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DIRECTOR OF POWER SUPPLY

KUA
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AIR REGULATION

April 15, 1998

Florida Department of Environmental Protection
Twin Tower Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: CANE ISLAND UNIT 1 NO_x EMISSIONS

Attention: Mr. Clair Fancy

Gentlemen:

Kissimmee Utility Authority (KUA) is requesting an amendment to Construction Permit No. AC49-205703 (PSD-FL-182) and the associated Title V operating permit to modify the Unit 1 15 ppmv nitrogen oxides (NO_x) emission limit compliance date during natural gas firing at the Cane Island Power Park. Specifically, KUA is requesting that Unit 1 be allowed to operate at its currently permitted 25 ppmv NO_x rate, while providing annual dry low emissions technology updates to the FDEP.

Representatives of KUA, General Electric (the combustion turbine manufacturer), and Black & Veatch (the permitting specialist) met with the Florida Department of Environmental Protection (FDEP) on November 6, 1997, to discuss this issue. Al Linero, Martin Costello, Susan DeVore, and Joseph Kahn from the FDEP were present at the meeting. The following sections describe the permitting history of the Unit, the past and current development of the dry low emission technology for the LM6000 machine, and the requested permit modifications. **Please note that the information contained under the "History of Dry Low Emissions (DLE) Development" section of the letter and Attachment A are considered proprietary and confidential by General Electric Company and should be treated as such.**

Permitting Background

The air construction application for the Cane Island Power Park was initially filed in 1992. The Cane Island Power Park consists of one GE LM6000-PA combustion turbine operating in simple cycle mode and one GE Frame 7EA combustion turbine operating in a combined cycle mode (i.e., including a heat recovery steam generator and steam turbine). Both units are capable and permitted to operate on natural gas or low sulfur distillate oil.

During the permit issuance process, an initial draft permit, dated October 20, 1992, was distributed by the FDEP to KUA for review. In the initial draft, the FDEP required that the Unit 1 NO_x emissions be lowered from 25 to 15 ppm via combustion technology improvements during natural gas firing by December 31, 1996. Based upon comments from KUA, Black & Veatch, and General Electric indicating that the development of the dry low emissions systems for the LM6000 had not yet begun; the FDEP revised the 15 ppm compliance date to December 31, 1997 in the final draft permit issued on November 18, 1992. The final permit issued on April 9, 1993 slightly revised the compliance date to January 1, 1998, allowing for the applicant to update the expected compliance dates annually. In addition, the FDEP added language that selective catalytic reduction (SCR) may be required since its application is technically feasible.

In accordance with permit condition No. 15 of the final permit, KUA submitted a letter to the FDEP on October 24, 1996, providing the revised expected compliance date for Unit 1 (January 1, 1999). The revised compliance date was based upon an aggressive development schedule proposed by General Electric for their aeroderivative line.

In early 1997, the FDEP requested that the tentative compliance date become a firm date in the permit. As discussed in the following section; due to technological difficulties, the dry low emissions combustor for the aeroderivative line has not proceeded in accordance with the previously anticipated schedule. Specific details regarding General Electric DLE development are discussed below and in Attachment A to this letter.

History of Dry Low Emissions (DLE) Development

General Electric launched the development of the dry low emissions (DLE) program for the aeroderivative combustion turbine line in 1990. Included in the development program was the LM6000 combustion turbine. At the time of installation at Cane Island, one mode of LM6000 was commercially available. This was the PA model which utilized water/steam for NO_x control. In late 1994, the PB model became commercially available. This model utilized the original LM6000 design but incorporated a DLE combustor for natural gas firing exclusively. Both of the original LM6000 models are no longer in production. These have been replaced with a newer design of aeroderivative machine, which has modifications to the booster vanes and LPT components to improve efficiency, promote stability through larger load ranges, and reduce exhaust noise. The PC model was made commercially available in the latter half of 1997. The PC model uses water/steam to control NO_x emissions and is capable of firing natural gas or fuel oil. The PD model, the DLE combustor version of the PC, was also made commercially available in late 1997.

