines to be constructed at the Suwannee River Plant site, Suwannee County, Florida.

The above referenced source will be considered for BACT determination when the BACT rule becomes effective about June 9, 1978.

You have been selected to participate in the BACT determination for this source. Enclosed for your review and evaluation is the complete application for BACT determination.

Your responding by June 16, 1978 will be appreciated.

JPS/VM/es

Enclosure

Turbo Power TechTalk

PUBLISHED BY
TURBO POWER & MARINE SYSTEMS

Principal Contaminants

Air pollution has been a product of man's progress since his earliest days on this continent. However, this has been of little concern until the present day when suddenly the cry is to "end all pollution." Air pollution is usually the unintentional result of some activity which emits undesirable substances into the air in either one or a combination of the following physical states:

(1) liquid or solid particles capable of remaining air-borne either permanently or for significantly long periods of time, or (2) gaseous contaminants which expand and mix with the gases of the atmosphere. The diameter of contaminant particles emitted from man-made sources varies greatly in size, from about 1000 microns (near the size of raindrops), to particles substantially less than one micron.

Particulates are considered to be particles generally larger than 50 microns, at which size they settle out of the atmosphere. Aerosols are usually particulates which range in size from 50 microns to something less than 0.01 microns. Most aerosols are considered to be less than 1 micron in diameter. The gases significant in air pollution represent a wide range of organic and inorganic compounds, as shown in Figure 1.

Power generating plants have been considered to be one of the major polluters of the environment but they actually account for approximately one-eighth of the total man-made air pollution within the United States. Gas turbines now used for power generation contribute an insignificant amount of this contamination. The principal contaminants emitted from gas turbines operating on distillate fuel are unburned hydrocarbons, carbon monoxide, oxides of nitrogen, sulfur dioxide, smoke and particulates. The magnitude of emissions from gas turbines varies with the operating power of the unit. Carbon monoxide and unburned hydrocarbons are only significant at starting and at low power operation such as idle, whereas oxides of nitrogen, smoke, particulates and sulfur dioxide become more significant at peak power.

The presence of carbon monoxide and unburned hydrocarbons at low power levels is primarily due to lower combustion efficiency that might be caused by poor fuel atomization, poor mixing of fuel and air or an inadequate zone burning rate. Oxides of nitrogen (NOx) formations are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Smoke is formed by carbon generated in a rich primary combustion zone or through quenching in the secondary burning zone. Particulate matter is a function of the fuel quality being consumed. Sulfur dioxide is fixed by the sulfur content in the distillate fuel being burned.

MAJOR CLASSES OF AIR CONTAMINANTS	SUBCLASSES OF AIR CONTAMINANTS	TYPICAL MEMBERS OF SUBCLASSES
Organic Gases	Hydrocarbons	Hexane, Benzene, Ethylene, Methane, Butane, Butadiene,
	Aldehydes and Ketones	Formaldehyde, Acetone.
	Other Organics	Chlorinated Hydrocarbons, Alcohols.
Inorganic Gases	Oxides of Nitrogen	Nitrogen Dioxide, Nitric Oxide.
	Oxides of Sulfur	Sulfur Dioxide, Sulfur Trioxide.
	Carbon Monoxide	Carbon Monoxide.
	Other Inorganics	Hydrogen Sulfide, Ammonia, Chlorine.
Aerosols	Solid Particulate Matter	Dusts, Smoke, Fumes.
	Liquid Particulate	Oil Mists, Entrained Liquid Droplets.

Figure 1

Diffusion of Pollutants

After the pollutants have been released it is necessary to determine how they are transported to a measuring instrument or receptor, and in what concentrations they arrive.

When a concentrated puff of pollutant is released from a source, it tends to expand due to the dynamic action of the atmosphere, and as the same amount of pollutant is now contained in a bigger volume of air, the concentration is decreased. This process of moving from a higher to a lower concentration is the process of diffusion and is accomplished within the atmosphere mainly by two agents, the wind speed and the turbulent motion of the air. The wind speed acts directly to reduce concentration as the effluent leaves the stack, that is, doubling the wind speed will halve the concentrations. Turbulence is generated primarily by the structure of the atmospheric temperature variation with height, and wind flow over surface roughness that acts to mix the pollutant with the ambient air. Source measurements can be made at existing sites whereas a mathematical dispersion model is used to estimate concentrations for future installations.

The most widely used model represents diffusion of the plume as a two phase problem. The first phase is the initial rise of the plume by virtue of its kinetic and thermal energy. The second phase is its diffusion downwind with an assumed vertical and horizontal distribution of concentration based on statistical reasoning.

Expressions defining the concentrations of pollutants have been established by several workers; TPM utilizes formulae for dispersion estimates (under varied atmospheric conditions) that have been compiled by the Environmental Protection Agency.

Regulatory Standards

It should be noted that the EPA has not, as of this date, provided air pollution regulations specifically for gas turbines.

Some states have used the EPA steam regulations as a guideline in establishing gas turbine exhaust emission standards.

Figure 2 lists the environmental standards most well known i.e., Los Angeles Rule 67, San Diego Rule 68 and the EPA Steam Regulations.

The FT4 gas turbine emission control program being conducted by TPM has had a goal of compliance with Los Angeles County Air Pollution Control District (LACAPCD) Rule 67 under all power conditions.

Requirements

	LACAPCD Rule 67		SDAPCD Rule 68		EPA Steam Reg.	
	Gas	Liquid	Gas	Liquid	Gas	Liquid
NOx — Lb/Hr	140	140				
NOx — Lb/MBTU					0.2	0.3
NOx — PPM Corr. 3% O_2			125	225		
Smoke — Ringelmann		1.0		1.0		1.0
SO_2 — Lb/Hr 0.3% S Fuel		200		200		
SO_2 — Lb/MBTU						.8
Part. — Lb/Hr		10		10		
Part. — Lb/MBTU						0.1

Figure 2

MAXIMUM PERMISSIBLE NITROGEN OXIDE EMISSIONS

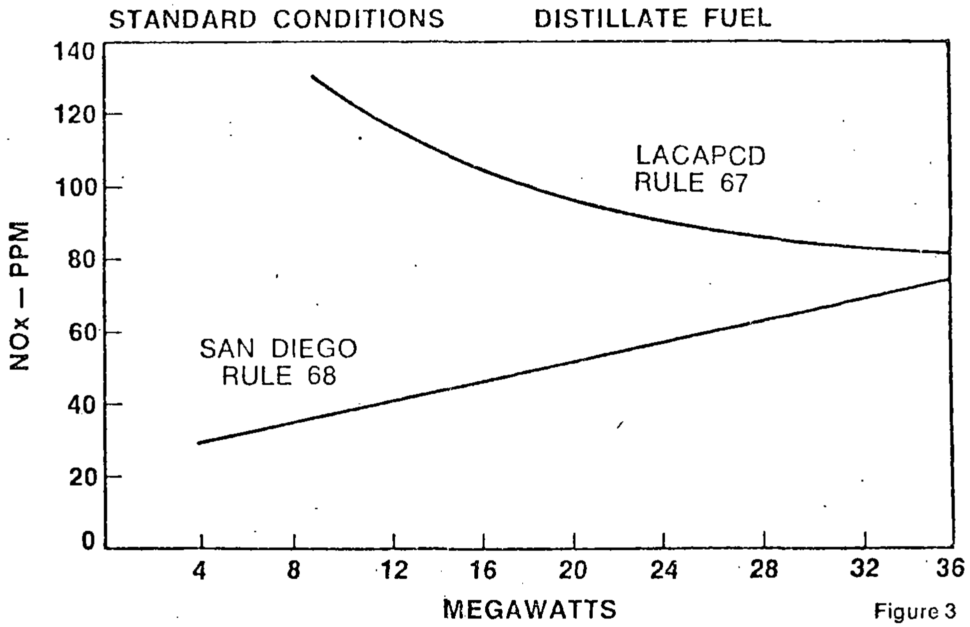


Figure 3

Figure 3 shows the maximum allowable NOx emission (in parts per million) as a function of power output for LACAPCD Rule 67 and San Diego Rule 68.

