



April 19, 2011

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BUREAU OF
AIR REGULATION

Bobby Bull, P.E.
New Source Review Section
Bureau of Air Regulation
Division of Air Resource Management
111 South Magnolia Drive, Suite No. 4
Tallahassee, Florida 32301

Re: Response to Request for Additional Information (RAI)
Project No. 0010001-011-AC
Florida Power Corporation d/b/a Progress Energy Florida, Inc.
University of Florida Cogeneration Plant
Alachua County

Dear Mr. Bull:

On October 13, 2010, Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) received a Request for Additional Information (RAI) from the Department. This RAI was in response to an incomplete application for revisions to the University of Florida Cogeneration Facility's (UF Cogen) NO_x and CO emission limits, the elimination of the duct burner emission testing requirements, and other permit modifications. Initial construction for this facility was authorized under air construction permit PSD-FL-181. The Department indicated that additional information regarding the following questions was required in order to continue processing the application request. The information provided below includes all assumptions, calculations and reference materials used or reflected in any of Progress Energy Florida's (PEF) responses.

1. The application requests a ton per year increase for both NO_x and CO emissions from the combustion turbine. You are stating that the baseline periods and inlet temperatures for the turbine should be re-evaluated at the time the existing turbine [48 megawatt (MW) combustion turbine] was permitted under air construction permit 0010001-003-AC. Throughout this emission unit's permitting history, different inlet temperatures have been used for calculating the equivalent pound per hour emission standard. A comparison of the emissions from the original combustion turbine (43 MW) and the replacement/existing turbine at ISO conditions [lower heating value (LHV) of each fuel, 59 °F temperature, 60% relative humidity, and 14.7 psia] is needed to further evaluate if the unit was permitted properly, as well as provide any ability to adjust the permit standards. All emission limits and TPY caps at the time of the conversion to the larger turbine should be considered in these calculations. Please present the information in tables similar to the following table for both pollutants throughout the facility's permitting history to date.

Response: The referenced example table was used as a template for the response (see Attachment 1 to this letter response). The Department is correct in that various reference temperatures have been associated with various expected hourly emission estimates, as emissions on a mass basis (lb/hr) are temperature dependent for combustion turbine operation. The intent was to document that a required maximum allowable hourly limit should be based on the worst-case inlet temperature condition, while a representative annual TPY rate should be based on annual operation at a reasonable assumed annual inlet temperature. This permitting history is presented as a chronology in the attached summary table, with a short description of each permitting action.

Throughout this emission unit's permitting history, different inlet temperatures have been used for calculating the equivalent pound per hour emission standard and then multiplying the hourly standard by the number of annual operating hours to obtain a TPY estimate. This is the approach that resulted in a ratcheting of the CO emission rate from 36 ppmvd and 35.8 lb/hr to 31.6 ppmvd and 29.9 lb/hr in Permit No. 00100001-006-AC. PEF had assumed that the hourly emission rate, as well as the corresponding ppmvd rate, would need to be reduced in order to justify additional allowable annual hours of operation. However, if you assume the same emissions calculation approach as is used in the Annual Operating Report (AOR) submittal (see response to Item 3 below), the CO emissions on a ton per year (TPY) basis would be determined employing the lb/mmBtu emission factor. This emission factor is determined during the annual CO compliance test. The annual natural gas usage in SCF/year and the heat content of the natural gas in Btu/SCF fuel is employed to determine total heat input for the year (mmBtu/year). This value is then multiplied by the lb/mmBtu emission factor and converted into a TPY value. In reviewing all of the CO emissions test data from 2001 to 2010, the highest CO emission factor value was reported as 0.07 lb/mmBtu. In addition, the highest monitored fuel usage during that period was 3,436 mmSCF, which was recorded in 2005. That equates to a worst-case TPY estimate of 125.4 TPY in the last 10 years, which is very close to the current CO cap of 127.5 TPY. If the Department could revert the CO standards back to the levels prior to Permitting Action 00100001-006-AC (i.e., 36 ppmvd and 35.8 lb/hr) and require monitoring for compliance with the CO cap on a lb/mmBtu basis, combined with annual fuel usage, PEF would have the flexibility necessary to provide continued service to the University of Florida and Shands Hospital.