The LM6000-PA utilizing water injection for NO_x control is currently capable of achieving 25 ppm NO_x when firing natural gas and 42 ppm when firing fuel oil. Because this model has been discontinued, there are no DLE development plans for these units. Thus, the only model available with DLE technology available is the PD unit. General Electric is currently working to achieve 25/65 ppm NO_x on gas/oil, and expects to demonstrate this capability at a customer site by the end of 1998. The tentative development plans indicate that the dual fuel units meeting a 25/42 ppm emission rate and the gas only fired units meeting a 15 ppm emission rate may be available for installation in 1999. The schedules will be more definitive upon completion of the performance tests in early 1998. The technical feasibility of a dual fuel 15/42 ppm machine will also be assessed during those performance tests. If it appears that these emission rates are technically achievable, a schedule will be developed showing the date when the dual fuel 15/42 DLE machine will be available. At this time it is expected that this date will be no earlier than the year 2000.

There are several factors contributing to the DLE development lag between the conventional frame machines and the single fuel aeroderivatives. Specifically, the combustor inlet temperatures are generally higher for aeroderivative machines due to higher compression ratios. This leads to more challenging design problems for combustor liner cooling and flashback avoidance for aeroderivatives. Combustor length and volume are also much higher for frame machines, providing more room for mixing and combustion processes. In addition, the introduction of dual fuel into the aeroderivative presents additional development difficulties. Incorporation of liquid fuel DLE into a gas fuel system makes both the gas and the liquid system design more challenging because the liquid fuel is more difficult to premix than natural gas, flashback is more of a problem with liquid fuel, and more distribution apparati need to fit into the same available space.

In summary, General Electric has pursued an aggressive schedule for DLE development. However, due to the difficulties associated with the unique constraints of dual fuel firing in aeroderivative machines, the earliest possible date for delivery of a 15/42 DLE machine at Cane Island would be 2000, if it is shown to be technically feasible at all.

Technical Justification for Requested Modification

To assist the Florida Department of Environmental Protection in making the requested changes to the permit, KUA is providing a brief technical justification document which provides the bases for the permit changes. The technical justification document is provided as Attachment B.

Requested Modification to Construction and Operation Permits

Based on the information provided in this letter, the associated attachments, and the aforementioned meeting, KUA hereby requests that the Cane Island construction permit be modified as follows:

Modify Condition 15(b) to:

For the simply cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv as soon as practicable. The permittee shall provide the Department an annual status report describing the development of the 15/42 DLE LM6000 machine, until such machine is installed at Cane Island or FDEP makes a determination that such a machine is infeasible to install at Cane Island.

Modify Table 1 (Part of Specific Condition 1) to:

Footnote B) the NO_x maximum limit will be lowered to 15 ppm as soon as practicable using appropriate combustion technology improvements unless the FDEP makes a determination that such a machine is infeasible to install at Cane Island.

These changes in the construction permit would subsequently require that Title V permit (not yet issued) be revised. The revised operating permit application pages incorporating the changes in the NO_x emission limit compliance date, including the responsible official certification pages, are provided as Attachment D.

Summary

KUA believes that this information should be sufficient to demonstrate to the FDEP that the Cane Island Unit 1 operating at the currently permitted emission rate of 25 ppm NO_x will not adversely affect air quality. If you have any questions concerning this submittal, please call me at (407) 933-7777 ext. 6-1232.

Sincerely,

AK Sharma

A.K. (Ben) Sharma
Director of Power Supply

AKS/ne

cc: James C. Welsh
Jeff Ling
Amy Carlson
Ziggy Biernacki

cc: Central District
EPA
NPS
Teresa

ATTACHMENT A

ATTACHMENT B

Attachment B
KUA Technical Justification Document for
Requested Modifications to Cane Island Power Park
Construction Permit AC-49-205703

Under the Florida Administrative Code, Section 62-212.300, the FDEP shall not allow the modification of a unit (and consequent modification of the air permit) which would cause or contribute to a violation of any air quality standard. In addition, sources falling under Section 62-212 requirements must demonstrate that Best Available Control Technology (BACT) provisions have been satisfied. These issues with respect to the Unit 1 NO_x emissions are addressed in the following sections.