FT4 Smoke Reduction

In 1969, production was started on a smoke reduction burner can. The new burner can included the use of 1) swirl cups and vanes which surround the six fuel nozzles of each of the eight combustion chambers. Swirl is imparted to the air entering the chamber to improve fuel atomization in the fuel spray pattern; 2) nozzle nuts with tangential air cooling slots to improve fuel atomization; 3) airflow distribution into the burner charged through a series of holes in the head to lean the fuel-air ratio in the primary combustion zone. Figure 4 shows the construction of the smoke-reducing burner can.

The initial goal was to reduce the visible emission from the FT4 gas turbine to a Von Brand Reflectance level of 95 or better which is acceptable to all known air pollution codes.

FT4 SMOKE REDUCING BURNER CAN

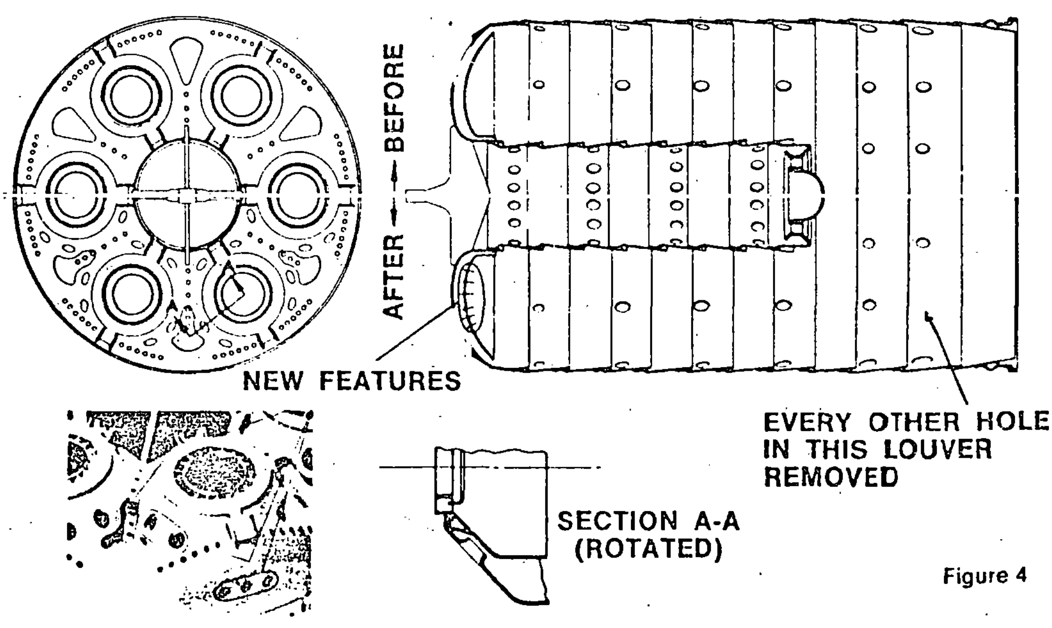


Figure 4

Von Brand Reflectance, Bacharach Smoke Number, and Ringelmann Numbers are different terms used to describe smoke from exhaust stacks. Figure 5 shows the Exhaust Smoke Measurement comparisons between Von Brand Reflectance, Bacharach and Ringelmann. Comparison of Von Brand Reflectance Numbers to visual observations is also shown.

The Von Brand Reflectance is most often used by TPM since it has been accepted by the industry as the most accurate method of determining smoke. A Von Brand instrument collects samples of particulate matter and aerosols on a continuous moving filter paper tape for subsequent analysis. Exhaust gas under test is sampled at a uniform rate by means of a probe positioned in the gas stream at a point of approximate average flow with the gas pulled thru the filter tape by means of a motor-driven pump or other vacuum source. Evaluation of the smoke stain is accomplished with a Photovolt Reflectometer which compares the reflectance of the smoke stain to a clean piece of filter tape. Clean is one hundred while a stain would read an amount less than 100.

The Bacharach Smoke Number, used by some power companies and state agencies, is obtained by drawing a specific volume of gas from the exhaust thru a spot filter over a normal period of approximately two minutes. The spot is then classified by comparing it with the Bacharach Smoke Scale which has ten standard graduated spots from 0 to 9, white to black.

EXHAUST SMOKE MEASUREMENT COMPARISONS

Von Brand Reflectance At 0.216 SCFM	Bacharach	Ringelmann	Color
100	0	0	Clear
99	1		
97	2		
94	3		
89	4		
85		1	
83	5		
75	6	2	
66	7		
60		3	
56	8		
45	9		
40		4	
20		5	Black

The following table can be used as a guide for comparing Von Brand Reflectance numbers to visual observations.

Appearance	Von Brand Reflectance Numbers
Clean Air	100
Clear — Heat Waves	95
Heat Waves with Faint Wisps	93
Slightly Visible	90
Visible Emission	85
Darker Smoke — Becoming Objectionable	80
Dark Smoke	75
Objectionable Smoke	70

Figure 5

The third method utilizes Ringelmann Numbers which are based on visual observation and is therefore quite subjective. It is expressed in degree of blackness in numbers from 0 to 5, with each number representing a 20% difference in opacity from clean to black. Here again interpolation can be made between numbers. This method has been used extensively by federal and state air pollution control agencies.

TPM is currently conducting a program to reduce further the smoke emission level of FT4 engines while burning distillate fuel by improving the fuel nozzles. This includes the use of aerating nozzles that atomize the fuel through the use of turbine compressor air introduced into the fuel spray at the nozzle outlet.

It is anticipated that these improved nozzles, which will be available in 1973 production gas turbines, will meet all known regulations. The expected smoke level will exceed Ringelmann No. 0.5 or Von Brand Reflectance No. 95. It should also be noted that the type of fuel used affects the smoke level as illustrated by Figure 6.

Sulphur Oxides

Sulphur oxides in exhaust gases, (chiefly sulphur dioxide, SO_2, with a trace of sulphur trioxide, SO_3), result from oxidation of essentially all of the sulphur in the fuel being burned. The higher the sulphur content, the more SOx produced. The high temperatures and flows encountered in gas turbine exhausts make SO_2 removal impractical. The only economical way to limit SO_2 is through the use of low sulphur content fuels.

SO_2 in sufficient concentration is known to be irritating to eyes and skin and is purported to contribute to respiratory disorders. There is some disagreement among experts as to whether SO_2 is harmful or beneficial to plant life over a long term.

Because of the irritating effects on humans, regulatory agencies will be increasingly vigilant in measuring SO_2 levels in the ambient air. In order to minimize the ambient concentrations, the EPA has established SO_2 limits for steam power plants of 0.8 pounds per million BTU of fuel input. Most gas turbine liquid fuels contain less than 0.5% sulphur, which will produce less than 0.5 pounds per million BTU SO_2.

