DAVID MCNEAL 404/562 9095

David - Attached are pages from GE paper "GE Heavy-Duty Gas Turbine Performance Characteristics" by F. J. Brooks, GE Power Systems, Schenectady NY. 1996.

It states evaporative cooling is limited to 59°F and above. It is good to have a "literature source". I would stick to the 50°F that I cited earlier.

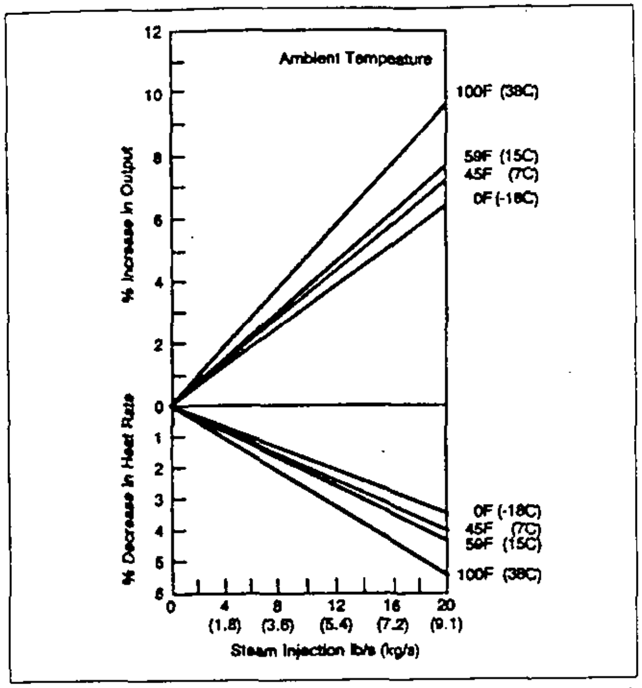
It is possible that for other applications (i.e. air conditioning in buildings) there may be a different practical limit. In any case I think I've now fully addressed this one.

Thanks

Al

Post-it® Fax Note 7671	Date 6/11	# of pages ▶ 3
To D. McNeal	From Al Linero	
Co./Dept.	Co. DEP-Air	
Phone #	Phone #	
Fax #	Fax #	

A. Linero 6/11



GT22047C

Figure 13. Effect of steam injection on output and heat rate

than that obtained on natural gas. In the case of higher heating value fuels, such as refinery gases, output and efficiency may be equal to or lower than that obtained on natural gas.

Dilutent Injection

Since the early 1970s, GE has used water or steam injection for NO_x control to meet applicable state and federal regulations. This is accomplished by admitting water or steam in the cap area or "head-end" of the combustion liner. Each machine and combustor configuration has limits on water or steam injection levels to protect the combustion system and turbine section. Depending on the amount of water or steam injection needed to achieve the desired NO_x level, output will increase because of the additional mass flow. Figure 13 shows the effect of steam injection on output and heat rate for an MS7001EA. These curves assume that steam is free to the gas turbine cycle, therefore heat rate improves. Since it takes more fuel to raise water to combustor conditions than steam, water injection does not provide an improvement in heat rate.

AIR EXTRACTION

In some gas turbine applications, it may be desirable to extract air from the compressor. Generally, up to 5% of the compressor airflow can be extracted from the compressor discharge casing without modification to casings or on-base piping. Pressure and air temperature will depend on the type of machine and site conditions. Air extraction between 6% and 20% may be possible, depending on the machine and combustor configuration, with some modifications to the casings, piping and controls. Such applications need to be reviewed on a case-by-case basis. Air extractions above 20% will require extensive modification to the turbine casing and unit configuration. Figure 14 shows the effect of air extraction on output and heat rate. As a "rule of thumb," every 1% in air extraction results in a 2% loss in power.

PERFORMANCE ENHANCEMENTS

Generally, controlling some of the factors that affect gas turbine performance is not possible. Most are determined by the planned site location and the plant configuration, i.e., simple- or combined-cycle. In the event additional output is needed, several possibilities to enhance performance may be considered.

Inlet Cooling

The ambient effect curve (Figure 8) clearly shows that turbine output and heat rate are improved as compressor inlet temperature decreases. Lowering the compressor inlet temperature can be accomplished by installing an

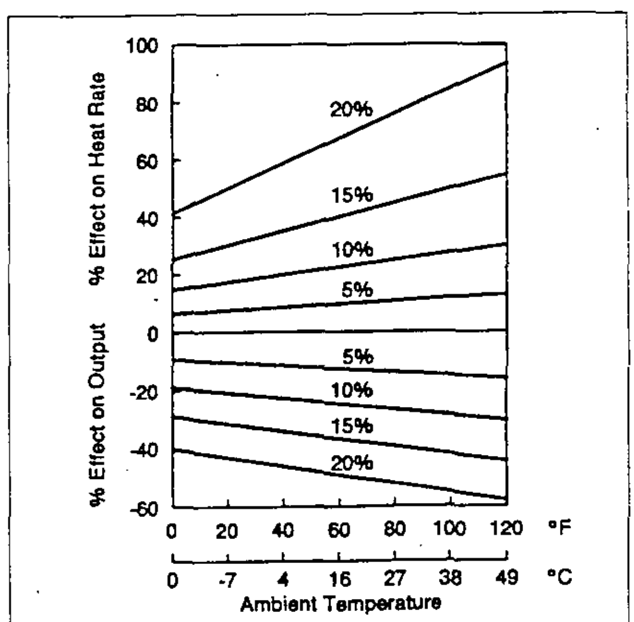


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Figure 14. Effect of air extraction on output and heat rate

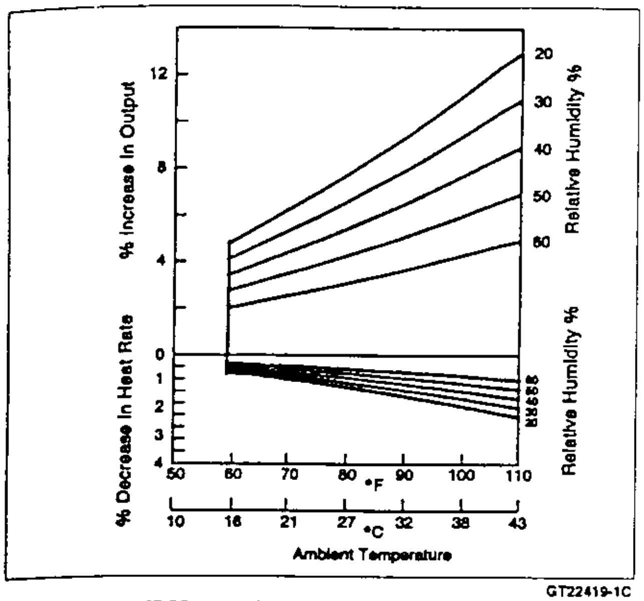


Figure 15. Effect of evaporative cooling on output and heat rate

evaporative cooler or inlet chiller in the inlet ducting downstream of the inlet filters. Careful application of these systems is necessary, as condensation or carryover of water can exacerbate compressor fouling and degrade performance. Generally, such systems are followed by moisture separators or coalescing pads to reduce the possibility of moisture carryover.