2. The duct burner has a permitted capacity of 188 mmBtu/hr. Based on the documentation provided and the conversation on October 7, the duct burner has not operated at a rate higher than 119.7 mmBtu/hr since the 2001 compliance test. The last documented test on record with the Department is from 2003 at values lower than the 2001 test. Safety issues are the main concern for testing at full capacity and testing issues were addressed in the application. Please provide an engineering report detailing these issues including but not limited to design issues, operation issues, and operating conditions which limit the operation of the duct burner.

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Response: As an integral part of the refurbishment project on Boiler Nos. 4 and 5, a vent was added for boiler performance testing to ensure performance at capacity after refurbishment. As you recall, Boiler Nos. 4 and 5 were refurbished for backup after the cogen facility was built.

A temporary steam vent system was installed on the cogen during the start-up period for the purposes of conducting steam blows; however, after commercial operation of the cogen unit, it was dismantled. As for the cogen's heat recovery steam generator (HRSG), there has never been a steam vent system for the specific purpose of testing. In addition, the current steam vent is inadequate to accommodate the steam generated while operating the duct burner without sufficient steam demand. The Heat Plant (i.e., Boiler Nos. 4 and 5) vent was intended to be temporary as part of that project. When it was determined that testing was required while firing the duct burner, the Heat Plant vent system was used; however, this steam vent system was never intended or designed to handle the steam generated when there is insufficient steam demand and the duct burner is fully fired. As a result, the duct burner was tested at the maximum duct burner heat input rate that the vent system could safely accommodate. Recently, a safety evaluation was performed on the steam vent system and, in addition to not meeting code, the system was deemed unsafe; as a result it has been dismantled.

The requested engineering report on the steam vent is included as Attachment 2 to this letter. Although the Engineering Report (March 2011) states that the vent on top of the HRSG is capable of testing the DB at approximately 30 mmBtu/hr in the summer and 70 mmBtu/hr in the winter, according to plant personnel there would still be a great deal of noise associated with testing at these respective heat input levels. PEF's preference would be to not test the DB at all and, if required, that testing not necessarily be conducted at maximum capacity. The Engineering report states that "it would be reasonable to find that emissions on this unit at low firing capacity are similar to emissions at higher firing conditions." This is because burner output is increased by placing additional burners in service. This provides more consistent combustion per burner than units that rely on changing fuel flow through each burner runner to change load. Therefore, emissions (i.e., on a lb/mmBtu basis) are fairly consistent across the DB regardless of load.

3. To show compliance with the annual tons per year limit for CO, how is the facility currently reporting this value? Is it consistent with the method requested in this application?

Response: The CO emissions on a ton per year (TPY) basis are determined employing the lb/mmBtu emission factor. This emission factor is determined during the annual CO compliance test. The annual natural gas usage in SCF/year and the heat content of the natural gas in Btu/SCF fuel is employed to determine total heat input for the year (mmBtu/year). This value is then multiplied by the lb/mmBtu emission factor and multiplied by one (1) ton/2,000 lbs which results in a TPY value. This calculation method is different from the basis assumed in the recent application, which was more focused on the lb/hr emission rate and the total operating hours per year.

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4. The application has requested several other revisions which are directly associated with the NOx and CO emissions review. Potential revisions to these air construction permit conditions within the Title V permit will be based upon any revisions to the NOx and CO emission standards. Additional comments may be forthcoming based upon your response to these comments. Any request for revisions to the Title V permit language not associated with an air construction permit shall be addressed at the time of the next Title V operating permit revision.

Response: As the Department has stated above, additional comments may be forthcoming based upon PEF's response to the other questions in the RAI. PEF will wait for the Department's assessment on this issue.

5. You requested permit language for the change out of the combustion turbine engine with "like/kind" replacement as part of the routine maintenance schedule of the unit. The following language is currently incorporated in Florida Gas Transmission's permits for similar types of turbine maintenance. It is the Department's intent to incorporate the same language to accommodate the same type of maintenance for your turbine. Please provide any comments on the language.

Response: Although the Agency's language is applicable to a natural gas compressor station gas turbine, PEF believes the suggested language could meet the intent of PEF's request with a great deal of work. However, in an effort to propose a simpler and cleaner approach, PEF would like to suggest the following language instead.