SO_2 can be measured by one of several batch sampling systems, such as the "West-Goeke" method, which uses a self-contained automatic chemical process to determine and read out SO_2 concentrations.

EFFECT OF FUEL TYPE ON SMOKE LEVELS — FT4C ENGINE

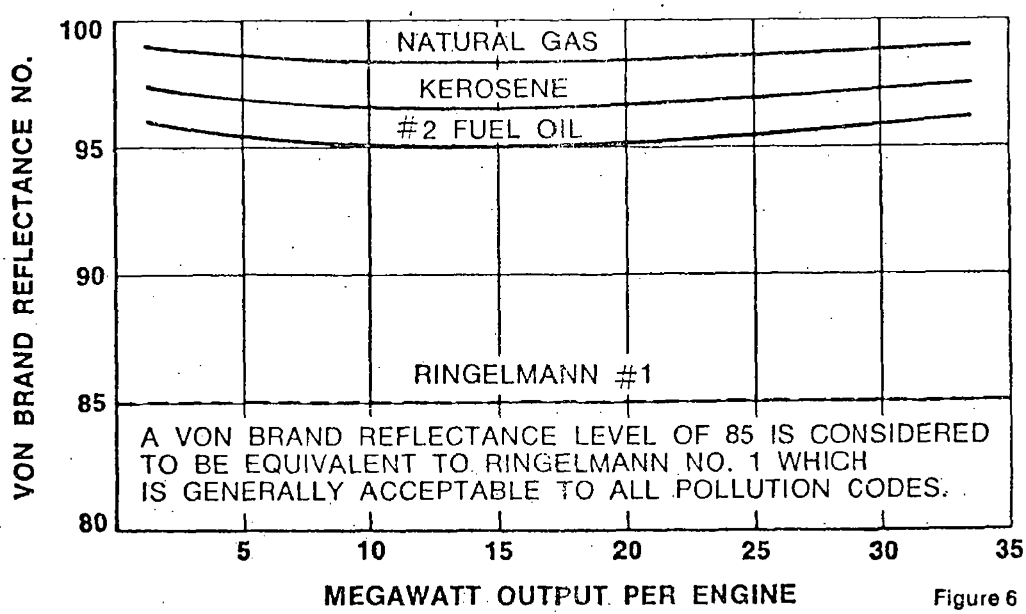


Figure 6

Particulates

Exhaust particulates are generally defined as any solids or condensibles, other than water, in the exhaust stream. In gas turbines burning liquid fuel, particulate emissions usually consist of dirt carried in by the inlet air; metallic ash from fuel contaminants; carbon from incomplete combustion; and condensible sulphur compounds, mostly H_2SO_3. The particle size and quantity will vary with air and fuel quality.

Gas exhaust particulates can be reduced by filtering the gas turbine inlet air, and by using fuels with low metal and sulphur levels. Further reduction is possible through improved combustor design to minimize unburned hydrocarbons.

Both LACAPCD Rule 67 and SDAPCD Rule 68 limit particulate emission to 10 pounds per hour. The EPA guidelines for steam plants, which many states are applying to all stationary power plants, has a limit of 0.1 pounds per million BTU of energy input. TPM FT4 gas turbines currently in service produce particulate levels of approximately 0.09 lb/MBTU.

Particulates are normally measured by taking a sample of the gas by means of a vacuum probe, passing it through either liquid baths or dry filter pads, and weighing the residue.

Oxides of Nitrogen

Combustion research has shown that oxides of nitrogen (NOx) levels are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Factors controlling the final NOx emission levels are:

1. Temperature in both the combustion reaction and dilution zones.
2. Residence times in both zones.
3. Mixing of fuel, air and combustion products.
4. Fuel vaporization.
5. Combustor inlet temperature and pressure.

It has been demonstrated that slow mixing, in conjunction with rich or heterogeneous mixtures, leads to high combustion temperatures and therefore high NOx levels.

A NOx reduction program was initiated for the FT4 gas turbine in early 1971 with a goal to meet the requirements of LACAPCD Rule 67.

A three-prong approach was used in order to accomplish this goal. This included 1) burner rig tests to verify burner design for obtaining the desired emission reduction, 2) flame rig tests for applied research in determining combustion characteristics, and 3) mathematical models or analytical prediction for burner modifications.

It was determined that water or steam injected directly into the primary zone of combustion served to reduce the flame temperature and promote mixing. Burner rig tests confirmed this reduction (Figure 7).

FT4 BURNER RIG RESULTS WITH WATER INJECTION

WATER OR STEAM / FUEL RATIO = 1

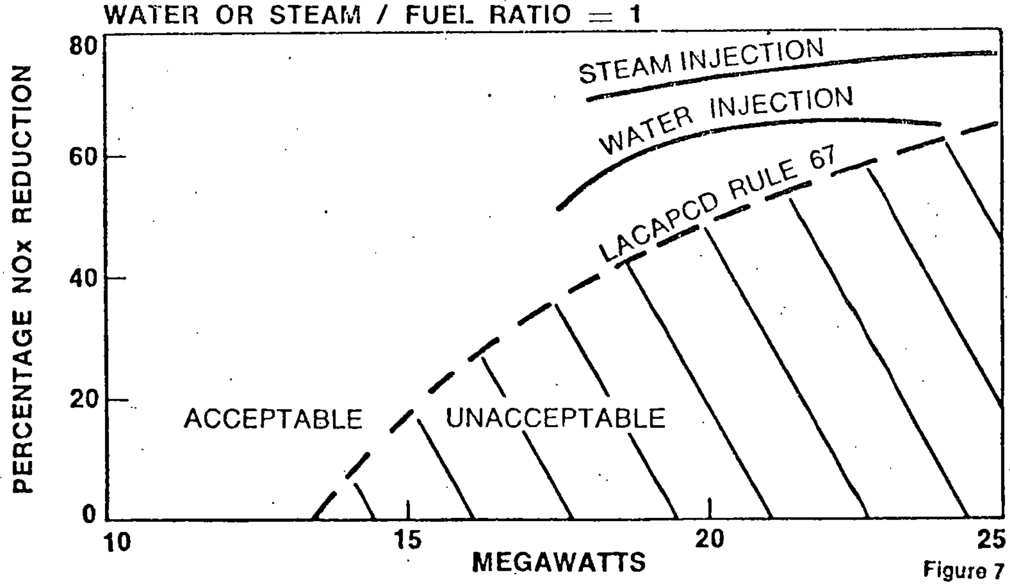


Figure 7

The test results showed a 65% NOx reduction while injecting water into the chamber and a 75% reduction while injecting steam. Steam injection was found to be more effective in reducing NOx than water injection on a pound for pound basis, in spite of the greater potential thermal effect of water. The latent heat of vaporization of water is not fully realized because of poor mixing and the slow vaporization rate of the water relative to fuel vaporization and combustion times.

The fact that water injection reduced NOx emission from gas turbines was further confirmed through full scale engine testing at a TPM field installation in southern California burning natural gas. The water flow rates were varied, NOx reductions were recorded, and the results are plotted in Figure 8.