As Figure 15 shows, the biggest gains from evaporative cooling are realized in hot, low-humidity climates. It should be noted, from Figure 15, that evaporative cooling is limited to ambient temperatures of 59 F/15 C and above because of the potential for icing the compressor. Information contained in Figure 15 is based on an 85% effective evaporative cooler. Effectiveness is a measure of how close the cooler exit temperature approaches the ambient wet bulb temperature. For most applications, coolers having an effectiveness of 85% or 90% provide the most economic benefit.

Chillers, unlike evaporative coolers, are not limited by the ambient wet bulb temperature. The achievable temperature is limited only by the capacity of the chilling device to produce coolant and the ability of the coils to transfer heat. Cooling initially follows a line of constant specific humidity (Figure 16). As saturation is approached, water begins to condense from the air, and mist eliminators are used. Further heat transfer cools the condensate and air, and causes more condensation. Because of the relatively high heat of vaporization of water, most of the cooling energy in this regime goes to condensation and little to temperature reduction.

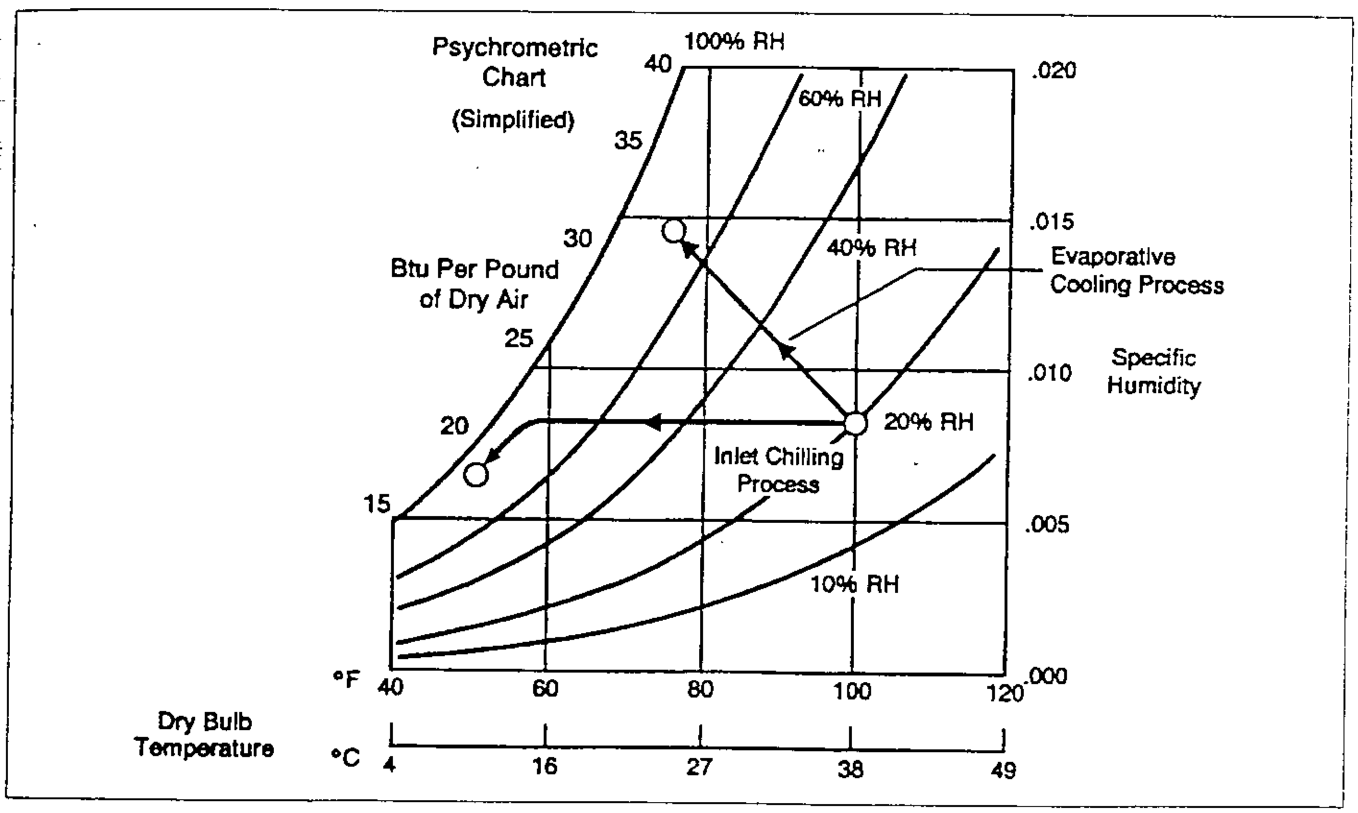


Figure 16. Inlet chilling process

4 pages

1/4

DAVID MC NEAL

David – I can't find my good articles. I think I loaned them to Marty Costello and he is in training.

Here is a decent article from Caldwell who supply the systems. According to Don Shepherd of Caldwell, the combustion turbine manufacturers advise against operating coolers below about 50 °F to avoid icing.

At very low temperatures, it might even be necessary to heat inlet air. So the heat input / temperature curve shouldn't change and emissions will still be at maximum under naturally-occuring low temp conditions.

Feel free to contact Shepherd at 502/964-6450.

If I find something better, I'll send it to you. Otherwise I'll have to pull out the psychometric chart and develop the information myself. Attached chart seems to show ranges for evaporative and indirect cooling.

In summary, the obvious gains are from high temp / low humidity conditions. There is nothing to gain at low temperature except to cause operating problems.

Thanks Al

2/4

CALDWELL ENERGY & ENVIRONMENTAL, INC.

4020 Tower Rd • Louisville, KY 40232
(502) 964-6450 • Fax: (502) 964-7444 • mail@caldwellenergy.com

POWERFog

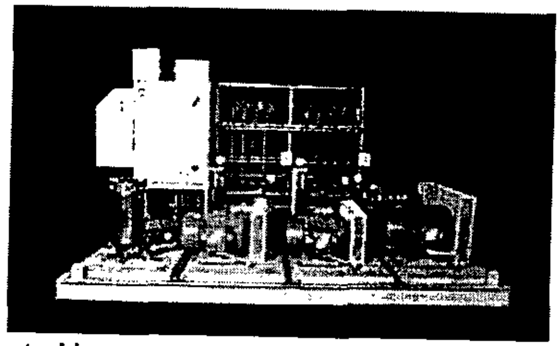
I'll try to get something that talks about lower practical limit and will send it to you. AL

Evaporative cooling has taken a revolutionary step...POWERFog. Traditional methods of cooling combustion turbine inlet air involved using uncontrolled amounts of water sprayed over wetted media. Now, injecting carefully regulated amounts of micron sized droplets into the inlet air of your combustion turbine(s) allows even more power to be generated. POWERFog systems can cool the air down to the saturation temperature of the ambient air without creating a power limiting pressure drop.

POWERFog systems cool atmospheric air from the dry bulb temperature all the way down to the wet bulb temperature. The drier the air, the more cooling can be achieved. You might think that these systems would not be effective in humid climates, but this is not true. While the dry bulb temperature increases as the sun moves higher in the sky, the wet bulb temperature stays relatively constant. This means that the greatest amount of cooling is achieved right when you need it most, during the hottest part of the day. At a design point of 95°F(35°C)/50% Relative Humidity (RH), a typical combustion turbine will realize about a six percent (6%) increase in power. In a dry hot climate, a 100°F(38°C)/20% RH condition will yield about an eleven percent (11%) increase. These systems are by far, the least expensive means to improve your plants performance. A typical simple payback is less than one year. Installation takes only a few days, and can frequently be done while your turbine is on-line.