Equipment Replacement Provision

Replacement of Gas Turbine and Components – The gas turbine system generally consists of the following components: gas turbine, accessory drive system, air inlet and filtration system, fuel delivery system, cooling system, lubrication system, control system, starting system, and exhaust system with stack. This aero-derivative gas turbine is designed with modular components to facilitate quick repairs. Common "wear items" include compressor vanes, turbine nozzles, compressor blades, turbine blades, fuel nozzles, combustion chambers, seals, and shaft packing. The concept of modular design extends to the complete replacement of the gas turbine. Replacements are authorized provided the following requirements are met.

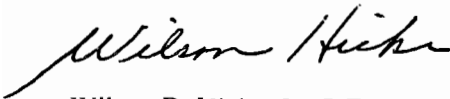
- a. *Gas Turbines and components shall be replaced with equivalent "like-kind" equipment. Replacement components may consist of upgraded equipment, but shall not increase the maximum heat input rate to or emissions from the gas turbine. Replacement components shall be designed*

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- c. Within 180 days of replacing a gas turbine, the permittee shall conduct emissions stack tests or RATA to demonstrate compliance with the emission standards for CO, NOx, and visible emissions. The permittee shall comply with the requirements for notification, test methods, test procedures, and reporting specified in this permit.*
- d. To up-rate a gas turbine or increase the maximum heat input rate, the permittee shall apply for prior approval through the air construction permit process.*

If you have any questions regarding the information presented here, please contact Mr. Chris Bradley by telephone at (727) 820-5962 or via e-mail at Chris.Bradley@pgnmail.com.

Best regards,




Wilson B. Hicks, Jr., P.E.
Plant Manager
University of Florida Co-Gen

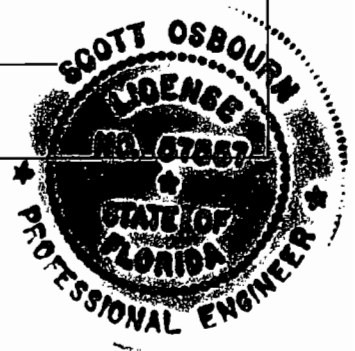
Cc: Scott Osbourn, P.E., Golder Associates
Chris Bradley, PEF

Attachments

Professional Engineer Certification

1. Professional Engineer Name: Scott H. Osbourn Registration Number: 57557
2. Professional Engineer Mailing Address... Organization/Firm: Golder Associates Inc.** Street Address: 5100 West Lemon St., Suite 208 City: Tampa State: FL Zip Code: 33609
3. Professional Engineer Telephone Numbers... Telephone: (813) 287-1717 ext. 53304 Fax: (813) 287-1716
4. Professional Engineer E-mail Address: sosbourn@golder.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> <i>(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> <i>(3) If the purpose of this application is to obtain a Title V air operation permit (check here <input type="checkbox"/>, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> <i>(4) If the purpose of this application is to obtain an air construction permit (check here <input type="checkbox"/>, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here <input checked="" type="checkbox"/>, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> <i>(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here <input type="checkbox"/>, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i> Signature:  Date: <u>4/19/11</u> (seal)

* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization # 00001670



ATTACHMENT 1
Permitting History Summary Table

Project Number (0010001-X)	Date Permit was Issued	Permitted Capacity in mmBtu/hr		Pollutant	CT Permitted Emissions			Emissions Cap (TPY)			Brief Project Summary
					ppmvd ¹ @ 15% O ₂	(Corrected to ISO - 59 °F)		CT ¹	DB	Facility	
		Permitted lb/hr limit	TPY limit			CT ¹	DB				
AC 01-204652 & PSD-FL-181	August 17, 1992	367.9/219.0 ¹	197.7 ²	NOx	25/42 ²	35.0/66.3	150.0/7.3 ⁴	142.7/7.3	24.6	194.3	This cogeneration project will reduce energy use substantially. Three boilers were removed & two others remained for back-up. Fuel for the CT generator will be natural gas w/ distillate oil used during periods of gas curtailment. This project represents a reduction in allowable emissions by taking the old inefficient boilers out of service. Particulate matter SO ₂ emissions shall be controlled by the firing of natural gas and/or low sulfur content (shall not exceed 0.5% by weight) No.2 fuel oil (BACT).
				CO	42/75	38.8/70.5	166.1/7.7 ⁴	158.0/7.7	36.9	202.6 ⁵	
-001-AV	December 01, 1999	399/384	187.0	NOx	25/42 ²	39.6/66.3	150.0/7.3 ⁴	142.7/7.3	24.6	194.3	Initial Title V Air Operation Permit for the 43 MW General Electric LM 6000 combustion turbine (CT) and duct burner (DB); both units began commercial service in 1994 and regulated under PSD-FL-181 & BACT dated August 17, 1992, & PSD-FL-181(A). In addition, the CT is regulated by 40 CFR 60, Subpart GG and the DB by 40 CFR 60, Subpart Db
				CO	42/75	38.8/70.5	166.1/7.7 ⁴	158.0/7.7	36.9	202.6 ⁵	
-003-AC	May 18, 2001	392/384	188	NOx	25/42.0 ²	39.6/66.3	141	141/7.3	24.6	194.3	The purpose of this permit as the replacement of the existing 43 MW General Electric LM6000 CT with a more efficient LM6000 incorporating SPRay INTercooling ("SPRINT") technology. NOx will be controlled by the water injection system. The emission limits @15%O will remain the same (Gas: 25 ppmvd; No. 2 oil: 42 ppmvd). Based on the maximum operating capacity (~48 MW vs. ~43 MW) the allowable annual operating hours at maximum rates have been reduced from 8,147 to 7,211. The current annual facility NOx emission cap remains at 194.3 tons per year (includes CT, DB & two back-up boilers). For natural gas firing the CO emissions limit @ 15% O ₂ was reduced to 36 from 42 ppmvd. In addition there was a reduction in the allowable annual CO emissions from 158 to 127.5 TPY. The fuel input limit for the turbine was changed to a total Btu basis for fuel oil & natural gas with a maximum usage of fuel oil.
				CO	36/75.0	35.8/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-004-AC	March 27, 2003	392/384	188	NOx	25/42.0 ²	39.6/66.3	141	141/7.3	24.6	194.3	The purpose of this permit was to extend 0010001-003-AC until December 31, 2003 to provide sufficient time to test the new unit and submit a complete Title V Permit Application reflecting the as-built project. At the time of issuance construction authorized by 010001-003-AC was completed
				CO	36/75.0	35.8/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-005-AV	January 05, 2004	Heat input vs. Power Output Curve attached to permit.	188 (LHV, 100 % load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141	24.6	194.3	The purpose of this permit (0010001-005-AV) was to revise the Title V Air Operation Permit. This permit revision incorporates: 1) the terms and limitations for the operation established in 0010001003-AC; 2) allowed an increase in heat input to the combustion turbine established 0010001-004-AC; 3) the changes contained 0010001-006-AC, which reduced the short-term allowable limits for CO and altered some NOx compliance language contained 0010001-003-AC & 004-AC; and 4) corrected the emissions unit IDs based on ARMS data.
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	