Probing within a standard combustion chamber determined temperature and NOx formation in the can at various stations along its axis. Figure 9 shows the temperatures and NOx measured across the chamber in the primary flame zone. This supports the theory that NOx formation is primarily a function of temperature and residence time. Fifty percent of NOx formation occurred within 0.5 milliseconds after combustion and production was terminated by 3 milliseconds. Probing the same combustion chamber with steam injected into the primary zone shows a reduction of peak temperatures as shown in Figure 10. NOx levels were significantly reduced by steam injection since the peak temperatures were reduced below the level required for high NOx formation.

H_2O INJECTION

ENGINE DEMONSTRATED REDUCTION

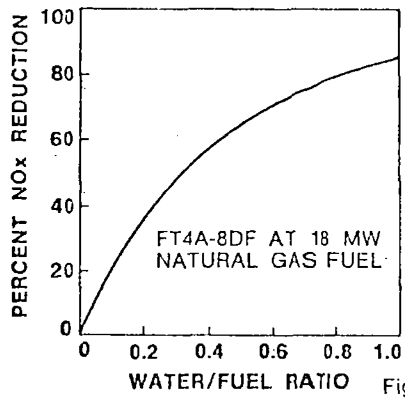


Figure 8

FT4 BURNER CAN TEMPERATURE & NOx TRAVERSE

EIGHT INCHES DOWNSTREAM OF NOZZLE

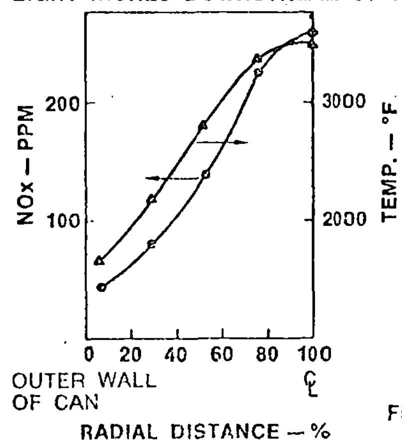


Figure 9

FT4 BURNER CAN TEMPERATURE & NOx TRAVERSE

EIGHT INCHES DOWNSTREAM OF NOZZLE
STEAM INJECTION — 1.4 LBS / LBS FUEL

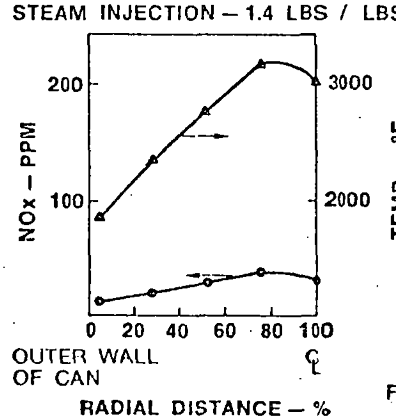


Figure 10

FT4 BURNER RIG NEW COMBUSTION PROGRAM RESULTS

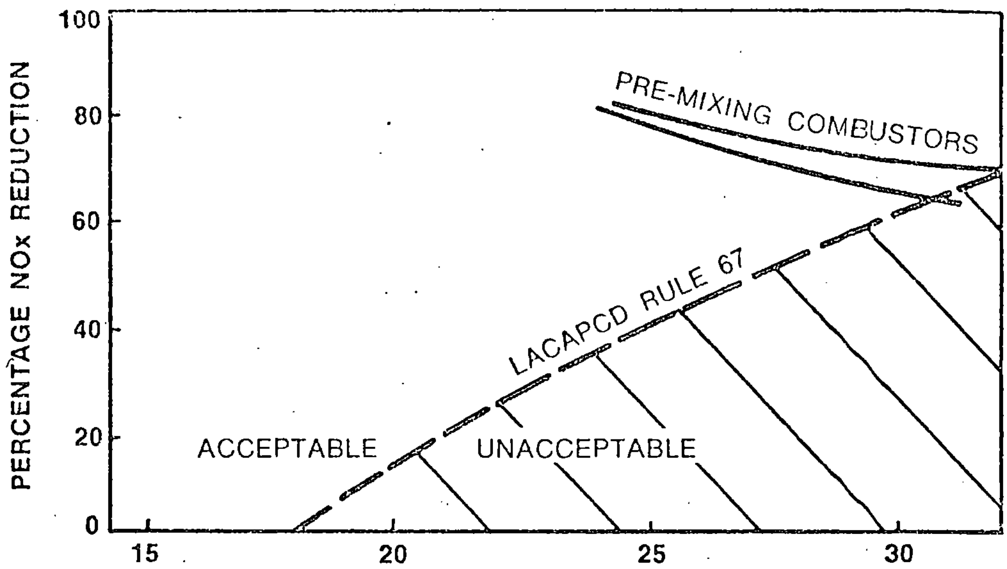


Figure 11

To eliminate the requirement for water or steam injection a new approach is being investigated through premixing and prevaporizing the fuel prior to combustion. Combustion rig tests using these techniques shown in Figure 11 have demonstrated that NOx emission levels are substantially below Rule 67 requirements. This "dry fix" enables the utility to meet existing and anticipated NOx requirements and at the same time retain the gas turbine remote siting capability by precluding the need for a major demineralized water or steam source. Plans are being implemented to make "dry fix" burner cans available in 1974 production engines.

Conversion Equations

Sometimes it is convenient to express NOx exhaust emissions in parts per million (ppm), pounds per hour (#/Hr.) or pounds per million BTU (#/10⁶BTU). The three equations shown in Figure 12 may be useful.

To find NOx (ppm)

$$\text{NOx (ppm)} = \frac{\text{NOx (\#/Hr)}}{\text{Wg (\#/Hr)}} \times \frac{\text{MOL WT AIR}}{\text{MOL WT NOx}} =$$

$$\frac{\text{NOx (\#/}10^6\text{BTU)}}{\text{Wg (\#/Hr)}} \times \frac{\text{HR (BTU/KwHr)}}{10^6} \times \text{OUTPUT (Kw)} \times \frac{\text{MOL WT Air}}{\text{MOL WT NOx}}$$

To find NOx (#/Hr)

$$\text{NOx (\#/Hr)} = \text{NOx (ppm)} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \text{Wg (\#/Hr)} =$$

$$\frac{\text{NOx }\left(\frac{\#}{10^6\text{BTU}}\right) \times \text{HR (BTU/KwHr)} \times \text{OUTPUT (Kw)}}{10^6}$$

To find NOx (#/10⁶BTU)

$$\text{NOx (\#/}10^6\text{BTU)} = \frac{\text{NOx (\#/Hr)} \times 10^6}{\text{Hr (BTU/KwHr)} \times \text{OUTPUT (Kw)}} =$$

$$\frac{\text{NOx (ppm)}}{\text{Hr (BTU/KwHr)}} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \frac{\text{Wg (\#/Hr)} \times 10^6}{\text{OUTPUT (Kw)}}$$

