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Florida Power & Light Company
West County Energy Center – Unit 3
Permit No. – PSD-FL-396
DEP File No. – 0990646-002-AC

WCPP Project 161354
WCPP Files 14.0100/32.0440
WCPP3-2011-TP-332
February 11, 2011
Email, Express Mail

RECEIVED
FEB 15 2011
BUREAU OF
AIR REGULATION

Ms. Elizabeth Walker
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road, MS 5500
Tallahassee, FL 32399-2400

Subject: **Regulatory Notification for CEMS Certification and Air Permit Compliance Testing**

Dear Ms. Walker:

On behalf of Florida Power & Light Company (FPL) and its Designated Representative, Sheila M. Wilkinson, the West County Power Partners, LLC (WCPP), EPC Contractor for construction of the new combined cycle generating unit at the FPL West County Energy Center – Unit 3, is submitting the CEMS Certification and Air Permit Compliance test protocols in accordance with 40 CFR Part 75.61(a)(1)(i) and 40 CFR Part 60.8(a) and the State of Florida Conditions of Certification Air Permit regulations.

If you have questions about this request, please contact Terry Apple at (913) 458-7220 or John Rachal at (561) 784-8048.

Very Truly Yours,

WEST COUNTY POWER PARTNERS, LLC

Gary G. Jamison / for
Mike Perkins
Project Executive

WS:hs
enclosures

cc: Dave McNeal, USEPA Air, Pesticides and Toxics Management (hard copy)
Art Diem, USEPA Clean Air Markets Division
Leigh Pell, FDEP Air Resource Management
Lee Hoefert, FDEP Southeast District
Mike Halpin, FDEP Sitting Coordination Office
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David Fawcett, FPL West County Environmental Leader
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Greg Hines, WCPP Site Environmental Manager
Terry Apple, WCPP Project Manager/ Project File
William Stevenson, WCPP Environmental Specialist

WEST COUNTY ENERGY CENTER BLOCK 3
UNITS 3A, 3B, and 3C
LOXAHATCHEE, FLORIDA

CERTIFICATION TEST PROTOCOL

PREPARED FOR: FLORIDA POWER AND LIGHT COMPANY

PREPARED BY: CUSTOM INSTRUMENTATION SERVICES CORPORATION

1/6/11

CERTIFICATION TEST PROTOCOL

1.0 OVERVIEW

The West County Energy Center Block 3 is a nominal 1,250 megawatt (MW) power plant located in Loxahatchee, Florida. Block 3 consists of three nominal 250 MW Model 501G gas turbines with three supplementary-fired heat recovery steam generators (HRSG) and a common 500 MW steam-electric generator. The individual turbines are identified as 3A, 3B, and 3C. The gas-fired combined cycle units will use ultralow sulfur (ULS) fuel oil as backup fuel. Exhaust gases from each turbine are discharged into the atmosphere through stacks approximately 150 feet above grade. A dedicated CEMS will monitor emissions from each turbine.

The Air Permit issued by the Florida Department of Environmental Protection requires Continuous Emission Monitoring Systems (CEMS) for oxides of nitrogen (NO_x), carbon monoxide (CO) and oxygen (O_2) be installed on the exhaust stacks of each gas turbine. The CEMS instrumentation will be used to demonstrate continuous compliance with the allowable emission limitation set forth in the permit. The CEMS also has to meet the monitoring and reporting requirements of the following:

Title 40 Code of Federal Regulations (CFR), Part 75 Appendix A
Specifications and Test Procedures

Title 40 CFR, Part 60, Appendix B
Performance Specification 4/4A - *Specifications and Test Procedures for Carbon Monoxide (CO) Continuous Emission Monitoring Systems in Stationary Sources*

2. CERTIFICATION STRATEGY

The certification testing includes procedures to satisfy both sets of regulations. To verify the accuracy of the analyzers and the sample locations, field testing will be conducted on the CEMS. The testing consists of a Relative Accuracy Test Audit (RATA), linearity check, Cylinder Gas Audit (CGA), 7-day calibration error test, and a cycle time test. All testing will be performed while the plant is operating at normal load. In addition, testing will be performed on the DAHS to verify formulas and missing data routines. All tests will be performed according to the prescribed methodologies described in 40 CFR Part 60 Appendix B, 40 CFR Part 75 Appendix A and Florida Department of Environmental Protection regulations. The pass/fail criteria for each test are listed in Table 1. The results of all tests performed for 40 CFR 75 will provided in XML format.

2.1 Relative Accuracy Test Audit

Air Hygiene was contracted by Custom Instrumentation Services, Inc. (CiSCO), the CEMS supplier, to provide testing to support the Part 60 and Part 75 Relative Accuracy Test Audits (RATA) at West County Energy Center Block 3. During the test, values will be recorded every minute and then averaged for the duration of the test period. These values are compared to the test teams values for the same test period. A RATA Protocol is provided in Appendix 1.

2.2 Linearity Check / Cylinder Gas Audit

CiSCO will perform the linearity test required by 40 CFR 75, Appendix A. The high range of the NO_x analyzers and the O_2 analyzers will be challenged three times with each of three levels of calibration gas (low, mid and high). A linearity test is not required on NO_x analyzer span values less than or equal to 30 ppm (as per 40 CFR 75, Appendix A, 6.2). The gases used will be EPA Protocol calibration gases certified within 2 percent of the specified concentration. The mean difference between the analyzer response and the calibration gas value, as a percentage of the calibration gas value, must be within 5%. Results are also acceptable if the difference between the mean response and the calibration gas is within 5 ppm for NO_x and 0.5% O_2. A report will be printed which shows the analyzer response for each injection. The results for the three runs will then be tabulated and will be included in the final report. The gases to be used are listed in Table 2.

In lieu of the Part 60 regulations, which do not require an initial CGA for the CO monitoring system, FPL, at their discretion may perform Cylinder Gas Audits on both ranges of the CO analyzers. Each analyzer will be challenged three times with two levels of calibration gas (low and mid). The mean difference between the analyzer response and the calibration gas value, as a percentage of the calibration gas value, must be within 15%. Results are also acceptable if the difference between the mean response and the calibration gas is within 5 ppm CO. A report will be printed which shows the analyzer response for each injection. The results for the three runs will then be tabulated and will be included in the final report. The gases to be used are listed in Table 2.

2.3 Calibration Error Tests

CiSCO will perform the 7-Day Calibration Error Tests on the high range of the NO_x analyzers and the O_2 analyzers in accordance with 40 CFR 75 Appendix A. A Calibration Error Tests is not required on NO_x analyzer span values of 50 ppm or less (as per 40 CFR 75, Appendix A, 6.3.1). Each analyzer will be challenged with zero and calibration gases each day for seven consecutive operating days (not necessarily consecutive calendar days). This data will be included in the final report. The analyzer response must be within 2.5% of span for NO_x and within 0.5% O_2 for the O_2 analyzer. Results are also acceptable if the difference is within 5 ppm for NO_x. A calibration report will be printed out daily and the results for the seven day period will be tabulated. The gases to be used are listed in Table 2.

2.4 Cycle Time Test

CiSCO will perform the cycle time tests for NO_x and O_2 pollutant concentration monitors in accordance to 40 CFR 75 Appendix A. To perform the cycle time test, the low and high ranges of the NO_x analyzers and the O_2 analyzers will be challenged with a zero gas and high level (80 to 100% of span) calibration gas. Both the upscale and down scale cycle times will be determined. The response time to reach 95% of the gas value must be less than 15 minutes for each analyzer. The longer of the two analyzers response time is the NO_x system response time. An audit report will be printed which shows the analyzer response. The results for each analyzer will then be tabulated. The gases to be used are listed in Table 2. This data will be included in the final report.

CiSCO will perform a response time test on the CO analyzers as per 40 CFR 60, Appendix B, Performance Specification 4A. To perform the response time test, the low and high ranges of the CO analyzers will be challenged three times with a zero gas and high level (80 to 100% of span) calibration gas. Both the upscale and down scale response times will be determined. The response time to reach 95% of the gas value must be less than 90 seconds for each analyzer. An audit report will be printed which shows the analyzer response. The results for each analyzer will then be tabulated. The gases to be used are listed in Table 2. This data will be included in the final report.

2.5 CEMS Calibration Drift Tests

In accordance with 40 CFR 60, Appendix B, Performance Specification (PS) 4A, CiSCO will perform calibration drift tests on the CO analyzers once a day for seven consecutive operating days. Both the low and high ranges of the CO analyzers must meet a limit of 5 percent drift, for 6 out of 7 days. This limit can be found in Section 13.1 of PS4A.

Note: FPL has obtained guidance and approval from Florida Department of Environmental Protection (FDEP) on past projects to perform the calibration drift test for CO on seven consecutive unit operating days rather than seven consecutive calendar days. This is consistent with other calibration drift requirements currently identified in 40 CFR Part 75, Appendix A, 6.3.1, and with 40 CFR Part 60.334(b)(1) Subpart GG.

2.6 *DAHS TESTING*

The DAHS verification consists of two tests; verification that all formulas identified in the monitoring plan are correctly programmed and verification that all necessary missing data procedures are correctly programmed. The DAHS tests will follow the procedures identified in 40 CFR Part 75 and applicable policy manuals. In addition, the software vendor will verify that all missing data scenarios are correct. A software verification statement and the formula verifications will be provided in the final report.

TABLE 1: CEMS CERTIFICATION PERFORMANCE SPECIFICATIONS

	PASS/FAIL CRITERIA	CITATION
RATA, NO_x lb/mmBtu	7.5% RA or $\pm$0.015 lb/mmBtu (for annual RA frequency)	40 CFR 75 App. B, 2.3.1.2(f)
LINEARITY NO_x High O_2	 5% of gas value or 5 ppm 5% of gas value or 0.5% O_2	 40 CFR75 App. A, 3.2
CALIBRATION ERROR NO_x High O_2	 2.5% of span or 5 ppm if span $\leq$200 ppm [R-A] 0.5% O_2	 40 CFR 75 App. A, 3.1
CYCLE TIME TEST NO_x High, NO_x Low, O_2	 $\leq$15 minutes	 40 CFR 75 App. A, 3.5
RATA CO lb/hr, ppm @ 15% O_2	 10% RA, 5% of standard, 5 ppm	 40 CFR 60, App. B, PS4/4A
CALIBRATION DRIFT TEST CO High, CO Low	 5.0% of range for 6 of 7 days	 40 CFR 60, App. B, PS4/4A See Note in Section 2.5
CYLINDER GAS AUDIT CO	 15% CGA error, 5 ppm	 40 CFR 60, App. F
RESPONSE TIME TEST CO High, CO Low	 $\leq$90 seconds	 40 CFR 60, App. B, PS4A
DAHS ACCURACY	Verify formulas and missing data routines	40 CFR 75

TABLE 2: GAS REQUIREMENTS FOR CERTIFICATION

	GAS TYPE	RANGE	CONCENTRATION
LINEARITY CHECK *	EPA Protocol	NO_x High O_2 High	Low - 40-60 ppm Mid - 100 - 120 ppm High - 160 - 200 ppm Low - 5 - 7.5% Mid - 12.5 - 15% High - 20 - 25 (21% air)
CALIBRATION ERROR**	EPA Protocol	NO_x High O_2 High	Zero, 160 - 200 ppm Zero, 20 - 25 (21% air)
CYCLE TIME	EPA Protocol EPA Protocol	NO_x Low NO_x High O_2 High	Zero, 8 - 10 ppm Zero, 160 - 200 ppm Zero, 20 - 25 (21% air)
CYLINDER GAS AUDIT	Certified Master Certified Master	CO Low CO High	Low - 2 - 3 ppm Mid - 5 - 6 ppm Low - 240 - 360 ppm Mid - 600 - 720 ppm
CALIBRATION DRIFT	Certified Master Certified Master	CO Low CO High	Zero, 8 - 10 ppm Zero, 960 - 1200 ppm
RESPONSE TIME	Certified Master Certified Master	CO Low CO High	Zero, 8 - 10 ppm Zero, 960 - 1200 ppm

*** No linearity check is required on span values of 30 ppm or less.**

**** No calibration error test is required on span values of 50 ppm or less**

APPENDIX 1

CEMS RELATIVE ACCURACY TEST AUDIT PROTOCOL

AIR HYGIENE, INC.

Testing Solutions for a Better World

CONTINUOUS EMISSIONS MONITORING SYSTEM RELATIVE ACCURACY TEST AUDIT AND LINEARITY TEST PROTOCOL

FOR
THREE MITSUBISHI 501G
CEMS (UNITS 3A, 3B, AND 3C)

PREPARED FOR
CUSTOM INSTRUMENTATION
SERVICES CORPORATION
AND
FLORIDA POWER & LIGHT

AT THE
WEST COUNTY
ENERGY CENTER
LOXAHATCHEE, FLORIDA

Florida Department of
Environmental Protection

January 5, 2011

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(918) 307-8865 or (888) 461-8778
www.airhygiene.com

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Prepared By:

Jake R. Fahlenkamp, QSTI, Director of Quality Assurance

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1.0 INTRODUCTION

1.1 General Facility Description

Florida Power & Light (FPL) owns and operates the West County Energy Center (West County) located at 20505 State Road 80 in Loxahatchee, Florida. The station's block three consists of three Mitsubishi 501G combustion turbine generators (CTGs) used in the production of electricity. Each 501G (Units 3A, 3B, and 3C) has a nominal rating of 250 megawatts (MW) operating in combined cycle with separate heat recovery steam generators (HRSGs). Each HRSG is equipped with a selective catalyst reduction (SCR) unit and duct burners. All units fire natural gas as the primary fuel and ultra low sulfur distillate fuel oil as a restricted alternate fuel.

The 501G stacks are circular and measure 21.95 feet (ft) (263.38 inches) in inner diameter at the test ports which are approximately 138 ft above grade level with an exit elevation of approximately 150 ft above grade level. The test ports are located 44.31 ft (531.75 inches) downstream and approximately 12 ft (144 inches) upstream from the nearest disturbances.

A single, dedicated continuous emissions monitoring system (CEMS) is installed on each unit. Each of the three CEMS configurations includes a Thermo Environmental Instruments (TECO) Model 42i/LS dual-range (0-10 and 0-200 parts per million (ppm)) nitrogen oxide (NOx) analyzer; TECO Model 48i dual range (0-10 and 0-1200 ppm) carbon monoxide (CO) analyzer; and Servomex Model 1440D single range (0-25 percent (%)) oxygen (O_2) analyzer. Each system also includes a data acquisition and handling system (DAHS).

1.2 Reason for Testing

West County is a newly constructed facility subject to the regulatory requirements of the Florida Department of Environmental Protection (FDEP) and the United States Environmental Protection Agency (EPA) for relative accuracy test audits (RATAs) and other aspects of CEMS certification (e.g. linearity tests). As such, testing will include monitoring for nitrogen oxides (NOx), carbon monoxide (CO), and oxygen (O_2) to conduct RATAs on all units following the guidelines of 40 Code of Federal Regulations (CFR) Part 60 and Part 75. Testing will also include performing linearity tests on each NOx and O_2 CEMS analyzer at each applicable range following the guidelines of 40 CFR Part 75.

2.0 SUMMARY

2.1 Owner Information

Company:	Florida Power & Light
Contact:	Danny Potter
Mailing Address:	20505 State Road 80 Loxahatchee, Florida 33470
Office:	(561) 904-4910
Cell:	(561) 358-0079
Email:	Danny.Potter@fpl.com

2.2 CEMS Contractor Information

Company:	Custom Instrumentation Services Corporation (CiSCO)
Contact:	Sarah Gray, Environmental Scientist
Mailing Address:	7325 South Revere Parkway Centennial, Colorado 80112
Office:	(303) 790-1000 ext 115
Fax:	(303) 790-7292
Email:	sgray@ciscocems.com

2.3 Test Contractor Information

Company:	Air Hygiene International, Inc.
Contact:	Jake R. Fahlenkamp, Director of Quality Assurance
Mailing Address:	5634 South 122nd East Avenue, Suite F Tulsa, Oklahoma 74146
Office:	(918) 307-8865
Cell:	(918) 407-5166
Fax:	(918) 307-9131
E-mail:	jake@airhygiene.com
Website:	www.airhygiene.com

2.4 Expected Test Start Date

Test dates are yet to be determined. Further notification will be provided by CiSCO and/or FPL as a testing schedule is determined.

2.5 Testing Schedule

The following schedule indicates specific activities required to be done each day; however, the schedule is flexible and can be extended as necessary if there are operational or testing delays. If there are no operational delays, this schedule can be completed as detailed by the testing crew. The details below describe the activities to be conducted.

Pre-test Activities	Due Date
1. Receive site safety training	day of arrival for setup
2. Conduct site inspection and pre-test meeting	per CiSCO and/or Air Hygiene
3. Prepare draft electronic test protocol	prior to start of project

On-Site Pre-testing Schedule	Time
Day 0 – Pre-test, initial site mobilization and setup	
• Arrive at site and attend safety training class	08:00 – 09:00
• Setup on first unit	09:00 – 11:00
• Conduct preliminary testing of test equipment	11:00 – 13:00

RATA Testing	**Time**
Day 1 – RATA, first unit, normal or alternative normal load	
• Daily setup and calibrations	08:00 – 09:00
• Conduct stratification testing • Stratification testing for NOx and O_2	09:00 – 10:00
• Conduct Testing for NOx, CO, and O_2 • NOx, CO, and O_2 testing: 9-12, 21-minute runs	10:00 – 16:00
• Teardown from first unit and setup on second unit	16:00 – 18:00

Additional days will follow the same timeline of Day 1 with unit test order determined by FPL and/or CiSCO. Linearity testing schedules will be determined by FPL and/or CiSCO as CEMS are available.

Activities after Testing	**Sequential Days**
• Demobilization of Testing Crew	Day 1
• Preparation of draft hard copy test report	Days 2 – 9
• Submit for review to CiSCO	Day 10
• Review and comment on draft by CiSCO	Days 11 – 14
• Incorporate CiSCO comments into draft copy	Days 15 – 19
• Submit for review to FPL	Day 20
• Review and comment on draft by FPL	Days 21 – 24
• Incorporate FPL comments into draft copy	Days 25 – 29
• Final reports delivered to FPL	Day 30

2.6 Hardcopy RATA Report Content

The hard-copy RATA Reports will be submitted to CiSCO within 30 days of completion of testing and meet the requirements of the FDEP and the EPA for stack emissions testing and CEMS certification. The reports will include discussion of the following:

- Introduction
- Plant and Sampling Location Description
- Summary and Discussion of Test Results Relative to Acceptance Criteria
- Sampling and Analytical Procedures
- QA/QC Activities
- Test Results and Related Calculations
- Sampling Log and Chain-of-Custody Records
- Audit Data Sheets

CiSCO personnel will conduct cycle response time tests and compile necessary information for the 7-day drift tests. Data will be submitted to Air Hygiene and included in the CEMS certification reports as necessary. The final certification report will be provided by CiSCO.

2.7 Equipment and Procedures

Test methods and parameters to satisfy 40 CFR Part 60 and 75 will include:

40 CFR Part 60, EPA Method 1 for sample location
40 CFR Part 60, EPA Method 3a for oxygen (O_2)

40 CFR Part 60, EPA Method 7e for nitrogen oxides (NOx)
40 CFR Part 60, EPA Method 10 for carbon monoxide (CO)
40 CFR Part 60, EPA Method 19 for F-Factor determination of stack exhaust flow
40 CFR Part 60, Appendix B, Performance Specifications #2, 3, and 4/4a
40 CFR Part 75, Appendix A and B for NOx-diluent

2.8 Proposed Variations

After the successful completion of a stratification test for NOx, CO, and O_2, RATAs will be conducted from one point if the test passes under the appropriate 40 CFR 75 criteria. 40 CFR 60 criteria for CO will be overridden.

The NO_2 to NO converter check will be verified using the Emission Measurement Center's ALT-013 acceptable alternative procedure to section 8.2.4 of EPA Method 7e in Appendix A of 40 CFR Part 60.

2.9 RATA Sampling Strategy

Relative accuracy test audits (RATAs) are used to verify the ability of a CEMS to accurately measure and report a given pollutant concentration or emissions rate from an affected source and to determine any bias in those measurements. The RATA is required for initial CEMS certification and, depending on those results, must be performed periodically thereafter during routine operation of the source. These relative accuracy tests will be carried out in accordance with the procedures in 40 CFR Part 60 and Part 75 (NOx-diluent). In addition, a bias test will be performed on the NOx-diluent system to meet 40 CFR 75 requirements.

The RATAs will be performed while the units are operating above 50 percent of the maximum operating load, as required under 40 CFR Part 60, and while the unit is operating within the normal or alternative normal load, as required under 40 CFR Part 75. The RATA pass/fail criteria will be determined by comparing the results from the CEMS to concurrent measurements from reference method (RM) analyzers over a prescribed series of test runs. Units of comparison for each pollutant will include: NOx (ppmvd, ppmvd@15%O_2, lb/hr, and lb/MMBtu); CO (ppmvd, ppmvd@15%O_2, and lb/hr); and O_2 (%), to the extent these units are available from the CEMS DAHS.

In accordance with 40 CFR 60, Appendix B, PS 2, Section 13.2, the NOx (ppmvd, ppmvd@15%O_2, and lb/hr) RATA results will be acceptable if the relative accuracy (RA) does not exceed 20.0 percent when average emissions during the test are greater than 50 percent of the emission standard or alternative relative accuracy (ARA) does not exceed 10.0 percent when the average emissions during the test are less than 50 percent of the emission standard. Part 60 further requires that the unit be operating at greater than 50 percent of normal load.

In accordance with 40 CFR 75, Appendix A, Section 3.3.2(a) and (b), the NOx-diluent (lb/MMBtu) RATA results will be acceptable if the relative accuracy (RA) does not exceed 10.0 percent or if during the RATA the average NOx emission rate is less than or equal to 0.2 lb/MMBtu and the average difference between the CEMS and reference method (RM) values does not exceed 0.02 lb/MMBtu. Passing this set of criteria requires the CEMS to be retested after no more than two quality assured operating quarters. Alternatively, in accordance with 40 CFR 75, Appendix B, Section 2.3.1.2(a) and (f), and Appendix B, Figure 2, the NOx-diluent RATA results will be acceptable if the RA does not exceed 7.5 percent or if during the RATA the average NOx emission rate is less than or equal to 0.2

lb/MMBtu and the average difference between the CEMS and RM values does not exceed 0.015 lb/MMBtu. Passing this set of criteria allows the CEMS to be retested after four quality assured operating quarters or at least within eight calendar quarters.

In accordance with 40 CFR 60, Appendix B, PS 3, Section 13.2, the O_2 (%) RATA results will be acceptable if the average difference between the CEMS and reference method (RM) values does not exceed 1.0 percent absolute.

In accordance with 40 CFR 60, Appendix B, PS 4 and 4A, Sections 13.2 of each, the CO (ppmvd, ppmvd@15%O_2, and lb/hr) relative accuracy (RA) test results will be acceptable if the RA does not exceed 10.0 percent, if the average difference between the CEMS and reference method (RM) values plus the 2.5 percent confidence coefficient (2.5%CC) does not exceed 5.0 parts per million (ppm), or if the alternative relative accuracy (ARA) does not exceed 5.0 percent. Part 60 further requires that the unit be operating at greater than 50 percent of normal load.

2.10 Linearity Testing Strategy

The Linearity Test is required for initial CEMS certification and will be carried out in accordance with the procedures in 40 CFR Part 75. This testing will be performed on the dual range NOx and single range O_2 analyzers, on each CEMS. Linearity tests will be conducted while the units are combusting fuel at typical duct temperatures and pressures; however, it is not necessary for the units to be generating electricity during the tests.

Linearity tests will be checked at three concentration levels (low, mid, and high) using EPA Protocol No. 1 gases, supplied by Air Hygiene, as required by 40 CFR Part 75. Linearity test results are considered to be acceptable for the CEMS if the difference between the known check gas concentration and the analyzer response is less than or equal to five percent of the reference concentration at each reference level. Alternative acceptance criteria are defined further in the regulations.

APPENDIX A
QA/QC PROGRAM

TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after each testing project. The following paragraphs detail the quality control techniques, which are rigorously followed during testing projects.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range of the predicted values.

After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data just collected. The criteria on acceptable data is that the instrument drift shall be no more than 3 percent of the full-scale response. Quality assurance worksheets are prepared to document the multipoint calibration checks and zero to span checks performed during the tests (**See Appendix D**).

The sampling systems are leak checked by demonstrating that a vacuum greater than 10 in Hg could be held for at least 1 minute with a decline of less than 1 in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. These checks are performed to ensure that ambient air has not diluted the sample. Any leakage detected prior to the tests would be repaired and another leak check conducted before testing commenced.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the calibration gases introduced via two paths. The first path is directly into the analyzer and the second path via the sample system at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criteria for acceptance is agreement within 5% of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± 1% accuracy for all gases. EPA Protocol No. 1 gases will be used where applicable to assign concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials.

AIR HYGIENE maintains a large variety of calibration gases to allow the flexibility to accurately test emissions over a wide range of concentrations.

APPENDIX B
TEST EQUIPMENT CONFIGURATION AND DESCRIPTION

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures to be used conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 3a, 7e, 10, and 19.

Figure 1 depicts the sample system that will be used for the NOx, CO, and O_2 tests. A stainless steel probe will be inserted into the sample ports of the stack to extract gas measurements from the emission stream at three points located at 0.4 (15.7), 1.2 (47.2), and 2.0 (78.7) meters (inches) from the wall of the stack or a single point in the stack determined after passing an initial stratification test. The gas sample will be continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample and through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample will be partitioned to the NOx, CO, and O_2 analyzers through rotameters that control the flow rate of the sample.

The schematic (Figure 1) shows that the sample system will also be equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments will be housed in an air-conditioned, trailer-mounted mobile laboratory. Gaseous calibration standards will be provided in aluminum cylinders with the concentrations certified by the vendor according to EPA Protocol No. 1.

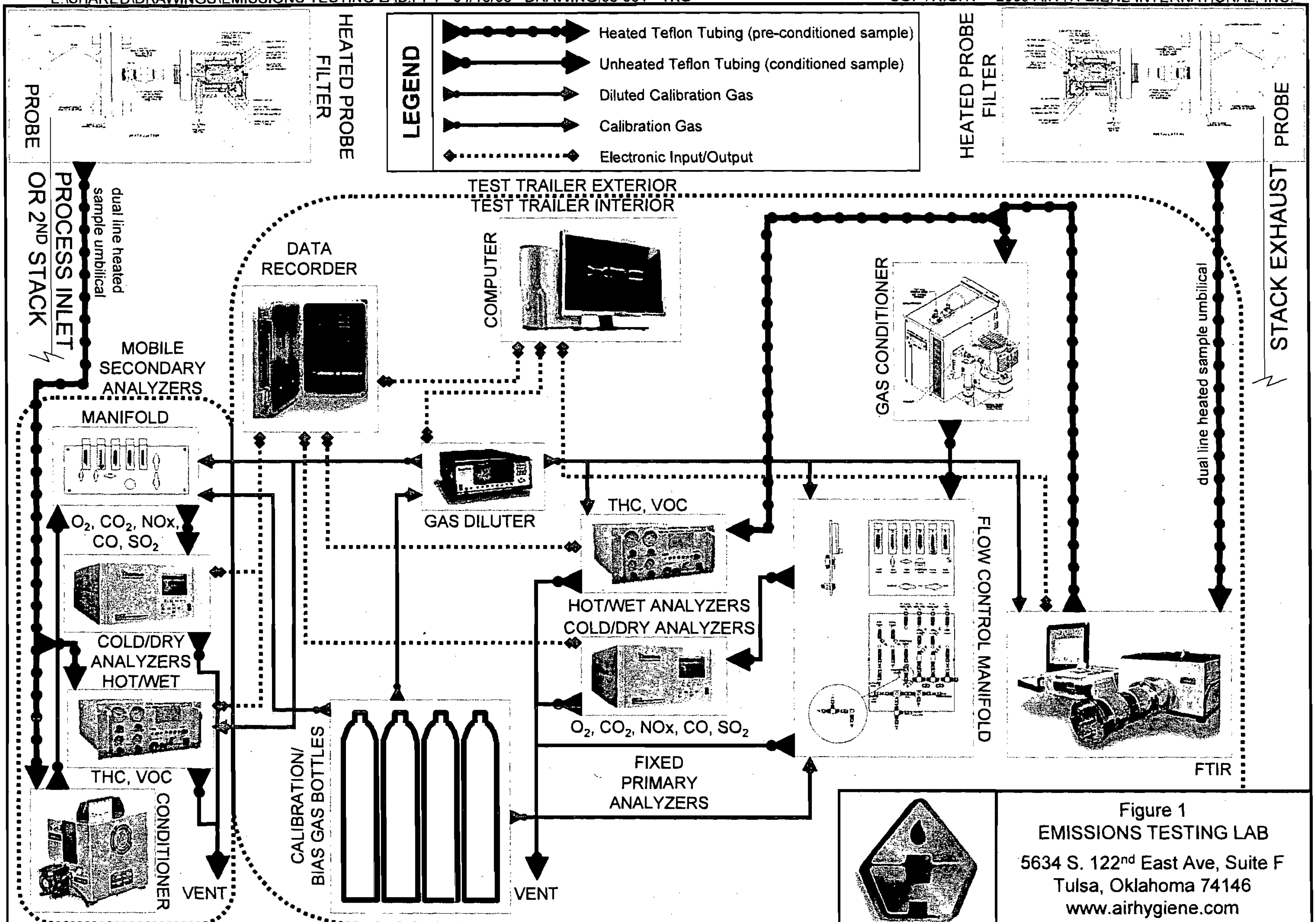
This general schematic also illustrates the analyzers to be used for the tests (i.e., NOx, CO, and O_2). All data from the Reference Method continuous monitoring instruments are recorded on a Logic Beach Hyperlogger. The Hyperlogger retrieves calibrated emissions data from each instrument every second. An average value is recorded every 30 seconds.

The stack gas analysis for O_2 concentrations will be performed in accordance with procedures set forth in EPA Method 3a. The O_2 analyzer uses a paramagnetic cell detector.

EPA Method 7e will be used to determine concentrations of NOx. A chemiluminescence analyzer will be used to determine the nitrogen oxides concentration in the gas stream. A NO_2 in nitrogen certified gas cylinder will be used to verify at least a 90 percent NO_2 conversion on the day of the test.

CO emission concentrations will be quantified in accordance with procedures set forth in EPA Method 10.

E:\SHARED\DRAWINGS\EMISSIONS TESTING LAB.PPT 04/18/08 DRAWING:08-001 TKG



Shown fully equipped. Some labs may not contain these features and others may contain additional features specific to certain scopes.

Figure 1
EMISSIONS TESTING LAB

5634 S. 122nd East Ave, Suite F
Tulsa, Oklahoma 74146
www.airhygiene.com
(888) 461-8778

TABLE #1: ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Max. Ranges	Sensitivity	Detection Principle
NOx	API 200AH or equivalent [1]	User may select up to 5,000 ppm	0.1 ppm	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear for listed ranges.
CO	API 300 or equivalent	User may select up to 3,000 ppm	0.1 ppm	Infrared absorption, gas filter correlation detector, microprocessor based linearization.
O_2	CAI 200 or equivalent	0-25%	0.1%	Paramagnetic cell, inherently linear.

[1] When applicable, to avoid interference from ammonia slip, API analyzers will be fitted with molybdenum converters and TECO analyzers contain in-line ammonia scrubbers.