Ambient Air Quality Impacts

<u>Summary</u>

The goal of the Prevention of Significant Deterioration (PSD) program, as promulgated as a result of the 1977 CAA Amendments, is to protect airshed air quality, ensuring that air quality in existing attainment areas does not significantly deteriorate or exceed national ambient air quality standards while providing a margin for future industrial growth. As shown in the following sections, the current operation of Unit 1 does not significantly impact air quality. Furthermore, the reduction of Unit 1 NO_x emissions to 15 ppm would have insignificant air quality benefits.

<u>Unit 1 Impacts</u>

In the Ambient Air Quality Impact Analysis submitted in support of Cane Island's Prevention of Significant Deterioration Permit application, dated June 1992, dispersion modeling was conducted in accordance with FDEP PSD modeling guidance. Specifically, screening level modeling was preliminarily performed to determine which operational case resulted in the highest ground level impacts. For the simple cycle combustion turbine (LM6000), the worst-case annual NO_x impacts occurred with 100 percent load operation, cold ambient temperatures (20F), distillate oil firing, and 8,760 hours per year of operation. For the combined cycle combustion turbine (GE 7EA), the worst-case annual NO_x impacts occurred with peak load operation, cold ambient temperatures (20F), distillate oil firing, and 8,760 hours per year of operation. Refined dispersion modeling was then conducted utilizing the Industrial Source Complex Short-Term (ISCST) model, receptor grid spacing out to 25 kilometers (including fenceline receptors), and five years of surface and upper air data collected at Orlando and Ruskin, respectively. When the two worst-case turbine scenarios were modeled together to represent the entire facility, the worst-case annual NO_x impact for the refined modeling (i.e.,for five years of data falling on the entire grid) was 0.7 ug/m^3. This impact is below the PSD significant impact levels, indicating that the project will not significantly cause or contribute to degradation of air quality in the area. The FDEP confirmed this modeling result during their review of the PSD permit application.

In order to determine the benefits to local air quality by reducing Unit 1 NO_x levels from a 25 ppm to 15 ppm level, calculations were performed. Considering that the Gaussian dispersion equations have linear proportionality between calculated concentrations and the emission rates, the air quality benefits were determined by ratioing. For the worst-case scenario, all of the impacts from the facility were assigned to the simple cycle turbine (Unit 1). Since the worst-case impacts were based on oil firing, the first calculation was performed to determine what the equivalent impacts would be for natural gas firing at 25 ppm NO_x. The equation was as follows:

$$\frac{36\ \text{lb/hr}}{61\ \text{lb/hr}} \times 0.7\ \text{ug/m}^3 = 0.41\ \text{ug/m}^3$$

Where,

36 lb/hr =	worst case mass emission rate for NO_x during natural gas firing, based upon a 25 ppm emission limit.
61 lb/hr =	worst case emission rate for NO_x during fuel oil firing,
0.7 ug/m^3 =	worst case ground level impact based on a 61 lb/hr firing rate.

Next, the impacts based on a 15 ppm firing rate were calculated using a similar ratioing technique.

$$\frac{22\ \text{lb/hr}}{61\ \text{lb/hr}} \times 0.7\ \text{ug/m}^3 = 0.25\ \text{ug/m}^3$$

Where,

22 lb/hr =	worst case mass emission rate for NO_x during natural gas firing based upon a 15 ppm emission limit.

Thus, the maximum annual air quality improvement at the worst-case receptor would be 0.41-0.25 ug/m^3, or 0.16 ug/m^3. At all other receptors the improvement in air quality would even be less. In addition, if the combined cycle unit emissions contributed to the worst-case impact location, the improvement would be less than calculated above. Therefore, reducing the NO_x emission level from 25 ppm to 15 ppm will result in insignificant air quality improvements with respect to NO_x impacts.