Project Number (0010001-X)	Date Permit was Issued	Permitted Capacity in mmBtu/hr		Pollutant	CT Permitted Emissions			Emissions Cap (TPY)			Brief Project Summary
		CT ¹	DB		ppmvd ¹ @ 15% O ₂	(Corrected to ISO - 59 °F)		CT ¹	DB	Facility	
						Permitted lb/hr limit	TPY limit				
-006-AC	October 09, 2003	Heat input vs. Power Output Curve attached to permit.	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141/7.3	24.6	194.3	0010001-006-AC was issued to correct the carbon monoxide (CO) emissions limits to avoid NSR Requirements. CO was not evaluated when the new combustion turbine was authorized by 0010001-003-AC and amended by 0010001-004-AC. Although revision 0010001-005-AV was ready to be issued, the CO error was discovered and 0010001-006-AC was issued to reduce the short-term allowable limits for CO and alter some compliance language associated with NOx established in previously issued 0010001-003-AC & 0010001-004-AC.
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-007-AV	January 01, 2005 (Signed December 21, 2004)	Heat input vs. Power Output Curve attached to permit.	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141	24.6	194.3	The purpose of this permit is to renew the Title V Air Operation Permit Renewal
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-008-AV	March 20, 2009	Heat input vs. Power Output Curve attached to permit.	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141	24.6	194.3	The purpose of this permit is for the revision of Title V Air Operation Permit No. 0010001-007-AV to incorporate the Clean Air Interstate Rule (CAIR) Part as an enforceable section of the permit.
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-009-AV	January 01, 2010 (Signed December 10, 2009)	Appendix HI – Heat Input vs. Ambient Temperature Curve	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141	24.6	194.3	The purpose of this permit is to renew the Title V Air Operation Permit for the facility.
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-010-AC	August 16, 2010	Appendix HI – Heat Input vs. Ambient Temperature Curve	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	141	141	24.6	194.3	The purpose of this permit is to maintenance and repair the backup steam Boilers Nos. 4 & 5. The construction project replaces boiler tubes, refractory, casing, insulation, steam drum internals, and various miscellaneous items in the back up boilers.
				CO	31.6/75.0	29.9/70.5	127.5/7.7 ⁶	127.5/7.7	36.9	172.1 ⁵	
-011-AC	RAI October 13, 2010	Appendix HI – Heat Input vs. Ambient Temperature Curve	188 (LHV, 100% load, 60% RH, 59 °F, 14.7 psia)	NOx	25/42.0 ²	39.6/66.3	156	141	24.6	194.3	PEF is seeking revisions to the CT emission limits for CO and NOx, as well as the compliance testing requirements for the duct burners. This allows for 8,256 hr/yr.
				CO	33.6/75.0	31.7/70.5	130.85	127.5/7.7	36.9	172.1 ⁵	

Notes:

- ¹ The limits for two (2) different fuels. The first value listed is the limit for natural gas and the second value is for No. 2 distillate fuel oil; i.e., Natural gas/ Fuel Oil.
- ² The concentration value listed here in part per million (ppm) is not a limit, but is the basis for the pounds per hour (lbs/hr) and the tons per year (TPY) limits.
- ³ There are no heat input limits in terms of mmBtu/hr in this permit (Permit No. eccc.cccccc). This permit established a maximum fuel flow limit for each emission unit as noted below.

Emission Unit	Natural Gas			No. 2 Fuel Oil		
	Mcf/hr [*]	MMcf/yr	hrs/yr [*]	Mgal/hr [*]	Mgal/yr	hrs/yr [*]
Turbine	367.9	2,997.2**	8,146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2,628.0	0	0	0

- ^{*} Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.
- ^{**} An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.
- ⁴ The natural gas tons per year (TPY) limit is based on combusting 100% natural gas in lieu of combusting any No. 2 fuel oil; i.e., combusting gas up to 8,563 hours/year. The No. 2 Fuel oil TPY limit is based on combusting a maximum of 635.1 Kgal/year and 219.0 hours/year of operation on No. 2 fuel oil
- ⁵ This facility-wide emission value is not a limit and was determined by summing the maximum annual emission permitted for the CT (natural gas & No. 2 fuel oil) and the DB; the steam boilers emissions were not included.
- ⁶ The air construction application (Project No. 0010001-006-AC) requested an emission limit of 131 TPY for CO if the CT fired natural gas for 8,760 hours/year. It is not clear if this scenario was addressed through the permitting process (See Specific Conditions B.5.a(1) and B.11.a(1)); however, the product of the 8,760 hours /year and the 29.9 lbs/hr is 130.96 TPY which rounds to 131 TPY

ATTACHMENT 2
Engineering Report

University of Florida Cogeneration
Gainesville, FL

Deltak HRSG Venting and Coen Duct Burner Evaluation



March 2011

Prepared by John Burney (Central Engineering)

Objective

The purpose of this evaluation was to quantify the burner output possible given the capacity of the existing high pressure superheater vent silencer. Some quantification of the seasonal variation in load demand is also provided.

Discussion

The capacity of the Fluid Kinetics high pressure vent silencer is 60,300 lb/hr per drawing 9670131 (attached). The Coen duct burner capacity is 244,565 standard cubic feet per hour according to the Coen technical manual (excerpt attached).