TABLE #2: ANALYTICAL INSTRUMENTATION TESTING CONFIGURATION

Parameter	Sample Methodology	Example Range	Sensitivity	Calibration Gases (based on example range)
NOx	RATA	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 4-6 ppm High = 10 ppm
CO	RATA	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 4-6 ppm High = 10 ppm
O_2	RATA	0-21%	0.1%	Zero = 0 ppm nitrogen Mid = 8.4-12.6% High = 21%

APPENDIX C
STACK DRAWINGS

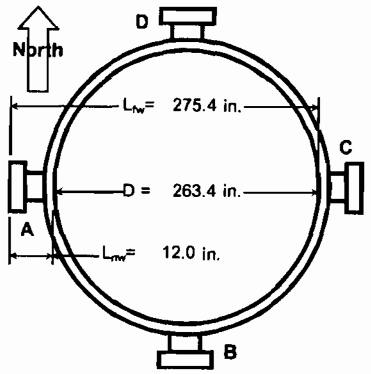
METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company	Florida Power & Light	**Date**	2011
Plant Name	West County Energy Center	**Project #**	cis-10-westcounty.fl-rata#1
Equipment	Mistubishi 501G	**# of Ports Available**	4
Location	Loxahatchee, Florida	**# of Ports Used**	4

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})	275.38	in.
Distance to Near Wall of Stack	(L_{nw})	12.00	in.*
Diameter of Stack	(D)	263.38	in.
Area of Stack	(A_s)	378.35	ft^2

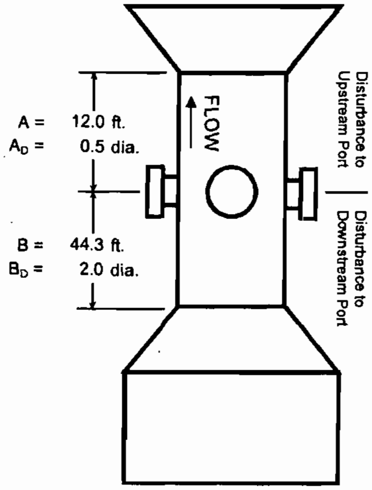
*assume 12 in. reference (must be measured and verified in field)

Distance from Disturbances to Port			
Distance Upstream	(A)	144.00	in.
Diameters Upstream	(A_D)	0.55	diameters
Distance Downstream	(B)	531.75	in.
Diameters Downstream	(B_D)	2.02	diameters



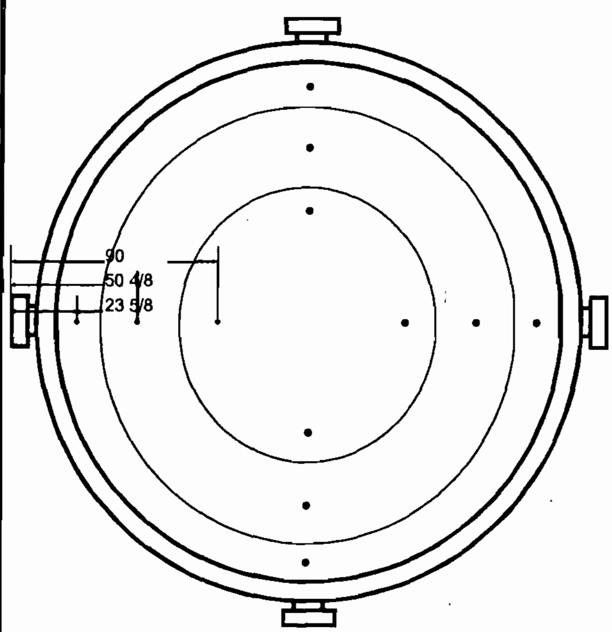
Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		Minimum Number of Traverse Points	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	Comp Stratification Criteria	Points
2.00-4.99	0.50-1.24	24	16	○ RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	○ Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	**Minimum Number of Traverse Points**	
Upstream Spec		24	16	**RATA Stratification**	
Downstream Spec		24	16	**Criteria**	**Points**
Traverse Pts Required		24	16	● Part75/60	12 RM1 pts
				○ 75 abrv (a)	3 points
				○ 75 abrv (b)	6 points
				12 points	

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
4	**Ports by**	3	**Pts / port**	**Stratification Traverse**
12	**Pts Used**	12	**Required**	**(RATA)**

Traverse Point Locations			
Traverse Point Number	**Percent of Stack Diameter**	**Distance from Inside Wall**	**Distance Including Reference Length**
	%	in.	in.
1	4.4%	11 5/8	23 5/8
2	14.6%	38 4/8	50 4/8
3	29.6%	78	90
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			



APPENDIX D
EXAMPLE TEMPLATES AND CALCULATIONS

AIR HYGIENE

RATA - FIELD DATA SHEET

Company:	
Location:	
Date:	
Unit Make and Model:	
Unit Number:	
Serial Number:	
Data Recorded By:	
Tested With AHI Unit(s):	Truck(s): Trailer(s):
LDEQ Warmup/Cal Req:	On (Day/Time): Cal (Day/Time):

CYLINDER SERIAL NUMBERS		O_2	NOx	CO
	Low			
	Mid			
	High			

CYLINDER SERIAL NUMBERS		THC	CO_2	SO_2
	Low			
	Mid			
	High			

RUN INFORMATION	Run #1	Run #2	Run #3	Run #4	Run #5	Run #6	Run #7	Run #8	Run #9	Run #10	Run #11	Run #12
Time Start (hh:mm:ss)												
Time Stop (hh:mm:ss)												
Rated Power (MW or hp)												
Actual Power (MW or hp)												
Barometric Pressure (in. Hg)												
Ambient Temperature (°F)												
Relative Humidity (%)												
CEMS DATA for O_2												
CEMS DATA for NOx												
CEMS DATA for CO												
CEMS DATA for SO_2												

CALIBRATION	O_2		NOx		CO		SO_2	
	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual
Zero Gas								
Low Gas								
Mid Gas								
High Gas								

NO_2 CONVERSION	
NO_2 Gas (ppm)	
NO Reading (ppm)	
NOx Reading (ppm)	
Cylinder Num	

BIAS	O_2		NOx		CO		SO_2	
	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid
Initial Run #1								
Run #1 / Run #2								
Run #2 / Run #3								
Run #3 / Run #4								
Run #4 / Run #5								
Run #5 / Run #6								
Run #6 / Run #7								
Run #7 / Run #8								
Run #8 / Run #9								
Run #9 / Run #10								
Run #10 / Run #11								
Run #11 / Run #12								
Run #12 Final								
Bias Gas Actual Conc.								

REPORT INFORMATION		
	INSTRUMENT	SERIAL #
O_2		
NOx		
CO		
THC		
CO_2		
SO_2		

RESPONSE TIME		
	TIME (hh:mm)	RESP (min)
Gas Inject	/ /	
1st Inst. @ 95%	/ /	/ /
2nd Inst. @ 95%	/ /	/ /
3rd Inst. @ 95%	/ /	/ /

Source Information	
Company	
Plant Name	
Equipment	
Location	

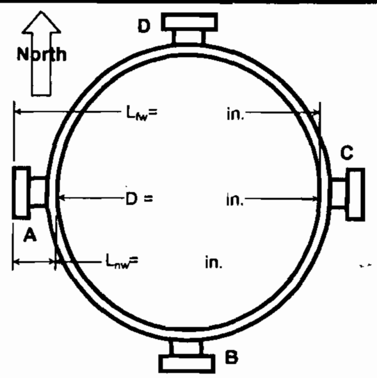
Test Information	
Date	
Project #	
Unit Number	
Load	
Number of Ports Available	
Number of Ports Used	

Stack and Test Type				
○	Isokinetic Traverse (Wet Chemistry Testing)			Circular Stack
○	Velocity Traverse (Flow and Flow RATA Test)			
○	Stratification Traverse (Compliance Test)		☐ RM 20	
◉	**Stratification Traverse (RATA)**	☐ Part 60	☑ Part 75	

METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})		in.
Distance to Near Wall of Stack	(L_{nw})		in.
Diameter of Stack	(D)		in.
Area of Stack	(A_s)		ft^2

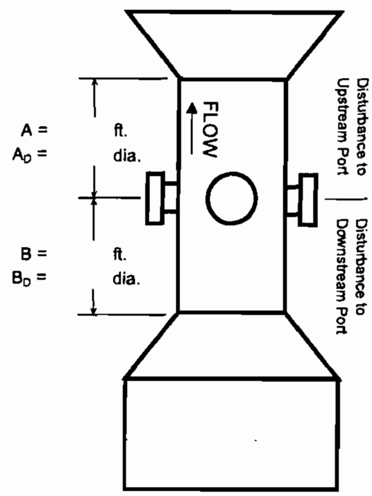


Distance from Disturbances to Port			
Distance Upstream	(A)		in.
Diameters Upstream	(A_D)		diameters
Distance Downstream	(B)		in.
Diameters Downstream	(B_D)		diameters

Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		Minimum Number of Traverse Points Comp Stratification	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	Criteria	Points
2.00-4.99	0.50-1.24	24	16	○ RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	○ Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	Minimum Number of Traverse Points RATA Stratification	
Upstream Spec					
Downstream Spec					
Traverse Pts Required				Criteria	Points
				○ Part75/60	12 RM1 pts
				○ 75 abrv (a)	3 points
				○ 75 abrv (b)	6 points

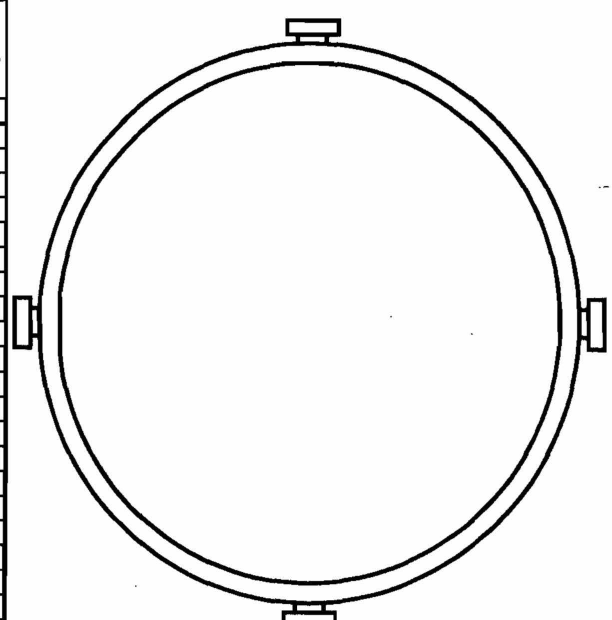
[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.

[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
	Ports by Pts Used		Pts / port Required	Stratification Traverse (RATA)

Traverse Point Locations			
Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
	%	in.	in.
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			



STRATIFICATION TRAVERSE (RATA) RESULTS

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

Traverse Point	Time Per Point	Point Start Time	Point Stop Time (Reading)	Diluent 1	Percent Difference	Pollutant 1	Percent Difference
	min.	hh:mm:ss	hh:mm:ss	%	%	ppm	%
Average							

RATA SAMPLE POINTS FOR CIRCULAR STACK

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

40 CFR 75 Criteria

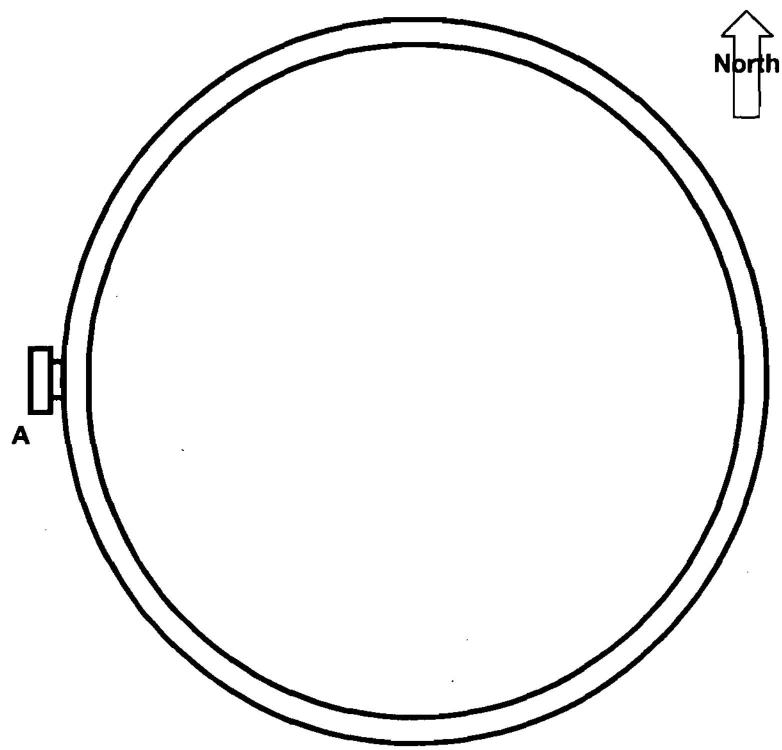
Stratification Results	
Maximum Percent Difference	No Test
Maximum Pollutant Conc. Diff.	No Test
Maximum Diluent Conc. Diff.	No Test
Stack Diameter	in.

Stratification Conclusions	
Maximum % Diff.	No Stratification Anticipated
Maximum Conc. Diff.	No Stratification Anticipated
Stack Diameter	D > 93.6 in.

Use Short RM Measurement Line

Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
	%	in.	in.
1			
2			
3			

Test Type
- ☐ Moisture, for MW
- ☐ Moisture, for wet-to-dry
- ☑ Gas
- ☐
- ☐ 6.5.6(b)(2) alt. points could apply



DRIFT AND BIAS CHECK		
Strat Test Pre and Post QA/QC Check	Diluent 1	Pollutant 1
Initial Zero		
Final Zero		
Avg. Zero		
Initial UpScale		
Final UpScale		
Avg. UpScale		
Sys Resp (Zero)		
Sys Resp (Upscale)		
Upscale Cal Gas		
Initial Zero Bias		
Final Zero Bias		
Zero Drift		
Initial Upscale Bias		
Final Upscale Bias		
Upscale Drift		
Alternative Specification Abs Diff: Initial Zero	-	
Alternative Specification Abs Diff: Final Zero		
Alternative Specification Abs Diff: Initial Upscale		
Alternative Specification Abs Diff: Final Upscale		
Calibration Span		
3% of Range (drift)		
5% of Range (bias)		

Respone Time (min)		
Sys. Response (min)		

Date/Time mm/dd/yy hh:mm:ss z s z s

INJECTIONS

x

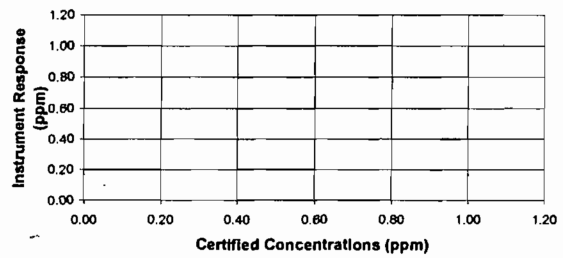
Air Permit # :	
Plant Name or Location:	
Date:	
Project Number:	
Manufacturer & Equipment:	
Model:	
Serial Number:	
Unit Number:	
Test Load:	
Tester(s) / Test Unit(s):	

		RUN																	
	UNITS	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Start Time	hh:mm:ss																		
End Time	hh:mm:ss																		
Bar. Pressure	in. Hg																		
Amb. Temp.	°F																		
Rel. Humidity	%																		
Spec. Humidity	lb water / lb air																		
Comb. Inlet Pres.	psig																		
NOx Water Inj.	gpm																		
Total Fuel Flow	SCFH																		
Heat Input	MMBtu/hr																		
Power Output	megawatts																		
Steam Rate	lb/hr																		

Calibration Date:
Client:

NOx Span (ppm) =

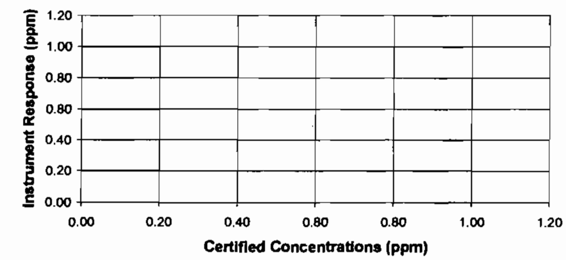
THERMO 42H (NOx Analyzer)				
Certified Concentration (ppm)	**Instrument Response (ppm)**	**Calibration Error (%)**	**Absolute Conc. (ppm)**	**Pass or Fail (±2%, ≤0.5ppm)**
Linearity =				



THERMO 42H (NOx Analyzer) Linearity Plot

CO Span (ppm) =

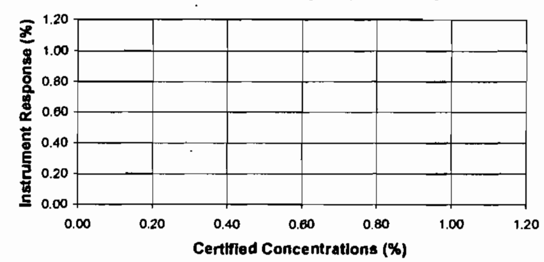
API 300 (CO Analyzer)				
Certified Concentration (ppm)	**Instrument Response (ppm)**	**Calibration Error (%)**	**Absolute Conc. (ppm)**	**Pass or Fail (±2%, ≤0.5ppm)**
Linearity =				



API 300 (CO Analyzer) Linearity Plot

O2 Span (%) =

SERVOMEX 1400 (O_2 Analyzer)				
Certified Concentration (ppm)	**Instrument Response (ppm)**	**Calibration Error (%)**	**Absolute Conc. (ppm)**	**Pass or Fail (±2%, ≤0.5%)**
Linearity =				



SERVOMEX 1400 (O2 Analyzer) Linearity Plot

NOx Converter Efficiency

Date:

Analyzer:

RM 7E, (08-15-06), 8.2.4.1 Introduce a concentration of 40 to 60 ppmv NO_2 to the analyzer in direct calibration mode and record the NOx concentration displayed by the analyzer. ... Calculate the converter efficiency using Equation 7E-7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. ... The NO_2 must be prepared according to the EPA Traceability Protocol and have an accuracy within 2.0 percent.

Audit Gas: NO_2 Concentration (C_v), ppmvd

Converter Efficiency Calculations:

Analyzer Reading, NO Channel, ppmvd

Analyzer Reading, NOx Channel, ppmvd

Analyzer Reading, NO_2 Channel ($C_{Dir(NO2)}$), ppmvd

Converter Efficiency, %

RM 7E, (08-15-06), 13.5 NO2 to NO Conversion Efficiency Test (as applicable). The NO2 to NO conversion efficiency, calculated according to Equation 7E-7 or Equation 7E-9, must be greater than or equal to 90 percent.

$$Eff_{NO2} = \left(\frac{C_{Dir}}{C_V}\right) \times 100$$

Eq. 7E-7 = $\frac{\text{ppmvd}}{\text{ppmvd}}$ x 100 =

Date/Time	Elapsed Time	NOx	NO
mm/dd/yy hh:mm:ss	Seconds	ppmvd	ppmvd

Fuel Data

Fuel F_d factor		SCF/MMBtu
Fuel Heating Value (HHV)		Btu/SCF

Weather Data

Barometric Pressure		in. Hg
Relative Humidity		%
Ambient Temperature		°F
Specific Humidity		lb H_2O / lb air

Unit Data

Unit Load		megawatts
Heat Input		lb/MMBtu
Steam Rate		Steam lb/hr
Combustor Inlet Pres.		psig
NOx Control Water Injection		gpm
Est. Stack Moisture		%
Stack Exhaust Flow (M2)		SCFH
Stack Exhaust Flow (M19)		SCFH

Run - 1

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)

RAW AVERAGE

		O_2 (%)	NOx (ppmvd)	CO (ppmvd)
	Serial Number:			
Bias	Initial Zero			
	Final Zero			
	Avg. Zero			
	Initial UpScale			
	Final UpScale			
	Avg. UpScale			

Upscale Cal Gas

EMISSIONS DATA	O_2	NOx	CO
Corrected Raw Average (ppm/% dry basis)			
Corrected Raw Average (ppm/% wet basis)			
Concentration (ppm@ %O_2)			
Concentration (ppm@ %O_2 &ISO)			
Emission Rate (lb/hr)			
Emission Rate (tons/day) at 24 hr/day			
Emission Rate (tons/year) at 8760 hr/yr			
Emission Rate (lb/MMBtu)			
Emission Rate (g/hp*hr)			

DRIFT AND BIAS CHECK			
Run - 1	O2	NOx	CO
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff: Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

DRIFT AND BIAS CHECK			
Run - 2	O2	NOx	CO
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff: Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

NOx RATA Data Sheet

RUN #	RUN TIME	USED	UNIT LOAD	RM	CEMS	RM-CEMS	
			(MW)	(ppmvd)	(ppmvd)	(diff)	($diff^2$)
1		NO					
2		NO					
3		NO					
4		NO					
5		NO					
6		NO					
7		NO					
8		NO					
9		NO					
10		NO					
11		NO					
12		NO					
Total							
Average							
Number of Runs							
Standard Deviation							
T-value							
Confidence Coefficient							

Relative Accuracy =

Part 60, Appendix B, Performance Specification 2,
8.4.1 RA Test Period. Conduct the RA test according to the procedure given in Sections 8.4.2 through 8.4.6 while the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart.
13.2 Relative Accuracy Performance Specification. The RA of the CEMS must be no greater than 20 percent when RM is used in the denominator of Eq. 2-6 (average emissions during test are greater than 50 percent of the emission standard) or 10 percent when the applicable emission standard (permit limit) is used in the denominator of Eq. 2-6 (average emissions during test are less than 50 percent of the emission standard).
Eq. 2.6 RA=([|d|+|CC|]*100)/RM

Part 75, Appendix A,
3.3.7 Relative Accuracy for NOX Concentration Monitoring Systems
(a) The following requirement applies only to NOX concentration monitoring systems (i.e., NOX pollutant concentration monitors) that are used to determine NOX mass emissions, where the owner or operator elects to monitor and report NOX mass emissions using a NOX concentration monitoring system and a flow monitoring system.
(b) The relative accuracy for NOX concentration monitoring systems shall not exceed 10.0 percent. Alternatively, for affected units where the average of the reference method measurements of NOX concentration (this means ppm) during the relative accuracy test audit is less than or equal to 250.0 ppm, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ± 15.0 ppm, wherever the 10.0 percent relative accuracy specification is not achieved.

Part 75, Appendix B,
2.3.1.2 Reduced RATA Frequencies. Relative accuracy test audits of primary and redundant backup SO2 pollutant concentration monitors, CO2 pollutant concentration monitors (including O2 monitors used to determine CO2 emissions), CO2 or O2 diluent monitors used to determine heat input, moisture monitoring systems, NOX concentration monitoring systems, flow monitors, NOX-diluent monitoring systems or SO2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:
(a) The relative accuracy during the audit of an SO2 or CO2 pollutant concentration monitor (including an O2 pollutant monitor used to measure CO2 using the procedures in appendix F to this part), or of a CO2 or O2 diluent monitor used to determine heat input, or of a NOX concentration monitoring system, or of a NOX-diluent monitoring system, or of an SO2-diluent continuous emissions monitoring system is ≤ 7.5 percent;

(e) For low SO2 or NOX emitting units (average SO2 or NOX reference method concentrations ≤ 250 ppm) during the RATA, when an SO2 pollutant concentration monitor or NOX concentration monitoring system fails to achieve a relative accuracy ≤ 7.5 percent during the audit, but the monitor mean value from the RATA is within ± 12 ppm of the reference method mean value;

Figure 2 to Appendix B of Part 75_Relative Accuracy Test Frequency Incentive System.

RATA	Semiannual(percent)(1)	Annual(1)
SO2 or NOX(3)	7.5% < RA ≤ 10.0% or ± 15.0 ppm(2)	RA ≤ 7.5% or ± 12.0 ppm(2)
SO2-diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.025 lb/mmBtu(2)
NOX-diluent	7.5% < RA ≤ 10.0% or ± 0.020 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.015 lb/mmBtu(2)
Flow	7.5% < RA ≤ 10.0% or ± 1.5 fps(2)	RA ≤ 7.5%
CO2 or O2	7.5% < RA ≤ 10.0% or ± 1.0% CO2/O2(2)	RA ≤ 7.5% or ± 0.7% CO2/O2(2)
Moisture	7.5% < RA ≤ 10.0% or ± 1.5% H2O(2)	RA ≤ 7.5% or ± 1.0% H2O(2)

(1) The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.
(2) The difference between monitor and reference method mean values applies to moisture monitors, CO2, and O2 monitors, low emitters, or low flow, only.
(3) A NOX concentration monitoring system used to determine NOX mass emissions under § 75.71.

CO RATA Data Sheet

RUN #	RUN TIME	USED	UNIT LOAD (MW)	RM (ppmvd)	CEMS (ppmvd)	RM-CEMS (diff)	RM-CEMS ($diff^2$)
1		NO					
2		NO					
3		NO					
4		NO					
5		NO					
6		NO					
7		NO					
8		NO					
9		NO					
10		NO					
11		NO					
12		NO					
Total							
Average							
Number of Runs							
Standard Deviation							
T-value							
Confidence Coefficient							

Relative Accuracy =
|d (difference in ppm)| + CC =

Part 60, Appendix B, Performance Specification 4,
1.2.1 This specification is for evaluating the acceptability of carbon monoxide (CO) continuous emission monitoring systems (CEMS) at the time of installation or soon after and whenever specified in an applicable subpart of the regulations. This specification was developed primarily for CEMS having span values of 1,000 ppmv CO.
13.2 Relative Accuracy. The RA of the CEMS must be no greater than 10 percent when the average RM value is used to calculate RA or 5 percent when the applicable emission standard (permit limit) is used to calculate RA.

Part 60, Appendix B, Performance Specification 4A,
1.2.1 This specification is for evaluating the acceptability of carbon monoxide (CO) continuous emission monitoring systems (CEMS) at the time of installation or soon after and whenever specified in an applicable subpart of the regulations. This specification was developed primarily for CEMS that comply with low emission standards (less than 200 ppmv).
13.2 Relative Accuracy. The RA of the CEMS must be no greater than 10 percent when the average RM value is used to calculate RA, 5 percent when the applicable emission standard (permit limit) is used to calculate RA, or within 5 ppmv when the RA is calculated as the absolute average difference between the RM and CEMS plus the 2.5 percent confidence coefficient.

O_2 RATA Data Sheet

RUN #	RUN TIME	USED	UNIT LOAD	RM	CEMS	RM-CEMS	
			(MW)	(%)	(%)	(diff)	($diff^2$)
1		NO					
2		NO					
3		NO					
4		NO					
5		NO					
6		NO					
7		NO					
8		NO					
9		NO					
10		NO					
11		NO					
12		NO					
Total							
Average							
Number of Runs							
Standard Deviation							
T-value							
Confidence Coefficient							

Average Difference =

Relative Accuracy =

Part 60, Appendix B, Performance Specification 3,
13.2 CEMS Relative Accuracy Performance Specification. The RA of the CEMS must be no greater than 1.0 percent O2 or CO2. (Where RA is defined as the average difference between nine runs.)

Part 75, Appendix A,
3.3.3 Relative Accuracy for CO2 and O2 Monitors
The relative accuracy for CO2 and O2 monitors shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the CO2 or O2 monitor measurements and the corresponding reference method measurement mean value, calculated using equation A-7 of this appendix, does not exceed ± 1.0 percent CO2 or O2.

Part 75, Appendix B,
2.3.1.2 Reduced RATA Frequencies
Relative accuracy test audits of primary and redundant backup SO2 pollutant concentration monitors, CO2 pollutant concentration monitors (including O2 monitors used to determine CO2 emissions), CO2 or O2 diluent monitors used to determine heat input, moisture monitoring systems, NOX concentration monitoring systems, flow monitors, NOX-diluent monitoring systems or SO2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:
(a) The relative accuracy during the audit of an SO2 or CO2 pollutant concentration monitor (including an O2 pollutant monitor used to measure CO2 using the procedures in appendix F to this part), or of a CO2 or O2 diluent monitor used to determine heat input, or of a NOX concentration monitoring system, or of a NOX-diluent monitoring system, or of an SO2-diluent continuous emissions monitoring system is ≤ 7.5 percent;

(h) For a CO_2 or O_2 monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within ± 0.7 percent CO_2 or O_2; and

Figure 2 to Appendix B of Part 75_Relative Accuracy Test Frequency Incentive System.

RATA	Semiannual(percent)(1)	Annual(1)
SO2 or NOX(3)	7.5% < RA ≤ 10.0% or ± 15.0 ppm(2)	RA ≤ 7.5% or ± 12.0 ppm(2)
SO2-diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.025 lb/mmBtu(2)
NOX-diluent	7.5% < RA ≤ 10.0% or ± 0.020 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.015 lb/mmBtu(2)
Flow	7.5% < RA ≤ 10.0% or ± 1.5 fps(2)	RA ≤ 7.5%
CO2 or O2	7.5% < RA ≤ 10.0% or ± 1.0% CO2/O2(2)	RA ≤ 7.5% or ± 0.7% CO2/O2(2)
Moisture	7.5% < RA ≤ 10.0% or ± 1.5% H2O(2)	RA ≤ 7.5% or ± 1.0% H2O(2)

(1) The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.
(2) The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters, or low flow, only.
(3) A NOX concentration monitoring system used to determine NOX mass emissions under § 75.71.

CO RATA Data Sheet

RUN #	RUN TIME	USED	UNIT LOAD	RM	CEMS	RM-CEMS	
			(MW)	(lb/hr)	(lb/hr)	(diff)	($diff^2$)
1		NO					
2		NO					
3		NO					
4		NO					
5		NO					
6		NO					
7		NO					
8		NO					
9		NO					
10		NO					
11		NO					
12		NO					
Total							
Average							
Number of Runs							
Standard Deviation							
T-value							
Confidence Coefficient							

Relative Accuracy =

|d (difference in ppm)| + CC =

Part 60, Appendix B, Performance Specification 4,

1.2.1 This specification is for evaluating the acceptability of carbon monoxide (CO) continuous emission monitoring systems (CEMS) at the time of installation or soon after and whenever specified in an applicable subpart of the regulations. This specification was developed primarily for CEMS having span values of 1,000 ppmv CO.

13.2 Relative Accuracy. The RA of the CEMS must be no greater than 10 percent when the average RM value is used to calculate RA or 5 percent when the applicable emission standard (permit limit) is used to calculate RA.

Part 60, Appendix B, Performance Specification 6,

13.2 CERMS Relative Accuracy (must be a rate i.e. lb/hr). The RA of the CERMS shall be no greater than 20 percent of the mean value of the RM's test data in terms of the units of the emission standard, or 10 percent of the applicable standard (permit limit), whichever is greater.

NOx RATA Data Sheet

RUN #	RUN TIME	USED	UNIT LOAD	RM	CEMS	RM-CEMS	
			(MW)	(lb/MMBtu)	(lb/MMBtu)	(diff)	($diff^2$)
1		NO					
2		NO					
3		NO					
4		NO					
5		NO					
6		NO					
7		NO					
8		NO					
9		NO					
10		NO					
11		NO					
12		NO					
Total							
Average							
Number of Runs							
Standard Deviation							
T-value							
Confidence Coefficient							
Relative Accuracy =							

Part 60, Appendix B, Performance Specification 2,
8.4.1 RA Test Period. Conduct the RA test according to the procedure given in Sections 8.4.2 through 8.4.6 while the affected facility is operating at more than 50 percent of normal load, or as specified in an applicable subpart.
13.2 Relative Accuracy Performance Specification. The RA of the CEMS must be no greater than 20 percent when RM is used in the denominator of Eq. 2-6 (average emissions during test are greater than 50 percent of the emission standard) or 10 percent when the applicable emission standard (permit limit) is used in the denominator of Eq. 2-6 (average emissions during test are less than 50 percent of the emission standard).
Eq. 2.6 RA=([|d|+|CC|]*100)/RM

Part 75, Appendix A,
3.3.2 Relative Accuracy for NOX-Diluent Continuous Emission Monitoring Systems
(a) The relative accuracy for NOX-diluent continuous emission monitoring systems shall not exceed 10.0 percent.
(b) For affected units where the average of the reference method measurements of NOX emission rate (this means lb/MMBtu) during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ±0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.