NOx is calculated as NO_2, Mol Wt = 46; Mol Wt Air = 29

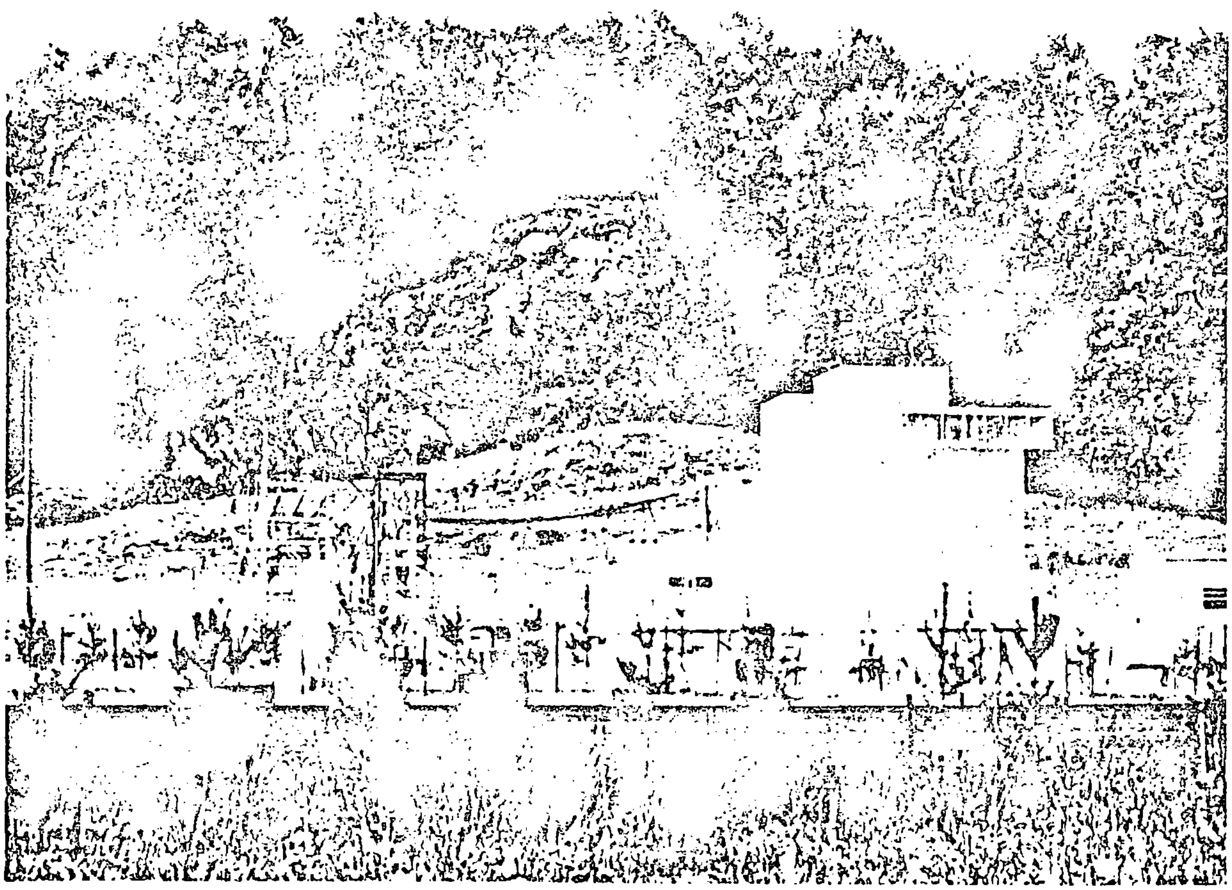
Figure 12

Summary

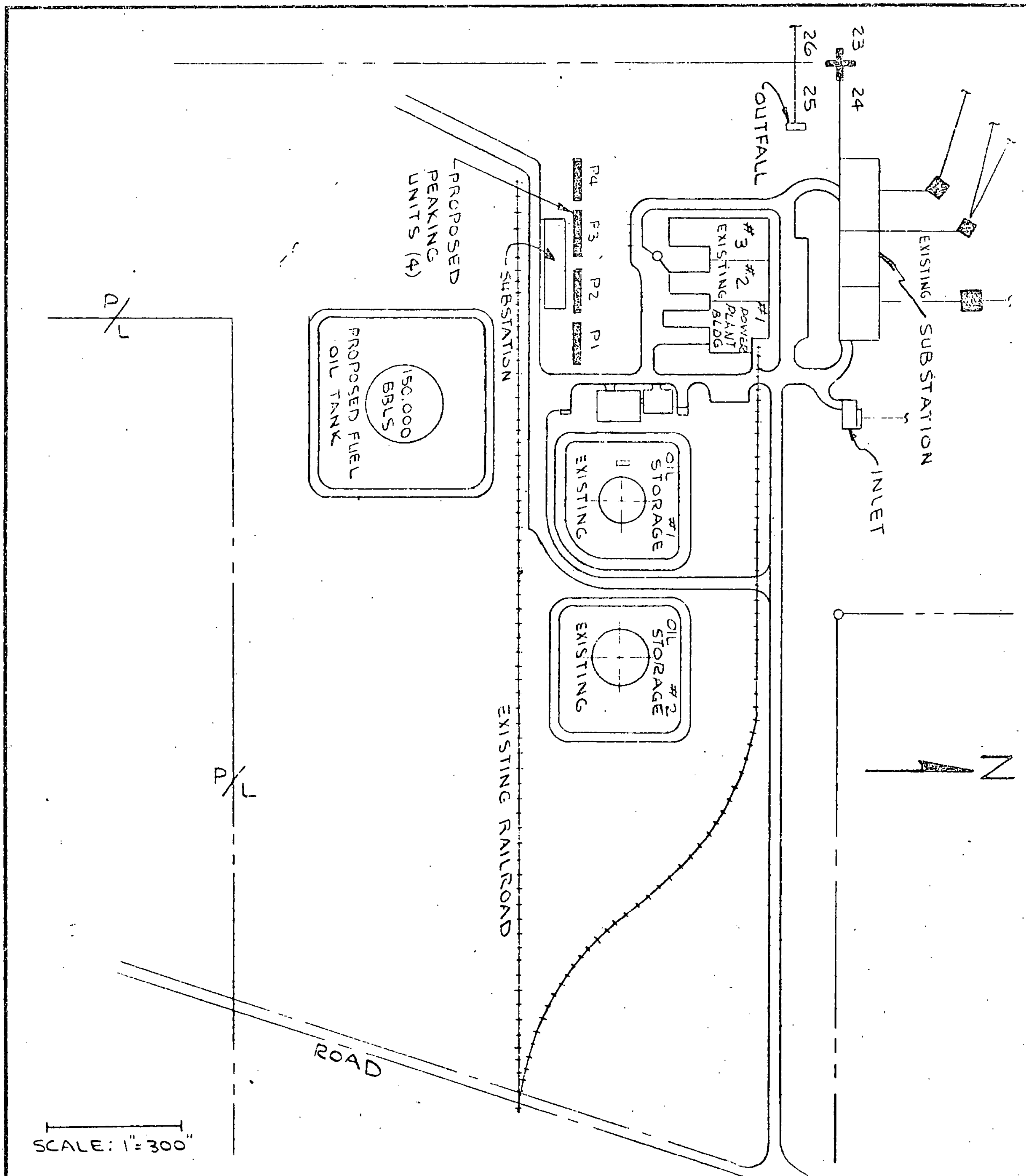
TPM recognizes the importance of clean air and will continue its intensive emission reduction program to keep abreast of and meet federal, state, and local regulatory standards. Actual rig and engine tests have demonstrated that the FT4C-1 engine can limit NOx emissions to meet known regulations by using water injection, steam injection, or the "dry fix".

The water or steam injection systems require provision of a demineralized water or steam source which is an added item of cost in most installations. Although TPM is prepared to provide such systems where they make economic sense, the "dry fix" approach appears to be the more desirable. The "dry fix" burner cans enable the customers to meet known NOx emission requirements without additional equipment or expense. This is particularly important in areas where water is scarce or unavailable. A demineralized water or steam source, which must be available for combined cycle plants, does not become a necessity for a TPM simple cycle gas turbine unit. This offers the customer maximum equipment selection flexibility when considering a TPM installation.