Looking back over the past years worth of operating data the maximum firing rate of the duct burner was 93,500 scfh. A chart of high pressure steam flow vs. burner fuel flow is attached. In general operations will fire the HRSG up to a maximum of 160,000 lbs/hr of high pressure steam flow at approximately 75,000 scfh. If additional flow is required one of the backup steam generators is used.

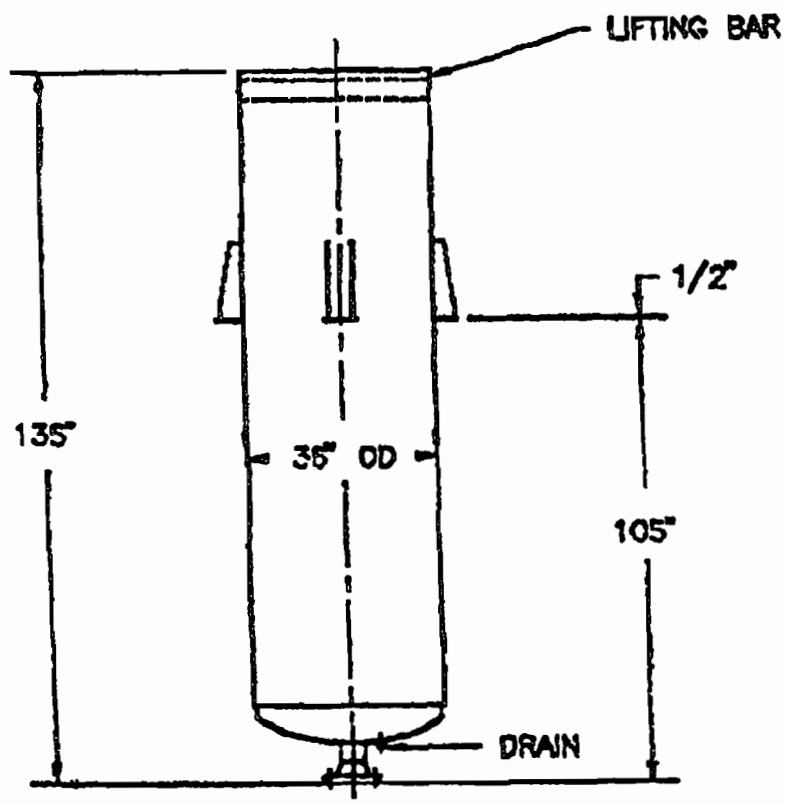
In the summer time more steam is generated than can be used by the University. This excess steam is vented through the Fluid Kinetics high pressure superheater vent. In the summer the vented flow runs between 30 klbs/hr and 40 klbs/hr. That leaves about 20 klbs/hr available before reaching the capacity of the vent silencer. Given that available capacity the duct burner could be fired up to approximately 30 mmbtu/hr. The vent flow is derived by subtracting high pressure superheater flow (HP flow) from high pressure feedwater flow (HPFW). The difference between the water going into the high pressure section and the steam coming out is the amount that goes through the vent. (Graph of seasonal flows for 2010 is attached)

There is additional capacity available in the winter months, but the demand is highly variable. Given the few weeks it takes to reserve a test crew it would be difficult to guarantee a maximum fired case at the time they arrive. If cooler weather testing is possible the duct burner could be run up to approximately 70 mmbtu/hr. A chart of high pressure superheater flow (HP Flow), burner fuel flow (Burner Flow) and high pressure feedwater flow (HPFW) vs time for 2010 is attached.

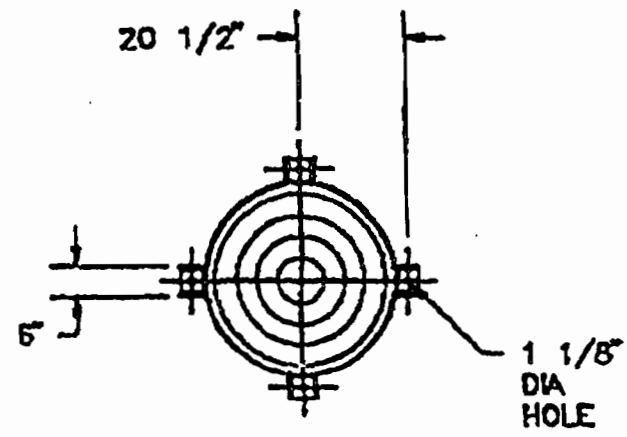
One additional comment, the burner output is increased by placing additional runners into service. This provides more consistent combustion than units that rely more on changing flow through each burner runner to change load. It would be reasonable to find that emissions on this unit at low firing capacity are similar to higher firing conditions.