System Design

All systems should be sized based on historical weather data for your plant's location. CE&E maintains a database of five years of hourly weather data for 262 stations around the country. Our advanced modeling system optimizes each CTIAC system relative to your technical and economic requirements. For each system there is an optimal design point which will maximize your return on investment in the system.



Performance Engineered Combustion Turbine Inlet Air Cooling

One of the most cost-effective ways to increase combustion turbine power output in high temperature ambient conditions is to reduce the air temperature by evaporating water into the turbine's inlet air. This denser air increases the mass flow to the turbine and since combustion turbines rely on this mass flow for power, output of the combustion turbine is significantly increased. On a 90°F day, with 20% relative humidity, inlet air temperature can be reduced to 63°F simply by evaporating water into the turbine's air stream. For the majority of combustion turbine types, this means a 9% increase in power output. The illustration above shows how a POWERFog system can improve your Combustion Turbine(s) performance.

Traditional methods of evaporating water into the inlet air use media blocks and de-misters that increase the pressure drop, and there for reduce the power output capability of combustion turbines. These systems also require a significant amount of annual maintenance.

A more efficient way to evaporate water into the inlet air stream is to use a device that creates a "fog" of micron sized droplets of water. These droplets can be made so small that they can achieve more evaporative efficiency than traditional evaporative coolers. Inlet pressure drop across the system typically cannot even be measured by plant instrumentation. Caldwell Energy will engineer and guarantee the superior performance of a POWERFog system over media type evaporative coolers.

3/4

Caldwell Energy engineered the POWERFog HP system specifically for combustion turbine applications. This Combustion Turbine Inlet Air Cooling (CTIAC) system uses Caldwell Energy's proprietary high pressure nozzle design which maximizes evaporative efficiency and hence the power output of the combustion turbine. Custom engineered advanced control system logic, combined with multiple nozzle arrays, are all designed to optimize the system's performance. Special features provide for safe system operation.

The POWERFog HP nozzle creates a fog by spraying a high pressure water jet at an impaction pin directly in front of the ejected water stream. Water pressure can vary, typically between 1,000 and 3,500 pounds per square inch depending on the required droplet size. A drawing of the POWERFog HP nozzle is illustrated in Figure 2. Increased pressure reduces the size of the droplets. The key to determining the system design is the residence time of the water droplets in the inlet air, prior to the cooled air entering the compressor of the combustion turbine. This defines the required droplet size.

Fogging systems cool inlet air down to the wet bulb temperature of the ambient. This makes it highly effective in dry climates but also effective in more humid ones. Fogging systems in humid climates are still economical since the hottest periods of a day coincide with the periods of lowest relative humidity. Figure 3 illustrates the temperature and humidity distribution for a hot, sunny, and humid day. Note that the wet bulb temperature remains relatively constant.

In the case where the residence time of the fog prior to entry into compressor section of the combustion turbine is short, high pressure systems may not ensure complete evaporation. To address this condition, Caldwell Energy developed the POWERFog US system. This system produces smaller droplets, a fraction of the diameter of high pressure systems. These smaller droplets allow for faster evaporation.

Internally mounted POWERFog systems can be installed during a 2-4 day outage while you are doing your turbine inspection. Externally mounted POWERFog systems can normally be installed while the combustion turbine is running.

Caldwell Energy engineers, designs, manufactures, and installs all types of Combustion Turbine Inlet Air Cooling (CTIAC) systems, including fogging, chilling, refrigeration, and thermal energy storage systems. Let us give you the complete cooling picture today.

POWERFog POWERChill POWERStor

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I'm sure this is impossible to real, I'll review ASHRAE book if I can find one. 4/4

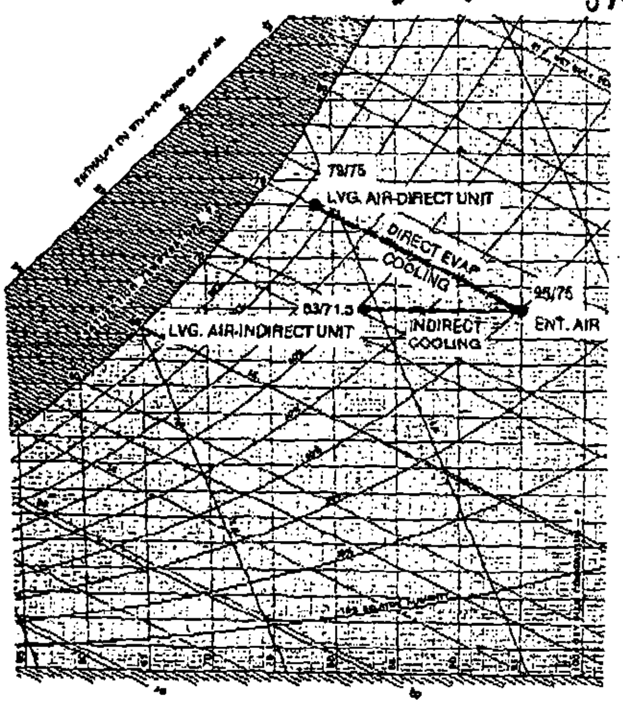

Fig. 1 Psychrometrics of Evaporative Cooling

The performance of an indirect evaporative cooling system can also be shown on a psychrometric chart. Many manufacturers of indirect evaporative cooling equipment use a similar definition of effectiveness as is used for a direct evaporative cooler. The term performance factor (PF) is also used. In indirect evaporative cooling, the cooling process in the primary airstream follows a line of constant moisture content (constant dew point). Performance factor (or effectiveness) is the dry-bulb depression in the primary airstream divided by the difference between the entering dry-bulb temperature of the primary airstream and the entering wet-bulb temperature of the secondary air. Depending on the heat exchanger design and relative air quantities of primary and secondary air, effectiveness ratings may be as high as 85%.

Continuing the example, assuming an effectiveness of 60%, and assuming both primary air and secondary air enter the apparatus at the outdoor condition of 95°F db and 75°F wb, the dry-bulb depression is 0.60 (95 − 75) = 12°F. The dry-bulb temperature leaving the indirect evaporative cooling process is 95 − 12 = 83°F. Because the process cools without adding moisture, the wet-bulb temperature is also reduced. Plotting on the psychrometric chart shows that the final wet-bulb temperature is 71.5°F. Because both the wet- and the dry-bulb temperatures in the indirect evaporative cooling process are reduced, indirect evaporative cooling can be used as a substitute for a portion of the refrigeration load in many applications.

Humidification

Air can be humidified with an evaporative cooler by three methods: (1) using recirculated water without prior treatment of the air, (2) preheating the air and treating it with recirculated water, or (3) using heated water. In any evaporative cooler installation, the air should not enter with a wet-bulb temperature of less than 39°F; otherwise, the water may freeze.