7.6.5 Bias Adjustment

(b) For single-load RATAs of SO2 pollutant concentration monitors, NOX concentration monitoring systems, and NOX-diluent monitoring systems and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A-12. Notwithstanding, when a NOX concentration CEMS or an SO2 CEMS or a NOX-diluent CEMS installed on a low-emitting affected unit (i.e., average SO2 or NOX concentration during the RATA ≦ 250 ppm or average NOX emission rate ≦ 0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A-10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may either be determined using Equation A-12, or a default BAF of 1.111 may be used.

Part 75, Appendix B,

2.3.1.2 Reduced RATA Frequencies. Relative accuracy test audits of primary and redundant backup SO2 pollutant concentration monitors, CO2 pollutant concentration monitors (including O2 monitors used to determine CO2 emissions), CO2 or O2 diluent monitors used to determine heat input, moisture monitoring systems, NOX concentration monitoring systems, flow monitors, NOX-diluent monitoring systems or SO2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

(a) The relative accuracy during the audit of an SO2 or CO2 pollutant concentration monitor (including an O2 pollutant monitor used to measure CO2 using the procedures in appendix F to this part), or of a CO2 or O2 diluent monitor used to determine heat input, or of a NOX concentration monitoring system, or of a NOX-diluent monitoring system, or of an SO2-diluent continuous emissions monitoring system is ≤ 7.5 percent;

(f) For units with low NOX emission rates (average NOX emission rate measured by the reference method during the RATA ≤ 0.200 lb/mmBtu), when a NOX-diluent continuous emission monitoring system fails to achieve a relative accuracy ≤ 7.5 percent, but the monitoring system mean value from the RATA, calculated using Equation A-7 in appendix A to this part, is within ± 0.015 lb/mmBtu of the reference method mean value;

Figure 2 to Appendix B of Part 75_Relative Accuracy Test Frequency Incentive System.

RATA	Semiannual(percent)(1)	Annual(1)
SO2 or NOX(3)	7.5% < RA ≤ 10.0% or ± 15.0 ppm(2)	RA ≤ 7.5% or ± 12.0 ppm(2)
SO2-diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.025 lb/mmBtu(2)
NOX-diluent	7.5% < RA ≤ 10.0% or ± 0.020 lb/mmBtu(2)	RA ≤ 7.5% or ± 0.015 lb/mmBtu(2)
Flow	7.5% < RA ≤ 10.0% or ± 1.5 fps(2)	RA ≤ 7.5%
CO2 or O2	7.5% < RA ≤ 10.0% or ± 1.0% CO2/O2(2)	RA ≤ 7.5% or ± 0.7% CO2/O2(2)
Moisture	7.5% < RA ≤ 10.0% or ± 1.5% H2O(2)	RA ≤ 7.5% or ± 1.0% H2O(2)

(1) The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

(2) The difference between monitor and reference method mean values applies to moisture monitors, CO2, and O2 monitors, low emitters, or low flow, only.

(3) A NOX concentration monitoring system used to determine NOX mass emissions under § 75.71.

Relative Accuracy Test Data
CEMS Results (NOx)

Parameter:	Oxides of Nitrogen
Date of Test:	
Reference Method:	EPA Method 7e
CEMS Analyzer Type:	Chemiluminescence
Manufacturer:	Advanced Pollution Instrumentation (API)
Model #:	200 AH
Serial #:	1234-56-789

RUN #	RUN TIME	UNIT LOAD	CONCENTRATIONS		RATES	
		(MW)	(ppmvd)	(ppm@ %O_2)	(lb/hr)	(lb/MMBtu)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						

Relative Accuracy Test Data
CEMS Results (CO)

Parameter:	Carbon Monoxide
Date of Test:	
Reference Method:	EPA Method 10
CEMS Analyzer Type:	Infrared Absorption
Manufacturer:	Advanced Pollution Instrumentation (API)
Model #:	300
Serial #:	1234-56-789

RUN #	RUN TIME	UNIT LOAD	CONCENTRATIONS		RATES	
		(MW)	(ppmvd)	(ppm@ %O_2)	(lb/hr)	(lb/MMBtu)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						

Relative Accuracy Test Data
CEMS Results (O_2)

Parameter:	Oxygen
Date of Test:	
Reference Method:	EPA Method 3a
CEMS Analyzer Type:	Paramagnetic Cell
Manufacturer:	Servomex
Model #:	1440
Serial #:	1234-56-789

RUN #	RUN TIME	UNIT LOAD (MW)	CONC. (%)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			

Relative Accuracy Test Data
Reference Method Results (NOx)

Parameter:	Oxides of Nitrogen
Date of Test:	
Reference Method:	EPA Method 7e
RM Analyzer Type:	Chemiluminescence
Manufacturer:	Advanced Pollution Instrumentation (API)
Model #:	200 AH
Serial #:	

RUN #	RUN TIME	UNIT LOAD	CONCENTRATIONS		RATES	
		(MW)	(ppmvd)	(ppm@ $\%O_2$)	(lb/hr)	(lb/MMBtu)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						

Relative Accuracy Test Data
Reference Method Results (CO)

Parameter:	Carbon Monoxide
Date of Test:	
Reference Method:	EPA Method 10
RM Analyzer Type:	Infrared Absorption
Manufacturer:	Advanced Pollution Instrumentation (API)
Model #:	300
Serial #:	

RUN #	RUN TIME	UNIT LOAD	CONCENTRATIONS		RATES	
		(MW)	(ppmvd)	(ppm@ $\%O_2$)	(lb/hr)	(lb/MMBtu)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						

Relative Accuracy Test Data
Reference Method Results (O_2)

Parameter:	Oxygen
Date of Test:	
Reference Method:	EPA Method 3a
RM Analyzer Type:	Paramagnetic Cell
Manufacturer:	Servomex
Model #:	1440
Serial #:	

RUN #	RUN TIME	UNIT LOAD (MW)	CONC. (%)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			

EXAMPLE CALCULATIONS (INFORMATION)

Specific Humidity (RH_{sp})

Note: RHsp (gr/lb) calculated using temperature, relative humidity, and barometric pressure with psychrometric chart, psychrometric calculator, or built in psychrometric algorithm.

$$RH_{sp}(lb/lb) = \left[\left(\frac{gr}{lb}\right) \times \frac{lb}{7000\ gr}\right]$$

RH_{sp}= $\frac{gr}{lb}$ x $\frac{1\ lb}{7000\ gr}$ = $\frac{lb\ H_2O}{lb\ Air}$

Fuel Flow Conversion (Q_f)

Note: Qf(lb/min) is a value uptained from the source operator.

$$Q_f = \left[Q_f \times G \times \left(\frac{1}{MW_{Fuel}}\right)\right]$$

Q_f = $\frac{lb}{min}$ x $\frac{60\ min}{hr}$ x $\frac{ft^3}{lb\text{-}mol}$ x $\frac{lb\text{-}mol}{lb}$ = SCFH

Combustor Inlet Pressure / Compressor Discharge Pressure (CIP / CDP)
(corrected from gauge to atmospheric pres. and,conv. to mm Hg.).

Note: CIP / CDP (psig) is a value obtained from the source operator.

$$CIP/CDP = \left[(psig + P) \times \frac{51.71493\ mmHg}{1\ psi}\right]$$

CIP / CDP = [psig +] x $\frac{51.71493\ mmHg}{1\ psia}$ = mmHg (abs)

Heat Rate (MMBtu/hr)

$$HR = \frac{HHV_{DRY} \times Q_f}{1{,}000{,}000}$$

Heat Rate = $\frac{Btu}{SCF}$ x $\frac{SCF}{hr}$ x $\frac{MMBtu}{10^6\ Btu}$ = $\frac{MMBtu}{hr}$

Estimated Stack Gas Moisture Content (B_{ws})

$$B_{ws}(\%) = \frac{2 \times Q_f}{Q_s} \times 100$$

B_{ws} = 2 x $\frac{SCF}{hr}$ x $\frac{hr}{SCF}$ x 100 = %

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (CALIBRATION)

Analyzer Calibration Error

RM 7E, (08-15-06), 12.2 Analyzer Calibration Error. For non-dilution systems, use Equation 7E-1 to calculate the analyzer calibration error for the low-, mid-, and high-level calibration gases. (calc for analyzer mid gas, if applicable)

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100$$ Eq. 7E-1

ACE = $\frac{ppm - \quad ppm}{ppm}$ x 100 = %

Calibration Error and Estimated Point, RM 25A, THC Analyzer

RM 25A, (07-19-06), 8.4 Calibration Error Test. Immediately prior to the test series (within 2 hours of the start of the test), introduce zero gas and high-level calibration gas at the calibration valve assembly. Adjust the analyzer output to the appropriate levels, if necessary. Calculate the predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response. Then introduce low-level and mid-level calibration gases successively to the measurement system. ... These differences must be less than 5 percent of the respective calibration gas value. (calc for THC analyzer mid gas, if applicable)

$$E_P = \frac{C_{Dir(H)} - C_{Dir(Z)}}{C_{V(H)} - C_{V(Z)}} \times C_{Dir(M)} + C_{Dir(Z)}$$ Eq. of a line y=mx+b

E_p = $\frac{ppm - \quad ppm}{ppm - \quad ppm}$ x ppm + = ppm

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100$$ Eq. 7E-1

ACE_{THC} = $\frac{ppm - \quad ppm}{ppm}$ x 100 = %

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (BIAS, DRIFT, AND CORRECTED RAW AVERAGE)

System Bias

RM 7E, (08-15-06), 12.3 System Bias. For non-dilution systems, use Equation 7E-2 to calculate the system bias separately for the low-level and upscale calibration gases. (calc for analyzer upscale gas, Run 1 initial bias, if applicable)

$$SB = \left(\frac{C_S - C_{Dir}}{CS} \right) \times 100$$ Eq. 7E-2

SB = $\frac{\text{ppm - } \quad \text{ppm}}{\text{ppm}}$ x 100 = %

Drift Assessment

RM 7E, (08-15-06), 12.5 Drift Assessment. Use Equation 7E-4 to separately calculate the low-level and upscale drift over each test run. (calc for analyzer upscale drift, Run 1, if applicable)

$$D = \left| SB_{final} - SB_i \right|$$ Eq. 7E-4

D = | % - % | = %

Alternative Drift and Bias

RM 7E, (08-15-06), 13.2 / 13.3 System Bias and Drift. Alternatively, the results are acceptable if |Cs – Cdir| is≤ 0.5 ppmv or if |Cs – Cv| is ≤ 0.5 ppmv (as applicable). (calc for analyzer initial upscale, Run 1, if applicable)

$$SB / D_{Alt} = \left| C_S - C_{Dir} \right|$$ Eq. Section 13.2 and 13.3

SB / D_{Alt} = | ppm - ppm | = ppm

Bias Adjusted Average

RM 7E, (08-15-06), 12.6 Effluent Gas Concentration. For each test run, calculate Cavg, the arithmetic average of all valid concentration values (e.g., 1-minute averages). Then adjust the value of Cavg for bias, using Equation 7E-5. (calc for analyzer, Run 1, if applicable)

$$C_{Gas} = \left(C_{Avg} - C_O \right) \times \left(\frac{C_{MA}}{C_M - C_O} \right)$$ Eq. 7E-5

C_{Gas} = (ppm - ppm) x ($\frac{\text{ppm}}{\text{ppm - } \quad \text{ppm}}$) = ppm

EXAMPLE CALCULATIONS (BSFC)

Using LHV with Q_f (Btu/hp*hr)

$$BSFC\,(Btu / hp \cdot hr) = Q_f$$

BSFC = $\frac{\text{Btu}}{\text{hp*hr}}$ = $\frac{\text{Btu}}{\text{hp*hr}}$

Using HHV with Q_f (SCFH)

$$BSFC\,(Btu / hp \cdot hr) = \frac{HHV \times Q_f}{bhp}$$

BSFC = $\frac{\text{Btu}}{\text{SCF}}$ x $\frac{\text{SCF}}{\text{hr}}$ x $\frac{1}{\text{hp}}$ = $\frac{\text{Btu}}{\text{hp*hr}}$

Using LHV with Q_f (SCFH)

$$BSFC\,(Btu / hp \cdot hr) = \frac{LHV \times Q_f}{bhp}$$

BSFC = $\frac{\text{Btu}}{\text{SCF}}$ x $\frac{\text{SCF}}{\text{hr}}$ x $\frac{1}{\text{hp}}$ = $\frac{\text{Btu}}{\text{hp*hr}}$

Using HHV with Q_f (Btu/hp*hr)

$$BSFC\,(Btu / hp \cdot hr) = \frac{Q_f \times HHV}{LHV}$$

BSFC = $\frac{\text{N/A} \quad \text{Btu}}{\text{hp*hr}}$ x $\frac{\text{Btu}}{\text{SCF}}$ x $\frac{\text{scf}}{\text{Btu}}$ = $\frac{\text{Btu}}{\text{hp*hr}}$

EXAMPLE CALCULATIONS (Emissions based on Table 29 values)

Emission Rate (lb/hr)
Q_f (Btu/hp*hr))

$$E(lb / hr) = \frac{E_{g / hp \cdot hr} \times bhp}{453.6}$$

E (lb/hr) = $\frac{\text{g}}{\text{hp*hr}}$ x $\frac{\text{lb}}{\text{453.6 g}}$ x hp = $\frac{\text{lb}}{\text{hr}}$

Emission Rate (g/hp-hr)
Q_f (Btu/hp*hr))

$$E\,(g / hp \cdot hr) = CRA \times Q_f \times FFactor \times MW \times \frac{1}{10^6} \times \frac{1}{10^6} \times \frac{453.6}{G} \times \frac{20.9\%}{20.9\% - CRA_{O_2}}$$

E (g/hp-hr) = ppm x $\frac{\text{Btu}}{\text{hp*hr}}$ x $\frac{\text{SCF}}{\text{MMBtu}}$ x $\frac{\text{lb}}{\text{lb-mol}}$ x $\frac{\text{1 parts}}{10^6 \text{ ppm}}$ x $\frac{\text{1 MMBtu}}{10^6 \text{ Btu}}$

x $\frac{\text{453.6 g}}{\text{lb}}$ x $\frac{\text{lb-mol}}{\text{SCF}}$ x $\frac{20.9\%}{20.9\% - \quad \%}$ = $\frac{\text{g}}{\text{hp*hr}}$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Stack Exhaust Flow (Q_S) - RM19

$$Q_S = \left(\frac{FFactor \times Q_f \times HHV}{1{,}000{,}000}\right) \times \left(\frac{20.9\%}{20.9\% - C_{Gas(O2)}}\right)$$

$$Q_S = \frac{SCF}{MMBtu} \times \frac{SCF}{hr} \times \frac{Btu}{SCF} \times \frac{MMBtu}{10^6\ Btu} \times \left[\frac{20.90\%}{20.9\% - \quad \%}\right] = \quad SCFH$$

NO_2 Conversion Efficiency Correction

RM 7E, (08-15-06), 12.8 NO2 - NO Conversion Efficiency Correction. If desired, calculate the total NOX concentration with a correction for converter efficiency using Equations 7E-8. (calc for non-bias corrected (raw) NOx gas, Run 1, if applicable)

$$NOx_{Corr} = NO + \frac{NOx - NO}{Eff_{NO2}} \times 100 \qquad \text{Eq. 7E-8}$$

$$NOx_{Corr} = \quad ppm + \frac{ppm - \quad ppm}{\%} \times 100 = \quad ppm$$

Moisture Correction

RM 7E, (08-15-06), RM7E, (08-15-06), 12.10 Moisture Correction. Use Equation 7E-10 if your measurements need to be corrected to a dry basis. (calc for THC analyzer, Run 1, if applicable) Note: Calculations may not match as Run 1 results are typically also bias adjusted

$$C_D = \frac{C_W}{1 - B_{WS}} \qquad \text{Eq. 7E-10}$$

$$C_D = \frac{ppmvw}{1 -} = \quad ppmvd$$

Diluent-Corrected Polutant Concentration, O_2 Based

RM 20, (11-26-02), 7.3.1 Correction of Pollutant Concentration Using O2 Concentration. Calculate the O2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right) \qquad \text{Eq. 20-4}$$

$$C_{adj} = \quad ppm \times \left(\frac{20.9\% - \quad \%}{20.9\% - \quad \%}\right) = \quad ppm@\%O_2$$

Diluent-Corrected Polutant Concentration, CO_2 Based

RM 20, (11-26-02), 7.3.2 Correction of Pollutant Concentration Using CO2 Concentration. Calculate the CO2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \frac{X_{CO2}}{C_{Gas(CO2)}} \qquad \text{Eq. 20-5}$$

$$C_{adj} = \quad ppm \times \frac{\%}{\%} =$$

7.2 CO_2 Correction Factor. If pollutant concentrations are to be corrected to percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as follows: 7.2.1 Calculate the fuel specific F_o, as follows:

$$F_0 = \frac{0.209\,F_d}{F_c} \qquad \text{Eq. 20-2}$$

$$F_0 = \frac{0.209 \times \quad SCF/MMBtu}{SCF/MMBtu} =$$

7.2.2. Calculate the CO_2 correction factor for correcting measurement data to percent oxygen, as follows:

$$X_{CO2} = \frac{20.9\% - AdjFactor}{F_0} \qquad \text{Eq. 20-3}$$

$$X_{CO2} = \frac{20.9\% - \quad \%}{} = \quad \%$$

Diluent-Corrected Polutant Concentration Corrected to ISO Conditions

40CFR60.335(b)(1), Conversion for conc. at ISO Conditions (68°F, 1 atm). Calculate, as follows: (calc for @% with Run 1 data, if applicable)

$$C_{ISO} = C_{Adj} \times \sqrt{\frac{P_r}{P_o}} \times e^{(19 \times (H_o - 0.00633))} \times \left(\frac{288}{T_a}\right)^{1.53}$$

$$C_{ISO} = \quad ppm@\%O_2 \times \left(\sqrt{\frac{\dfrac{psig + 14.69232\ psi}{0.01933677\ psi/mm\ Hg.}}{\dfrac{psig + \quad psi}{0.01933677\ psi/mm\ Hg.}}}\right) \times 2.718^{(19 \times (\quad lb/lb - 0.00633))} \times \left(\frac{288\ K}{K}\right)^{1.53} = \quad ppm@\%\ and\ ISO$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Emissions Rate (lb/hr)

Calculation for pound per hour emission rate. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

$$E_{lb/hr} = \frac{\text{ppm}}{10^6\ \text{ppm/part}} \times \frac{\text{SCFH} \times \quad \text{lb/lb-mol}}{\text{SCF/lb-mol}} = \frac{\text{lb}}{\text{hr}}$$

Emissions Rate (ton/year)

Calculation for tons per year emission rate based on 8760 hours per year. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{ton/yr} = \frac{E_{lb/hr} \times hr_{year}}{2000}$$

$$E_{ton/yr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{hr}}{\text{year}} \times \frac{\text{ton}}{2000\ \text{lb}} = \frac{\text{ton}}{\text{year}}$$

Emissions Rate (lb/MMBtu)

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in ng/J (lb/million Btu). (calc for gas Run 1, if applicable)

Oxygen Based

12.2.1 Oxygen-Based F Factor, Dry Basis. When measurements are on a dry basis for both O_2 (%O_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}}$$

Eq. 19-1

$$E_{lb/MMBtu} = \frac{\text{ppm} \times \quad \text{SCF/MMBtu} \times \quad \text{lb/ppm*ft}^3 \times 20.9\%}{20.9\% - \quad \%} = \frac{\text{lb}}{\text{MMBtu}}$$

Carbon Dioxide Based

12.2.4 Carbon Dioxide-Based F Factor, Dry Basis. When measurements are on a dry basis for both CO_2 (%CO_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}}$$

Eq. 19-6

$$E_{lb/MMBtu} = \frac{\text{ppm} \times \quad \text{SCF/MMBtu} \times \quad \text{lb/ppm*ft}^3 \times 100\%}{\%} = \frac{\text{lb}}{\text{MMBtu}}$$

Conversion Constant

Convc for

$$Conv_c(lb/ppm \cdot ft^3) = \frac{\frac{MW}{G}}{10^6}$$

$$Conv_c = \frac{\frac{\text{lb}}{\text{lb•mole}} \times \frac{\text{lb•mole}}{\text{SCF}}}{10^6} = \frac{\text{lb}}{\text{ppm-ft}^3}$$

Sulfur Dioxide Rate (lb/MMBtu), 40CFR60, App. A, RM 19, Eq. 19-25 (11/20/03)

$$SO_2(lb/MMBtu) = 0.97 \times K \times \frac{S(wt\%)}{GCV}$$

$$SO_2 = 0.97 \times \frac{2\times10^4\ \text{Btu}}{\text{wt\%•MMBtu}} \times \frac{\text{wt\%}}{\text{Btu/lb}} = \frac{\text{lb}}{\text{MMBtu}}$$

Emissions Rate (g/hp-hr)

Calculation for grams per horsepower-hour. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{g/hp\text{-}hr} = \frac{E_{lb/hr} \times 453.6}{mw \times 1314.022} \; or \; \frac{E_{lb/hr} \times 453.6}{hp}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{1}{\text{mw}} \times \frac{\text{mw}}{1314.022\ \text{hp}} = \frac{\text{g}}{\text{hp*hr}}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{1}{\text{hp}} = \frac{\text{g}}{\text{hp*hr}}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RATA RESULTS)

Difference (d)

40 CFR 75, App A, (08-04-06), 7.3.1 Arithmetic Mean. Calculate the arithmetic mean of the differences, d , of a data set as follows. (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$d = \sum_{i=1}^{n} d_i$$

Eq. A-7

d = - =

Standard Deviation

40 CFR 75, App A, (08-04-06), 7.3.2 Standard Deviation. Calculate the standard deviation, Sd, of a data set as follows: (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i \right)^2}{n} \right]}{n-1} \right]^{\frac{1}{2}}$$

Eq. A-8

$$S_d = \sqrt{\frac{\ \ -^{2}\ \left[\ \ \right]^2}{\ \ -\ 1}} =$$

Confidence Coefficient

40 CFR 75, App A, (08-04-06), 7.3.3 Confidence Coefficient. Calculate the confidence coefficient (one-tailed), cc, of a data set as follows. (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$CC = t_{0.025} \times \frac{S_d}{\sqrt{n}}$$

Eq. A-9

$$CC = \quad \times \frac{\quad}{\sqrt{\quad}} =$$

T-Values	n	2	3	4	5	6	7	8	9
	$t_{0.025}$	12.706	4.303	3.182	2.776	2.571	2.447	2.365	2.306

2.5 percent confidence coefficients

Relative Accuracy

40 CFR 75, App A, (08-04-06), 7.3.4 Relative Accuracy. Calculate the relative accuracy of a data set using the following equation. (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$RA = \frac{|d_{AVG}| + |CC|}{RM_{AVG}} \times 100$$

Eq. A-10

$$RA = \frac{|\quad| + |\quad|}{\quad} \times 100 = \quad \%$$

Alternative Relative Accuracy

40 CFR 75, App A, (08-04-06), Alternative Relative Accuracy. Calculate the alternative relative accuracy of a data set using the following equation. (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$ARA = \frac{|d_{AVG}| + |CC|}{AS} \times 100$$

$$RA = \frac{|\quad| + |\quad|}{\quad} \times 100 = \quad \%$$

Bias Adjustment Factor (BAF)

40 CFR 75, App A, (08-04-06), 7.6.5 Bias Adjustment. (a) If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation: (calc for data, if applicable. Note: This is an example calculation which may not have any bearing on the actual test requirements.)

$$BAF = 1 + \left(\frac{|d_{AVG}|}{CEM_{AVG}} \right)$$

Eq. A-12 d_{AVG}= < |CC| = ⇨ BAF = $1 + \frac{|\quad|}{\quad} =$

Note: BAF only applies if the mean difference (d) is greater than the absolute value of the confidence coefficient.

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

RM 7E, (08-15-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

ACE = Analyzer calibration error, percent of calibration span.
B_{WS} = Moisture content of sample gas as measured by Method 4 or other approved method, percent/100.
C_{Avg} = Average unadjusted gas concentration indicated by data recorder for the test run.
C_D = Pollutant concentration adjusted to dry conditions.
C_{Dir} = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode.
C_{Gas} = Average effluent gas concentration adjusted for bias.
C_M = Average of initial and final system calibration bias (or 2-point system calibration error) check responses for the upscale calibration gas.
C_{MA} = Actual concentration of the upscale calibration gas, ppmv.
C_O = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas.
C_S = Measured concentration of a calibration gas (low, mid, or high) when introduced in system calibration mode.
C_{SS} = Concentration of NOx measured in the spiked sample.
C_{Spike} = Concentration of NOx in the undiluted spike gas.
C_{Calc} = Calculated concentration of NOx in the spike gas diluted in the sample.
C_V = Manufacturer certified concentration of a calibration gas (low, mid, or high).
C_W = Pollutant concentration measured under moist sample conditions, wet basis.
CS = Calibration span.
D = Drift assessment, percent of calibration span.
E_p = The predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response.
Eff_{NO2} = NO_2 to NO converter efficiency, percent.
H = High calibration gas, designator.
L = Low calibration gas, designator.
M = Mid calibration gas, designator.
NOFinal = The average NO concentration observed with the analyzer in the NO mode during the converter efficiency test in Section 16.2.2.
NOxCorr = The NOx concentration corrected for the converter efficiency.
NOxFinal = The final NOx concentration observed during the converter efficiency test in Section 16.2.2.
NOxPeak = The highest NOx concentration observed during the converter efficiency test in Section 16.2.2.
Q_{Spike} = Flow rate of spike gas introduced in system calibration mode, L/min.
Q_{Total} = Total sample flow rate during the spike test, L/min.
R = Spike recovery, percent.
SB = System bias, percent of calibration span.
SB_i = Pre-run system bias, percent of calibration span.
SB_f = Post-run system bias, percent of calibration span.
SB / D_{AS} = Alternative absolute difference criteria to pass bias and/or drift checks.
SCE = System calibration error, percent of calibration span.
SCE_i = Pre-run system calibration error, percent of calibration span.
SCE_{final} = Post-run system calibration error, percent of calibration span.
Z = Zero calibration gas, designator.

40CFR60.335(b)(1), (09-20-06), Nomenclature. The terms used in the equations are defined as follows:

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
P_o = observed combustor inlet absolute pressure at test, mm Hg
H_o = observed humidity of ambient air, g H_2O/g air
e = transcendental constant, 2.718
T_a = ambient temperature, K

Small Engine and FTIR Nomenclature. The terms used in the equations are defined as follows:

bhp = brake horsepower
hp = horsepower
Q_{sys} = system flow (lpm)
Q_m = matrix spike flow (lpm)

RM 19, (07-29-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

AdjFactor = percent oxygen or carbon dioxide adjustment applied to a target polltant

B_{wa} = Moisture fraction of ambient air, percent.

Btu = British thermal unit

$\%_C$ = Concentration of carbon from an ultimate analysis of fuel, weight percent.

$\%_{CO2d}, \%_{CO2w}$ = Concentration of carbon dioxide on a dry and wet basis, respectively, percent.

CIP / CDP = Combustor inlet pressure / compressor discharge pressure (mm Hg); note, some manufactures reference as PCD.

E = Pollutant emission rate, ng/J (lb/million Btu).

E_a = Average pollutant rate for the specified performance test period, ng/J (lb/million Btu).

E_{ao}, E_{ai} = Average pollutant rate of the control device, outlet and inlet, respectively, for the performance test period, ng/J (lb/million Btu).

E_{bi} = Pollutant rate from the steam generating unit, ng/J (lb/million Btu).

E_{bo} = Pollutant emission rate from the steam generating unit, ng/J (lb/million Btu).

E_{ci} = Pollutant rate in combined effluent, ng/J (lb/million Btu).

E_{co} = Pollutant emission rate in combined effluent, ng/J (lb/million Btu).

E_d = Average pollutant rate for each sampling period (e.g.,24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g., amount of fuel bunkered), ng/J (lb/million Btu).

E_{di} = Average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu).

E_g = Pollutant rate from gas turbine, ng/J (lb/million Btu).

E_{ga} = Daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent O_2.

E_{jo},E_{ji} = Matched pair hourly arithmetic average pollutant rate, outlet and inlet, respectively, ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

E_h = Hourly average pollutant, ng/J (lb/million Btu).

E_{hj} = Hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

EXP = Natural logarithmic base (2.718) raised to the value enclosed by brackets.

Fc = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19

F_d, F_w, F_c = Volumes of combustion components per unit of heat content, scm/J (scf/million Btu).

ft^3 = cubic feet

G = ideal gas conversion factor

(385.23 SCF/lb-mol at 68 deg F & 14.696 psia)

GCM = gross Btu per SCF (constant, compound based)

GCV = Gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).

GCV_p, GCV_r = Gross calorific value for the product and raw fuel lots, respectively, dry basis, kJ/kg (Btu/lb).

$\%_H$ = Concentration of hydrogen from an ultimate analysis of fuel, weight percent.

H_b = Heat input rate to the steam generating unit from fuels fired in the steam generating unit, J/hr (million Btu/hr).

H_g = Heat input rate to gas turbine from all fuels fired in the gas turbine, J/hr (million Btu/hr).

$\%_{H2O}$ = Concentration of water from an ultimate analysis of fuel, weight percent.

H_r = Total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

K = volume of combustion component per pound of component (constant)

K = Conversion factor, 10^{-5} (kJ/J)/(%) [10^6 Btu/million Btu].

K_c = (9.57 scm/kg)/% [(1.53 scf/lb)/%].

K_{cc} = (2.0 scm/kg)/% [(0.321 scf/lb)/%].

K_{hd} = (22.7 scm/kg)/% [(3.64 scf/lb)/%].

K_{hw} = (34.74 scm/kg)/% [(5.57 scf/lb)/%].

K_n = (0.86 scm/kg)/% [(0.14 scf/lb)/%].

K_o = (2.85 scm/kg)/% [(0.46 scf/lb)/%].

K_s = (3.54 scm/kg)/% [(0.57 scf/lb)/%].

K_{sulfur} = $2x10^4$ Btu/wt%-MMBtu

K_w = (1.30 scm/kg)/% [(0.21 scf/lb)/%].

lb = pound

ln = Natural log of indicated value.

L_p,L_r = Weight of the product and raw fuel lots, respectively, metric ton (ton).

$\%_N$ = Concentration of nitrogen from an ultimate analysis of fuel, weight percent.

$M_{\%}$ = mole percent

mol = mole

MW = molecular weight (lb/lb-mol)

MW_{AIR} = molecular weight of air (28.9625 lb/lb-mole)[1]

NCM = net Btu per SCF (constant based on compound)

$\%_O$ = Concentration of oxygen from an ultimate analysis of fuel, weight percent.

$\%_{O2d}$, $\%_{O2w}$ = Concentration of oxygen on a dry and wet basis, respectively, percent.

P_B = barometirc pressure, in Hg

P_s = Potential SO2 emissions, percent.

$\%_S$ = Sulfur content of as-fired fuel lot, dry basis, weight percent.

S_e = Standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

$\%_{Sf}$ = Concentration of sulfur from an ultimate analysis of fuel, weight percent.

S(wt%) = weight percent of sulfur, per lab analysis by appropriate ASTM standard

S_i = Standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

S_o = Standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

$\%S_p$, $\%S_r$ = Sulfur content of the product and raw fuel lots respectively, dry basis, weight percent.

SCF = standard cubic feet

SH = specific humidity, pounds of water per pound of air

$t_{0.95}$ = Values shown in Table 19-3 for the indicated number of data points n.

T_{amb} = ambient temperature, °F

W/D Factor = 1.0236 = conv. at 14.696 psia and

68 deg F (ref. Civil Eng. Ref. Manual, 7th Ed.)

X_{CO2}=CO_2 Correction factor, percent.

X_k = Fraction of total heat input from each type of fuel k.

Calculations, Formulas, and Constants

The following information supports the spreadsheets for this testing project.