Typical TPM simple-cycle FT4 Twin Pac installation.



FLORIDA POWER CORPORATION
SYSTEM ENGINEERING DEPARTMENT

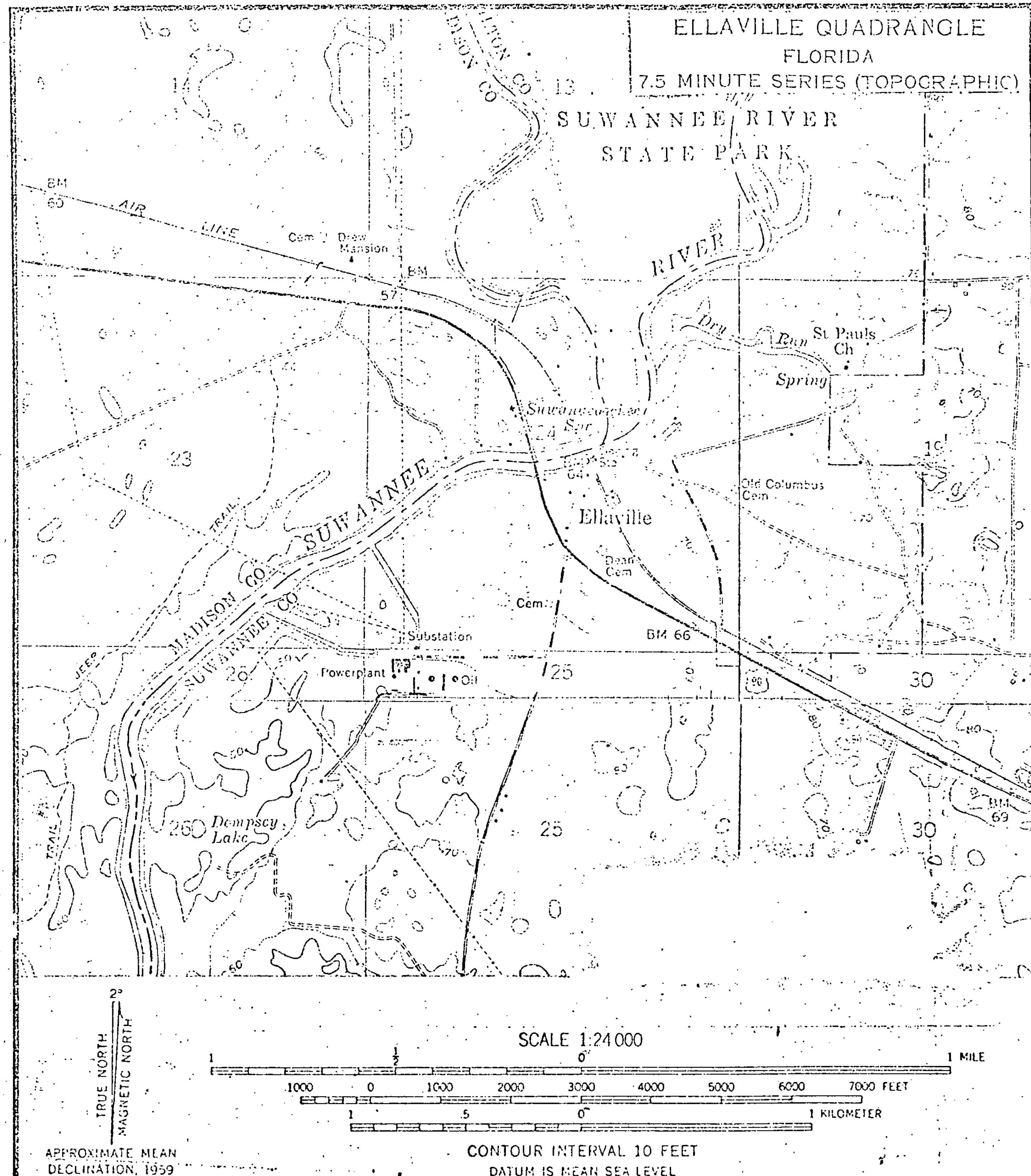


REVISIONS		
NO.	DATE	

SITE PLAN FOR
PROPOSED SUWANNEE
RIVER PEAKERS

DRAWN BY MWP
DATE 2-2-78
CHECKED
APPROVED R O [illegible]
SCALE 1" = 300'

SRP-L1-A-0



NO.	DATE	REVISION	BY	CK.	APP.

DATE 2-2-78 SCALE AS NOTED BY MWP CK. [illegible] APP. [illegible]