Recirculated Spray Water

Except for both the small amount of outside energy added by the recirculating pump in the form of shaft work and the small amount of heat leakage into the apparatus from outside (including through the pump and its connecting piping), evaporative cooling is strictly adiabatic. Evaporation occurs from the recirculated liquid. Its temperature should adjust to the thermodynamic wet-bulb temperature of the entering air.

The whole airstream is not brought to complete saturation, but its state point should move along a line of constant thermodynamic wet-bulb temperature. The extent to which the leaving air temperature approaches the thermodynamic wet-bulb temperature of the entering air is expressed by a saturation effectiveness ratio, often called the humidifying effectiveness in humidifiers. The representative saturation, or humidifying effectiveness, of a spray-type air washer with various spray arrangements is listed in Table 1.

The degree of saturation depends on the extent of the contact between air and water. Other conditions being equal, a low-velocity airflow is conducive to higher humidifying effectiveness.

Table 1 Effectiveness of Spray Arrangements in a Spray-Type Air Washer

Bank	Arrangement	Length, ft	Effectiveness, %
1	Downstream	4	50 to 60
1	Downstream	6	60 to 75
1	Upstream	6	65 to 80
2	Downstream	8 to 10	80 to 90
2	Opposing	8 to 10	85 to 95
2	Upstream	8 to 10	90 to 98

Preheating Air

Preheating the air increases both the dry- and wet-bulb temperatures and lowers the relative humidity, but it does not alter the humidity ratio (i.e., the mass ratio of water vapor to dry air). At a higher wet-bulb temperature, but with the same humidity ratio, more water can be absorbed per unit mass of dry air in passing through the evaporative cooler (if the humidifying effectiveness of the evaporative cooler is not adversely affected by operation at the higher wet-bulb temperature). The analysis of the process that occurs in the evaporative cooler is the same as that for recirculated water. The final preferred conditions are achieved by adjusting the amount of preheating to give the required wet-bulb temperature at the entrance to the evaporative cooler.

Heated Recirculated Water

Even if heat is added to the recirculated water, the mixing in the evaporative cooler may still be regarded as adiabatic. The state point of the mixture should move toward the specific enthalpy of the heated water. By elevating the water temperature, it is possible to raise the air temperature (both dry and wet bulb) above the dry-bulb temperature of the entering air.

The relative humidity of the leaving air may be controlled by (1) bypassing some of the air around the evaporative cooler and remixing the two airstreams downstream or (2) automatically reducing the number of operating spray nozzles or sections of media wetted by operating valves in the different recycle header branches.

Dehumidification and Cooling

Evaporative coolers are also used to cool and dehumidify air. Heat and moisture removed from the air raise the water temperature. If the entering water temperature is below the entering wet-bulb temperature, both the dry- and wet-bulb temperatures are lowered. Dehumidification results if the leaving water temperature is below the entering dew-point temperature. Moreover, the final water temperature is determined by the sensible and latent heat pickup and the amount of water circulated. However, this final temperature must not exceed the final required dew point, with one or two degrees below dew point being common.

4020 Tower Road
Louisville, Kentucky
Phone: 502-964-6450
Fax: 502-964-7444

CALDWELL ENERGY & ENVIRONMENTAL, INC.

Fax

Company: | From: Don Shepherd
Attn: Al Legre
Fax: 850-922-6979 | Pages(Including Cover): 2
Phone: | Date: 6/10/97
Re: | CC:
EVAP-Cooling

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Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

May 6, 1999

9737572-0100

Mr. C.H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Attention: Ms. Teresa Heron

RE: Inlet Foggers – Putnam Plant Combustion Turbines DEP File 1070014-003-AC
Inlet Foggers – Martin Plant Combustion Turbines DEP File 0850001-005-AC
Florida Power & Light Company (FPL)

Dear Teresa:

This correspondence is submitted to address the Department's information request related to the installation of direct water spray fogging system to the inlet of the Putnam and Martin combustion turbines. The information requested is presented below and in the attachments to this correspondence.

1. Information Requested: Please submit additional data to support the statement that the emission rate does not change as a result of inlet fogging.

   Information Submitted: As discussed in the application, the use of the direct water spray fogging systems will increase the relative humidity of the gas stream while concomitantly reducing the temperature due to adiabatic cooling of the inlet air. This effect is no different than when the turbine is operated under the same ambient conditions that occurs during the normal course of operation in any year. However, it allows the turbine to operate under such ambient conditions more frequently and thus can effect annual emissions. The influence on the emission rate of increasing the relative humidity and temperature is explained in EPA's Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines (EPA-453/R-93-007, January 1993). In Section 4.2.1.3 the report provides information that indicates emissions of NO_x decrease with increasing relative humidity. Also, the mass emission of NO_x decreases per mass of fuel input. This is also the same as lower emissions per amount electric power generated (since power and fuel input are directly related). The lower NO_x emissions with increasing relative humidity and lower temperature can be shown using the equation in Section 4.2.1.3; the adjustment equation in 40 C.F.R. Part 60 Subpart GG, Section 60.335(c)(1).

Table 1 presents calculation of relative NO_x concentrations for various temperatures and relative humidity. As can be seen from the table the relative NO_x concentration decreases with increasing humidity and decreasing temperature. The combined effect can be seen in the last column. Please find attached relevant pages from the EPA cited document. This EPA information is supported by the results of the testing performed at the Putnam Plant that indicated no change in emission rate (concentration) when the fogging system was used. These data also demonstrated no statistical change in CO concentrations as well.

The potential applicability of New Source Performance Standards (NSPS) Subpart GG to the Putnam turbines would be dependant on whether the installation of a fogging system is considered a modification under Section 60.14 of 40 C.F.R. 60. (Note: The NSPS already apply to the Martin turbines; these turbines meet lower emission levels as BACT.) The determination is based on whether a physical change resulted in an increase in the emission rate that is expressed in kilograms per hour. The emission rate can be determined using AP-42, materials balance, CEMs or manual stack tests [see paragraphs (1) and (2) of Section 60.14]. The tests must conducted under representative performance of the facility and that all operating which can effect emissions must be held constant to the maximum degree feasible. As described above, the inlet foggers only changes the ambient conditions that do occur during the normal operation of the turbine. Testing under the requirement to maintain all operating which may effect emissions (i.e., in this case temperature and relative humidity) constant would produce the same result. Thus, the short-term emission rates do not change. Nonetheless, the fogging system does increase the long-term emissions for which a limit on the operation of the fogging system has been requested to keep the increase below the PSD significant emission rate.

2. Information Requested: In reference to Table 1 and 2. (Part II of the Supporting Information), indicate the nominal values for power out, heat rate and heat input.

Information Submitted: The information presented in Table 1 presents the *rate of change* of power, heat rate and heat input for the turbine. The basis of the information is the attached performance curves. As noted from the curves the performance (fuel input and power) is a linear function of inlet temperature. The primary purpose of using the performance curves is to determine the increase in heat rate as a function of temperature. This was determined from the performance curves as 4 mmBtu per °F for Putnam and as 4.7 mmBtu per °F shown in Table 1. Note that the Putnam calculations have been updated to reflect as 4 mmBtu per °F rather than 3 mmBtu per °F in the original submittal. This was then used with the hours of operation to calculate the tons per year. An example for Putnam: 4 mmBtu / °F x 0.44 lb/mmBtu x 8 °F/hour x 1,280 hours x 1 ton/2,000 lb = 9.01 tons/year for NO_x. As noted in the application, AP-42 emission factors were used which for NO_x are from 17 to 25 percent higher than the actual observed emissions. The 4 mmBtu / °F was determined from the performance curves as follows: At 50 °F the heat input is 1,100 mmBtu/hr based on high heating value (HHV). At 100 °F, the heat input is 900 mmBtu/hr (HHV). The difference is 200 mmBtu/hr (1,100 –

900) over 41 °F (100 – 59) or 4 mmBtu / °F. For oil firing the rate was determined to be 3.2 mmBtu / °F using the same procedure.