Conclusions

Firing at the full capacity of the duct burner is not possible with the current arrangement. Duct fired testing can be consistently performed at 30 mmbtu/hr in the summer or 70 mmbtu/hr in the winter. Lower firing level performance will be representative of higher firing levels with the operating arrangement of the duct burners.



FRONT ELEVATION



TOP VIEW

TITLE:
SILENCER (START-UP VENT)

FPC
REV.
A

SERVICE: START-UP VENT SILENCER
FLUID: STEAM
MW: 18
FLOW RATE: 60300 lb/hr
VALVE UPSTREAM TEMP.: 720F
VALVE UPSTREAM PRESS.: 700 psi(g)
SHELL MATL: 3/16" 304 Stainless Steel
ACOUSTIC FACING MATL: 16 GA TYPE 304 Stainless Steel
PACKING MATL: LONG STRAND GLASS FIBER
INLET: 4"-600# RFWN, 304 Stainless Steel
OUTLET: VENT TO ATMOSPHERE
DRAIN: 1" NPT CPLG W/PLUG
EXTERIOR FINISH: SAND BLAST SSPC-SP6

PRESSURE DROP: 590 psi
WEIGHT: 1,690 lbs

CUSTOMER: DELTAK CORP.
REF: DELTAK PROJ. # G92009
TAG: 1

UF



FLUID KINETICS CORPORATION
VENTURA, CALIFORNIA

MODEL 505 36-105-348

DR.	DATE	DRAWING NO.
CP	02/26/98	9670131

REV.	DATE	BY	CHKD.	DESCRIPTION
1	02/26/98	CP	CP	ISSUED FOR FABRICATION

Bill of Materials

COEN FILE N° 40D-11797-1-000

JOB SPECIFICATIONS (CONTINUED):

C. MAIN GAS FUEL DATA:

1. NATURAL GAS: LOW HEATING VALUE: 920 BTU/SCF
SPECIFIC GRAVITY: 0.62
2. FLOW: 244,565 SCFH
3. SUPPLY PRESSURE AT THE INLET TO MAIN GAS TRAIN: 30 PSIG
4. SUPPLY TEMPERATURE AT THE INLET TO MAIN GAS TRAIN: 77 °F
5. MAIN GAS HEADER PRESSURE AT MAXIMUM LOAD: 10.33 PSIG

D. PILOT GAS FUEL DATA:

1. NATURAL GAS: LOW HEATING VALUE: 920 BTU/SCF
SPECIFIC GRAVITY: 0.62
2. FLOW: 4000 SCFH
3. SUPPLY PRESSURE: 30 PSIG MAXIMUM AT THE INLET OF THE TRAIN. APPROXIMATELY 5.0 PSIG DOWNSTREAM OF THE PRESSURE REGULATOR (SUPPLIED BY COEN).
4. SUPPLY TEMPERATURE: 77 °F

E. SCANNER COOLING AIR DATA:

1. BLOWER OUTLET PRESSURE: 1.99 PSIG (55 "WC)
2. FLOW: 280 SCFM

NOTE: THIS WILL SUPPLY COOLING AIR FOR A MAXIMUM OF TWENTY (20) SCANNERS AND EIGHT (8) SIGHT PORTS ONLY. SIGHT PORTS ARE SUPPLIED BY DELTAK.