GENERAL AREA LOCATION MAP

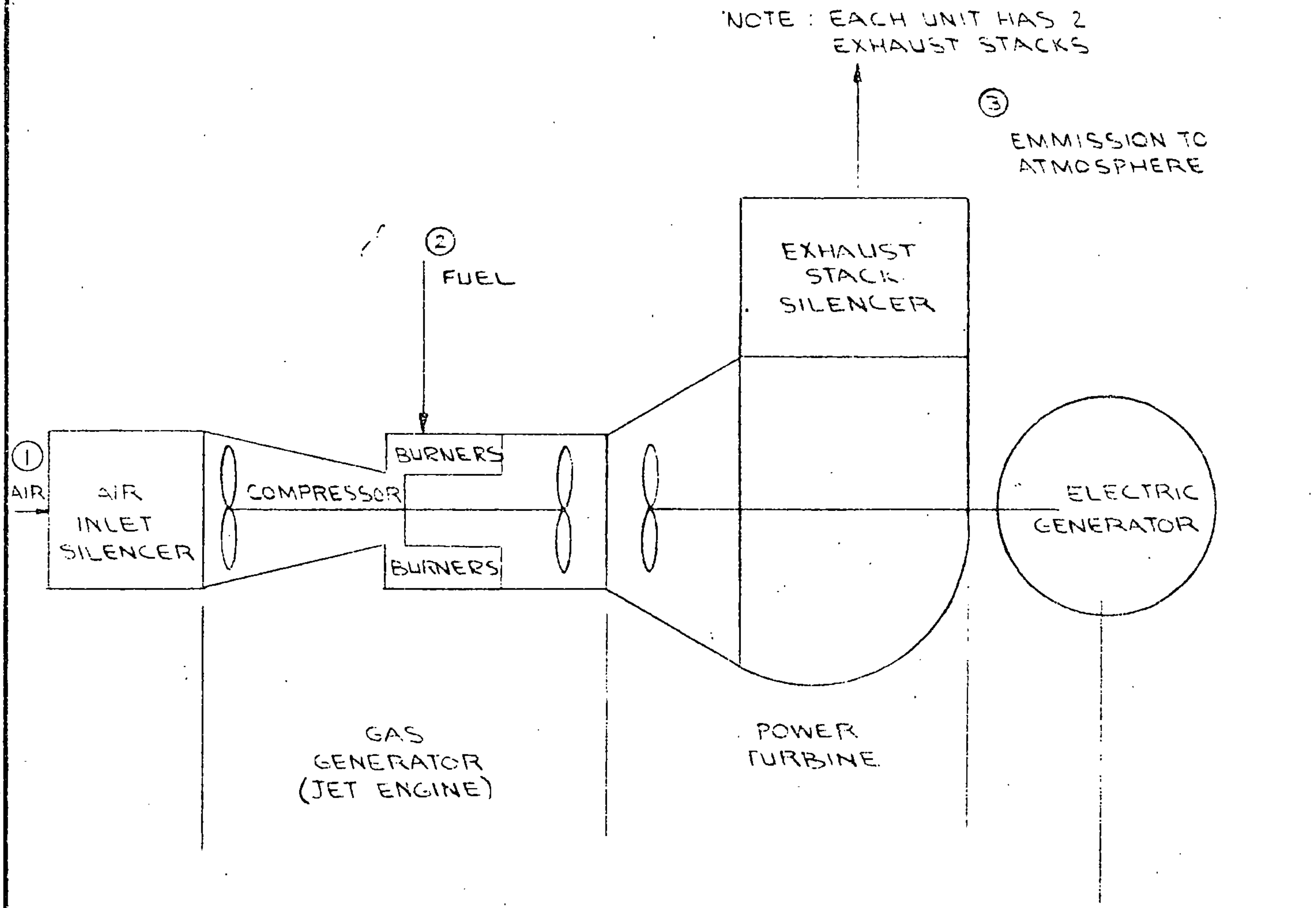
PROJECT SUWANNEE R. GAS TURB. UNITS

FLORIDA POWER CORPORATION
ST. PETERSBURG, FLORIDA

DRAWING NO. SRP-L2 -A-O

FLORIDA POWER CORPORATION

SYSTEM ENGINEERING DEPARTMENT



NOTE : EACH UNIT CONSISTS OF 1 ELECTRIC GENERATOR AND 2 JET ENGINES

NOTE : UNIT IS SYMETRICAL ABOUT ℄

REVISIONS			
NO	DATE		
		FLOW DIAGRAM SUWANNEE RIVER PEAKERS	DRAWN BY [signature] DATE 2/6/75 CHECKED APPROVED SCALE
			DWG. NO. SRP-L3-A-O

Unit P-1

ST. JOHNS RIVER
RECEIVED
MAY 12 1978
SUB DISTRICT
GAINESVILLE BRANCH

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION FOR DETERMINATION OF BEST

AVAILABLE CONTROL TECHNOLOGY FOR AIR POLLUTION SOURCES

SOURCE STATUS: (X) New ( ) Modification

Company Name: FLORIDA POWER CORPORATION County: Suwannee

Source Identification: Suwannee River Plant Peaking Unit Addition

Source Location: Street: Suwannee River Plant Site City: ______

UTM: East: 503,673 North: 2,415,157 (coordinates of existing center stack)

Appl. Name and Title: J. T. Rodgers, Assistant Vice President

Appl. Address: P. O. Box 14042, St. Petersburg, FL 33733

Appl. Phone: 813/866-4765

DEPARTMENT USE ONLY

Date Appl. Received: ______

Notice of Receipt:

Newspaper: ______ Date: ______

Florida Administrative Weekly Date: ______

BACT Determination: ______

Declared by Secretary: ______ Date: ______

BACT: ______

NOTICE OF DETERMINATION

Newspaper: ______ Date: ______

Florida Administrative Weekly Date: ______

NOTE: All data is for one (1) gas turbine unit operating at a peak load of 63,000 MW at an ambient temperature of 59°F.

I. DETAILED DESCRIPTION OF SOURCE

A. Describe The Manufacturing Process at the Facility and the Unit Operation to be Controlled. Discuss the Source of Emissions, Existing Control Devices, the Expected Improvement in Performance, With Ambient Ambient Air Quality Standards or Applicable PSD Increments. Attach Additional Sheet If Necessary.

See attached Exhibit A

B. For This Source Indicate Any Previous DER Permits, Order and Notices; Including Issuance Dates and Expiration Dates.
None

C. Raw Materials, Fuels, and Chemicals Used:

DESCRIPTION	HOURLY USE	CONTAMINANT TYPE	%WT.	RELATION TO FLOW DIAGRAM
Distillate Fuel Oil	37,910#/hr	Ash	0.1% Max	(2)
		Sulfur	0.5% Max	
Air	2,196,000#/hr			(1)

D. Process Rate

1. Total Process Input Rate: 2,235,000#/hr (Air and Fuel)
2. Produce Output Rate: 2,235,000#/hr (Exhaust Gas)
3. Operation Time: 1,500 Hrs/yr

a. XXXXXXXXXX b. XXXXXXXXX c. XXXXXXXXXX

d. Seansons: Operate daytime and early evenings to supply power during periods of high system electrical load for a range of 4 hours per run and during emergency conditions.

II. BEST AVAILABLE CONTROL TECHNOLOGY DATA

A. Emission Limitations For Any Pollutants Emitted From The Source Pursuant To 17-2, F.A.C.?

Yes (X) No ( ) FOR CLASS II AREA MAXIMUM ALLOWABLE INCREASE IN CONCENTRATIONS

CONTAMINANT	RATE OR CONCENTRATION
Particulate	Annual geometric mean: 19 ug/m^3 24 hr max 37 ug/m^3
SO_X as SO_2	Annual arithmetric mean: 20 ug/m^3 24 hr max: 91 ug/m^3 3 hr max: 512 ug/m^3
NO_X as NO_2	-------
HC as (H_4)	--------
CO	--------
Visible emissions & opacity	Less than 20%

B. Are Standards Of Performance For New Stationary Sources Pursuant To 40 C.F.R. Part 60 Applicable To The Source?

Yes ( ) No (X) However standards are proposed for SO_X and NO_X see below and footnote.

CONTAMINANT	RATE OR CONCENTRATION
Particulate	*Not Applicable
SO_X as SO_2	*150 ppm by volume
NO_X as NO_2	** 75 ppm by volume STD (Allowable emission)
HC as (H_4)	*Not Applicable
CO	*Not Applicable

C. Has EPA Declared The Best Available Control Technology For This Class Of Sources? (If Yes Attach Copy)

Yes ( ) No (X)

CONTAMINANT	RATE OR CONCENTRATION

*Reference is made to page 53783, Selection of Pollutants, Federal Register, Vol. 42, No. 191, Monday, October 3, 1977.

**The actual NO_X Emission Rate is adjusted according to the requirements on Page 53789 of the above referenced Federal Register.

D. What Emission Levels Do You Propose As Best Available Control Technology? Also see D continued at bottom of page.

CONTAMINANT	(ACTUAL ESTIMATED EMISSIONS) RATE OR CONCENTRATION Lbs/Hr	T/Yr
Particulate	38	28.5
SO_X as SO_2	379	284
NO_X as NO_2	250	187.5
HC as (H_4)	9	6.75
CO	86	64.5

E. Describe The Existing Control and Treatment Technology (If Any) N/A

1. Control Device:

2. Operating Principles:

3. Efficiency*:

4. Capital Costs:

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

CONTAMINANT	RATE OR CONCENTRATION Before Device	After Device

10. Stack Parameters

a. Height: Ft.

b. Diameter: Ft.

c. Flow Rate: ACFM

d. Temperature: °F

e. Velocity: FPS

D. (Continued)

CONTAMINATE	RATE OR CONCENTRATION
SO_X as SO_2	95 ppm by volume
NO_X as NO_2	**75 ppm by volume STD (Allowable Emission)
Opacity	Less than 20%

F. Describe The Control and Treatment Technology Available (As Many Types As Applicable Use Additional Pages If Necessary)

1. NO_2 Control and Treatment Technology (Wet Method) See Exhibit B

a. Control Device:

b. Operating Principles:

c. Efficiency: (See Footnote)

d. Capital Cost: $945,000.

e. Life: 20 years

f. Operating Cost: $759,000 per year

g. *Energy: 375,000 KWHR

h. Maintenance Cost: Significant information is presently unavailable to determine maintenance Cost

i. Availability of Construction Material and Process Chemicals: Equipment is available and demineralized water will be used for the control process

j. Applicability to Manufacturing Processes:
The control strategy is well adapted to the process and is currently available

k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels:
The plant site has adequate space to install the necessary water treatment and storage facility for the NO_x control.