An example for Martin: 4.7 mmBtu / °F x 0.09 lb/mmBtu x 5.5 °F/hour x 6,240 hours x 1 ton/2,000 lb = 7.26 tons/year for NO_x. The Martin emission rates, as noted in Tables 1 and 2, are based on maximum potential rate in the PSD permit. For NO_x, the maximum emission rate is 177 lb/hour at maximum heat input of 1,966 mmBtu/hr which is 0.09 mmBtu/hr (177/1,966). The 4.7 mmBtu / °F was determined from the heat rate curves as follows: At 60 °F the heat input is 1,550 mmBtu/hr based on high heating value (HHV). At 90 °F, the heat input is 1,690 mmBtu/hr (HHV). The difference is 140 mmBtu/hr (1,690 – 1,550) over 30 °F (90 – 60) or 4.66 mmBtu / °F; this value was rounded to 4.7 mmBtu / °F. This rate was used for both gas and oil firing.

3. Information Requested: Submit the heat input curves for these units.

   Information Submitted: The heat input curves for the Martin Units are attached. The heat input curves for the Putnam Plant are attached.

4. Information Requested: Estimate actual emissions for each facility's turbines and worst case emission rate scenario.

   Information Submitted: The actual emission for each facility is presented in the Annual Operating Report (these will be forwarded separately). As noted in the information supplied in Item 2 above, the emission estimates are based the maximum potential emission rate based on either AP-42 in the case of Putnam and the PSD permit in the case of Martin. Since the requested is based on an incremental increase in annual emissions using the maximum potential emission rates and a maximum amount of fogging (°F-hours per year), the worst case emission estimate is presented in the application.

5. Information Requested: Submit hours of operation for each turbine.

   Information Submitted: The AOR contain the hours of operation.

Your prompt review of the application is appreciated. If there are any further questions, please call.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal
Professional Engineer No. 14996

SEAL

KFK/jkk

Enclosures

cc: Rich Piper, Repowering Licensing Manager
Robert Bergstrom, Putnam Plant General Manager
John Lindsay, Martin Plant General Manager
Bob Burgess, FPL
Jay Blum, FPL

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Table 1a Emission Estimates of the Putnam Facility Combined Cycle Combustion Turbines with Inlet Air Cooling System with Direct Water Spray Inlet Fogging (Natural Gas Combustion).

Performance Basis			
Temperature Decrease	°F (1)	8	
Power Increase		3.28%	PPN Charts
Heat Rate Decrease		1.06%	Westinghouse
Heat Input Increase		2.22%	
Heat Input Change	mmBtu/ °F	4	
Hours/year		1280 (2)	
Hours-°F/year		10,240	hours/year times temperature decrease

Pollutants	Units	Emissions (3)	Comments
PM	lb/MMBtu	0.0168	AP-42 Section 3.1
	TPY	0.34	per machine
NO_x	lb/MMBtu	0.44	AP-42 Section 3.1
	TPY	9.01	per machine
SO_2	lb/MMBtu	0.00286	1 grain/100 cf natural gas
	TPY	0.06	per machine
CO	lb/MMBtu	0.11	AP-42 Section 3.1
	TPY	2.25	per machine
VOC	lb/MMBtu	0.024	AP-42 Section 3.1
	TPY	0.49	per machine

Legend - TPY: tons per year

(1) Temperature decrease is annual average temperature differential of ambient temperature to compressor inlet temperature utilizing inlet fogger.

(2) Hours of fogger operation based on estimate of 8 hours per day and 160 days per year. .

(3) Emission factor references - Title V Permit No. 1070014-001-AV, PPSC PA 74-0, EPA AP-42 Emission Factors Section 3.1 "Stationary Gas Turbines".

Table 2a Emission Estimates of the Putnam Facility Combined Cycle Combustion Turbines with Inlet Air Cooling System with Direct Water Spray Inlet Fogging (No. 2 Fuel Oil Combustion).

Performance Basis			
Temperature Decrease	°F (1)	8	
Power Increase		3.28%	PPN Charts
Heat Rate Decrease		1.06%	Westinghouse
Heat Input Increase		2.22%	
Heat Input Change	mmBtu/ °F	3.2	
Hours/year		100 (2)	
Hours-°F/year		800	hours/year times temperature decrease

Pollutants	Units	Emissions (3)	Comments
PM	lb/MMBtu	0.0293	AP-42 Section 3.1
	TPY	0.04	per machine
NO_x	lb/MMBtu	0.698	AP-42 Section 3.1
	TPY	0.89	per machine
SO_2	lb/MMBtu	0.7	Based on Title V Permit
	TPY	0.90	per machine
CO	lb/MMBtu	0.048	AP-42 Section 3.1
	TPY	0.06	per machine
VOC	lb/MMBtu	0.017	AP-42 Section 3.1
	TPY	0.02	per machine

Legend - TPY: tons per year

(1) Temperature decrease isannual average temperature differential of ambient temperature to compressor inlet temperature utilizing inlet fogger.

(2) Hours of fogger operation.

(3) Emission factor references - Title V Permit No. 1070014-001-AV, PPSC PA 74-01, EPA AP-42 Emission Factors Section 3.1 "Stationary Gas Turbines".

Part II

Application for Air Permit
Installation of Direct Water Spray Fogging Systems
Putnam Plant

Introduction

Florida Power & Light Company is proposing to install direct water spray fogging systems in the inlet ducts of the existing 4 combustion turbines in combined cycle configuration at the Putnam Plant. The purpose of the inlet foggers to provide adiabatic inlet air cooling which increase turbine output and decreases heat rate. The project is part of increasing capacity in a cost effective manner.

Description

The direct inlet fogging systems achieve adiabatic cooling using water to form fine droplets (fog). The fog is produced by injection grids placed in the turbine inlet duct that use nozzles that produce a fine spray. The small fog particles (about 10 to 20 microns) extract the latent heat of vaporization from the gas stream when the water droplet is converted to gas. Heat is removed at a rate of 1,075 Btu/lb of water. The result of the fogging is a cooler more moisture laden air stream. Figure 1 presents a schematic of a typical fogging system.

The amount of heat removed is highly dependent upon the ambient air conditions. The two most important parameters are the dry bulb temperature and relative humidity. As moisture is added to the inlet air by the fogging, the vaporization of the fog droplets cools the air toward the wet-bulb temperature. For the proposed project, the design condition is 95°F and 50 percent relative humidity. The resultant wet bulb temperature, based on psychrometric charts is 79°F. At 100 percent saturation the inlet cooling system would result in a 16°F decrease of the turbine inlet air.