Given Data:

Ideal Gas Conversion Factor = 385.23 SCF/lb-mol at 68 deg F & 14.696 psia

Fuel Heating Value is based upon Air Hygiene's fuel gas calculation sheet. All calculations are based upon a correction to 68 deg F & 14.696 psia

High Heating Values (HHV) are used for the Fuel Heating Value, F-Factor, and Fuel Flow Data per EPA requirements.

ASTM D 3588

Molecular Weight of NOx (lb/lb-mole) =	46.01
Molecular Weight of CO (lb/lb-mole) =	28.00
Molecular Weight of SO2 (lb/lb-mole) =	64.00
Molecular Weight of THC (propane) (lb/lb-mole) =	44.00
Molecular Weight of VOC (methane) (lb/lb-mole) =	16.00
Molecular Weight of NH3 (lb/lb-mole) =	17.03
Molecular Weight of HCHO (lb/lb-mole) =	30.03

40CFR60, App. A., RM 19, Table 19-1

Conversion Constant for NOx =	0.0000001194351
Conversion Constant for CO =	0.0000000726839
Conversion Constant for SO2 =	0.0000001661345
Conversion Constant for THC =	0.0000001142175
Conversion Constant for VOC (methane) =	0.0000000415336
Conversion Constant for NH_3 =	0.0000000442074
Conversion Constant for HCHO =	0.0000000779534

NOTE: units are lb/ppm*ft^3

Formulas:

1. Corrected Raw Average (C_{Gas}), 40CFR60, App. A, RM 7E, Eq. 7E-5 (08/15/06)

$$C_{Gas} = (C_{Avg} - C_O)\times\left(\frac{C_{MA}}{C_M - C_O}\right)$$

2. Correction to % O_2, 40CFR60, App. A, RM 20, Eq. 20-5 (11/26/02)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right)$$

3. Emission Rate in lb/hr

$$E_{lb/hr} = \frac{C_{Gas}}{10^6}\times\frac{Q_S \times MW}{G}$$

4. Emission Concentration in lb/MMBtu (O_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas}\times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}}$$

5. Emission Concentration in lb/MMBtu (CO_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas}\times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}}$$

RATA SHEET CALCULATIONS

d = Reference Method Data - CEMS Data

S_d = Standard Deviation

CC = Confident Coefficient

n = number of runs

$t_{0.025}$ = 2.5 percent confidence coefficent T-values

RA = relative accuracy

ARA = alternative relative accuracy

BAF = Bias adjustment factor

n	t	n	t	n	t
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

1. Difference

$$d = \sum_{i=1}^{n} d_i$$

2. Standard Deviation

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

3. Confident Coefficient

$$CC = t_{0.025}\times\frac{S_d}{\sqrt{n}}$$

4. Relative Accuracy

$$RA = \frac{|d_{AVG}| + |CC|}{RM_{AVG}}\times 100$$

5. Alternative Relative Accuracy

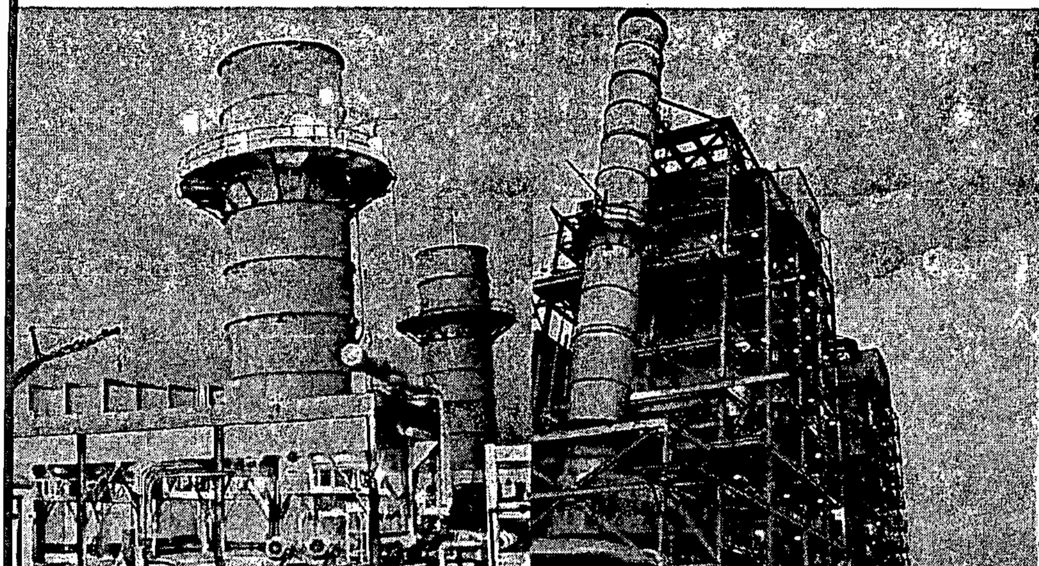
$$ARA = \frac{|d_{AVG}| + |CC|}{AS}\times 100$$

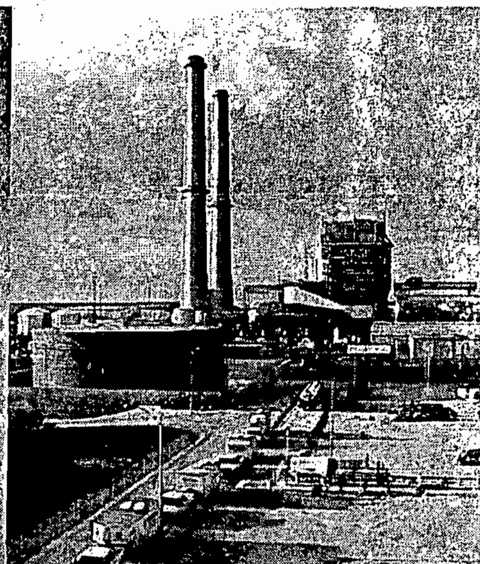
5. Bias Adjustment Factor

$$BAF = 1 + \left(\frac{|d_{AVG}|}{CEM_{AVG}}\right)$$

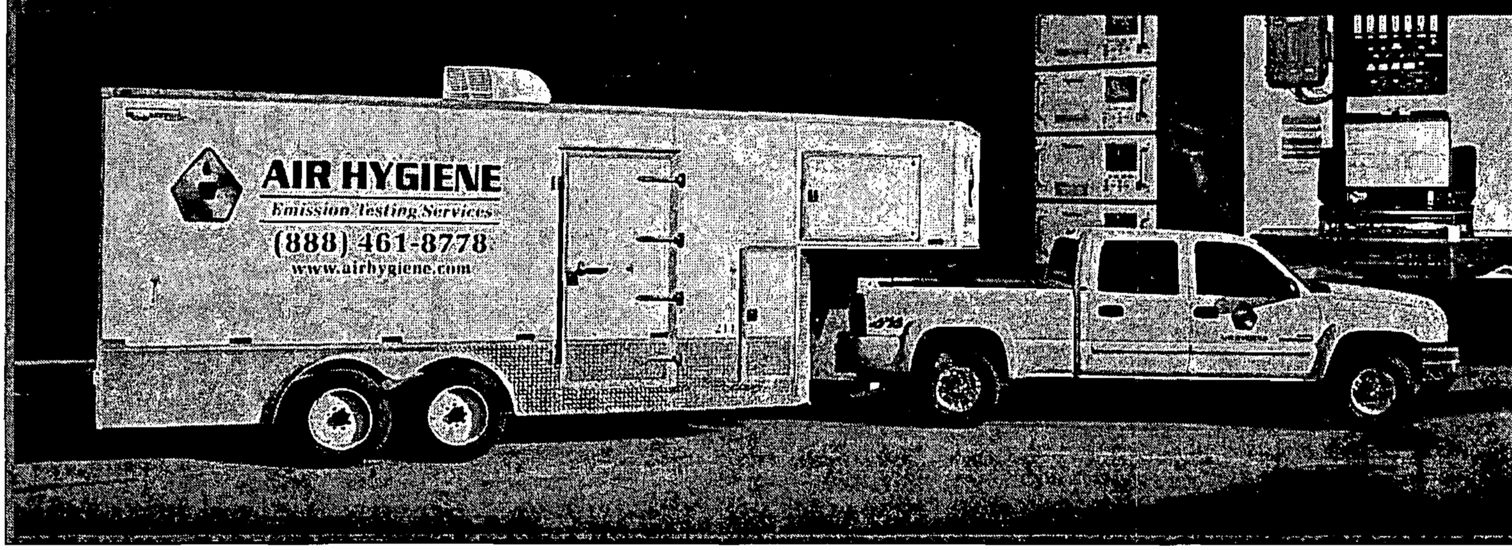
APPENDIX E
STATEMENT OF QUALIFICATIONS

AIR HYGIENE, INC.





Testing Solutions for a Better World



Statement of Qualifications - 2010

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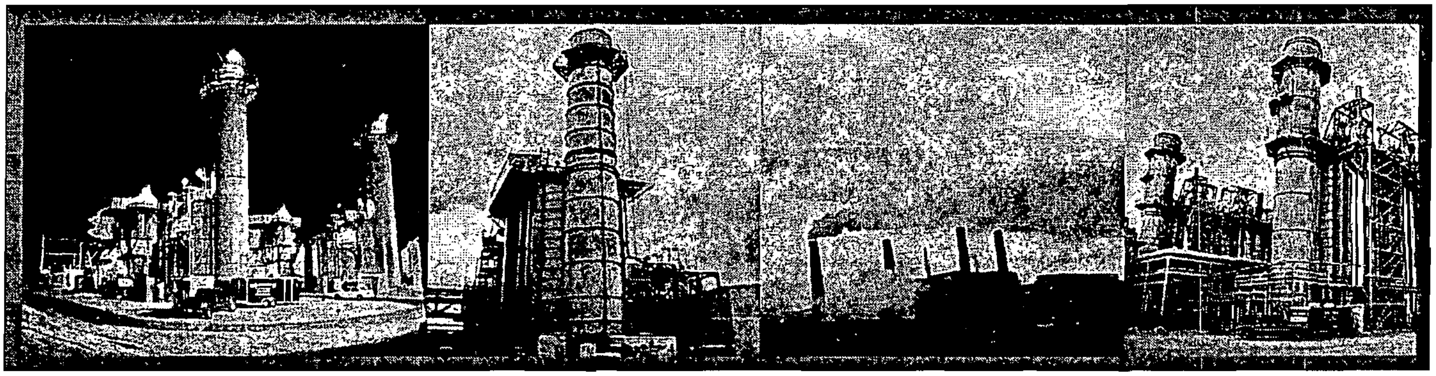


STATEMENT OF QUALIFICATIONS

AIR HYGIENE

AIR EMISSION TESTING SERVICES
www.airhygiene.com
January, 2010

INTRODUCTION

AIR HYGIENE INTERNATIONAL, INC. (AIR HYGIENE) is a professional air emission testing services firm operating from corporate headquarters in Tulsa, Oklahoma for over 13 years. Additional field offices with ready for field use testing labs are strategically located in Houston, Texas; Las Vegas, Nevada; and Philadelphia, Pennsylvania to serve all fifty (50) United States, Mexico, and Canada. AIR HYGIENE specializes in air emission testing services for combustion sources burning multiple fuels with multiple control devices and supporting equipment.

AIR HYGIENE has testing laboratories which serve all fifty (50) of the United States and North America. Each mobile laboratory can be equipped with the following equipment and capabilities:

1. State-of-the-Art air emission analyzers, computers, and datalogging software. All designed into an efficient system to provide the fastest, most reliable data possible!
2. Dual racks for multiple source testing simultaneously or multiple points on a single source (in/out SCR, etc.)!
3. NIST traceable gases for the most accurate calibration. Ranges as low as five (5) ppm!
4. PM_{10}, NH_3, mercury (Hg), sulfuric acid mist (H_2SO_4), SO_3, and formaldehyde sampling equipment!
5. VOC testing with on-board gas chromatograph to remove methane and ethane!
6. On-board printers to provide hard copies of testing information on-site!
7. Networking capabilities to provide real-time emission data directly into the control room!

AIR HYGIENE is known for providing professional services which include the following:

- Superior, cost saving services to our clients!
- High quality emission testing personnel with service oriented, friendly attitude!
- Meeting our client's needs whether it is 24 hour a day testing or short notice mobilization!
- Using great equipment that is maintained and dependable!
- Understanding the unique startup and operational needs associated with combustion sources!

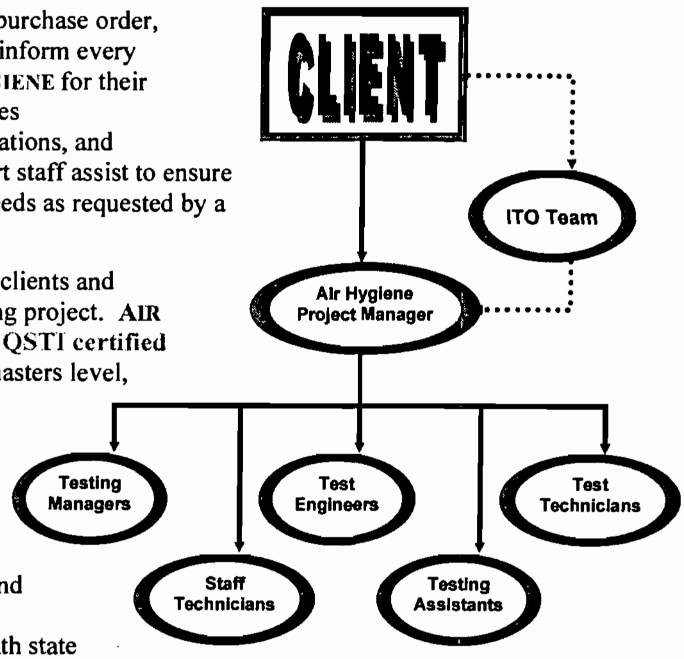
MISSION STATEMENT

Our mission is to provide innovative, practical, top-quality services allowing our clients to increase operating efficiency, save money, and comply with federal/state requirements. We believe our first responsibility is to the client. In providing our unique services, the owners of AIR HYGIENE demand ethical conduct from each employee of the company. The character and integrity of AIR HYGIENE employees allows our clients to feel confidence in the air testing services of AIR HYGIENE. Through a long-term commitment to this mission, AIR HYGIENE is known as a company committed to improving our clients' operations.

AIR HYGIENE ... Does work worth paying for every time!
... Is well known for our emission testing services and uncompromising efforts to serve our clients!
... Does work that matters!
... Is proud of our emission testing capabilities!
... Provides exciting growth opportunities for energetic individuals!

EMISSION TESTING TEAM

Air Hygiene International, Inc. (AIR HYGIENE) intends to exceed your expectations on every project. From project management to field-testing teams, we're committed to hard work on your behalf. The job descriptions and flowchart below outline AIR HYGIENE's client management strategy for your testing services.



From the initial request through receipt of the purchase order, the Inquisition To Order (ITO) team strives to inform every client of the benefits gained by using AIR HYGIENE for their emission testing project. The ITO team includes representatives from the sales, marketing, operations, and contracts divisions. In addition, several support staff assist to ensure the ITO team provides the support for client needs as requested by a client or project manager.

Project Managers are the primary contact for clients and ultimately responsible for every emission testing project. AIR HYGIENE's Project Managers include ten (10) QSTI certified testing experts with experience ranging from masters level, professional engineers to industry experts with over 5,000 testing projects completed. Each project is assigned a Project Manager based primarily upon geographic location, then industry experience, contact history, and availability. The Project Manager prepares the testing strategy and organization for the project. This includes preparation of testing protocol; coordination with state agencies, client representatives, and any interested third parties. The site testing and report preparation are executed under the direction of the Project Manager from start to finish.

Testing Managers have completed Air Hygiene's rigorous demonstration of capability training program and are capable of operating all testing equipment and performing all test methods required for your testing project. Testing Managers assist Project Managers by leading the field testing when required, preparing draft reports, calibrating equipment, and overseeing testing team on-site.

Test Engineers have significant background and understanding of emission testing or related services. Test Engineers prepare pre-test drawings for port location, ensure on-site logistics for electrical and mechanical/structural needs, and conduct on site testing as directed by the Project Manager and/or Testing Manager. Test Engineers often have special understanding of process and/or regulations applicable to specific testing jobs, which provide great value to both the client and Project Manager in testing strategies.

Test Technicians experience ranges from new hire with technical degree and experience to technicians who have performed up to 500 emission tests. All test technicians have a basic understanding of emission training and are involved in daily training and under supervision to continue to develop testing skills. Test Technicians have testing experience with AIR HYGIENE equipment along with a variety of industries and source equipment. Test Technicians may operate isokinetic sampling trains or gas analyzers on-site under the direction of the Project Manager and assist with preparation of field reports and quality assurance procedures.

Staff Technicians are entry-level personnel who have performed less than 500 emission tests. Staff Technicians perform pre-test equipment preparation, on-site test preparation, and testing assistance under the direction of Project Manager and/or Testing Manager. At least one Staff Technician is assigned to every project to assist on-site. Staff Technicians connect sampling probes to ports, assist with leak checks, raise and lower equipment to and from sampling platform, and other support activities under the direction of the Project Manager and/or Testing Manager.

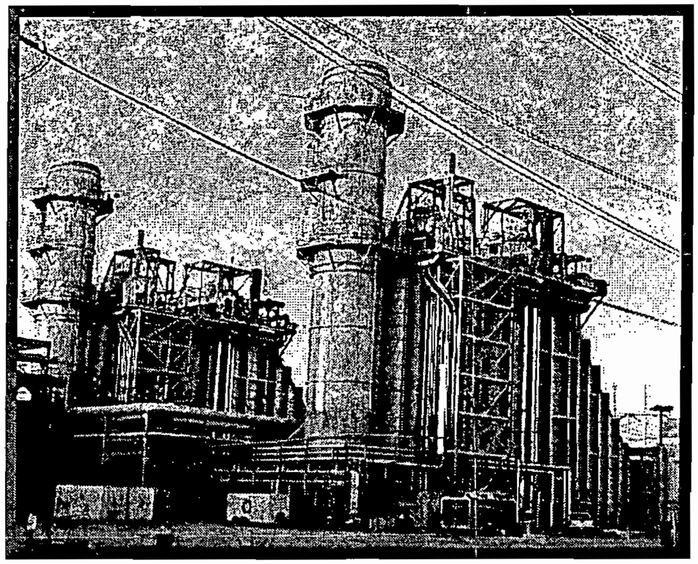
Testing Assistants are entry-level personnel who have performed less than 100 emission tests. Testing Assistants help with equipment set-up, teardown, and simple testing procedures (i.e. move probe, fill ice bath, clean impingers, etc.) as directed.

AIR HYGIENE, INC.

Testing Solutions for a Better World

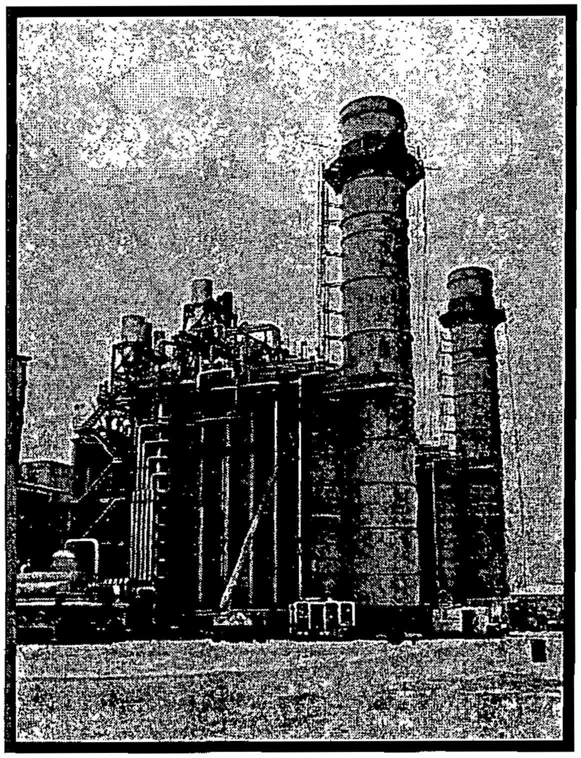
AIR HYGIENE Emission Services Summary

AIR HYGIENE is a privately-held professional services firm headquartered in Tulsa, Oklahoma with additional field offices in Las Vegas, Nevada, Houston, Texas; Ft. Worth, Texas; Shreveport, Louisiana; and Philadelphia, Pennsylvania. **AIR HYGIENE** specializes in emission testing services for a variety of industries including solid, liquid, & gas fired utility plants, turbines, engines, refineries, printers, glass plants, chemical plants, various manufacturers and related industries.



AIR HYGIENE provides turn-key emission testing services with fast-turnaround which include:

1. Pre-test site visit;
2. Consulting on port locations and setup;
3. Preparation of test plan for state agency;
4. Coordination with state agency for emission testing;
5. On-site emission testing services; and
6. Preparation of draft and final reports.



AIR HYGIENE has mobile laboratories that serve all 50 United States and North America. **AIR HYGIENE** has performed over 15,000 emission tests on a variety of sources.

AIR HYGIENE performs air emission certification compliance testing on combustion sources (natural gas, biomass, coal, fuel oil, jet fuel, etc), NSPS sources, and Title V compliance sites. Our experience ranges from emission testing for new PSD facilities, MACT and RACT required performance certification testing to Relative Accuracy Test Audits (RATA Tests) for Continuous Emission Monitoring Systems (CEMS) and Parametric Emission Monitoring Systems (PEMS).

Air Hygiene has conducted numerous emission testing projects, which involved multiple groups relying upon instantaneous reporting of important test data. These projects relied upon **Air Hygiene**'s **SPIDER** network. The **SPIDER** network provides Simultaneously Produced Information During Emission Readings (**SPIDER**) between the emission monitoring system and multiple locations (i.e. control room, test center, office, etc.). Hence, you can view real-time emission testing data on-demand from any location you choose using our wireless network data-logging system!

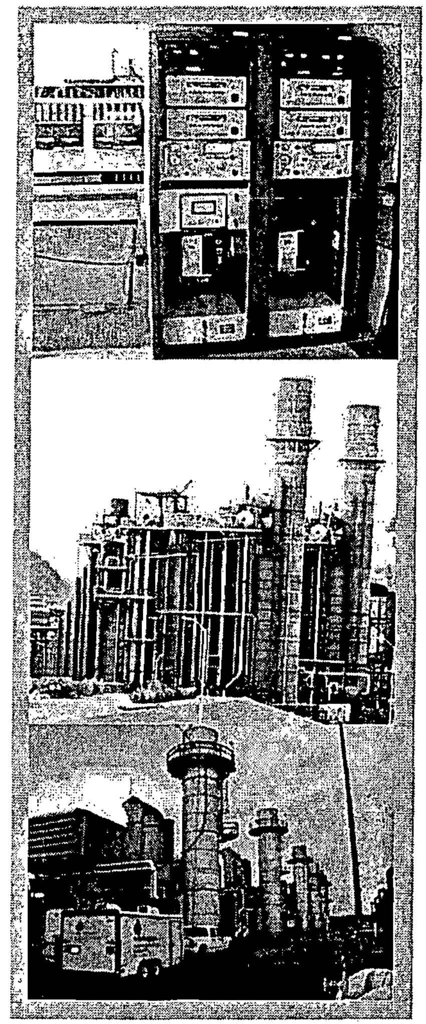
AIR HYGIENE performs FTIR testing by EPA Method 320 321, & ASTM D-6348 for Hazardous Air Pollutants (HAPS) including formaldehyde, benzene, xylene, toluene, hexane, ammonia, hydrogen chloride, etc. This methodology provides real-time analysis of these critical pollutants.

AIR HYGIENE specializes in the following types of pollutants and EPA Reference Methods (RM):

- Exhaust Flow – RM 2 &/or 19
- Carbon Dioxide (CO_2) – RM 3a
- Oxygen (O_2) – RM 3a &/or 20
- Moisture – RM 4
- Particulates (PM) – RM 5(filterable) & 202/OTM-028
- PM < 10 microns (PM_{10}) – RM 201a
- PM < 2.5 microns ($PM_{2.5}$) – RM 201b
- PM sizing (elzone analysis)
- Sulfur Dioxide (SO_2) – RM 6c
- Nitrogen Oxides (NOx) – RM 7e &/or 20
- Sulfuric Acid Mist (SO3) – RM 8a (control condensate)
- Opacity – RM 9
- Carbon Monoxide (CO) – RM 10
- Hydrogen Sulfide (H_2S) – RM 11
- Lead – RM 12
- Dioxin & Furans – RM 23
- Total Hydrocarbons (THC) – RM 25a
- Volatile Organic Compounds (VOC) RM 25a & RM 18
- Metals – RM 29
- Chrome – RM 306
- Formaldehyde – RM 320 & ASTM D-6348 (FTIR)
- HAPS – FTIR – RM 320, 321, & ASTM D-6348 (FTIR)
- Ammonia – RM 320, CTM-027, or BAAQMD ST-1B
- **Mercury – RM 30b-Sorbent Tubes (both with on-site analysis, Ontario-Hydro, and RM 29**

TESTING EXPERIENCE

AIR HYGIENE testing personnel include ten (10) QSTI certified test managers and account for more than one hundred (100) years of testing experience and over 18,000 emission tests. Our testing services have involved interaction with all 50 state agencies and EPA regional offices. AIR HYGIENE testing personnel are rigorously trained on EPA reference test methods from 40 CFR Part 51, 60, 63, and 75 along with ASTM methods. All testing personnel are instructed and tested on test responsibilities and must complete a "Demonstration of Capability" test per the AIR HYGIENE Quality Assurance Manual and the AIR HYGIENE Emission Testing Standard Operating Procedures Handbook.



AIR HYGIENE has completed testing on over 250 power plants including in excess of 1,000 combustion turbines and 50 coal fired boilers 100,000 megawatts (MW). ***Let us add your project to our list of satisfied customers!***

TESTING SUCCESS STORIES

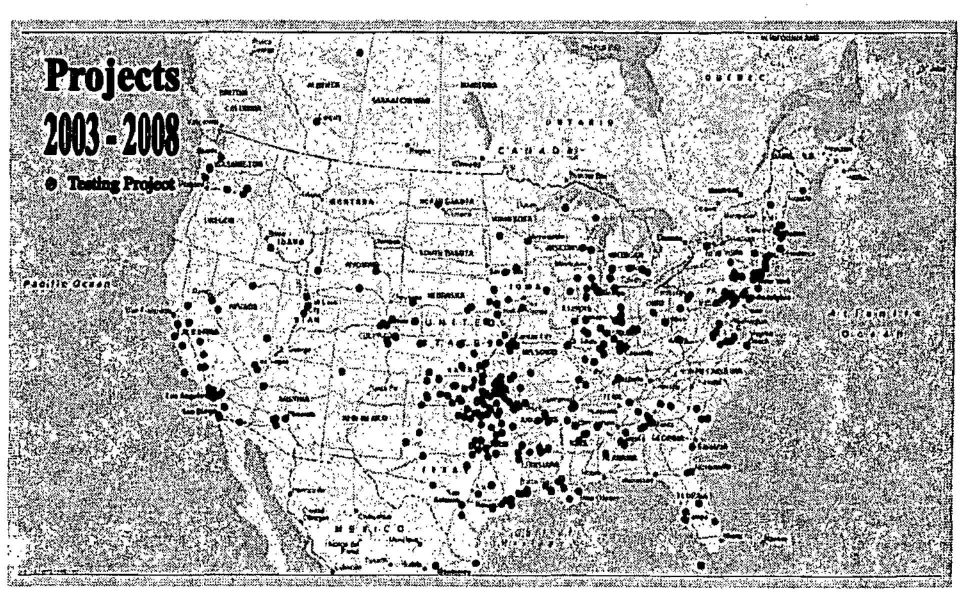
AIR HYGIENE personnel have performed thousands of testing projects which have yielded significant benefits for our clients. The following project descriptions briefly discuss some of these emission testing projects.

- Conducted Mercury (Hg), PM, selected metals, HCl, Chlorine, and gas testing to verify status with the industrial boiler MACT on six coal fired units at three (3) locations.
- Conducted inlet/outlet baghouse emission testing for Mercury (Hg) to determine control efficiency using Ontario-Hyrdo testing methodology.
- Conducted numerous projects optimizing SCR performance by conducting inlet & outlet SCR analysis for NH_3, NOx, flow, and Oxygen. Used information to assist with flow optimization and AIG tuning.
- Conducted federal and state required compliance testing for NOx, CO, PM-10 (front & back-half), SO_2, VOC, Ammonia, Formaldehyde, Opacity, RATA testing (NOx and CO) for new and updated power plants with both simple and combined cycle turbines firing natural gas and fuel oil.
- Conducted dry low NOx burner tuning and performance testing for various models of GE, Siemens Westinghouse, Mitsubishi, Pratt & Whitney, and ABB combustion turbines to verify manufacturer's emission guarantees for clients in preparation for compliance testing.
- Performed power plant emission testing for natural gas & fuel oil fired combustion turbines. Tests included federal required testing per 40 CFR Part 75, state air permit requirements, RATA testing, and emission testing to verify manufacturer's guarantee's during electric/heat output performance testing.

TESTING LOCATIONS

AIR HYGIENE bases mobilization charges on the distance from your site to the closest of six (6) regional starting points covering all 50 United States. These include Las Vegas, Tulsa, Houston, Ft. Worth, Shreveport, and Philadelphia.

Each start point is located such that the AIR HYGIENE test teams can mobilize to your site within 24 hours at affordable costs to ensure we are price competitive to any U.S. location.



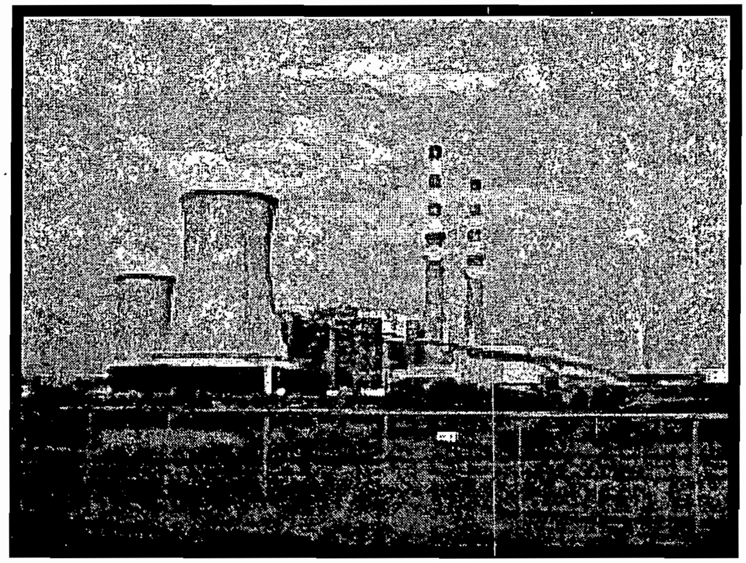
AIR HYGIENE, INC.

Testing Solutions for a Better World

COMBUSTION TESTING SERVICES SUMMARY

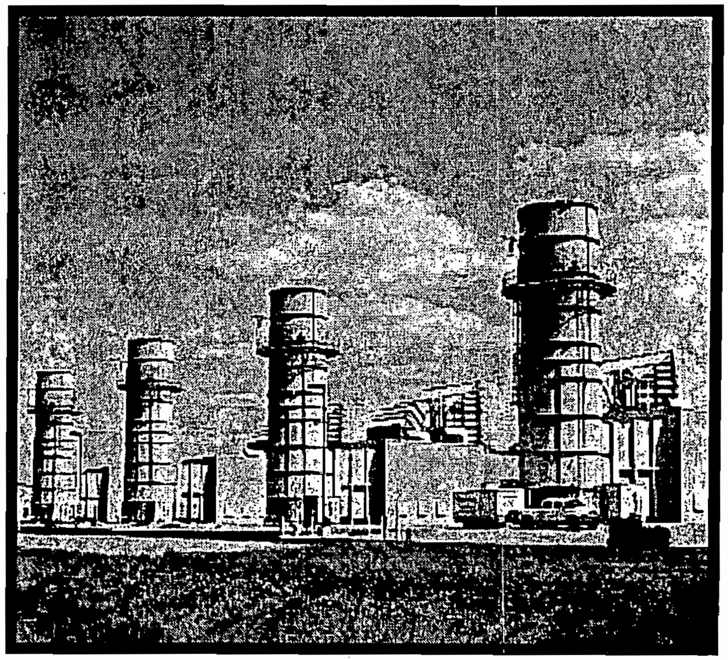
Thank you for your consideration of the combustion emission testing services of Air Hygiene International, Inc. (**AIR HYGIENE**). The following list details some of the testing services and extras **AIR HYGIENE** includes with each testing job.