2. NO_2 Control and Treatment Technology (Dry Method) See Exhibit B

a. Control Device:

b. Operating Principles:

c. Efficiency:

d. Capital Cost:

e. Life:

f. Operating Cost:

g. Energy:

h. Maintenance Cost:

Insufficient information is available from manufacturers on dry NO_x control to complete this section, since the equipment is not commercially available at the present time. The Company cannot indicate that dry NO_x control is a practical control method at the present time. However, the Company is leaving the option open in that this control methodology may be demonstrated soon by manufacturer's test programs.

i. Availability of Construction Materials and Process Chemicals:

j. Applicability to Manufacturing Processes:

k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels;

* Energy to be Reported in Units of Electrical Power - KWH Design Rate.

F. 1. (c) Efficiency: Description of NO_x control will be in accordance with specifications of a particular manufacturer. Use of steam is not contemplated since boilers will not be installed on site. Water injection will be used with expected efficiency - adequate to reduce the NO_x emission level to 75 ppm by volume (Standard) (Allowable Emission)**

3. SO_2 Control and Treatment Technology

a. Control Device: Distillate fuel will not exceed .5% sulfur by weight

b. Operating Principles:

c. Efficiency: (See Footnote Below)

d. Capital Cost: The capital cost is lower when using distillate fuel when compared to a higher sulfur less expensive fuel.

e. Life:

f. Operating Cost:

g. Energy:

h. Maintenance Cost:

i. Availability of Construction Materials and Process Chemicals:

j. Applicability to Manufacturing Processes:

The control strategy is well suited to the process.

k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels: It is anticipated that no difficulties will be realized in acquiring the low sulfur fuel to meet the aforementioned control technology for SO_2. Appropriate contract(s) would be secured subsequent to acquiring all necessary governmental licensing for the project.

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:

d. Capital Cost:

e. Life:

f. Operating Cost:

g. Energy:

h. Maintenance Cost:

i. Availability of Construction Materials and Process Chemicals:

j. Applicability to Manufacturing Processes:

k. Ability to Construct with Control Device, Install in Available Space, and Operate within Proposed Levels:

3 (c). Efficiency: For peaking unit installations, low sulfur distillate fuel is normally used to provide maximum reliability. There is no feasible control device for removing SO_2 from a combustion turbine exhaust gas when high sulfur fuel is used. (High sulfur fuel is defined as that with a sulfur content over 0.8% which would exceed the EPA proposed emission limits).

G. Describe the Control Technology Selected: SO_2 Control will be Distillate Fuel Oil, NO_X Control: Wet or Dry Method. See Para. 10, REASONS FOR SELECTION AND DESCRIPTION OF SYSTEMS and attached Exhibit B. Also refer to F1, 2, & 3 on the preceding two pages.

1. Control Device:
2. Efficiency:
3. Capital Cost:
4. Life:
5. Operating Cost:
6. Energy:
7. Maintenance Cost:
8. Manufacturer: General Electric Co., Westinghouse Corp., Brown Boveri, United Technologies.
9. Other locations Where Employed on Similar Processes: Presently is not employed at any FPC facility

a.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

b.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

c.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

d.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

d. (7) Emissions: (continued)

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

c.

(1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

10. Reason For Selection and Description of Systems: NO_X Control - recommendation from manufacturer to be requested in Specs. Methodology available Wet & Dry Method, See Exhibit B. Specifications will require compliance with Federal and State regulations on NO_X Control.
SO_2 Control - Fuel - Reason: Only existing feasible control technology available for SO_2.

11. Emissions:

CONTAMINANT	ACTUAL ESTIMATED MAXIMUM DISCHARGE RATE OR CONCENTRATION Lbs/Hr	T/Hr
Particulate	38	28.5
SO_X as SO_2	379	284
NO_X as NO_2	250	187.5
HC as (H_4)	9	6.75
CO	86	64.5

12. Stack Parameters:**

a. HEIGHT: 22 Ft. Minimum

b. Cross sectional area 130 sq. ft. (Rectangular)

c. Gas Flow Rate: 1,255,500 ACFM

d. Gas Exit Temperature: 726°F to 800°F

e. Velocity: 153 FPS

** Depending on the selection of a manufacturer, there will be one or two stacks per unit.

13. Fuels:

TYPE	HOURLY USE* AVG.	HOURLY USE* MAX.	HOURLY HEAT INPUT MILLION BTU/HR. AVG.	HOURLY HEAT INPUT MILLION BTU/HR. MAX.
Distillate Fuel Oil	Varies	37,910	Varies	739 X 10^6 BTU/Hr.

NOTE; Fuel consumption will vary with load and ambient temperature. The consumption listed is for one (1) gas turbine unit operating at peak load at 59°F ambient temperature.

TYPE	DENSITY	%S Maximum by % Weight	%N	%ASH Maximum
Distillate Fuel Oil	6.8 Lb/Gal	0.5%		0.1%

*Gaseous Cu. Ft./Hr. Liquid & Solid: Lbs./Hr.

14. Wates Generated, Disposal Method, Cost of Disposal; Waste water due to water demineralization plant may be disposed of in existing percolation pond. Appropriate licensing will be acquired from the DER if wet method of NO_x Control is choosen.

H. Discuss the Social Impact of the Selected Technology Versus Other Applicable Technologies. (i.e. Jobs, Payroll, Production, Taxes, Energy, Etc.)
Include Assessment of the Environmental Impact of the Sources

Social Impacts: See Exhibit C

Environmental Impacts: See Exhibit D

III. ADDITIONAL ATTACHED INFORMATION.

A. Show Derivation of Total Process Input Rate and Product Weight.

B. Show Derivation of Efficiency Estimation. See B below.

C. An 8½"x 11" Flow Diagram Which Will, Without Revealing Trade Secrets, Identify the Individual Operations and/or Processes. Indicate Where Raw Materials Enter, Where Solid and Liquid Waste Exist, Where Gaseous Emissions and/or Airborne Particles Are Evolved and Where Finished Products Are Obtained.
See Dwg. No. SRP-L3-A-0

D. An 8½"x 11" Plot Plan Showing the Exact Location of Manufacturing Processes and Outlets for Airborne Emissions. Relate All Flows to the Flow Diagram.
See Dwg. No. SRP-L1-A-0

E. An 8½"x 11" Plot Plan Showing the Exact Location of the Establishment, and Points of Airborne Emissions In Relation to the Surrounding Area, Residences and Other Permanent Structures and Roadways.
See Dwg. No. SRP-L2-A-0

F. Attach All Scientific, Engineering, and Technical Material, Reports, Publications, Journals, and Other Competent Relevant Information Describing the Theory and Appplication of the Requested Best Available Control Technology.

B. Heat Rate 11,734 BTU/KW-HR. (Higher Heating Value)

1 KW - HR = 3413 BTU

$$\frac{3413}{11{,}734} = 29\%$$