While adiabatic cooling is most efficient for dry climates, adiabatic cooling in Florida can be an effective means of inlet air cooling during the late morning to evening hours. This period is typically 8 to 10 hours per day from about 10 am to 8 pm. In the early morning hours and evening hours, the typical relatively humidity in Florida is 70 to 90 percent depending on the climatic conditions. Because of the highly variable nature of ambient air conditions, the annual average inlet cooling was assumed to be 8°F. This average was reviewed against a 30 year record of meteorological data for Jacksonville and found to be representative of the range in conditions that occur over an annual period. This includes cooling associated with the typical mid-afternoon summer days and early morning/evening periods that occur year-round. The typical mid-afternoon cooling for Jacksonville would be 14°F and would occur in July with a mid-afternoon temperature of 91°F and 58 percent relative humidity. During January, the mid-afternoon cooling would be about 7°F. The typical cooling that would occur in the early morning hours of evening hours with temperatures of about 80°F and a relative humidity of 80 percent would be 5°F. This cooling also assumes that the gas stream can be 100 percent saturated. The ambient air conditions that are modified by the fogging system occur naturally but are more frequent with the fogging system. For example, the average minimum temperatures for the months of November through April range from 41.7°F to 55.7°F with relative humidities ranging from 83 to 88 percent. The amount of adiabatic cooling would range from 1 to 2°F. For the Putnam Plant, an 8°F average reduction was assumed in the calculations for primarily daytime operation.

Turbine Performance and Emission Estimates

The effect of decreasing the turbine inlet air through the use of fogging will be to increase the mass flow of air that can go through the turbine which allows higher heat input and power output. The combustion turbine is also more efficient since the heat rate decreases with decreasing temperature. For the Westinghouse Model 501B5A combustion turbines at the Putnam plant, an 8°F average decrease in temperature would result in a 3.3 percent increase in power and an associated 1.1 percent decrease in heat rate. Thus, while power increases, the production of power is more efficient with concomitant lower emissions per MW-hr generated. The increase in heat rate as a function of temperature decrease is a linear function and for the Putnam turbines would be 4 mmBtu/hr/°F for gas firing and 3.2 mmBtu/hr/°F for oil firing. The data were determined using Westinghouse supplied data (see Attachment A).

Because the turbine is operating on its original power curve, the emission characteristics do not change from what would normally occur at that temperature and relative humidity. An evaluation of emissions from the fogging tests conducted at the FPL Putnam plant did not result in any statistically significant differences in emission rates (see Attachment B). The increase in emissions of criteria pollutants associated with fogging were determined using emission limits contained in the Title V Permit for the facility. This provides the maximum potential allowed and would conservatively estimate emission rates. Table 1 and 2 presents a summary of the operating conditions and emission increases resulting from fogging firing natural gas and distillate fuel oil, respectively. The annual emissions were determined by multiplying the heat input increase per degree Fahrenheit times the emissions rate in lb/mmBtu for the number of hours of proposed for the turbines. The degree F-hours/year is the total amount of annual temperature reduction proposed for fogging and was calculated by using the average temperature reduction multiplied by the hours of year assumed. For example, the degree F-hours for gas firing are calculated by multiplying 1,280 hours times 8°F or 10,240°F-hours. Each turbine inlet fogging system will be equipped with temperature probes to determine the amount of inlet cooling. This reduction will be recorded for each hour of fogger operation. For the Putnam turbines, a maximum of 10,240°F-hours of operation when firing natural gas and 800°F-hours of operation when firing distillate fuel oil was used as the basis for annual emission estimates for each turbine.

The use of AP-42 emission factors is appropriate for estimating maximum potential annual emissions since there are no emission limits for NO_x. This is especially conservative for NO_x since actual emissions are much lower. Over the last two years, quarterly emissions reported from CEM data ranged from 0.322 lb/mmBtu to 0.398 lb/mmBtu. The annual averages from CEM data ranged from 0.351 to 0.371 lb/mmBtu for 1997 and 0.354 to 0.375 lb/mmBtu for 1998. Using an emission factor of 0.44 lb/mmBtu to estimate maximum potential annual emissions, would overestimate annual emissions from 17 to 25 percent greater than that actual observed. Thus, the annual estimated emissions based on AP-42 emission factors are conservative.

Regulatory Applicability

A modification is defined in Rule 62-210.200 Florida Administrative Code (F.A.C.) as any physical change in, or a change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air pollutant subject to regulation under the Clean Air Act. A modification to a major source of air pollution, such as the Putnam Plant, may be subject to review under the Department's Prevention of Significant Deterioration (PSD) rules codified in Rule 62-212.400 F.A.C.

The proposed installation of direct water spray fogging systems is a modification according to Rule 62-212.200 (188) F.A.C., since annual emissions will potentially increase as a result of the increased power and heat input. This has been confirmed by the Department in its December 31, 1998 correspondence to FPL.

Based on the available data, it is concluded that the emission rate does not change as a result of inlet fogging. Therefore, increase in annual potential emissions can be conservatively determined through the use of increases in heat input associated with the use of the fogging systems. For the 4 combustion turbines (CTs) the maximum potential annual increase in emissions is estimated as follows:

Summary of Maximum Annual Emissions - All Units

Pollutant	Gas Tons/Year	Oil Tons/Year	Oil & Gas Total
PM	1.38	0.15	1.53
NO_x	36.04	3.57	39.62
SO_2	0.23	3.58	3.82
CO	9.01	0.25	9.26
VOC	1.97	0.09	2.08
Degree Fahrenheit-Hours per year	10,240	800	
Additional Degree Fahrenheit-Hours on Gas	1,015	0	
Total Degree Fahrenheit-Hours Gas Only	11,255	0	

These maximum potential emission rates are less than the significant emission rates in Table 62-212.400-2 in Rule 62-212.400 F.A.C. and therefore PSD would not apply. The pollutant closest to the PSD significant emission rates when firing natural gas is NO_x. Emissions of SO_2 are primarily associated with distillate fuel oil which is only used a backup to natural gas. For natural gas only, the maximum potential NO_x emissions would be 39.62 tons/year at 11,255°F-hours per year per CT. This is equivalent to 1.6°F-hours of gas firing for each hour of oil firing (i.e., 1,015°F-hours/800°F-hours = 1.27°F-hours). The emissions of the other pollutants would be 1.52 tons/year for PM, 0.25 tons/year for SO_2, 9.9 tons/year for CO and 2.16 tons/year for VOC.

FPL proposes that the amount of fogging allowed by the Department be based on a cumulative amount of operating hours for the 4 combustion turbines. This would amount to 45,020°F-hours of operation when firing only natural gas. If only natural gas is fired, the proposed amount of hours would be decreased by 1.27°F-hours for each °F-hour when fuel oil was fired during an annual period. As described previously, the emission rates would not be affected. In addition, during periods when the fogging system is not used, the operation of the CTs will not be affected by this request and will be operated according to the Department's previous approvals (e.g., authorized to operate 8,760 hours/year/CT).

As described previously, the inlet fogging systems will have temperature monitoring equipment which will record the actual temperature reduction for each hour of operation. These data will be summarized monthly and reported to the Department with the Annual Operating Reports demonstrating that the annual period does not exceed 45,020°F-hours for the facility.

Attachment A

The following data were obtained from performance curves in the range that fogging would be most effective (gas firing shown).