Types of Air Testing Services for Combustion Sources:



- Boiler or Turbine tuning/mapping for NOx, CO, O2, CO2, flow, temperature, &/or NH_3 emissions
- Pollutant testing to verify EPC contractual emission guarantees
- Research and Development (R&D) emission data research and emissions optimization
- Mercury (Hg) testing with on-site data
- 40 CFR Part 60 Subpart GG or KKKK – Turbine Compliance Testing
- 40 CFR Part 75 – Acid Rain Classified Equipment Testing
- 40 CFR Part 75 Appendix E – Peaking Plant CEMS alternative NOx emissions versus Heat Input mapping
- RATA Testing on CEMS systems for NOx, CO, SO_2, CO_2 or O_2, Flow (3-D & Wall effects)
- QA/QC Plans, Monitoring Plans, Linearity Checks, Testing Protocols, etc. are provided with our high quality, service oriented emission testing services
- Initial permit compliance testing for PM, PM-10, PM-2.5, SO_2, NOx, CO, H2SO4, HCl, Hg, exhaust flow, moisture, O_2, CO_2, Ammonia, Formaldehyde, other HAPs

AIR HYGIENE will provide the following testing services:



- On-site, real-time test data
- Fuel F-Factor calculation data sheet
- Experienced emission testing personnel
- Flexible testing schedules to meet your needs
- Electronic reports provided on CD upon request
- Extensive experience with all 50 state agencies in the U.S., Mexico, & Canada
- EPA Protocol 1 Certified Gases (one percent accuracy) for precise calibration
- Low range (0-10 ppm) equipment calibration and measurement available
- Test protocol preparation, coordination with state agency, and site personnel
- Numerous mobile testing labs, which may be used for your projects across the U.S.
- State-of-the-art data logging technology to allow real-time examination of meaningful emission data
- Monitor your emissions data measured in our test lab from your control room via our datalogging network system

AIR HYGIENE is committed to providing testing teams that will take the time to meet your needs. We ensure the job is completed on time with the least amount of interruption to your job and site operation as possible. Thank you for considering our services.

AIR HYGIENE, INC.

Testing Solutions for a Better World

SYNERGISTIC APPROACH TO POWER PLANT CONSTRUCTION PROJECT TESTING

Power plants continue to be built, modified, and improved across the United States. These new or modified facilities are at the forefront of clean energy. Emission rates and limits continue to decrease. These units are very efficient, environmentally friendly, and meet the stringent requirements set forth by the Environmental Protection Agency (EPA) and associated state agencies. AIR HYGIENE has developed a unique strategy to help owners demonstrate compliance with testing solutions for difficult sampling locations to meet complicated requirements.

Unique Testing Strategy

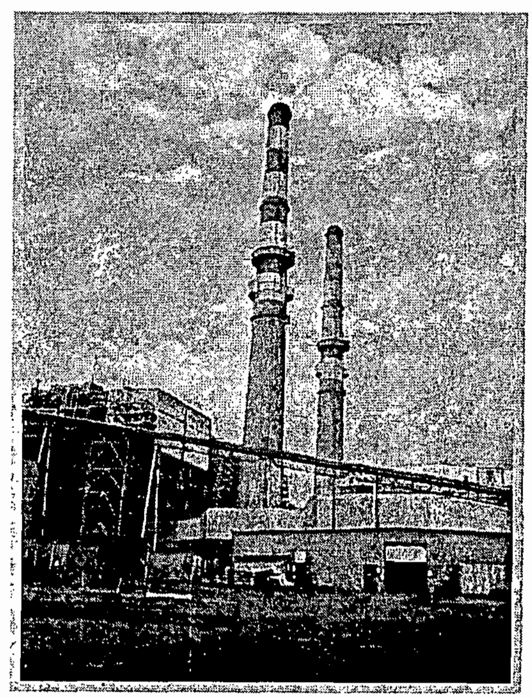
AIR HYGIENE has developed a synergistic approach to assisting the various groups involved in the completion of a commissioning/startup unit or modification project. AIR HYGIENE strives to combine the multiple testing aspects involved with bringing a combustion unit to commercial service. By conducting the various emission tests required for a new combustion unit using one test company, the following benefits are a given:

1. Save money by...
   a. Reduced mobilizations
   b. Combined tests yield reduced fuel usage and site time
   c. Bulk projects receive quantity discounts
2. Improve efficiency through familiarity with site needs
3. Site personnel and testing team are comfortable working together

These projects typically involve some or all of the following groups. There is not a defined set of responsibilities that will match every project. The table below simply suggests a typical list of testing responsibilities.

Responsible Party	**Testing Responsibilities**
Owner	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Operator	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Turbine/Boiler manufacturer	Contractual emission guarantees of unit (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
EPC & Construction Company	Contractual emission guarantees including control devices (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
CEMS Supplier	Initial RATA testing (i.e. NOx, CO, SO2, CO2, O2, flow)
Lending Party (i.e. bank)	No responsibility, but concerned with outcome of all tests
Environmental Consultant	Concerned with air permit and overall compliance; may select the test contractor and provide oversight for testing

Example Project:



A recent project provides a prime example of the synergistic benefits of using AIR HYGIENE to perform your commissioning/startup or remodification testing needs for performance and compliance. Eight GE Frame 7FA turbines were taken from performance testing through compliance testing in 20 days. The following tests were performed on each turbine:

- NOx tuning and mapping
- Contractual performance testing for NOx, CO, VOC, SO_2, NH_3, & PM_{10}
- 40 CFR Part 60 Subpart GG: testing for NOx and CO at max load
- 40 CFR Part 75: NOx & CO RATA certification on CEMS
- State required compliance testing for NOx, CO, VOC, NH_3(on-site analysis), formaldehyde (on-site analysis by FTIR), opacity and SO_2 burning natural gas

Test data was provided on-site for all tests, except PM-10. Electronic files were e-mailed for review to the turbine manufacturer, owner & operator, and environmental consultant within 24 hours following completion of site work. Complete reports including PM-10 were submitted to interested parties within 10 days following each blocks completion.

Power Plant Testing Experience

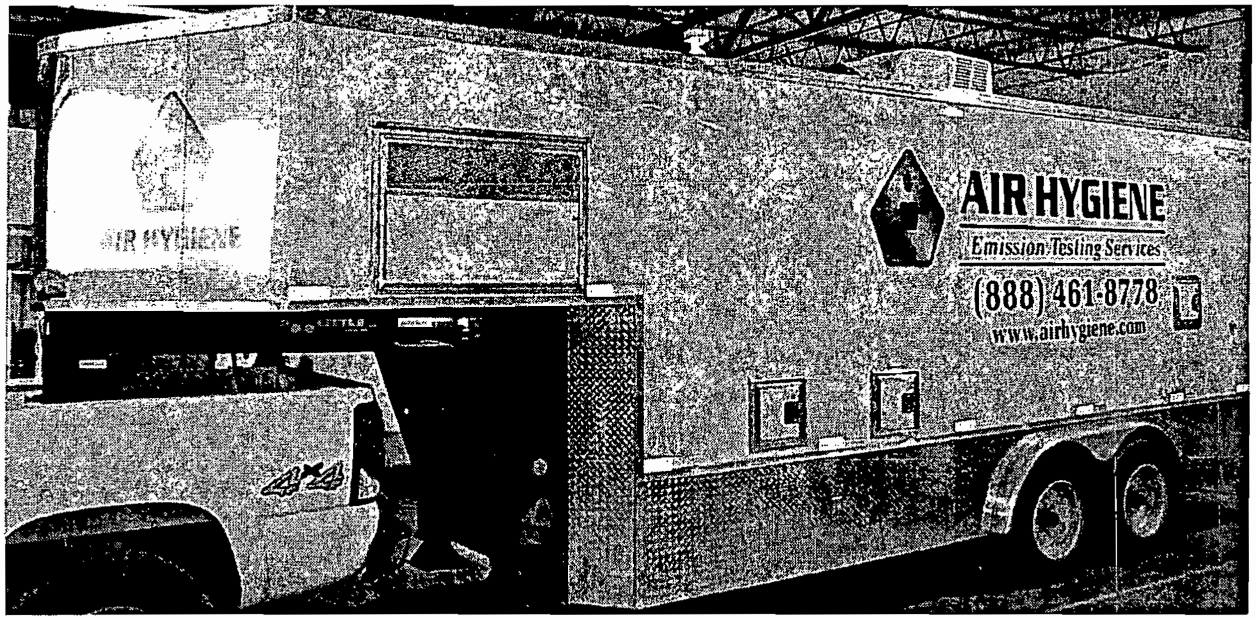
AIR HYGIENE personnel have over one hundred (100) years of testing experience on combustion turbines, coal fired boilers, gas fired boilers, landfill gas, wood fired, & diesel fired engines across the United States. AIR HYGIENE has 15 combustion labs serving all 50 states from one corporate office in Tulsa, OK and five (5) additional field offices (Houston, TX; Ft. Worth, TX; Shreveport, Louisiana; Las Vegas, NV; & Philadelphia, PA). AIR HYGIENE has tested plants ranging from 50 to 2,000 megawatts in both simple and combined cycle operation with controls including:

- Selective Catalytic Reduction - Ammonia injection
- Steam/Water injection
- Sprint injection
- Dry Low NOx burners (DLN)

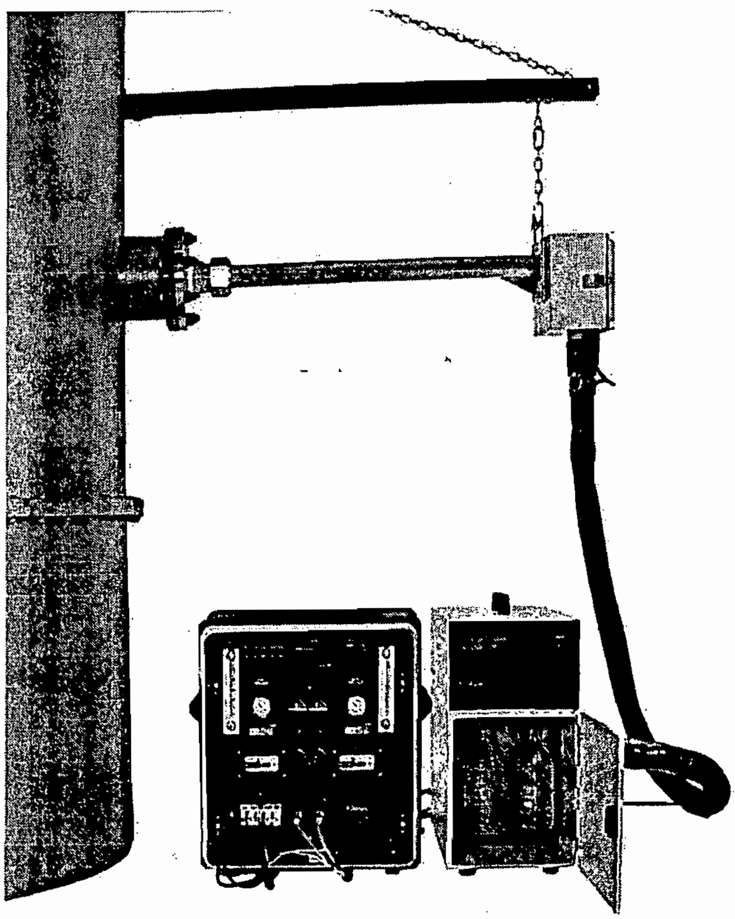
AIR HYGIENE has completed testing at over 250 plants on 1,000 combustion turbines, 50 coal fired boilers, 20 gas fired boilers, and other sources representing 100,000 plus megawatts (MW). AIR HYGIENE has proven through our numerous projects that we can be relied upon for uncompromised quality, service flexibility, and loyalty to our clients no matter where the job nor what the situation may be. ***Let us add your upcoming project to our list of satisfied customers!***

Air Hygiene Mercury Testing

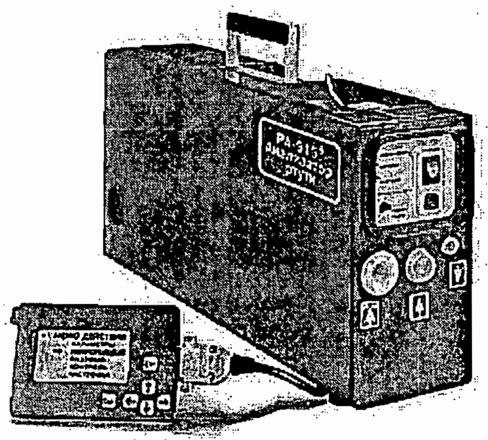
Air Hygiene Mercury Testing Lab

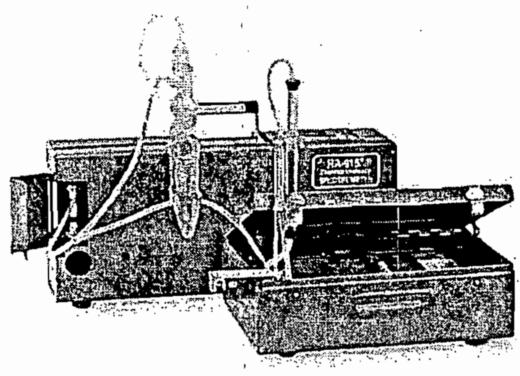


Apex 30B Console & Probe



Ohio Lumex: RA915+ Analyzer with RP-91 Attachment for Ontario Hydro or 30b sorbent trap analysis on-site





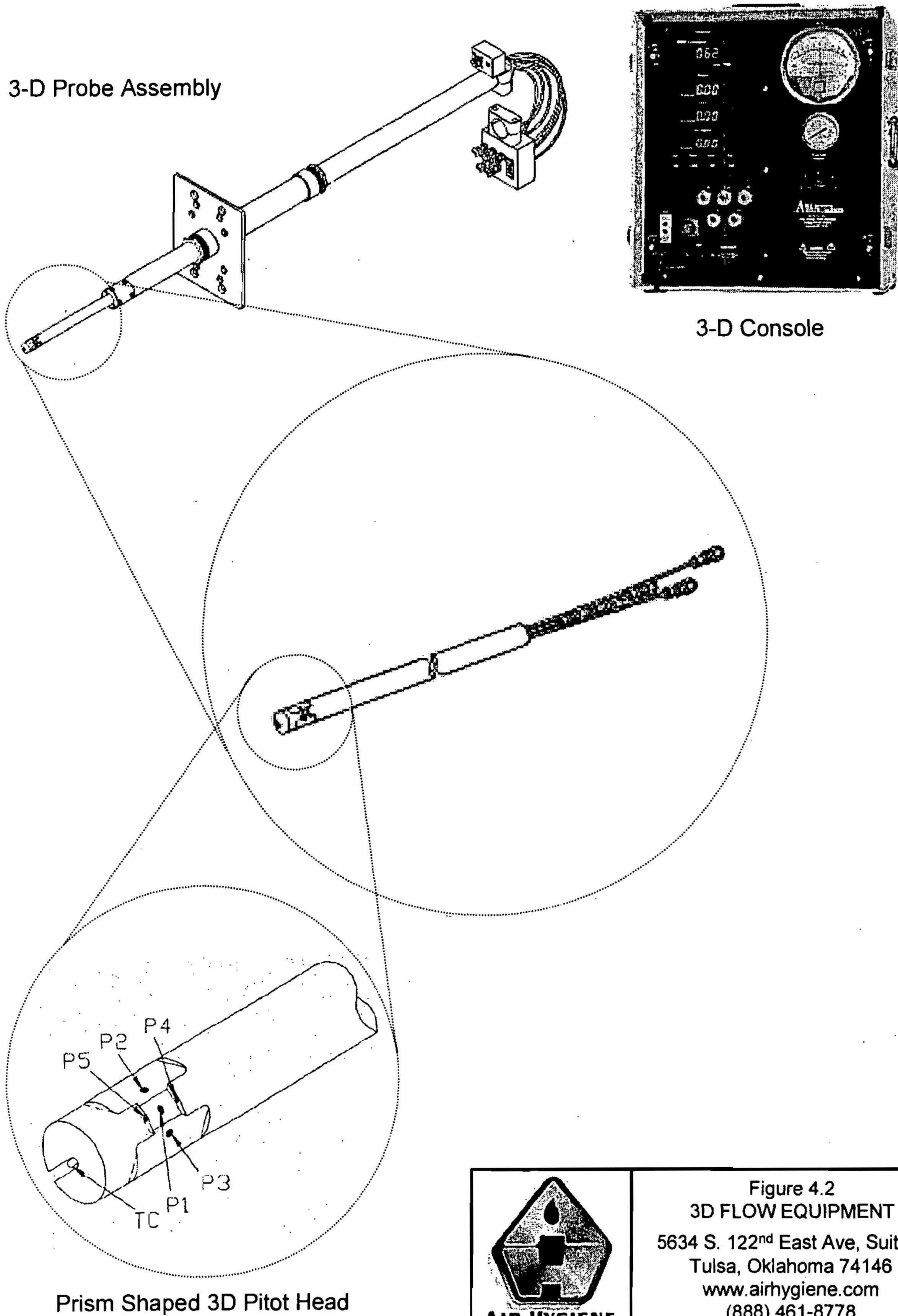


Figure 4.2
3D FLOW EQUIPMENT

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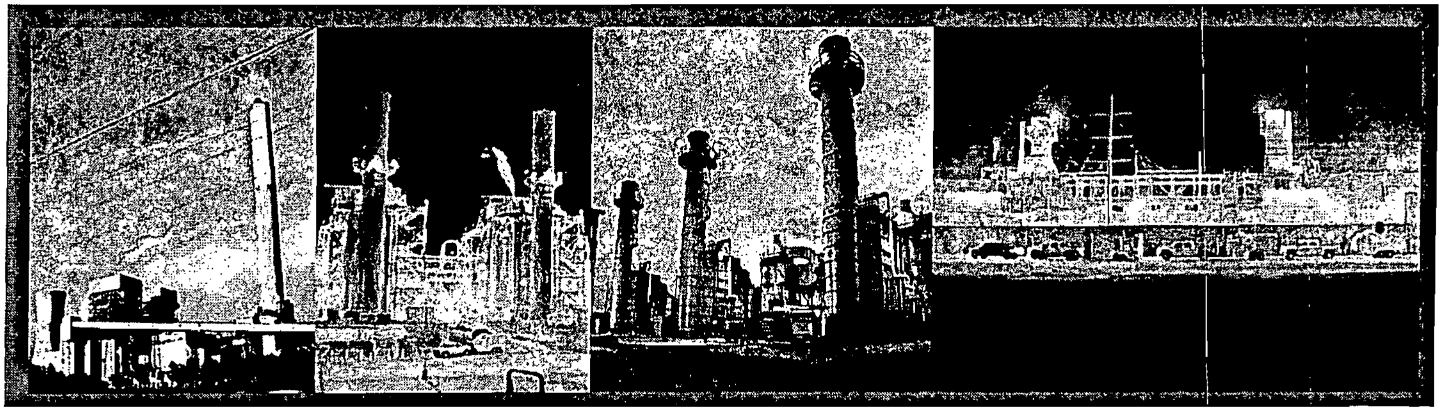

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures used by **AIR HYGIENE** during tests conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 3a, 6c, 7e, 10, 18, 19, 20, and 25a.

The flowchart on the next page depicts the sample system used by **AIR HYGIENE** for analysis of oxygen (O_2), carbon dioxide (CO_2), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC) tests. A heated stainless steel probe is inserted into the sample ports of the stack to extract gas measurements from the emission stream. The gas sample is continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample is partitioned to the O_2, CO_2, SO_2, CO, and NOx analyzers through glass and stainless steel rotameters that control the flow rate of the sample. The VOC sample is measured as a wet gas.

The flowchart shows that the sample system is also equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments are housed in an air-conditioned trailer which serves as a mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 is used to determine the cylinder concentrations where applicable (i.e. NO_x calibration gases).

All data from the continuous monitoring instruments are recorded on a Logic Beach Hyperlogger which retrieves calibrated electronic data from each instrument every second and reports an average of the collected data every 30 seconds and 10 seconds. The averaging time can be selected to meet the clients needs. **This data is available instantaneously for printout, statistical analysis, viewable by actual values, or examined by a trending graph!**

The number of test runs, test loads, and length of runs is based upon federal and state requirements for the facility. Typical run times associated with emission testing are as follows:

Type of Test	# of runs	Length of runs
O_2 Traverse (GG)	1 run @ low load (8 – 48 points)	2 minutes per point
NOx Stratification Test	1 run @ base load (12 points)	2 – 4 minutes per point
Subpart GG or KKKK	3 runs @ 4 loads (30%, 50%, 75%, & 100%)	15 – 60 minutes per run
RATA	9 – 12 runs @ normal load	21 minutes per run
State Permit Test (gases)	3 runs @ base load	1 hour per run
State Permit Test (particulates)	3 runs @ base load	2 – 4 hours per run

The stack gas analysis for O_2 and CO_2 concentrations are performed in accordance with procedures set forth in EPA Method 3a (EPA Method 20 for O_2 on combustion turbines). The O_2 analyzer uses a paramagnetic cell detector. The CO_2 analyzer uses an infrared detector.

CO emission concentrations are quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer is used for this purpose.

NOx emission concentrations are measured in accordance with procedures set fort in EPA Method 7e and/or 20. A chemiluminescence analyzer is used to determine the nitrogen oxides concentration in the gas stream.

Total hydrocarbons (THC), non-methane, non-ethane hydrocarbons also known as volatile organic compounds (VOC) are analyzed in accordance with procedures set forth in EPA Methods 18 & 25a. A flame ionization detector calibrated with methane is used to determine the THC concentration in the gas stream and VOCs analyzed by GC to determine methane, ethane, and remaining VOCs per EPA Method 18 determination with gas chromatograph using FID detector.

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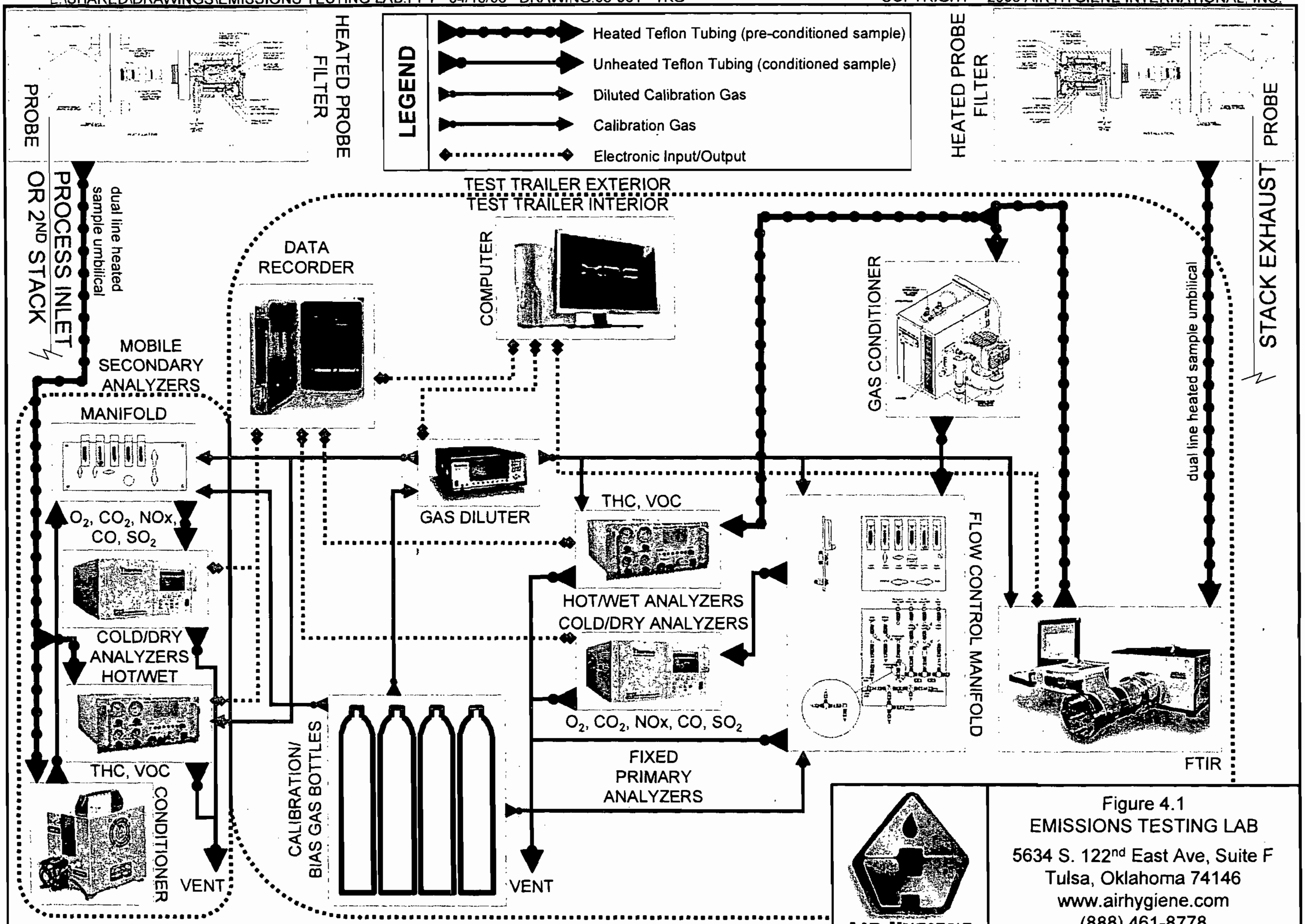

Figure 4.1
EMISSIONS TESTING LAB

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Shown fully equipped. Some labs may not contain these features and others may contain additional features specific to certain scopes.

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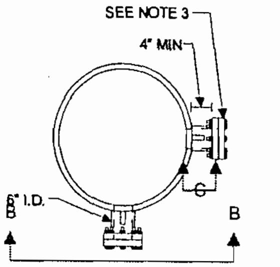

SECTION A
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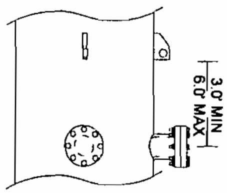

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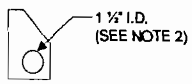

SECTION C
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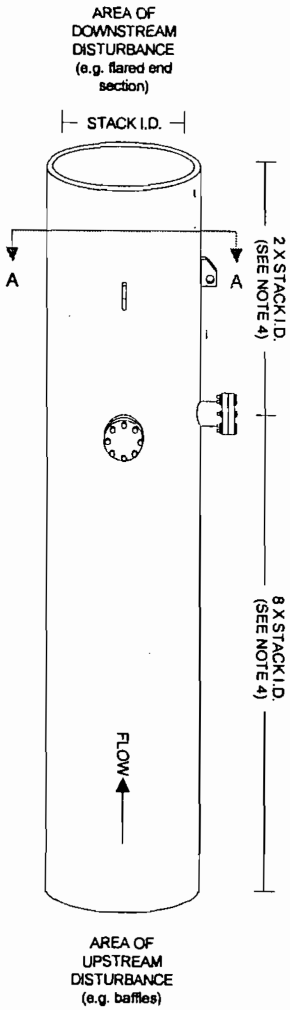

PARTIAL STACK
not to scale

NOTES

1. TWO PORTS WITH CENTERLINES AT 90° ANGLES
2. ⅜ INCH THICK STEEL, WELDED TO STACK EXTERIOR, PROVIDES PLACE TO HOOK CHAIN FOR RAIL ASSEMBLY
3. MINIMUM THREE INCH INNER DIAMETER STEEL PIPE, WELDED TO STACK EXTERIOR, HOLE CUT INTO STACK WALL, NO POTRUSIONS OR OBSTRUCTIONS INSIDE STACK WALL
4. IF TOTAL STACK LENGTH IS NOT AVAILABLE, EPA MINIMUM REQUIREMENTS ARE ½ X STACK I.D. FROM PORTS TO TOP AND 2 X STACK I.D. FROM PORTS TO BOTTOM

AIR HYGIENE

PORT INSTALLATION DIAGRAM

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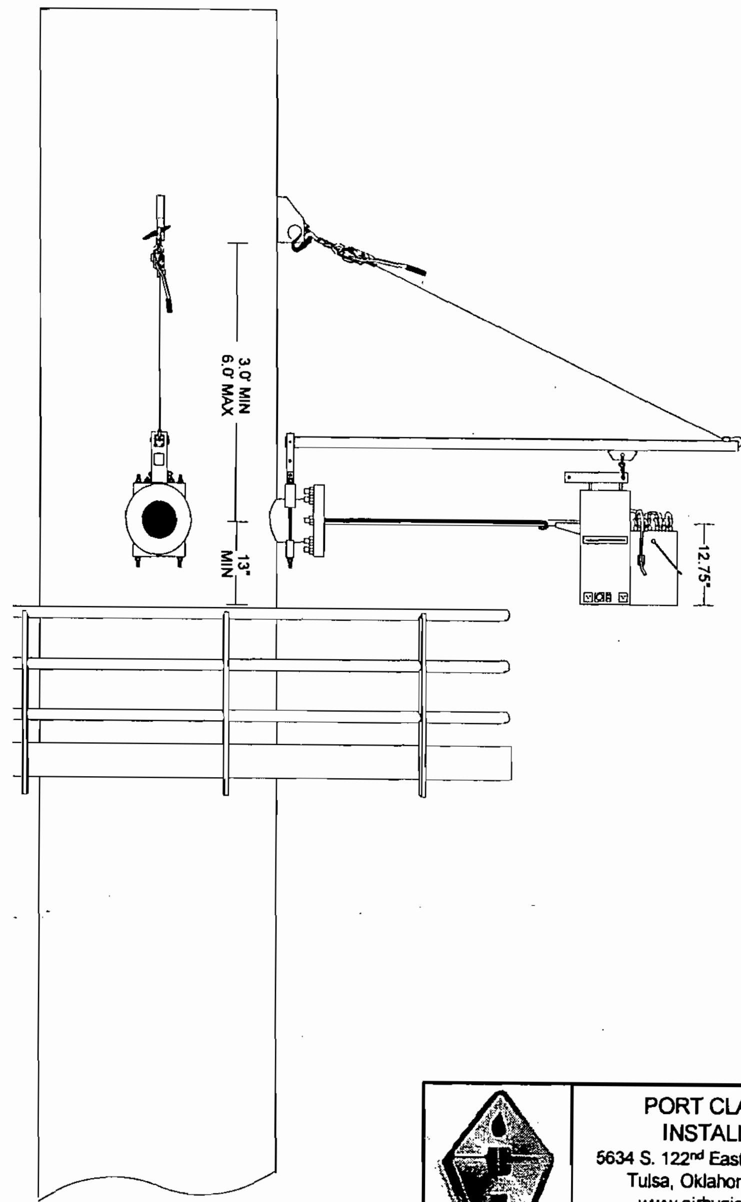

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AIR HYGIENE

PORT CLAMPS INSTALLED

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TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after turbine testing projects. This section describes each of those activities.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± two percent of range of the predicted values.

NO_2 to NO conversion is checked via direct connect with a EPA Protocol certified concentration of NO_2 in a balance of nitrogen. Conversion is verified to be above 90 percent.