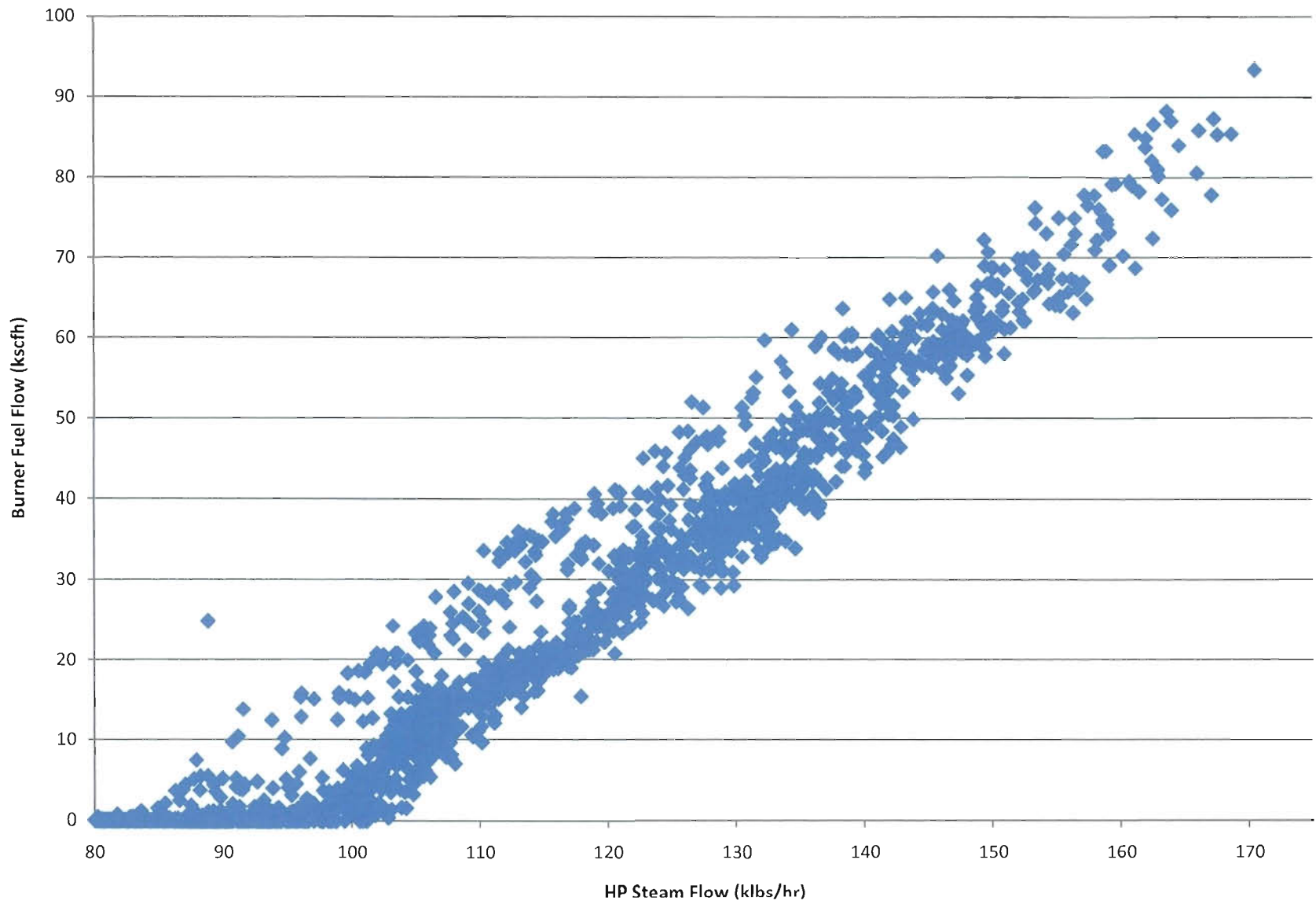
F. UTILITIES AVAILABLE:

1. CONTROL POWER: 120 VOLT/1 PHASE/60 HZ
2. MOTORS: 460 VOLT/3 PHASE/60 HZ
3. INSTRUMENT AIR (DRY & FILTERED): 80-100 PSIG

G. INSTALLATION DATA:

1. ELEVATION: 100 FEET ABOVE SEA LEVEL.
2. DUCT BURNER AND PIPING MODULE LOCATION: OUTDOORS.
3. ELECTRICAL CLASSIFICATION: NON-HAZARDOUS - NEMA 4.
4. APPROXIMATE BURNER WEIGHT: 13,500 LBS.
5. APPROXIMATE PIPING MODULE WEIGHT: 2,600 LBS.

HP Steam Flow vs Burner Output



Seasonal Variation in Duct Firing and Steam Demand