Plant Site:	Putnam Plant; GTs 11, 12, 21 and 22	
Turbine Model:	Westinghouse 501B5A	
Turbine Inlet Temperature (°F)	100	50
Difference (°F)		50
Heat Input (mmBtu/hr)	900	1,100
Difference (mmBtu/hr)		200
Rate (mmBtu/hr/ °F)[a]		4.00

Note: [a] heat input difference divided by temperature difference.

PB93-156586

EPA-453/R-93-007

Alternative Control Techniques Document-- NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature. This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5}e^{19(Ho-0.00633)}(288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

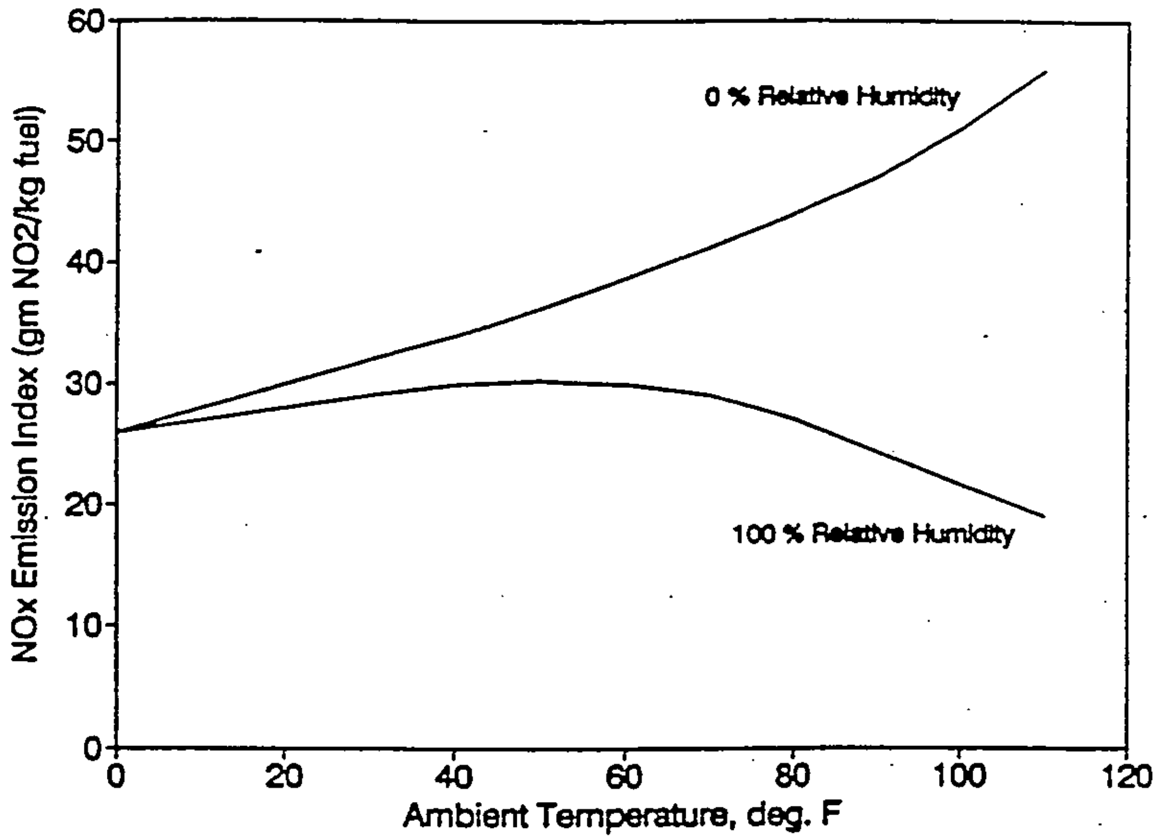

Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

FPL

September 18, 1997

Mr. Scott M. Sheplak, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Draft Permit No. 1070014-001-AV
<u>FPL Putnam Plant Initial Title V Permit</u>

Dear Mr. Sheplak:

Enclosed for your use please find a copy of the heat input vs. ambient temperature graph for the subject facility.

If you have any questions, please do not hesitate to contact me at (561) 691-7058.

Very truly yours,

Richard Piper
Senior Environmental Specialist
Florida Power & Light Company

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AIR REGULATION

cc: Pat Wilson

PPN / PPN

FPL

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach, FL 33408

November 10, 1997

Mr. Scott M. Sheplak, P.E.
State of Florida
Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Draft Permit No. 1070014-001-AV
Heat Input Information for Oil Firing
<u>FPL Putnam Plant Initial Title V Permit</u>

Dear Mr. Sheplak:

Attached for your use please find a graph of the ambient temperature vs. heat input data for the Putnam plant combustion turbine units for distillate oil firing.

If you have any questions, please do not hesitate to contact me at (561) 691-7058.