In fact, lowering the NO_x emissions to 15 ppm via utilization of an selective catalytic reduction (SCR) system may increase overall emissions from the combustion turbine. Typical SCR systems are designed and permitted to emit 10-20 ppm of ammonia slip when the turbine is firing natural gas. The ammonia that passes through the system chemically reacts with any sulfur trioxide and forms ammonium bisulfates and ammonium sulfates, forms of particulate matter. The environmental benefits associated with the reductions in NO_x emissions would be offset then by the increases in ammonia and particulate matter emissions. The onsite storage of ammonia would also create a potential for accidental release that did not previously exist.

Unit 1 Emission Levels

Unit 1 has historically operated for approximately 2,000 to 3,000 hours per year or less. In contrast, Unit 2 has operated at about double the hours as Unit 1. Unit 2 was permitted to operate at a 25 ppm NO_x level while firing natural gas until January 1, 1998, at which time the Unit is to meet a 15 ppm emission limit. Due to the rapid advances in dry low NO_x technology on the Frame 7EA machine, it was possible to install a machine that operated at a 15 ppm NO_x level or below. Thus, Unit 2 has been operating since early 1995 at rates of 1/2 to 2/3 of its permitted levels. After January 1, 1998, Unit 2 will still be operating at rates less than its 15 ppm emission level. Considering that the 120 MW Frame 7EA is three times the size of the LM6000 and operates at twice the capacity factor, it is easy to demonstrate that the overall NO_x annual tons emitted from the facility (Unit 1 at 25 ppm and Unit 2 <15 ppm) is less than the 1998 permit levels of 15 ppm for both Units. The calculations follow.

Pre-1998:

Unit 1 permit level (25 ppm) 35 lb/hr NO_x
Unit 2 permit level (25 ppm) 117 lb/hr NO_x
Unit 1 actual level (25 ppm) 35 lb/hr NO_x
Unit 2 actual level (~12 ppm) ~56 lb/hr NO_x

Projected Post 1998:

Unit 1 permit level (15 ppm) 21 lb/hr NO_x
Unit 2 permit level (15 ppm) 70.2 lb/hr NO_x
Unit 1 actual level (25 ppm) 35 lb/hr NO_x
Unit 2 actual level (~12 ppm) ~56 lb/hr NO_x

Best Available Control Technology Issues

Permit BACT Assessment

A complete BACT assessment was provided for NO_x as part of the PSD permit application. The BACT assessment included an economic assessment for the installation of lowest achievable emission rate (LAER) technology and less stringent options. LAER in that case was considered to be selective catalytic reduction on both the simple cycle and combined cycle combustion turbines. The incremental levelized costs of installing SCR on the LM6000 (Unit 1) firing fuel oil for 8,760 hours per year was $9,200 per ton of NO_x removed. The incremental costs for natural gas firing were computed to be $13,700 per ton of NO_x removed. The costs were high because very little NO_x (in tpy) is produced by the

40 MW LM6000 unit in the first place.

Revised BACT Costs

A rough estimate was performed to determine what the BACT costs would be for installing (retrofitting) an SCR system on the existing Unit 1 at the Cane Island Power Park. Since the time the original BACT was prepared, catalyst capital costs have declined. However, the decline in SCR capital costs is partially offset by the added costs of moving the Unit 1 stack to allow sufficient room for the necessary ductwork for the SCR. Based upon 8,760 hours per year of natural gas operation, the incremental costs associated with lowering the NO_x emissions from 25 to 15 ppm via SCR are $11,000 per ton of NO_x removed. Because Unit 1 was installed to provide peaking capacity, the Unit has never operated more than a few thousand hours per year. Accounting for the capacity factor in the BACT costs (assuming a 25 percent annual capacity factor) would result in an incremental cost of $44,000 per ton of NO_x removed. This cost exceeds even the most stringent BACT cost thresholds established in the ozone and NO_x nonattainment districts of California.

Comparable BACTs for LM6000s

Although BACT assessments are performed on a case-by-case basis to allow for project-specific perturbations in design and associated costs, EPA has issued guidance documents to bring consistency to the process. In keeping with this approach, a comparison of the proposed Cane Island BACT to other LM6000 BACT determinations was performed. A list of US installations of LM6000's was obtained from General Electric. This list is provided as Attachment C.