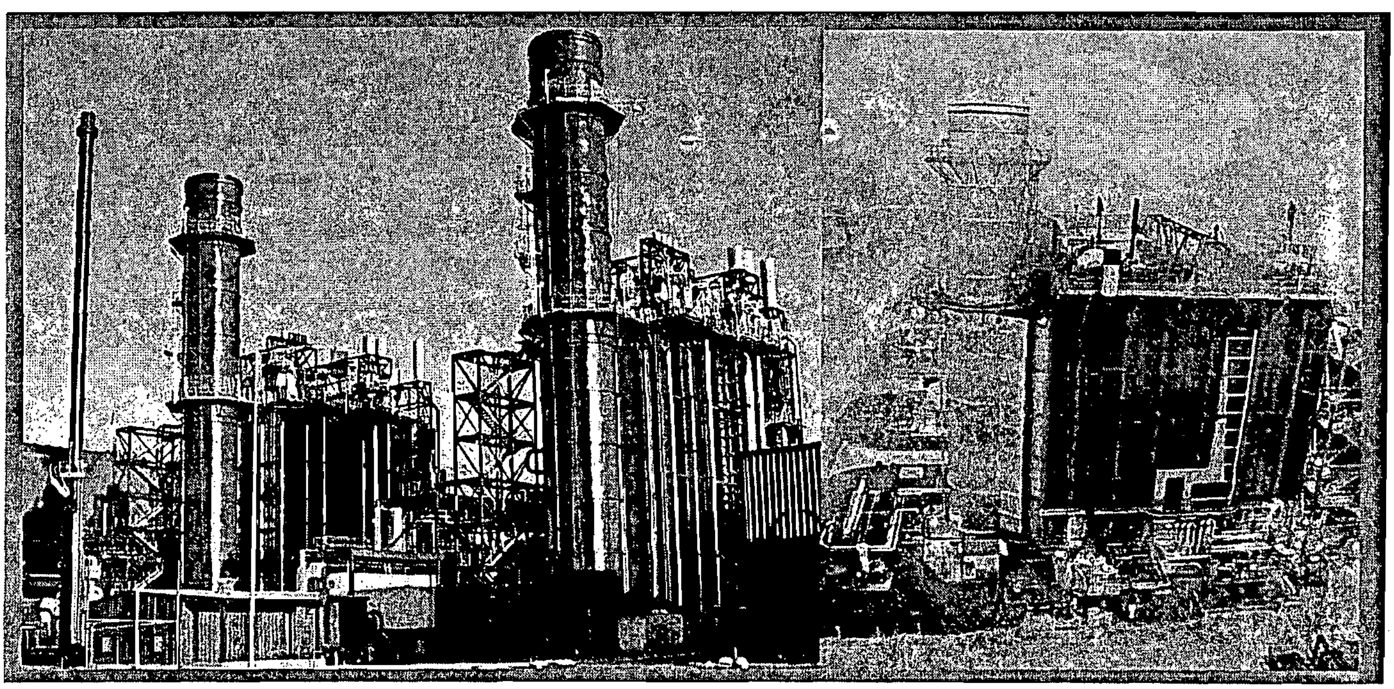
Instruments are both factory tested and periodically field challenged with interference gases to verify the instruments have less than a two percent interference from CO_2, SO_2, CO, NO, and O_2.

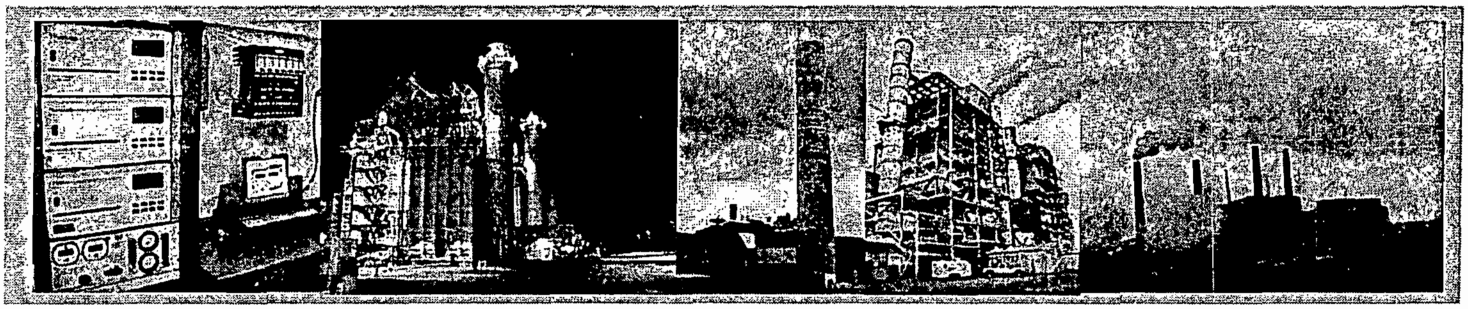
After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data collected. The criterion for acceptable data is that the instrument drift is no more than three percent of the full-scale response. Quality assurance worksheets summarize all multipoint calibration linearity checks and the zero to span checks performed during the tests are included in the test report.

The sampling systems is leak-checked by demonstrating that a vacuum greater than 10 in. Hg can be held for at least one minute with a decline of less than one in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. This test is conducted to ensure that ambient air does not dilute the sample. Any leakage detected prior to the tests is repaired and another leak check conducted before testing will commence.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the responses of the calibration gases introduced via two paths. The first path is directly into the analyzers and the second path includes the complete sample system with injection at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criterion for acceptance is agreement within five percent of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± one percent accuracy for all gases. EPA Protocol No. 1 is used, where applicable, to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM). The gas calibration sheets as prepared by the vendor are included in the test report.





QUALITY ASSURANCE PROGRAM SUMMARY

AIR HYGIENE ensures the quality and validity of its emission measurement and reporting procedures through a rigorous quality assurance (QA) program. The program is developed and administered by an internal QA team and encompasses five major areas:

1. QA reviews of reports, laboratory work, and field testing;
2. Equipment calibration and maintenance;
3. Chain-of-custody;
4. Training; and
5. Knowledge of current test methods.

QA Reviews

AIR HYGIENE's review procedure includes review of each source test report, along with laboratory and fieldwork, by the QA Team. The most important review is the one that takes place before a test program begins. The QA Team works closely with technical division personnel to prepare and review test protocols. Test protocol review includes selection of appropriate test procedures, evaluation of interferences or other restrictions that might preclude use of standard test procedures, and evaluation and/or development of alternate procedures.

Equipment Calibration and Maintenance

The equipment used to conduct the emission measurements is maintained according to the manufacturer's instructions to ensure proper operation. In addition to the maintenance program, calibrations are carried out on each measurement device according to the schedule outlined by the Environmental Protection Agency. Quality control checks are also conducted in the field for each test program. Finally, AIR HYGIENE participates in a PT gas program by analyzing blind gases semi-annually to ensure continued quality.

Chain-of-Custody

AIR HYGIENE maintains full chain-of-custody documentation on all samples and data sheets. In addition to normal documentation of changes between field sample custodians, laboratory personnel, and field test personnel, AIR HYGIENE documents every individual who handles any test component in the field (e.g., probe wash, impinger loading and recovery, filter loading and recovery, etc.). Samples are stored in a locked area to which only AIR HYGIENE personnel have access. Field data sheets are secured at AIR HYGIENE's offices upon return from the field.

Training

Personnel's training is essential to ensure quality testing. AIR HYGIENE has formal and informal training programs, which include:

1. Participation in EPA-sponsored training courses;
2. A requirement for all technicians to read and understand Air Hygiene Incorporated's QA manual;
3. In-house training relating to 40 CFR Part 60 Appendix A methods and QA meetings on a regular basis;
4. OSHA 40 hour Hazwopper Training;
5. Visible Emission (Opacity) Training; and
6. Maintenance of training records.

Knowledge of Current Test Methods

With the constant updating of standard test methods and the wide variety of emerging test procedures, it is essential that any qualified source tester keep abreast of new developments. AIR HYGIENE subscribes to services, which provide updates on EPA reference methods, rules, and regulations. Additionally, source test personnel regularly attend and present papers at testing and emission-related seminars and conferences. AIR HYGIENE personnel maintain membership in various relevant organizations associated with gas fired turbines.

AIR HYGIENE, INC.

Testing Solutions for a Better World

F-Factor Datasheet and Fuel Gas Analysis

Company: XYZ Power
Location: XYZ Power Plant
Date: April 9, 2001

Values to enter from fuel gas analysis by GPA 2166.

Font Scheme:
Blue Font = enter new data
Black Font = calculated data
Green Font = Labels for columns & rows
Red Font = Important results with notes

Gas Component		Mole (%)	Molecular Weight (lb/lb-mole)	lb Component per lb-Mole of Gas	Weight % of Component	Fuel Heat Value [HHV] (Btu/scf)[1]	Fuel Heat Value [LHV] (Btu/scf)[1]
Methane	CH4	96.491	16.04	15.477	92.97	974.27	877.20
Ethane	C2H6	2.115	30.07	0.636	3.82	37.41	34.22
Propane	C3H8	0.186	44.1	0.082	0.49	4.68	4.31
iso-Butane	iC4H10	0.019	58.12	0.011	0.07	0.62	0.57
n-Butane	nC4H10	0.023	58.12	0.013	0.08	0.75	0.69
Iso-Pentane	iC5H12	0.008	72.15	0.006	0.03	0.32	0.30
n-Pentane	nC5H12	0.005	72.15	0.004	0.02	0.20	0.19
Hexanes	C6H14	0.025	86.18	0.022	0.13	1.19	1.10
Heptanes	C7H16	0.000	100.21	0.000	0.00	0.00	0.00
Octanes	C8H18	0.000	114.23	0.000	0.00	0.00	0.00
Carbon Dioxide	CO2	0.510	44.01	0.224	1.35	0.00	0.00
Nitrogen	N2	0.618	28.01	0.173	1.04	0.00	0.00
Hydrogen Sulfide	H2S	0.000	34.08	0.000	0.00	0.00	0.00
Oxygen	O2	0.000	32	0.000	0.00	0.00	0.00
Helium	He	0.000	4	0.000	0.00	0.00	0.00
Hydrogen	H2	0.000	2	0.000	0.00	0.00	0.00
Totals (dry)		100.000		16.648	100.00	1019.44	918.57
Totals (wet)						1001.66	902.55

[1] Standardized to 60°F and 1 atm to match fuel flow data

If total is not 100.000 then the mol% data was either entered incorrectly or the gas analysis is incomplete. Sometimes small differences are due to rounding error.

High Heat Value of dry gas (HHV-dry)
This is the primary fuel heat value used in emission testing calculations.

Low Heat Value of dry gas. LHV-dry

High Heat Value of wet Gas. HHV-wet

Low Heat Value of wet gas. LHV-wet

Characteristics of Fuel Gas		
Molecular Weight of gas =	16.648	lb/lb-mole
Btu per lb. of gas =	23239.7689	gross (HHV)
Btu per lb. of gas =	20940.2961	net (LHV)
wt % VOC in fuel gas =	0.83	%
Specific Gravity =	0.5749	

Value used to convert THC readings to VOC.

Component	Weight %
carbon	73.71
oxygen	0.98
hydrogen	24.27
nitrogen	1.04
helium	0.00
sulfur	0.00
Total	100.00

F-Factor (scf dry exhaust per MMBtu [HHV] = 8641.17

(Based on EPA RM-19) at 68°F and 1 atm

Fuel Specific F-Factor. Note that EPA Method 19 lists natural gas's F-factor as 8710.

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

GCV = Gross Btu per lb. of gas (HHV)

EXAMPLE TESTING DATASHEET FOR GASES
XYZ Power Plant
GE GTG Frame 7FA Combustion Turbine
Fuel: Natural Gas

Fuel Data

Fuel F-Factor	8,671.5	SCF/MMBtu
Generator Output	172.0	MW
Fuel Flow	515,040.8	SCFH
Fuel Heating Value (HHV)	1,076.5	Btu/SCF
Combustor Inlet Pressure	8,166.5	mm Hg
Heat Input (LHV)	500.6	MMBtu/hr
Stack Moisture Content	8.4	%
Stack Exhaust Flow	13,600,266.4	SCFH

Weather Data

Barometric Pressure	29.11	in. Hg
Relative Humidity	82	%
Dry Bulb Temperature	72	F
Specific Humidity	0.0142443	lb H2O/lb air
Wet Bulb Temperature	68	F

yellow - supporting information
blue - raw testing data
red - final results

Run #1 - 100% High Load

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
06/27/01 11:47:32	16770	13.57	5.05	-0.38	0.59	0.59	5.09
06/27/01 11:48:02	16800	13.57	5.85	-0.26	0.63	0.63	4.83
06/27/01 11:48:32	16830	13.55	6.37	-0.44	0.71	0.71	4.71
06/27/01 11:49:02	16860	13.54	6.83	0.60	0.83	0.83	4.33
06/27/01 11:49:32	16890	13.55	7.26	0.25	0.99	0.99	4.49
06/27/01 11:50:02	16920	13.55	6.44	-0.24	1.14	1.14	4.64
06/27/01 11:50:32	16950	13.54	6.28	-0.75	1.29	1.29	4.79
06/27/01 11:51:02	16980	13.55	5.68	-0.68	1.46	1.46	4.96
06/27/01 11:51:32	17010	13.58	6.01	-1.14	1.60	1.60	5.10
06/27/01 11:52:02	17040	13.49	5.05	1.36	1.69	1.69	5.19
06/27/01 11:52:32	17070	13.60	5.14	-0.47	1.70	1.70	5.20
06/27/01 11:53:02	17100	13.61	4.58	0.69	1.69	1.69	5.19
06/27/01 11:53:32	17130	13.62	4.93	0.90	1.65	1.65	5.15
06/27/01 11:54:02	17160	13.62	4.69	0.54	1.64	1.64	5.14
06/27/01 11:54:32	17190	13.61	4.83	0.64	1.59	1.59	5.09
06/27/01 11:55:02	17220	13.61	4.76	-0.07	1.60	1.60	5.10
06/27/01 11:55:32	17250	13.64	4.86	-0.02	1.59	1.59	5.09
06/27/01 11:56:02	17280	13.63	4.38	0.92	1.51	1.51	5.01
06/27/01 11:56:32	17310	13.61	4.94	-0.01	1.47	1.47	4.97
06/27/01 11:57:02	17340	13.61	4.89	0.27	1.47	1.47	4.97
06/27/01 11:57:32	17370	13.61	4.82	1.28	1.46	1.46	4.96
06/27/01 11:58:02	17400	13.61	4.69	1.55	1.46	1.46	4.96
06/27/01 11:58:32	17430	13.60	4.23	1.16	1.46	1.46	4.96
06/27/01 11:59:02	17460	13.59	4.69	-0.26	1.46	1.46	4.96
06/27/01 11:59:32	17490	13.57	4.89	-1.46	1.49	1.49	4.99
06/27/01 12:00:02	17520	13.58	4.86	-1.49	1.53	1.53	5.03
06/27/01 12:00:32	17550	13.59	4.79	-0.79	1.53	1.53	5.03
06/27/01 12:01:02	17580	13.58	4.76	-1.57	1.54	1.54	5.04
06/27/01 12:01:32	17610	13.57	4.65	1.17	1.53	1.53	5.03
06/27/01 12:02:02	17640	14.24	4.69	0.01	1.52	1.52	5.02
06/27/01 12:02:32	17670	13.54	4.83	1.68	1.52	1.52	5.02
06/27/01 12:03:02	17700	13.55	5.70	1.31	1.53	1.53	5.03
06/27/01 12:03:32	17730	13.55	5.66	-0.73	1.53	1.53	5.03
06/27/01 12:03:32	17760	13.55	5.04	-0.48	1.53	1.53	5.03
RAW AVERAGE		13.6	5.2	0.1	1.4	1.4	5.0

QA/QC Data Control

		O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
Bias & Drift Checks	**Initial Zero**	0.2	0.3	-0.2	0.0	0.1	0.1
	Final Zero	0.2	0.5	-0.2	0.2	0.2	0.1
	Avg. Zero	0.2	0.4	-0.2	0.1	0.2	0.1
	Initial UpScale	12.1	5.8	4.0	3.4	28.3	9.0
	Final UpScale	12.1	5.7	4.0	3.3	28.2	8.8
	Avg. UpScale	12.1	5.8	4.0	3.4	28.3	8.9
Upscale Cal Gas		12.0	5.7	4.0	3.5	28.0	9.0

Emissions Data

	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvd)*	SO_2 (ppmvd)	CO_2 (%)
Corrected Raw Averages	13.5	5.1	0.3	1.5	1.3	5.0
ppm @ 15% O_2	N/A	4.2	0.2	1.2	1.0	N/A
ppm @ 15% O_2 & ISO	N/A	4.7	0.2	1.4	1.1	N/A
Emission Rate (lb/MMBtu)	N/A	0.015	0.000	0.004	0.005	N/A
Emission Rate (lb/hr)	N/A	8.46	0.27	2.40	2.84	N/A
Emission Rate (ton/year) @ 8760 hr/yr	N/A	37.07	1.20	10.49	12.43	N/A
Emission Rate (g/MW·hr)	N/A	0.06	0.00	0.02	0.02	N/A

*VOC data in Emissions Data Table has been converted to dry values by the equation below.

*VOC uncorrected raw average * (100/100-stack moisture content)

CLIENT REFERENCES

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AIR HYGIENE, INC.

Testing Solutions for a Better World

EMISSIONS TEST PROTOCOL

FOR
THREE MITSUBISHI 501G
COMBUSTION GAS TURBINES
(UNITS 3A, 3B, AND 3C)

PREPARED FOR
BLACK AND VEATCH
AND
FLORIDA POWER AND LIGHT

AT THE
WEST COUNTY
ENERGY CENTER
LOXAHATCHEE, FLORIDA

Florida Department of
Environmental Protection
Permit No. PSD-FL-396

January 5, 2011

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January 5, 2011

Prepared By:

Jake Fahlenkamp, QSTI, Director of Quality Assurance

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Table of Contents

1.0 INTRODUCTION

1.1 General Facility Description

Florida Power & Light (FPL) owns and operates the West County Energy Center (West County) located at 20505 State Road 80 in Loxahatchee, Florida. West County is a nominal 3,750 megawatt (MW) greenfield power plant and consists of three combined cycle units (Unit 1, 2 and 3). Each combined cycle unit consists of: three nominal 250 MW Mitsubishi Model 501G combustion turbine-electrical generator (CTGs) sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSGs) with selective catalytic reduction (SCR) reactors; one nominal 428 million British thermal units per hour (MMBtu/hour) based on low heat value (LHV) natural gas-fired duct burner (DB) located within each of the three HRSG's; and a common nominal 500 MW steam turbine-electrical generator (STG). The total nominal generating capacity of each of the "3 on 1" combined cycle unit is approximately 1,250 MW.

Each CTG has a nominal heat input rate of 2,333 MMBtu/hr when firing natural gas and 2,117 MMBtu/hr when firing distillate fuel oil (based on a compressor inlet air temperature of 59 degrees Fahrenheit (°F), the lower heating value (LHV) of each fuel, and 100 percent load), includes an automated gas turbine control system, and has dual-fuel capability of firing natural gas as the primary fuel or ultra-low sulfur distillate (ULSD) fuel oil as a restricted alternate fuel. Each HRSG recovers exhaust, heat energy from each of the CTGs. Each Unit delivers steam to each STG. The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of carbon monoxide (CO), particulate matter (PM), sulfuric acid mist (H_2SO_4), sulfur dioxide (SO_2) and volatile organic compounds (VOCs). Dry Low-NOx (DLN) combustors for gas firing and water injection for oil firing reduce nitrogen oxides (NOx) emissions. A selective catalyst reduction (SCR) system further reduces NOx emissions.

The 501G stacks are circular and measure 21.95 feet (ft) (263.38 inches) in diameter at the test ports which are approximately 138 ft above grade level with an exit elevation of approximately 150 ft above grade level. The test ports are located approximately 44.31 ft (531.75 inches) downstream and approximately 12 ft (144 inches) upstream from the nearest disturbances.

1.2 Reason for Testing

West County Unit 3 is a newly constructed plant subject to the regulatory requirements of the Florida Department of Environmental Protection (FDEP) [FDEP Permit No. PSD-FL-396, DEP File No. 0990646-002-AC, Appendix F] and the United States Environmental Protection Agency (EPA) [40 Code of Federal Regulations (CFR) Part 60, Subpart GG and Subpart KKKK] for initial compliance air emissions testing. As such, testing will include monitoring for NOx, CO, total hydrocarbons/volatile organic compounds (THC/VOC), ammonia slip (NH_3), fuel based total sulfur content (S), opacity, carbon dioxide (CO_2), and oxygen (O_2); on all units following the guidelines of 40 Code of Federal Regulations (CFR) Part 60. Each of these parameters will be monitored under two test conditions, while the units are operating on natural gas with duct burners (DB) firing and while the units are operating on natural gas without DB firing.

This Protocol has been prepared and will be submitted to the FDEP prior to the first scheduled test date.

2.0 SUMMARY

2.1 Owner Information

Company:	Florida Power & Light
Contact:	Danny Potter
Mailing Address:	20505 State Road 80 Loxahatchee, Florida 33470
Office:	(561) 904-4910
Cell:	(561) 358-0079
Email:	Danny.Potter@fpl.com

2.2 EPC Contractor Information

Company:	Black and Veatch Energy
Contact:	William Stevenson, Air Quality Control
Mailing address:	11401 Lamar Avenue Overland Park, Kansas 66211
Telephone:	(913) 458-8549
Fax:	(913) 458-2934
Email:	StevensonWP@bv.com

2.3 Test Contractor Information

Company:	Air Hygiene International, Inc.
Contact:	Jake Fahlenkamp, Director of Quality Assurance
Mailing Address:	5634 South 122nd East Avenue, Suite F Tulsa, Oklahoma 74146
Office:	(918) 307-8865
Cell:	(918) 407-5166
Fax:	(918) 307-9131
E-mail:	jake@airhygiene.com
Website:	www.airhygiene.com

2.4 Expected Test Start Date

Test dates are yet to be determined. Further notification will be provided by Black and Veatch (BV) Energy and/or FPL as a testing schedule is determined.

2.5 Testing Schedule

The following schedule indicates specific activities required to be done each day; however, the schedule is flexible and can be extended as necessary if there are operational or testing delays. If there are no operational delays, this schedule can be completed as detailed by the testing crew. The details below describe the activities to be conducted.

Pre-test Activities	**Due Date**
1. Receive site safety training	day of arrival for setup
2. Conduct site inspection and pre-test meeting	per BV and/or Air Hygiene
3. Prepare draft electronic test protocol	prior to start of project

On-Site Pre-testing Schedule	**Time**
Day 0 – Pre-test, initial site mobilization and setup	
• Arrive at site and attend safety training class	08:00 – 09:00
• Setup on Unit 3A	09:00 – 11:00
• Conduct preliminary testing of equipment	11:00 – 13:00

Compliance Testing	**Time**
Day 1 – Compliance Testing, Unit 3A, natural gas, base load without DB	
• Daily setup and calibrations	06:00 – 07:00
• Conduct stratification testing and preliminary flow traverse	07:00 – 08:00
• Stratification testing for NOx and O_2	
• Flow traverse for cyclonic flow profile, stack velocity, and stack temperature	
• Conduct Testing for NOx, CO, THC/VOC, opacity, CO_2, and O_2	08:00 – 13:00
• NOx, CO, THC/VOC, opacity, CO_2, and O_2 testing (3, 1- hour test runs)	
• Conduct Testing for NH_3 Slip	08:00 – 13:00
• NH_3 testing (3, 1-hour test runs)	
• CO, CO_2, and O_2 will be monitored for molecular weight determinations	
• Collect fuel gas sample for component analysis and total S	08:00 – 13:00
• Fire Duct Burners and at test base load with DB	13:00 – 14:00
• Conduct Testing for NOx, CO, THC/VOC, opacity, CO_2, and O_2	14:00 – 19:00
• NOx, CO, THC/VOC, opacity, CO_2, and O_2 testing (3, 1- hour test runs)	
• Conduct Testing for NH_3 Slip	14:00 – 19:00
• NH_3 testing (3, 1-hour test runs)	
• CO, CO_2, and O_2 will be monitored for molecular weight determinations	
• Collect fuel gas sample for component analysis and total S	14:00 – 19:00
Day 2 – Setup Unit 3B	
• Setup	08:00 – 09:00
• Conduct preliminary testing of equipment	09:00 – 12:00

Additional days will follow the same timeline of Day 1 through Day 2 with unit test order determined by FPL and/or BV. Each unit will require one day of testing and one setup day following testing on each unit.

Activities after Testing	**Sequential Days**
• Demobilization of Testing Crew	Day 1
• Preparation of draft hard copy test report	Days 2 – 9
• Submit for review to BV	Day 10
• Review and comment on draft by BV	Days 11 – 14
• Incorporate BV comments into draft copy	Days 15 – 19
• Submit for review to FPL	Day 20
• Review and comment on draft by FPL	Days 21 – 24
• Incorporate FPL comments into draft copy	Days 25 – 29
• Final reports delivered to FPL	Day 30

2.6 Hardcopy Compliance Report Content

The hard-copy compliance reports will be submitted to BV within 30 days of completion of testing and meet the requirements of the FDEP and the United States Environmental Protection Agency (EPA) for stack emissions testing. The reports will include discussion of the following:

- Introduction
- Plant and Sampling Location Description
- Summary and Discussion of Test Results Relative to Acceptance Criteria
- Sampling and Analytical Procedures
- QA/QC Activities
- Test Results and Related Calculations
- Sampling Log and Chain-of-Custody Records
- Audit Data Sheets

2.7 Equipment and Procedures

Reference methods (RM) and parameters to satisfy 40 CFR Part 51, 60, and 63 will include:

40 CFR Part 60, EPA RM 1 for sample location
40 CFR Part 60, EPA RM 2 for stack gas velocity
40 CFR Part 60, EPA RM 3a for O_2 and CO_2
40 CFR Part 60, EPA Method 4 for stack gas moisture content
40 CFR Part 60, EPA RM 7e for NOx
40 CFR Part 60, EPA RM 9 for opacity
40 CFR Part 60, EPA RM 10 for CO
40 CFR Part 60, EPA RM 18 for methane/ethane analysis, as required
40 CFR Part 60, EPA RM 19 for F-Factor determination of stack exhaust flow
40 CFR Part 60, EPA RM 25a for VOC
40 CFR Part 63, EPA Conditional Test Method (CTM) – 027 for NH_3 slip
EPA Report #600/4-79-020 Method 350.3 for NH_3 analysis
American Society of Testing Materials (ASTM) 6667-01 for sulfur content of natural gas
Gas Processors Association (GPA) 2261 M for component analysis of natural gas

2.8 Proposed Variations

The NO_2 to NO converter check will be verified using the Emission Measurement Center's ALT-013 acceptable alternative procedure to section 8.2.4 of EPA Method 7e in Appendix A of 40 CFR Part 60 utilizing a NO_2 concentration around 50 parts per million.

In lieu of borosilicate glass nozzles and probe liners, CTM-027 will utilize stainless steel and inconel to prevent breakage, particularly during port changes.

RM 19 stoichiometrically calculated stack exhaust flows will be used to convert all gaseous, NH_3 concentrations to emission rates.

If measured total hydrocarbon (THC) emission rates are below the required volatile organic compound (VOC) limits, all THCs will be assumed as VOCs and RM 18 analysis for methane and ethane will not be conducted.

2.9 Compliance Sampling Strategy

Testing will be performed on each CTG, at two separate load conditions, while the units are combusting natural gas with duct firing and while the units are firing natural gas without duct firing. The emission compliance tests will follow the requirements of 40 CFR Part 51, 60, 63, and the FDEP permit. The tests for NOx, CO, THC/VOC, opacity, NH_3, CO_2, and O_2 will include at least three runs, approximately 60-minutes in duration at each load.

During each test run the following parameters will be recorded, based on availability, by the system operators from the system PLC and/or DAHS: water injection (gal/min), load (megawatts), heat input (MMBtu/hr), fuel flow (scfh), combustor inlet / compressor discharge pressure (psig), ambient temperature (^oF), ambient pressure (in. Hg), and ambient relative humidity (%).

Gas Testing – EPA RM 3a, 7e, 10, 19, and 25a

A stratification test will be performed prior to air permit testing to determine the proper sample location(s). The air permit emissions test will include three test runs with analysis for NOx, CO, VOC, CO_2, and O_2 on the CTGs at each load. EPA RM 19 will be used to determine exhaust flow and calculate emission rates in pounds per million British thermal units (lb/MMBtu), lb/hr, and tons per year (tpy) at each load.

Opacity Observations – EPA RM 9

Visual observations for opacity from each CTG at each load and from the AB will be determined using EPA RM 9. This method determines the level of any visible emissions that occur during the observation period. It requires that the opacity of emission be determined by a trained and certified individual. Three 60-minute runs will be observed from the proper location(s) on the CTG exhaust stack. The opacity level will be recorded every 15 seconds.

Ammonia Slip Testing and Analysis – CTM 027

Ammonia slip testing will be conducted on each CTG at each load. Each test run will be approximately 60 minutes. An S-type pitot tube will be used to measure cyclonic flow and velocity pressure in accordance with EPA RM 2. This data will be correlated with meter coefficients, temperatures, barometric pressure, and exhaust gas moisture (EPA RM 4) to determine the exhaust gas dry flow rate. NH_3 samples will be collected following CTM 027 with an isokinetic sampling train utilizing a stainless steel nozzle and inconel probe liner. A scale will be used to measure net weight gain from each impinger to determine moisture gain.

The exit of the filter holder is connected to a series of four full size impingers. The first two impingers (Greensburg Smith) each contain 100 mL of 0.1 N H_2SO_4 which absorbs the ammonia when the sample is drawn through. The third impinger (Modified) is empty. The fourth contains a tared quantity of silica gel. The impingers are maintained at a temperature below 68^oF for the duration of each test.

Procedures for selecting sampling locations and for operation of the apparatus are derived from CTM 027 and associated EPA RMs 1 through 4. The sampling apparatus is leak-checked before and after each test run. Sampling is performed at an isokinetic rate greater than 90 percent and less than 110 percent.

The first impinger catch is measured, its weight recorded and the catch transferred to container No. 1. The second and third impinger catches are measured, their weights recorded and the catches transferred to container No. 2. The weight gain is added to the silica gel weight gain of the fourth impinger to determine the stack gas moisture content. The connective glassware from the filter to the first impinger is rinsed with de-ionized water into container No. 1. The connective glassware from the back of impinger 1 to the front of impinger 4 is rinsed with de-ionized water into container No. 2.

Container contents are poured into a graduated cylinder and their volume recorded. After recording the volume the samples are returned to their respective containers, sealed, shaken and labeled, and the liquid level is marked. The samples are then refrigerated at approximately 39°F and allowed to slowly warm to laboratory room temperature before analysis.

NH_3 analysis is conducted using EPA Report #600/4-79-020 Method 350.3 on site by AHI. The ammonia is determined potentiometrically using an ion selective ammonia electrode and a pH meter having an expanded millivolt scale or a specific ion meter. The ammonia electrode uses a hydrophobic gas-permeable membrane to separate the sample solution from an ammonium chloride internal solution. Ammonia in the sample diffuses through the membrane and alters the pH of the internal solution, which is sensed by a pH electrode. The constant level of chloride in the internal solution is sensed by a chloride selective ion electrode which acts as the reference electrode.

A series of standard solutions covering the concentration range of the samples by diluting either the stock or standard solutions of ammonium chloride are prepared. The electrometer is calibrated by placing 100 mL of each standard solution in clean 150 mL beakers. The electrode is then immersed into standard of lowest concentration and 1 mL of 10N sodium hydroxide (NaOH) solution is added while mixing. The electrode is kept in the solution until a stable reading is obtained. This procedure is repeated with the remaining standards, going from lowest to highest concentration. The samples are then analyzed at room temperature following the same procedure as measuring the standards.