Very truly yours,

Rich Piper

Rich Piper
Senior Environmental Specialist
Florida Power & Light Company

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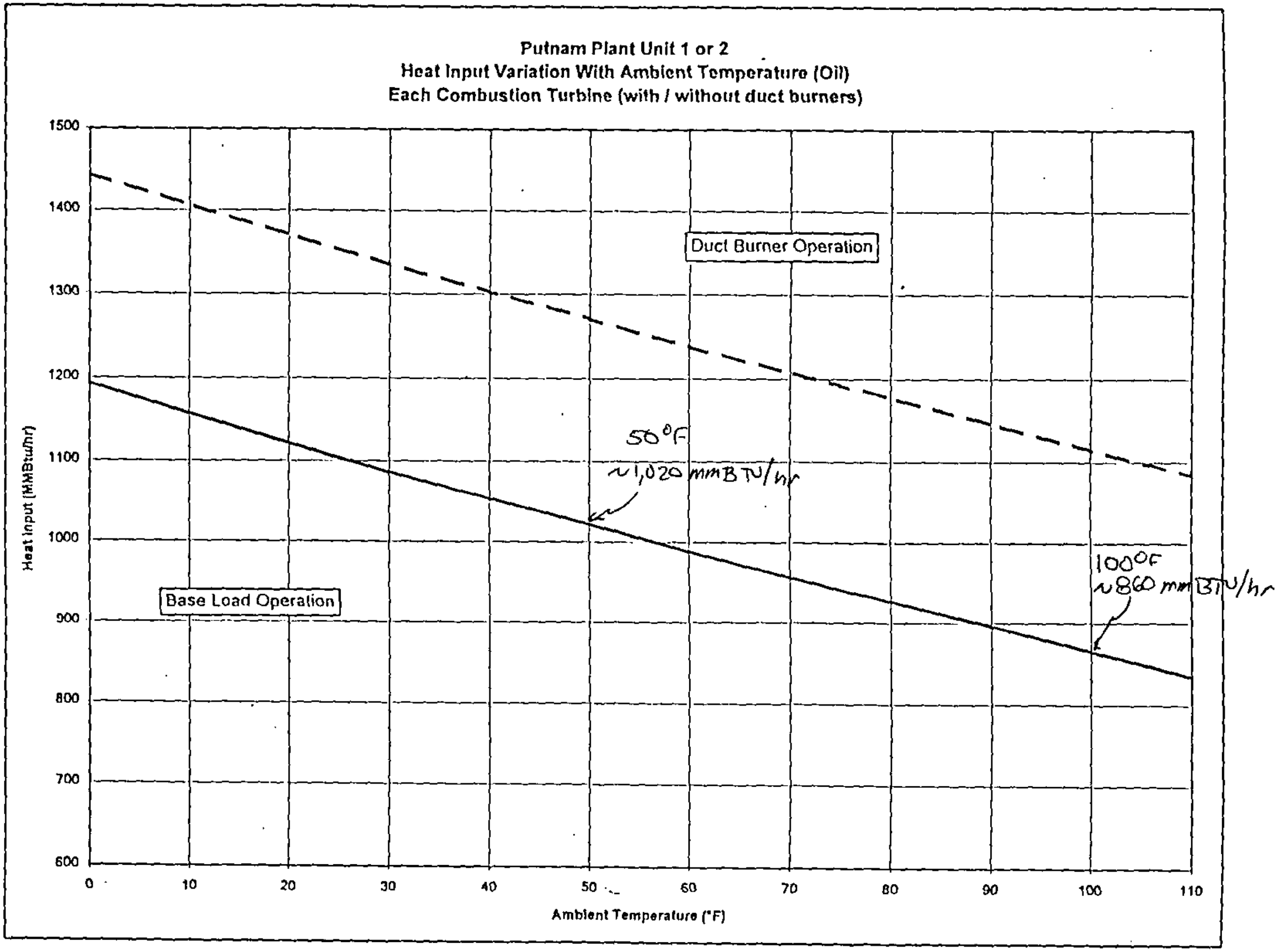
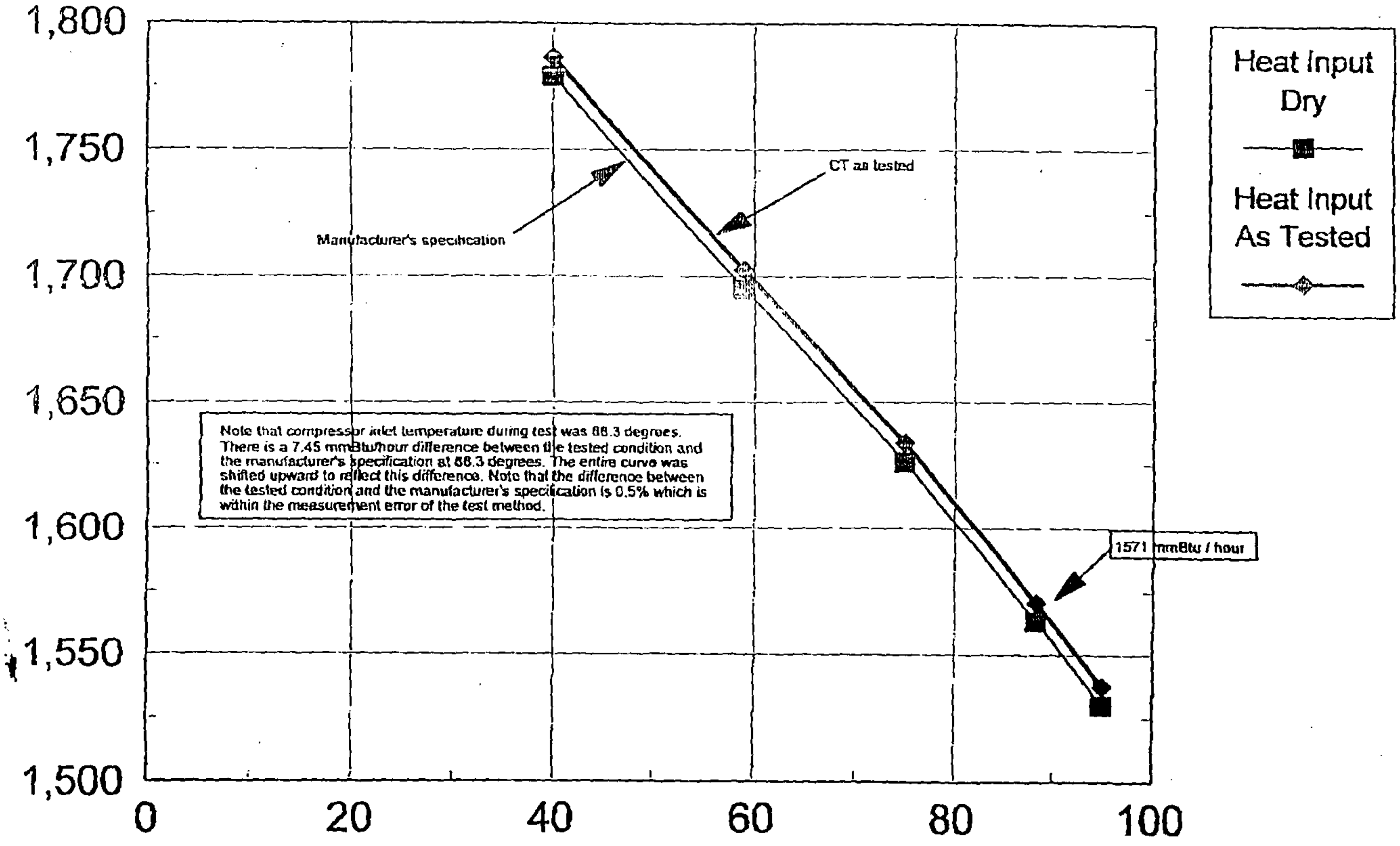
AIR REGULATION


Putnam Plant Unit 1 or 2
Heat Input Variation With Ambient Temperature (Oil)
Each Combustion Turbine (with / without duct burners)
Heat Input (MMBtu/hr)
1500
1400
1300
1200
1100
1000
900
800
700
600
0
10
20
30
40
50
60
70
80
90
100
110
Ambient Temperature (°F)
Duct Burner Operation
Base Load Operation
50°F
~1,020 mmBTU/hr
100°F
~860 mmBTU/hr

Martin Unit 3B

Heat Input vs. Ambient Temperature Curve



FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 26, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard Piper
Repowering Licensing Manager
Florida Power & Light Company
Post Office Box 14000
Juno Beach, Florida 33408

Re: Inlet Foggers – Putnan Plant Combustion Turbines DEP File 1070014-003- AC
Inlet Foggers – Martin Plant Combustion Turbines DEP File 0850001-005- AC

Dear Mr. Piper:

The Department received your applications for the installation of the direct water spray fogging system at the FPL's Martin and Putnan Plants. Based on a technical review, the applications are incomplete. Pursuant to Rules 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C., please submit the following information, including all relevant reference materials and calculations:

1. Please submit additional data to support the statement that the emission rate does not change as a result of inlet fogging.
2. In reference to Table 1 and 2. (Part II of the Supporting Information), indicate the nominal values for power output, heat rate and heat input increase.
3. Submit the heat input curves for these units.
4. Estimate actual emissions for each facility's turbines and worst case emission rate scenario.
5. Submit hours of operations for each turbine.

Please contact Teresa Heron at 850/921-9529 if you have any questions.

Sincerely,

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

CHF/th

cc: Ken Kosky, P.E
Chris Kirts, NED
Isidore Goldman, SED

Z 333 618 104

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Return Receipt Showing to Whom, Date, & Addressee's Address	
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PS Form **3800**, April 1995

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33408

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