As shown, the LM6000-PA's have been installed at over three dozen stations across the United States and Canada. Of these, six have been installed in Florida. The permitted NO_x emission limits for the LM6000-PAs located in Florida while burning natural gas are all at 25 parts per million. It is important to note that all of the Florida installations with the exception of the Cane Island Unit 1 are operated in combined cycle mode. The only other LM6000-PA that has been permitted for simple cycle operation exclusively is located in Minnesota and was permitted at a NO_x level of 25 ppm.

Only three of the LM6000-PA's installed to date have required the use of an SCR system on the back end of the turbine. In all of these cases, the base NO_x emissions from natural gas firing upstream of the SCR were 42 ppm or higher, the units were located in an ozone and/or NO_x nonattainment area or transport region, and the units were operating in combined cycle mode.

Thus, as shown by the compilation of permitted NO_x levels for LM6000-PA combustion turbines, the BACT determinations have resulted in permitted emissions commensurate with the original limit established for the Cane Island Unit 1 (i.e., 25 ppm).

Implications with Other CAA Programs
In addition to the PSD program requirements, the Cane Island Power Park Units 1 and 2 are also subject to the provisions of the Acid Rain Program (Title IV), and the Part 70 Operating Permit Program (Title V). The centerpiece of the acid rain program is the utilization of allowances to track annual SO_2 emissions from electric generating facilities and unit-type specific NO_x emissions. Neither of these programs would be affected by allowing Unit 1 to remain at its current operating conditions (i.e., 25 ppm NO_x during natural gas firing).

As stated earlier, the Cane Island Power Park would become subject to a new program, the accidental release program as found at 40 CFR Part 68, if SCR was installed to comply with the 15 ppm NO_x emission limit.

ATTACHMENT C

LM6000 Fleet Emission Data

S/N	Config	Customer	Site Name	Location	Type	Site Emissons NOx(ppm)	CO(pph)
185-101	PA-NDW	Energy Initiatives	Lake 2	Umatilla, FL	CC/Cogen	25	
185-102	PA-NDW	Energy Initiatives	Pasco 2	Dade City, FL	CC/Cogen	25	
185-103	PA-NDW	Energy Initiatives	Pasco 1	Dade City, FL	CC/Cogen	25	
185-104	PA-NDW	Energy Initiatives	Lake 1	Umatilla, FL	CC/Cogen	25	
185-106	PA-NGS	TransAlta	Trans Alta #1	Ottawa, Canada	CC/Cogen	42	
185-108	PA-NGS	TransAlta	Trans Alta #GE-101	Mississauga, Canada	CC/Cogen	42	
185-109	PA-NDW	US Generating	E Syracuse 1	E. Syracuse, NY	CC/Cogen		
185-110	PA-NDW	US Generating	E Syracuse 2	E. Syracuse, NY	CC/Cogen		
185-111	PA-NGW	Hutchinson Utilities Comm.	City of Hutchinson	Hutchinson, MN	SC/	25	N/A
185-112	PA-NGS	TransAlta	Trans Alta #GE-102	Mississauga, Canada	CC/Cogen	42	
185-113	PA-NDW	KIAC Partners --	Kennedy Airport 1	Queens, NY	CC/Cogen	25 (to 42 with water)	17.29
185-114	PA-NDW	CEA/Brooklyn Union Gas	Kennedy Airport 2	Queens, NY	CC/Cogen	25 (to 42 with water)	17.29
185-116	PA-NGS	Florida Power Corp	U of Florida	Gainesville, FL	CC/Cogen	25	none
185-117	PA-NDW	Lake Superior Power	Union Energy #1	Sault St. Marie, Ont	CC/Cogen	dry	
185-119	PA-NDW	Northeast Utilities	South Meadow Station	Hartford, Conneticut			
185-120	PA-NGW	Lake Superior Power	Union Energy #2	Sault St. Marie, Ont	CC/Cogen	dry	
185-126	PA-NGS	Thermo	Ft. Lupton A (lease -107)	Ft. Lupton, CO	CC/Cogen	42	
185-129	PA-NGW	Las Vegas Cogen, LP	Las Vegas Cogen	Las Vegas, NV	CC/Cogen	60	10 ppm
185-130	PA-NGS	Thermo	Ft. Lupton C (lease -138)	Ft. Lupton, CO	CC/Cogen	42	
185-132	PA-NDW	CEA Nissequogue	SUNY	Stony Brook, NY	CC/Cogen	25	41.6
185-133	PA-NDW	Cogen Partners of America	Progresso Foods	Vineland, NJ	CC/Cogen	60 ppm	
185-134	PA-NDW	Kissimmee Util. Authority	Kissimmee	Kissimmee, FL	SC	25(gas)/42(liq)	
185-135	PA-NGS	Thermo	Ft. Lupton B	Ft. Lupton, CO	CC/Cogen	42	
185-136	PA-NGS	Thermo	Ft. Lupton D	Ft. Lupton, CO	CC/Cogen	42	
185-137	PA-NGS	Thermo	Ft. Lupton E	Ft. Lupton, CO	CC/Cogen	42	
185-143	PA-NGW	Kamine/Besicorp Allegany		Hume, NY	CC/Cogen	65ppm (9ppm SCR)	15
185-146	PA-NGW		Thermo Monfort				
185-147	PA-NDW	Sithe Energies	AG Energy	Ogdensburg, NY	CC/Cogen	75(scr to 9ppm)	15/18 ppm
185-152	PA-NDW	S.M.U.D.	Carson Energy #1	Elk Grove, CA	CC/Cogen		
185-157	PA-NGW	Arroyo Energy	Goal Line Operations	Escondido, CA	CC/Cogen	42 ppm (5 ppm SCR)	25 ppm
185-158	PA-NGW	S.M.U.D.	Carson Energy #2	Elk Grove, CA	Peaker		
185-160	PA-NDW	OMPA	Ponca City Steam Unit #1	Ponca City, Oklahoma			
185-162	PA-NDW	Willamette Industries, Inc.	Albany Paper Mill	Albany, Oregon	CC/Cogen		