APPENDIX A
QA/QC PROGRAM

TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after each testing project. The following paragraphs detail the quality control techniques, which are rigorously followed during testing projects.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range of the predicted values.

After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data just collected. The criteria on acceptable data is that the instrument drift shall be no more than 3 percent of the full-scale response. Quality assurance worksheets are prepared to document the multipoint calibration checks and zero to span checks performed during the tests (**See Appendix D**).

The sampling systems are leak checked by demonstrating that a vacuum greater than 10 in Hg could be held for at least 1 minute with a decline of less than 1 in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. These checks are performed to ensure that ambient air has not diluted the sample. Any leakage detected prior to the tests would be repaired and another leak check conducted before testing commenced.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the calibration gases introduced via two paths. The first path is directly into the analyzer and the second path via the sample system at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criteria for acceptance is agreement within 5% of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± 1% accuracy for all gases. EPA Protocol No. 1 gases will be used where applicable to assign concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials.

AIR HYGIENE maintains a large variety of calibration gases to allow the flexibility to accurately test emissions over a wide range of concentrations.

APPENDIX B
TEST EQUIPMENT CONFIGURATION AND DESCRIPTION

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures to be used conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 2, 3a, 4, 7e, 10, 18, 19, 25a; 40 CFR Part 63; and CTM-027.

Figure 1 depicts the sample system that will be used for the NOx, CO, THC, CO_2, and O_2 tests. A stainless steel probe will be inserted into the sample ports of the stack to extract gas measurements from the emission stream at multiple points or a single point determined after conducting an initial stratification test. The gas sample will be continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample and through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample will be partitioned to the NOx, CO, CO_2, and O_2 analyzers through rotameters that control the flow rate of the sample. Exhaust samples will be routed to the THC analyzer prior to gas conditioning.

The schematic (Figure 1) shows that the sample system will also be equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments will be housed in an air-conditioned, trailer-mounted mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor according to EPA Protocol No. 1.

This general schematic also illustrates the analyzers to be used for the tests (i.e., NOx, CO, and O_2). All data from the Reference Method continuous monitoring instruments are recorded on a Logic Beach Hyperlogger. The Hyperlogger retrieves calibrated emissions data from each instrument every second. An average value is recorded every 30 seconds.

The stack gas analysis for O_2 and CO_2 concentrations will be performed in accordance with procedures set forth in EPA Method 3a. The O_2 analyzer uses a paramagnetic cell detector and the CO_2 analyzer uses a continuous nondispersive infrared analyzer.

EPA Method 7e will be used to determine concentrations of NOx. A chemiluminescence analyzer will be used to determine the nitrogen oxides concentration in the gas stream. A NO_2 in nitrogen certified gas cylinder will be used to verify at least a 90 percent NO_2 conversion on the day of the test.

CO emission concentrations will be quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer will be used for this purpose.

THC emission concentrations will be quantified in accordance with procedures set forth in EPA Method 25a. A continuous flame ionization (FID) analyzer will be used for this purpose. All THC results will be assumed as VOCs. If results are greater than the permit limits a Tedlar bag sample will be taken and analyzed according to Method 18 for methane and ethane content. These results will then be subtracted from the THC concentrations to determine the VOC concentrations.

Figure 2 represents the sample system used for the NH_3 tests. For NH_3 a heated stainless steel probe sheath with an inconel liner will be inserted into a single sample point of the stack to extract gas measurements from the emission stream through a filter and glass impinger train in a constant flow rate fashion. Flow rates will be monitored with rotameters and total sample volumes will be measured with dry gas meters.

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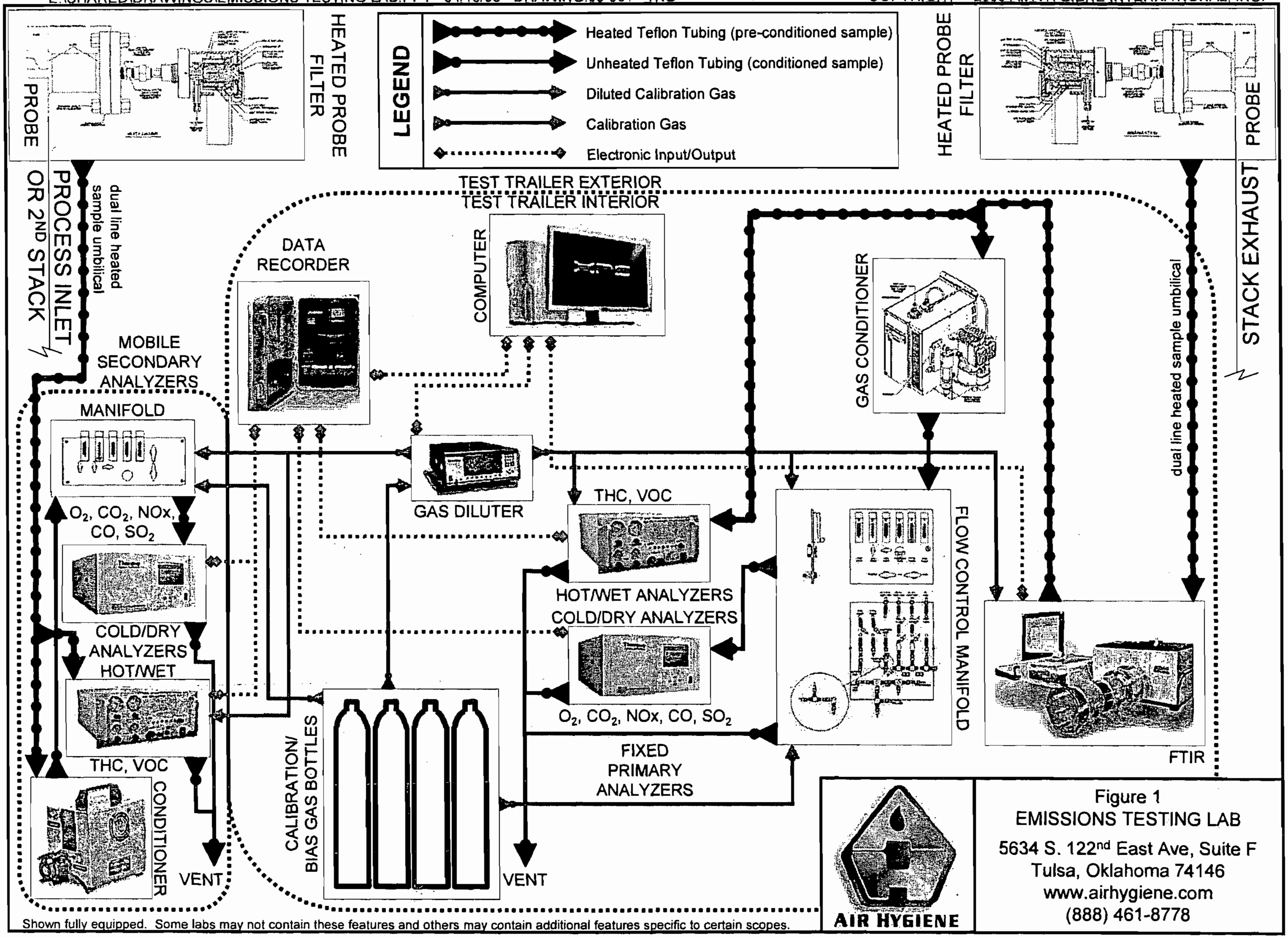

Figure 1
EMISSIONS TESTING LAB

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Tulsa, Oklahoma 74146
www.airhygiene.com
(888) 461-8778

Shown fully equipped. Some labs may not contain these features and others may contain additional features specific to certain scopes.

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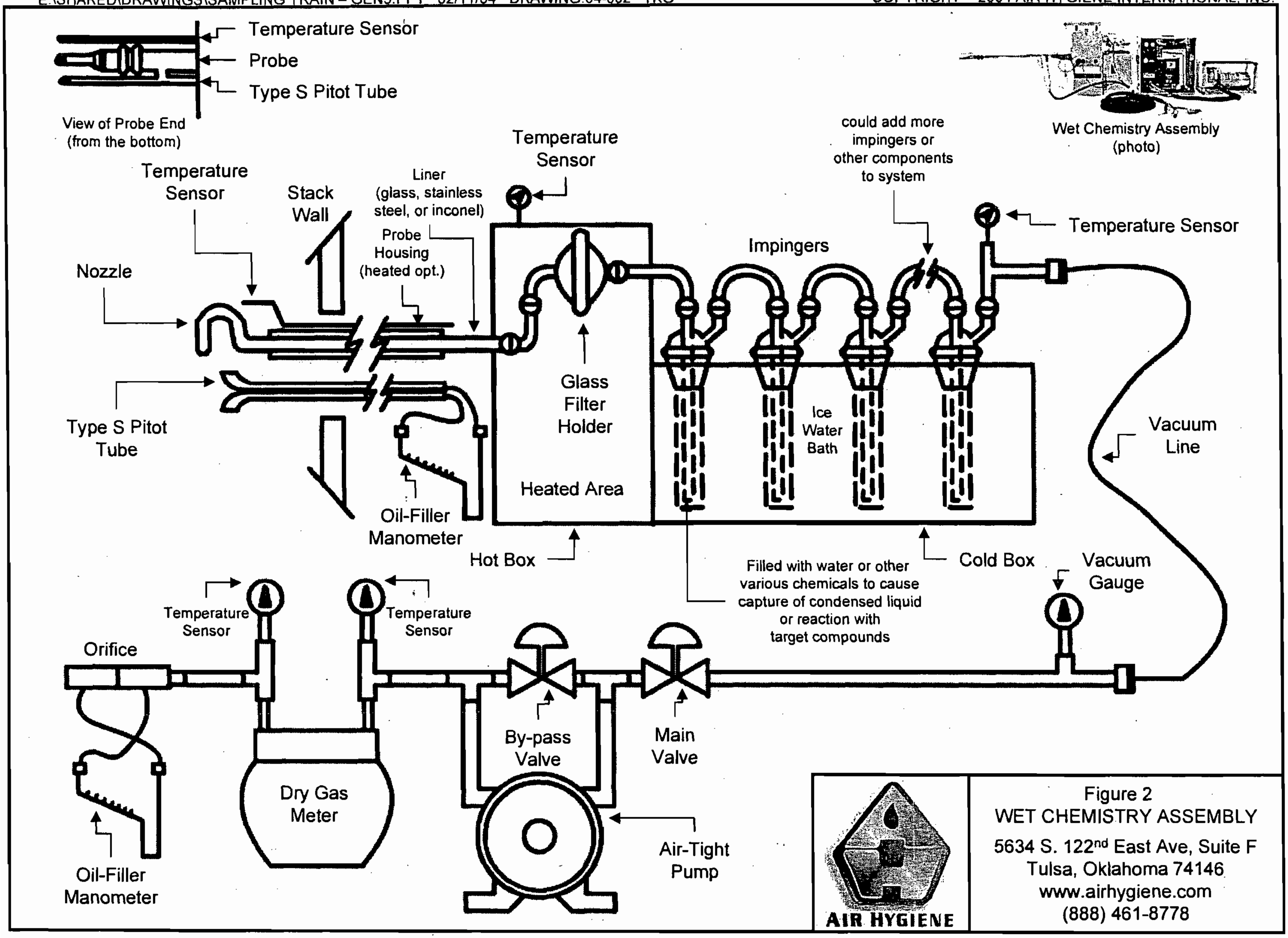

Figure 2
WET CHEMISTRY ASSEMBLY

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TABLE #1: TESTING MATRIX

Parameter	Source	Fuel	Duct Firing	Load	No. Runs and Duration
NOx	CTG	Natural Gas	Yes or No	100%	1 Strat Test (60 minutes)
	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
O_2	CTG	Natural Gas	Yes or No	100%	1 Strat Test (60 minutes)
	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
CO_2	CTG	Natural Gas	Yes	100%	during NH_3
	CTG	Natural Gas	No	100%	during NH_3
CO	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
VOC	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
NH_3	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
Opacity	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs
Fuel Analysis	CTG	Natural Gas	Yes	100%	3, 60 minute test runs
	CTG	Natural Gas	No	100%	3, 60 minute test runs

TABLE #2: ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Max. Ranges	Sensitivity	Detection Principle
NOx	API 200AH or equivalent (1)	User may select up to 5,000 ppm	0.1 ppm	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear for listed ranges.
CO	API 300 or equivalent	User may select up to 3,000 ppm	0.1 ppm	Infrared absorption, gas filter correlation detector, microprocessor based linearization.
CO_2	FUJI 3300 or equivalent	0-20%	0.1%	Nondispersive infrared
THC	THERMO 51 or equivalent	User may select up to 10,000 ppm	0.1 ppm	Flame Ionization Detector
O_2	CAI 200 or equivalent	0-25%	0.1%	Paramagnetic cell, inherently linear.

TABLE #3: ANALYTICAL INSTRUMENTATION TESTING CONFIGURATION

Parameter	Sample Methodology	Example Range	Sensitivity	Calibration Gases (based on example range)
NOx	7e	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 4-6 ppm High = 10 ppm
CO	10	0-50 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 20-30 ppm High = 50 ppm
CO_2	3a	0-20%	0.1%	Zero = 0 ppm nitrogen Mid = 8-12% High = 20%
THC	25a	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Low = 2.5-3.5 ppm Mid = 4.5-5.5 ppm High = 8-9 ppm
O_2	3a	0-21%	0.1%	Zero = 0 ppm nitrogen Mid = 8.4-12.6% High = 21%

TABLE #4: PERMIT LIMITS

Parameter	Source	Fuel	Duct Firing	Limit
NOx	CTG	Natural Gas	Yes	2.0 ppmvd@15%O_2 / 24.2 lb/hr
	CTG	Natural Gas	No	2.0 ppmvd@15%O_2 / 20.0 lb/hr
CO	CTG	Natural Gas	Yes	7.6 ppmvd@15%O_2 / 52.5 lb/hr
	CTG	Natural Gas	No	4.1 ppmvd@15%O_2 / 23.2 lb/hr
VOC	CTG	Natural Gas	Yes	1.5 ppmvd@15%O_2 / 5.4 lb/hr
	CTG	Natural Gas	No	1.2 ppmvd@15%O_2 / 4.1 lb/hr
NH_3	CTG	Natural Gas	Yes	5.0 ppmvd@15%O_2
	CTG	Natural Gas	No	5.0 ppmvd@15%O_2
Opacity	CTG	Natural Gas	Yes	10%
	CTG	Natural Gas	No	10%
Fuel Analysis	CTG	Natural Gas	Yes	2 gr S/100 SCF of gas
	CTG	Natural Gas	No	2 gr S/100 SCF of gas

APPENDIX C
STACK DRAWINGS

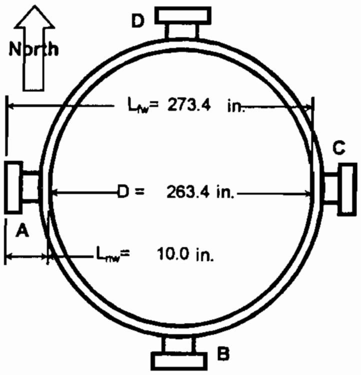
METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company	Black and Veatch Energy	**Date**	TBD
Plant Name	West County Energy Center	**Project #**	bv-10-westcounty.fl-comp#2
Equipment	Mitsubishi 501G	**# of Ports Available**	4
Location	Loxahatchee, Florida	**# of Ports Used**	4

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})	273.38	in.
Distance to Near Wall of Stack	(L_{nw})	10.00	in.*
Diameter of Stack	(D)	263.38	in.
Area of Stack	(A_s)	378.41	ft^2

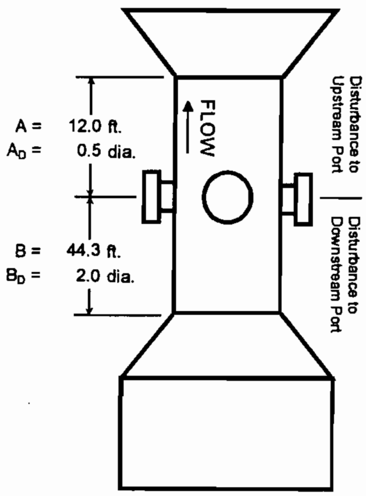
*assume 10 in. reference (must be measured and verified in field)

Distance from Disturbances to Port			
Distance Upstream	(A)	144.00	in.
Diameters Upstream	(A_D)	0.55	diameters
Distance Downstream	(B)	531.75	in.
Diameters Downstream	(B_D)	2.02	diameters



Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		**Minimum Number of Traverse Points Comp Stratification**	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	**Criteria**	**Points**
2.00-4.99	0.50-1.24	24	16	● RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	O Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12	12 points	
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	Minimum Number of Traverse Points RATA Stratification	
Upstream Spec		24	16		
Downstream Spec		24	16		
Traverse Pts Required		24	16	Criteria	Points
				O Part75/60	12 RM1 pts
				O 75 abrv (a)	3 points
				O 75 abrv (b)	6 points

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
4	**Ports by**	3	**Pts / port**	**Stratification Traverse**
12	**Pts Used**	12	**Required**	**(Compliance Test)**

Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
	%	in.	in.
1	4.4%	11 5/8	21 5/8
2	14.6%	38 4/8	48 4/8
3	29.6%	78	88
4			
5			
6			
7			
8			
9			
10			
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24			

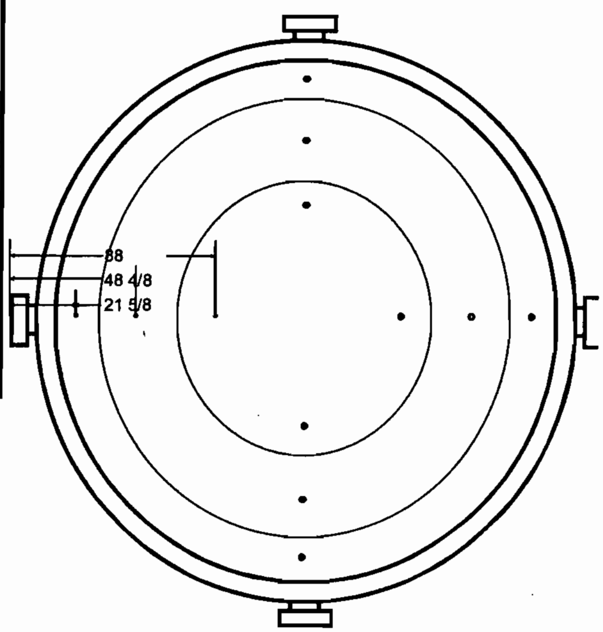


Figure 4 – CTG Gas Traverse Points

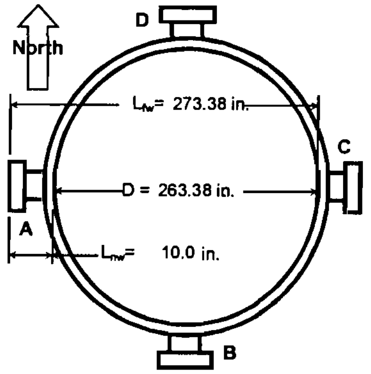
METHOD 1 - ISOKINETIC TRAVERSE FOR A CIRCULAR SOURCE

Company	Black and Veatch Energy	**Date**	TBD
Plant Name	West County Energy Center	**Project #**	bv-10-westcounty.fl-comp#2
Equipment	Mitsubishi 501G	**# of Ports Available**	4
Location	Loxahatchee, Florida	**# of Ports Used**	4

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})	273.38	in.
Distance to Near Wall of Stack	(L_{nw})	10.00	in.*
Diameter of Stack	(D)	263.38	in.
Area of Stack	(A_s)	378.41	ft^2

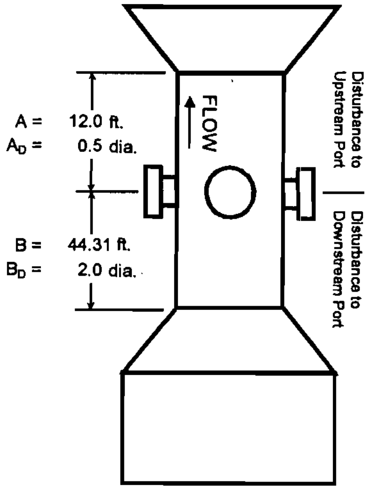
*assume 10 in. reference (must be measured and verified in field)

Distance from Disturbances to Port			
Distance Upstream	(A)	144.00	in.
Diameters Upstream	(A_D)	0.55	diameters
Distance Downstream	(B)	531.75	in.
Diameters Downstream	(B_D)	2.02	diameters



Number of Traverse Points Required					
Diameters to Flow Disturbance		**Minimum Number of[1] Traverse Points**		Minimum Number of Traverse Points Comp Stratification	
Down (B_D) Stream	**Up (A_D) Stream**	**Particulate Points**	Velocity Points	Criteria	Points
2.00-4.99	0.50-1.24	24	16	O RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	O Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	Minimum Number of Traverse Points RATA Stratification	
Upstream Spec		24	16		
Downstream Spec		24	16		
Traverse Pts Required		24	16	Criteria	Points
				O Part75/60	12 RM1 pts
				O 75 abrv (a)	3 points
				O 75 abrv (b)	6 points

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
4	**Ports by**	6	**Pts / port**	**Isokinetic Traverse**
24	**Pts Used**	24	**Required**	**(Wet Chemistry**

Traverse Point Locations			
Traverse Point Number	**Percent of Stack Diameter**	**Distance from Inside Wall**	**Distance including Reference Length**
	%	in.	in.
1	2.1%	5 4/8	15 4/8
2	6.7%	17 5/8	27 5/8
3	11.8%	31 1/8	41 1/8
4	17.7%	46 5/8	56 5/8
5	25.0%	65 7/8	75 7/8
6	35.6%	93 6/8	103 6/8
7			
8			
9			
10			
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23			
24			

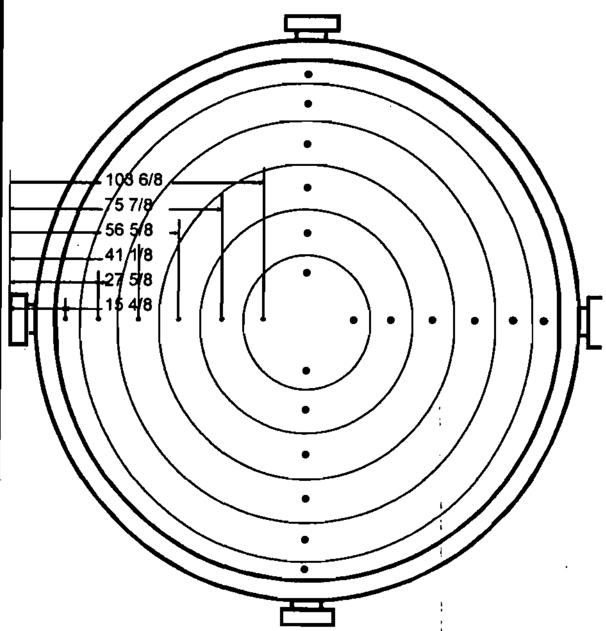


Figure 5 - CTG Wet Chemistry Points

APPENDIX D
EXAMPLE TEMPLATES AND CALCULATIONS

AIR HYGIENE

SINGLE LOAD TEST - FIELD DATA SHEET

Company:		
Location:		
Date:		
Unit Make and Model:		
Unit Number:		
Serial Number:		
Data Recorded By:		
Tested With AHI Unit(s):	Truck(s):	Trailer(s):
LDEQ Warmup/Cal Req:	On (Day/Time):	Cal (Day/Time):

CYLINDER SERIAL NUMBERS		O_2	NOx	CO
	Low			
	Mid			
	High			

CYLINDER SERIAL NUMBERS		THC	CO_2	SO_2
	Low			
	Mid			
	High			

RUN INFORMATION	Load		
	______% #1	______% #2	______% #3
Time Start (hh:mm:ss)			
Time Stop (hh:mm:ss)			
Rated Power (MW or hp)			
Actual Power (MW or hp)			
Barometric Pressure (in. Hg)			
Ambient Temperature (°F)			
Relative Humidity (%)			
Fuel Flow (lb/min)			
Fuel Flow (SCF/hr)=(lb/min)*21.7			
Specific Humidity (gr/lb)			
Spec. Hum. (lb H_2O/lb air)=(gr/lb)/7000			
PCD (psi)			
PCD (mm Hg)=(psi+14.24)*51.71493			
NOx Water Injection (gpm)			

NO_2 CONVERSION	
NO_2 Gas (ppm)	
NO Reading (ppm)	
NOx Reading (ppm)	
Cylinder Num	

REPORT INFORMATION		
	INSTRUMENT	SERIAL #
O_2		
NOx		
CO		
THC		
CO_2		
SO_2		

RESPONSE TIME		
	TIME (hh:mm)	RESP (min)
1st Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		
2nd Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		
3rd Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		

CALIBRATION	O_2		NOx		CO		THC		CO_2		SO_2	
	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual
Zero Gas												
Low Gas												
Mid Gas												
High Gas												

BIAS	O_2		NOx		CO		THC		CO_2		SO_2	
	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid
Initial Run #1												
Run #1 / Run #2												
Run #2 / Run #3												
Run #3 / Final												
Bias Gas Actual Conc.		______		______		______		______		______		______

Source Information	
Company	
Plant Name	
Equipment	
Location	

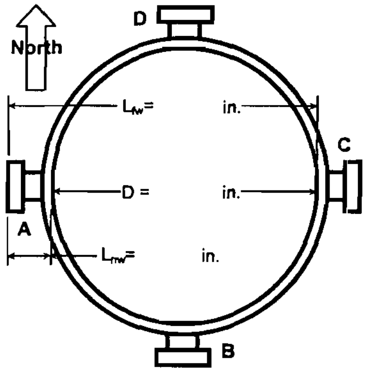
Test Information	
Date	
Project #	
Unit Number	
Load	
Number of Ports Available	
Number of Ports Used	

Stack and Test Type				
○	Isokinetic Traverse (Wet Chemistry Testing)			Circular Stack
○	Velocity Traverse (Flow and Flow RATA Test)			
○	Stratification Traverse (Compliance Test)		☐ RM 20	
◉	**Stratification Traverse (RATA)**	☐ Part 60	☑ Part 75	

METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company		**Date**	
Plant Name		**Project #**	
Equipment		**# of Ports Available**	
Location		**# of Ports Used**	

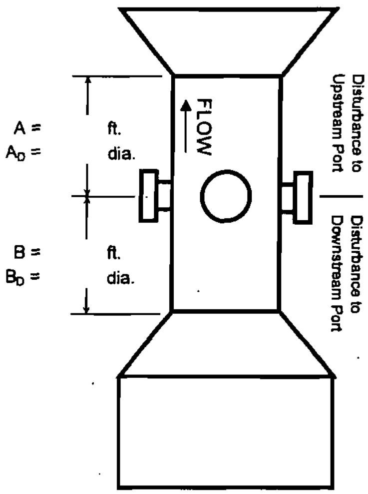
Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})		in.
Distance to Near Wall of Stack	(L_{nw})		in.
Diameter of Stack	(D)		in.
Area of Stack	(A_s)		ft^2



Distance from Disturbances to Port			
Distance Upstream	(A)		in.
Diameters Upstream	(A_D)		diameters
Distance Downstream	(B)		in.
Diameters Downstream	(B_D)		diameters

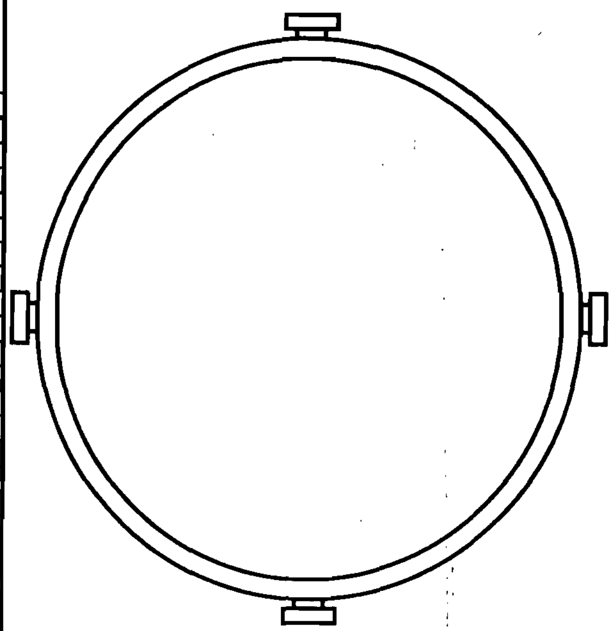
Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		Minimum Number of Traverse Points	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	Comp Stratification Criteria	Points
2.00-4.99	0.50-1.24	24	16	○ RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	○ Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	**Minimum Number of Traverse Points**	
Upstream Spec				**RATA Stratification**	
Downstream Spec				**Criteria**	**Points**
Traverse Pts Required				○ Part75/60	12 RM1 pts
				○ 75 abrv (a)	3 points
				○ 75 abrv (b)	6 points

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
	Ports by Pts Used		**Pts / port Required**	**Stratification Traverse (RATA)**

Traverse Point Locations			
Traverse Point Number	**Percent of Stack Diameter**	**Distance from Inside Wall**	**Distance Including Reference Length**
	%	in.	in.
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			



STRATIFICATION TRAVERSE (RATA) RESULTS

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

Traverse Point	Time Per Point	Point Start Time	Point Stop Time (Reading)	Diluent 1	Percent Difference	Pollutant 1	Percent Difference
	min.	hh:mm:ss	hh:mm:ss	%	%	ppm	%
Average							

RATA SAMPLE POINTS FOR CIRCULAR STACK

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

40 CFR 75 Criteria

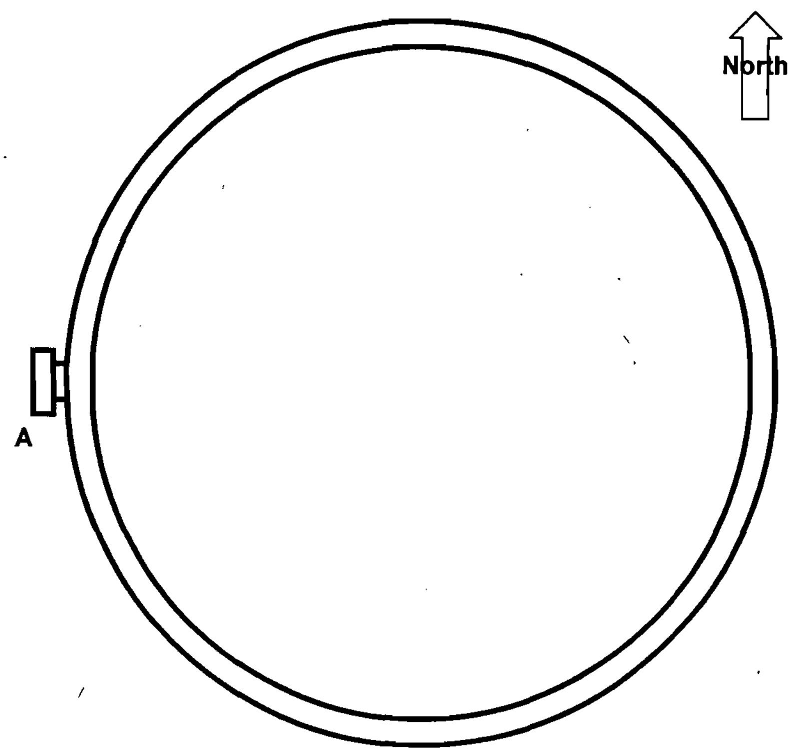
Stratification Results	
Maximum Percent Difference	No Test
Maximum Pollutant Conc. Diff.	No Test
Maximum Diluent Conc. Diff.	No Test
Stack Diameter	in.

Stratification Conclusions	
Maximum % Diff.	No Stratification Anticipated
Maximum Conc. Diff.	No Stratification Anticipated
Stack Diameter	D > 93.6 in.