185-168	PA-NGWG03	Northeast Utilities	Devon Station	Conneticut					
185-172	PA-NGSG03	Northeast Utilities	Devon Station	Conneticut					
185-181	PA-NDW	Potter Power	Potter Power	Tunis, Canada	CC/Cogen	Dry		N/A	
185-182	PA-NGWP06	Northland Power	Iroquois Falls	Iroquois Falls, Canada	CC/Cogen	Dry		N/A	
185-185	PA-NGWP06	NortHand Power	Iroquois Falls	Iroquois Falls, Canada	CC/Cogen	Dry		N/A	
185-191		SMUD- P&G							
185-204	PA-NDWG07	Northeast Utilities	Devon Station	Conneticut					
185-213		Northeast Utilities	Devon Station	Conneticut					
190-206	PB-NGD	CSW/ARK 1	Orange Cogen	Bartow, FL	Cogen		25		25
190-207	PB-NGD	CSW/ARK 2	Orange Cogen	Bartow, FL	Cogen		25		25
190-212	PB-NGDG08	TransAlta	Windsor						

ATTACHMENT D

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :		01-Jan-1998		
3. Requested Allowable Emissions and Units :		15.00	ppm@15%O2	
4. Equivalent Allowable Emissions : 22.00	lb/hour	96.36	tons/year	
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Future allowable emission limit (in lbs/MBtu) from permit AC49-205703 for natural gas for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Note the permit stated an annual emissions limit of 90.86 tpy for 8,260 hr/yr of natural gas operation and 19 tpy for the remaining 500 hr/yr of fuel oil firing (total 109.86 tpy). The above emissions are calculated assuming 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4. The NOx maximum limit will be lowered to 15 ppm@15%O2 by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved, the applicant will provide the Department with the expected compliance dates which will be updated annually.				

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Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		25.00	ppm@15%O2	
4. Equivalent Allowable Emissions : 36.00	lb/hour	157.68	tons/year	
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Note the peremit listed 148.68 tpy for 8,260 hr/yr of natural gas operation and 19 tpy for the remaining 500 hy/yr of fuel oil firing (total 167.68 tpy). The above emissions are calculated assuming 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4.				