Use Short RM Measurement Line

Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
	%	in.	in.
1			
2			
3			

Test Type
- ☐ Moisture, for MW
- ☐ Moisture, for wet-to-dry
- ☑ Gas
- ☐
- ☐ 6.5.6(b)(2) alt. points could apply



DRIFT AND BIAS CHECK		
Strat Test Pre and Post QA/QC Check	Diluent 1	Pollutant 1
Initial Zero		
Final Zero		
Avg. Zero		
Initial UpScale		
Final UpScale		
Avg. UpScale		
Sys Resp (Zero)		
Sys Resp (Upscale)		
Upscale Cal Gas		
Initial Zero Bias		
Final Zero Bias		
Zero Drift		
Initial Upscale Bias		
Final Upscale Bias		
Upscale Drift		
Alternative Specification Abs Diff: Initial Zero		
Final Zero		
Initial Upscale		
Final Upscale		
Calibration Span		
3% of Range (drift)		
5% of Range (bias)		

Respone Time (min)		
Sys. Response (min)		

Date/Time mm/dd/yy hh:mm:ss z s z s

INJECTIONS

x

Client:
Location:
Date:
Project #:

Natural Gas - Fuel Analysis — Standardized to 68 deg F and 14.696 psia - EPA Standards

Gas Component		Mole (%)	Molecular[1] Weight (lb/lb-mole)	Lbs Component per Lb-Mole of Gas	Wt. % of Component	Ideal Gross[1,3] Heating Value (Btu/ft^3)	Fuel Heat Value [HHV] (Btu/SCF)	Ideal Net[1,3] Heating Value (Btu/ft^3)	Fuel Heat Value [LHV] (Btu/SCF)
Methane	CH_4								
Ethane	C_2H_6								
Propane	C_3H_8								
iso-Butane	iC_4H_{10}								
n-Butane	nC_4H_{10}								
Iso-Pentane	iC_5H_{12}								
n-Pentane	nC_5H_{12}								
Hexanes	C_6H_{14}								
Heptanes	C_7H_{16}								
Octanes	C_8H_{18}								
Carbon Dioxide	CO_2								
Nitrogen	N_2								
Hydrogen Sulfide	H_2S								
Oxygen	O_2								
Helium	He								
Hydrogen	H_2								
Totals						dry		dry	
						wet[2,5]		wet[2,5]	

Characteristics of Fuel Gas		
Molecular Weight of gas =		lb/lb-mole
Btu per lb. of gas[4] =		gross (HHV)
Btu per lb. of gas[4] =		net (LHV)
Density of fuel gas[2] =		lb/cu. ft
Wt % VOC in fuel gas =		%
Specific Gravity[1] =		

Component	Wt%
carbon	
oxygen	
hydrogen	
nitrogen	
helium	
sulfur	
Total	

F-Factor (SCF dry exhaust per MMBtu [HHV]) =
(Based on EPA RM-19) at 68 deg F and 14.696 psia

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of natural gas based on specific gravity multiplied by density of air at 68 deg F and 14.696 psia.

References:

[1] ASTM D 3588
[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg
[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III
[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna
[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

Air Permit # :	
Plant Name or Location:	
Date:	
Project Number:	
Manufacturer & Equipment:	
Model:	
Serial Number:	
Unit Number:	
Test Load:	
Tester(s) / Test Unit(s):	

		RUN																	
	UNITS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Start Time	hh:mm:ss																		
End Time	hh:mm:ss																		
Bar. Pressure	in. Hg																		
Amb. Temp.	°F																		
Rel. Humidity	%																		
Spec. Humidity	lb water / lb air																		
Comb. Inlet Pres.	psig																		
NOx Water Inj.	gpm																		
Total Fuel Flow	SCFH																		
Heat Input	MMBtu/hr																		
Power Output	megawatts																		
Steam Rate	lb/hr																		

Client:
Location:
Date:
Project #:

Fuel Oil - Fuel Analysis

Characteristics of Fuel Gas		
Molecular Weight of oil =		lb/lb-mole
Btu per lb. of oil =		gross (HHV)
Btu per lb. of oiil =		net (LHV)
Density of fuel oil[2] =		lb/cu. ft
Density of fuel oil[2] =		lb/gal
Specific Gravity =		@ 68 deg F

Standardized to 68 deg F and 14.696 psia

Component	Wt%
carbon	
oxygen	
hydrogen	
nitrogen	
helium	
sulfur	
Total	

Fuel Oil HHV Conv.	
HHV (Btu/lb)	
HHV (Btu/SCF)	

Fuel Oil LHV Conv.	
LHV (Btu/lb)	
LHV (Btu/SCF)	

F-Factor (SCF dry exhaust per MMBtu [HHV]) =
(Based on EPA RM-19) at 68 deg F and 14.696 psia

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of fuel oil based on lab analysis or specific gravity multiplied by density of water at 68 deg F and 14.696 psia.

References:

[1] ASTM D 3588

[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg

[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III

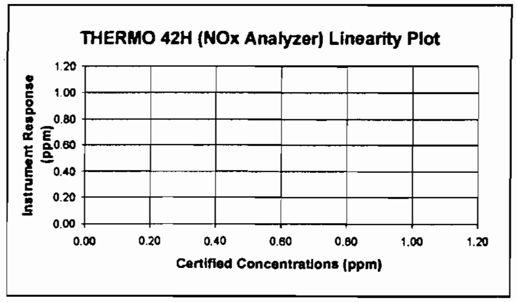
[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna

[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

Calibration Date:
Client:

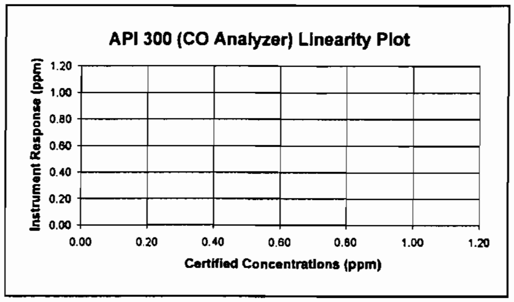
NOx Span (ppm) =

THERMO 42H (NOx Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5ppm)
Linearity =				



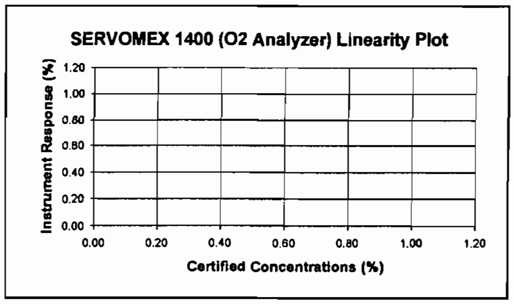
CO Span (ppm) =

API 300 (CO Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5ppm)
Linearity =				



O2 Span (%) =

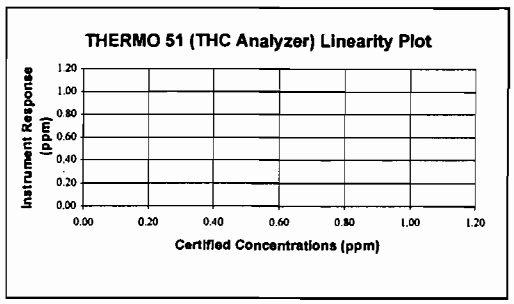
SERVOMEX 1400 (O_2 Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5%)
Linearity =				



THC Range (ppm) =

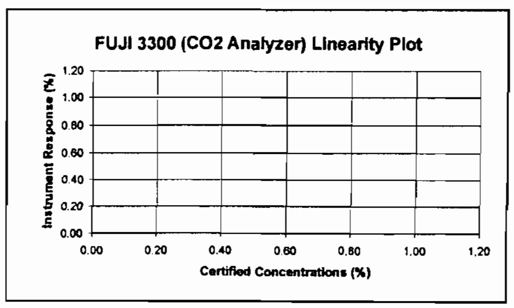
THERMO 51 (THC Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Estimated Point (ppm)	Pass or Fail (±2,5%)[1]
Linearity =				

[1]-zero/high based on 2% of span,low/mid based on 5% of concentration



CO2 Span (%) =

FUJI 3300 (CO_2 Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5%)
Linearity =				



NOx Converter Efficiency

Date:

Analyzer:

RM 7E, (08-15-06), 8.2.4.1 Introduce a concentration of 40 to 60 ppmv NO_2 to the analyzer in direct calibration mode and record the NOx concentration displayed by the analyzer. ... Calculate the converter efficiency using Equation 7E-7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. ... The NO_2 must be prepared according to the EPA Traceability Protocol and have an accuracy within 2.0 percent.

Audit Gas: NO_2 Concentration (C_v), ppmvd

Converter Efficiency Calculations:

Analyzer Reading, NO Channel, ppmvd

Analyzer Reading, NOx Channel, ppmvd

Analyzer Reading, NO_2 Channel ($C_{Dir(NO2)}$), ppmvd

Converter Efficiency, %

RM 7E, (08-15-06), 13.5 NO2 to NO Conversion Efficiency Test (as applicable). The NO2 to NO conversion efficiency, calculated according to Equation 7E-7 or Equation 7E-9, must be greater than or equal to 90 percent.

$$Eff_{NO2} = \left(\frac{C_{Dir}}{C_V}\right) \times 100$$

Eq. 7E-7 = $\frac{\text{ppmvd}}{\text{ppmvd}}$ x 100 =

Date/Time	Elapsed Time	NOx	NO
mm/dd/yy hh:mm:ss	Seconds	ppmvd	ppmvd

Fuel Data

Fuel F_d factor		SCF/MMBtu
Fuel Heating Value (HHV)		Btu/SCF

Weather Data

Barometric Pressure		in. Hg
Relative Humidity		%
Ambient Temperature		°F
Specific Humidity		lb H_2O / lb air

Unit Data

Unit Load		megawatts
Heat Input		lb/MMBtu
Steam Rate		Steam lb/hr
Combustor Inlet Pres.		psig
NOx Control Water Injection		gpm
Est. Stack Moisture		%
Stack Exhaust Flow (M2)		SCFH
Stack Exhaust Flow (M19)		SCFH

Run - 1

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)

RAW AVERAGE

	O_2	NOx	CO
Serial Number:			
	(%)	(ppmvd)	(ppmvd)
Initial Zero			
Final Zero			
Avg. Zero			
Bias			
Initial UpScale			
Final UpScale			
Avg. UpScale			

Upscale Cal Gas

EMISSIONS DATA	O_2	NOx	CO
Corrected Raw Average (ppm/% dry basis)			
Corrected Raw Average (ppm/% wet basis)			
Concentration (ppm@ %O_2)			
Concentration (ppm@ %O_2 &ISO)			
Emission Rate (lb/hr)			
Emission Rate (tons/day) at 24 hr/day			
Emission Rate (tons/year) at 8760 hr/yr			
Emission Rate (lb/MMBtu)			
Emission Rate (g/hp*hr)			

DRIFT AND BIAS CHECK			
Run - 1	**O2**	**NOx**	**CO**
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff — Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

DRIFT AND BIAS CHECK			
Run - 2	**O2**	**NOx**	**CO**
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff — Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

TABLE A.2
LOAD 1 DATA SUMMARY

Parameter	Run - 1	Run - 2	Run - 3	Average
Start Time (hh:mm:ss)				
End Time (hh:mm:ss)				
Run Duration (min)				
Bar. Pressure (in. Hg)				
Amb. Temp. (°F)				
Rel. Humidity (%)				
Spec. Humidity (lb water / lb air)				
Turbine Fuel Flow (SCFH)				
Stack Flow (RM19) (SCFH)				
Power Output (megawatts)				
NOx (ppmvd)				
NOx (lb/hr)				
NOx (lb/MMBtu)				
NOx (g/hp*hr)				
CO (ppmvd)				
CO (lb/hr)				
CO (lb/MMBtu)				
CO (g/hp*hr)				
O_2 (%)				

TABLE A.3
LOAD 2 DATA SUMMARY

Parameter	Run - 4	Run - 5	Run - 6	Average
Start Time (hh:mm:ss)				
End Time (hh:mm:ss)				
Run Duration (min)				
Bar. Pressure (in. Hg)				
Amb. Temp. (°F)				
Rel. Humidity (%)				
Spec. Humidity (lb water / lb air)				
Turbine Fuel Flow (SCFH)				
Stack Flow (RM19) (SCFH)				
Power Output (megawatts)				
NOx (ppmvd)				
NOx (lb/hr)				
NOx (lb/MMBtu)				
NOx (g/hp*hr)				
CO (ppmvd)				
CO (lb/hr)				
CO (lb/MMBtu)				
CO (g/hp*hr)				
O_2 (%)				

EXAMPLE CALCULATIONS (FFACTOR)

RM 19, (07-19-06), 2.0 Summary of Method, 2.1 Emission Rates. Oxygen (O_2) or carbon dioxide (CO_2) concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant co

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in lb/MMBtu. The pollutant concentration must be in lb/scf and the F factor must be in scf/MMBtu. If the pollutant concentration (C) is not in the appropriate units, use Table 19–1 in Section 17.0 to make the proper conversion. An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry F factor (F_d) includes all components of combustion less water, the wet F factor (F_w) includes all components of combustion, and the carbon F factor (F_c) includes only carbon dioxide.

Mark's Std Hdbk, 10th ed.,pg 4-26
High Heat Value Dry (HHV_{dry}), calc for Methane (single component for the fuel gas)

$$HHV_{dry}(Btu/SCF)=\left[\left(\frac{M_{\%}}{100}\right)\times GCM\right]$$

$$HHV_{dry}=\frac{\%}{100.00}\times\frac{Btu}{SCF}=\frac{Btu}{SCF}$$

Mark's Std Hdbk, 10th ed., pg 4-26
Low Heat Value Dry (LHV_{dry}), calc for Methane (single component for the fuel gas)

$$LHV_{dry}(Btu/SCF)=\left[\left(\frac{M_{\%}}{100}\right)\times NCM\right]$$

$$LHV_{dry}=\frac{\%}{100.00}\times\frac{Btu}{SCF}=\frac{Btu}{SCF}$$

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
High Heat Value Wet (HHV_{wet}), calc for entire sample (all components of the fuel gas)

$$HHV_{wet}(Btu/SCF)=\frac{HHV_{dry}}{W/D.factor}$$

$$HHV_{wet}=\frac{Btu/SCF}{}=Btu/SCF$$

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
Low Heat Value Wet (LHV_{wet}), calc for entire sample (all components of the fuel gas)

$$LHV_{wet}(Btu/SCF)=\frac{LHV_{dry}}{W/D.factor}$$

$$LHV_{wet}=\frac{Btu/SCF}{}=Btu/SCF$$

Lbs Component per Lb-Mol of Gas (CM), calc for Methane (single component for the fuel gas)

$$CM(lb/lb-mol)=\left[\left(\frac{M_{\%}}{100}\right)\times MW\right]$$

$$CM=\frac{\%}{100.00}\times\frac{lb}{lb\text{-}mol}=\ \_\_\_\ lb/lb\text{-}mol$$

ASTM D 3588
Fuel Molecular Weight (MW_{Fuel})

$$MW_{Fuel}(lb/lb\cdot mol)=\left[\sum(CM)\right]$$

MW_{Fuel} = lb/lb-mol
\+ lb/lb-mol
\+ etc. = lb/lb-mol

Btu per Lb of Gas Gross (**GCV**)

$$GCV(Btu/lb)=\left[\frac{HHV_{dry}\times G}{MW_{Fuel}}\right]$$

$$GCV=\frac{Btu/SCF\times ft^3/lbmol}{lb/lb\text{-}mol}=Btu/lb$$

ASTM D 3588 (SG)
Specific Gravity

$$SG=\left[\frac{MW_{Fuel}}{MW_{AIR}}\right]$$

$$SG=\frac{lb/lb\text{-}mol}{28.96\ lb/lb\text{-}mol}=$$

Btu per Lb of Gas Net (**NCV**)

$$NCV(Btu/lb)=\left[\frac{LHV_{dry}\times G}{MW_{Fuel}}\right]$$

$$NCV=\frac{Btu/SCF\times ft^3/lbmol}{lb/lb\text{-}mol}=Btu/lb$$

Weight Percent of Component ($C_{\%}$), methane

$$C_{\%}(\%)=\left[\left(\frac{CM}{MW_{Fuel}}\right)\times 100\right]$$

$$C_{\%}=\frac{lb/lb\text{-}mol}{lb/lb\text{-}mol}\times 100=\ \%$$

RM 19, (07-19-06), **Weight Percent of Volatile Organic Compounds** ($VOC_{\%}$)

$$VOC_{\%}(\%)=\left[\sum_{C_3H_8}^{C_8H_{18}}M_{\%}\right]$$

$$VOC_{\%}=\ \%+\ \%+\ \%+\ etc.=\ \%$$

RM 19, (07-19-06), 12.3.2 Determined **F Factors**. If the fuel burned is not listed in Table 19–2 or if the owner or operator chooses to determine an F factor rather than use the values in Table 19–2, use the procedure below: 12.3.2.1 Equations. Use the eq

RM 19, (07-19-6), 12.1 Nomenclature

K (scf/lb)/%

H	3.64
C	1.53
S	0.57
N_2	0.14
O_2	0.46

$$F_d=\frac{K(K_{hd}\%H+K_c\%C+K_s\%S+K_n\%N-K_o\%O)}{GCV}\qquad\text{Eq. 19-13}$$

$$F_d=\frac{10^6Btu}{MMBtu}\times\left[\frac{3.64\ SCF}{lb\cdot\%}\times\ \%+\frac{1.53\ SCF}{lb\cdot\%}\times\ \%+\frac{0.57\ SCF}{lb\cdot\%}\times\ \%+\frac{0.14\ SCF}{lb\cdot\%}\times\ \%-\frac{0.46\ SCF}{lb\cdot\%}\times\ \%\right]\times\frac{lb}{Btu}=\frac{SCF}{MMBtu}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (INFORMATION)

Specific Humidity (RH_{sp})

Note: RHsp (gr/lb) calculated using temperature, relative humidity, and barometric pressure with psychrometric chart, psychrometric calculator, or built in psychrometric algorithm.

$$RH_{sp}(lb/lb) = \left[\left(\frac{gr}{lb}\right) \times \frac{lb}{7000\,gr}\right]$$

RH_{sp} = $\frac{\quad gr}{lb}$ x $\frac{1\ lb}{7000\ gr}$ = $\frac{lb\ H_2O}{lb\ Air}$

Fuel Flow Conversion (Q_f)

Note: Qf(lb/min) is a value uptained from the source operator.

$$Q_f = \left[Q_f \times G \times \left(\frac{1}{MW_{Fuel}}\right)\right]$$

Q_f = $\frac{\quad lb}{min}$ x $\frac{60\ min}{hr}$ x $\frac{\quad ft^3}{lb\text{-}mol}$ x $\frac{lb\text{-}mol}{lb}$ = SCFH

Combustor Inlet Pressure / Compressor Discharge Pressure (CIP / CDP) (corrected from gauge to atmospheric pres. and conv. to mm Hg.)

Note: CIP / CDP (psig) is a value obtained from the source operator.

$$CIP/CDP = \left[(psig + P) \times \frac{51.71493\ mmHg}{1 psi}\right]$$

CIP / CDP = [psig +] x $\frac{51.71493\ mmHg}{1\ psia}$ = mmHg (abs)

Heat Rate (MMBtu/hr)

$$HR = \frac{HHV_{DRY} \times Q_f}{1{,}000{,}000}$$

Heat Rate = $\frac{\quad Btu}{SCF}$ x $\frac{\quad SCF}{hr}$ x $\frac{MMBtu}{10^6\ Btu}$ = $\frac{\quad MMBtu}{hr}$

Estimated Stack Gas Moisture Content (B_{ws})

$$B_{ws}(\%) = \frac{2 \times Q_f}{Q_s} \times 100$$

B_{ws} = 2 x $\frac{\quad SCF}{hr}$ x $\frac{hr}{\quad SCF}$ x 100 = %

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (CALIBRATION)

Analyzer Calibration Error

RM 7E, (08-15-06), 12.2 Analyzer Calibration Error. For non-dilution systems, use Equation 7E-1 to calculate the analyzer calibration error for the low-, mid-, and high-level calibration gases. (calc for analyzer mid gas, if applicable)

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100 \qquad \text{Eq. 7E-1}$$

ACE = $\frac{ppm - \quad ppm}{ppm}$ x 100 = %

Calibration Error and Estimated Point, RM 25A, THC Analyzer

RM 25A, (07-19-06), 8.4 Calibration Error Test. Immediately prior to the test series (within 2 hours of the start of the test), introduce zero gas and high-level calibration gas at the calibration valve assembly. Adjust the analyzer output to the appropriate levels, if necessary. Calculate the predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response. Then introduce low-level and mid-level calibration gases successively to the measurement system. ....These differences must be less than 5 percent of the respective calibration gas value. (calc for THC analyzer mid gas, if applicable)

$$E_P = \frac{C_{Dir(H)} - C_{Dir(Z)}}{C_{V(H)} - C_{V(Z)}} \times C_{Dir(M)} + C_{Dir(Z)}$$

Eq. of a line y=mx+b

E_p = $\frac{ppm - \quad ppm}{ppm - \quad ppm}$ x ppm + = ppm

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100 \qquad \text{Eq. 7E-1}$$

ACE_{THC} = $\frac{ppm - \quad ppm}{ppm}$ x 100 = %

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (BIAS, DRIFT, AND CORRECTED RAW AVERAGE)

System Bias

RM 7E, (08-15-06), 12.3 System Bias. For non-dilution systems, use Equation 7E-2 to calculate the system bias separately for the low-level and upscale calibration gases. (calc for analyzer upscale gas, Run 1 initial bias, if applicable)

$$SB = \left(\frac{C_S - C_{Dir}}{CS}\right) \times 100$$ Eq. 7E-2

SB = (ppm - ppm) / ppm x 100 = %

Drift Assessment

RM 7E, (08-15-06), 12.5 Drift Assessment. Use Equation 7E-4 to separately calculate the low-level and upscale drift over each test run. (calc for analyzer upscale drift, Run 1, if applicable)

$$D = \left|SB_{final} - SB_i\right|$$ Eq. 7E-4

D = | % - % | = %

Alternative Drift and Bias

RM 7E, (08-15-06), 13.2 / 13.3 System Bias and Drift. Alternatively, the results are acceptable if |Cs – Cdir| is≤ 0.5 ppmv or if |Cs – Cv| is ≤ 0.5 ppmv (as applicable). (calc for analyzer initial upscale, Run 1, if applicable)

$$SB / D_{Alt} = \left|C_S - C_{Dir}\right|$$ Eq. Section 13.2 and 13.3

SB / D_{Alt} = | ppm - ppm | = ppm

Bias Adjusted Average

RM 7E, (08-15-06), 12.6 Effluent Gas Concentration. For each test run, calculate Cavg, the arithmetic average of all valid concentration values (e.g., 1-minute averages). Then adjust the value of Cavg for bias, using Equation 7E-5. (calc for analyzer, Run 1, if applicable)

$$C_{Gas} = \left(C_{Avg} - C_O\right) \times \left(\frac{C_{MA}}{C_M - C_O}\right)$$ Eq. 7E-5

C_{Gas} = (ppm - ppm) x (ppm / (ppm - ppm)) = ppm

EXAMPLE CALCULATIONS (BSFC)

Using LHV with Q_f (Btu/hp*hr)

$$BSFC\ (Btu / hp \cdot hr) = Q_f$$

BSFC = Btu / hp*hr = Btu / hp*hr

Using HHV with Q_f (SCFH)

$$BSFC\ (Btu / hp \cdot hr) = \frac{HHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using LHV with Q_f (SCFH)

$$BSFC\ (Btu / hp \cdot hr) = \frac{LHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using HHV with Q_f (Btu/hp*hr)

$$BSFC\ (Btu / hp \cdot hr) = \frac{Q_f \times HHV}{LHV}$$

BSFC = N/A Btu / hp*hr x Btu / SCF x scf / Btu = Btu / hp*hr

EXAMPLE CALCULATIONS (Emissions based on Table 29 values)

Emission Rate (lb/hr)
Q_f (Btu/hp*hr))

$$E(lb / hr) = \frac{E_{g/hp \cdot hr} \times bhp}{453.6}$$

E (lb/hr) = g / hp*hr x lb / 453.6 g x hp = lb / hr

Emission Rate (g/hp-hr)
Q_f (Btu/hp*hr))

$$E(g / hp \cdot hr) = CRA \times Q_f \times FFactor \times MW \times \frac{1}{10^6} \times \frac{1}{10^6} \times \frac{453.6}{G} \times \frac{20.9\%}{20.9\% - CRA_{O_2}}$$

E (g/hp-hr) = ppm x Btu / hp*hr x SCF / MMBtu x lb / lb-mol x 1 parts / 10^6 ppm x 1 MMBtu / 10^6 Btu x 453.6 g / lb x lb-mol / SCF x 20.9% / (20.9% - %) = g / hp*hr

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Stack Exhaust Flow (Q_S) - RM19

$$Q_S = \left(\frac{FFactor \times Q_f \times HHV}{1{,}000{,}000}\right) \times \left(\frac{20.9\%}{20.9\% - C_{Gas(O2)}}\right)$$

$$Q_S = \frac{SCF}{MMBtu} \times \frac{SCF}{hr} \times \frac{Btu}{SCF} \times \frac{MMBtu}{10^6\ Btu} \times \left[\frac{20.90\%}{20.9\% - \quad \%}\right] = \quad SCFH$$

NO_2 Conversion Efficiency Correction

RM 7E, (08-15-06), 12.8 NO2 - NO Conversion Efficiency Correction. If desired, calculate the total NOX concentration with a correction for converter efficiency using Equations 7E-8. (calc for non-bias corrected (raw) NOx gas, Run 1, if applicable)

$$NOx_{Corr} = NO + \frac{NOx - NO}{Eff_{NO2}} \times 100 \qquad \text{Eq. 7E-8}$$

$$NOx_{Corr} = \quad ppm + \frac{ppm - \quad ppm}{\quad \%} \times 100 = \quad ppm$$

Moisture Correction

RM 7E, (08-15-06), RM7E, (08-15-06), 12.10 Moisture Correction. Use Equation 7E-10 if your measurements need to be corrected to a dry basis. (calc for THC analyzer, Run 1, if applicable) Note: Calculations may not match as Run 1 results are typically also bias adjusted

$$C_D = \frac{C_W}{1 - B_{WS}} \qquad \text{Eq. 7E-10}$$

$$C_D = \frac{\quad ppmvw}{1 - \quad} = \quad ppmvd$$

Diluent-Corrected Pollutant Concentration, O_2 Based

RM 20, (11-26-02), 7.3.1 Correction of Pollutant Concentration Using O2 Concentration. Calculate the O2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right) \qquad \text{Eq. 20-4}$$

$$C_{adj} = \quad ppm \times \left(\frac{20.9\% - \quad \%}{20.9\% - \quad \%}\right) = \quad ppm@\%O_2$$

Diluent-Corrected Pollutant Concentration, CO_2 Based

RM 20, (11-26-02), 7.3.2 Correction of Pollutant Concentration Using CO2 Concentration. Calculate the CO2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \frac{X_{CO2}}{C_{Gas(CO2)}} \qquad \text{Eq. 20-5}$$

$$C_{adj} = \quad ppm \times \frac{\quad \%}{\quad \%} =$$

7.2 CO_2 Correction Factor. If pollutant concentrations are to be corrected to percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as follows: 7.2.1 Calculate the fuel specific F_0, as follows:

$$F_0 = \frac{0.209 F_d}{F_c} \qquad \text{Eq. 20-2}$$

$$F_0 = \frac{0.209 \times \quad SCF/MMBtu}{SCF/MMBtu} =$$

7.2.2. Calculate the CO_2 correction factor for correcting measurement data to percent oxygen, as follows:

$$X_{CO2} = \frac{20.9\% - AdjFactor}{F_0} \qquad \text{Eq. 20-3}$$

$$X_{CO2} = \frac{20.9\% - \quad \%}{\quad} = \quad \%$$

Diluent-Corrected Pollutant Concentration Corrected to ISO Conditions

40CFR60.335(b)(1), Conversion for conc. at ISO Conditions (68°F, 1 atm). Calculate, as follows: (calc for @% with Run 1 data, if applicable)

$$C_{ISO} = C_{Adj} \times \sqrt{\frac{P_r}{P_o}} \times e^{(19 \times (H_o - 0.00633))} \times \left(\frac{288}{T_a}\right)^{1.53}$$

$$C_{ISO} = \quad ppm@\%O_2 \times \left(\sqrt{\frac{\dfrac{psig + 14.69232\ psi}{0.01933677\ psi/mm\ Hg.}}{\dfrac{psig + \quad psi}{0.01933677\ psi/mm\ Hg.}}}\right) \times 2.718^{(19 \times (\quad lb/lb - 0.00633))} \times \left(\frac{288\ K}{\quad K}\right)^{1.53} = \quad ppm@\%\ and\ ISO$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Emissions Rate (lb/hr)

Calculation for pound per hour emission rate. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

$$E_{lb/hr} = \frac{\text{ppm}}{10^6 \text{ ppm/part}} \times \frac{\text{SCFH x} \quad \text{lb/lb-mol}}{\text{SCF/lb-mol}} = \frac{\text{lb}}{\text{hr}}$$

Emissions Rate (ton/year)

Calculation for tons per year emission rate based on 8760 hours per year. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{ton/yr} = \frac{E_{lb/hr} \times hr_{year}}{2000}$$

$$E_{ton/yr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{hr}}{\text{year}} \times \frac{\text{ton}}{\text{2000 lb}} = \frac{\text{ton}}{\text{year}}$$

Emissions Rate (lb/MMBtu)

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in ng/J (lb/million Btu). (calc for gas Run 1, if applicable)

Oxygen Based

12.2.1 Oxygen-Based F Factor, Dry Basis. When measurements are on a dry basis for both O_2 (%O_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}} \qquad \text{Eq. 19-1}$$

$$E_{lb/MMBtu} = \frac{\text{ppm x} \quad \text{SCF/MMBtu x} \quad \text{lb/ppm*ft}^3 \text{ x 20.9\%}}{20.9\% - \quad \%} = \frac{\text{lb}}{\text{MMBtu}}$$

Carbon Dioxide Based

12.2.4 Carbon Dioxide-Based F Factor, Dry Basis. When measurements are on a dry basis for both CO_2 (%CO_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}} \qquad \text{Eq. 19-6}$$

$$E_{lb/MMBtu} = \frac{\text{ppm x} \quad \text{SCF/MMBtu x} \quad \text{lb/ppm*ft}^3 \text{ x 100\%}}{\%} = \frac{\text{lb}}{\text{MMBtu}}$$

Conversion Constant

Convc for

$$Conv_c(lb/ppm \cdot ft^3) = \frac{\frac{MW}{G}}{10^6}$$

$$Conv_c = \frac{\frac{\text{lb}}{\text{lb•mole}} \times \frac{\text{lb•mole}}{\text{SCF}}}{10^6} = \frac{\text{lb}}{\text{ppm-ft}^3}$$

Sulfur Dioxide Rate (lb/MMBtu), 40CFR60, App. A, RM 19, Eq. 19-25 (11/20/03)

$$SO_2(lb/MMBtu) = 0.97 \times K \times \frac{S(wt\%)}{GCV}$$

$$SO_2 = 0.97 \times \frac{2\text{x}10^4 \text{ Btu}}{\text{wt\%•MMBtu}} \times \frac{\text{wt\%}}{\text{Btu/lb}} = \frac{\text{lb}}{\text{MMBtu}}$$

Emissions Rate (g/hp-hr)

Calculation for grams per horsepower-hour. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{g/hp\text{-}hr} = \frac{E_{lb/hr} \times 453.6}{mw \times 1314.022} \text{ or } \frac{E_{lb/hr} \times 453.6}{hp}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{453.6 g}}{\text{lb}} \times \frac{1}{\text{mw}} \times \frac{\text{mw}}{\text{1314.022 hp}} = \frac{\text{g}}{\text{hp*hr}}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{453.6 g}}{\text{lb}} \times \frac{1}{\text{hp}} = \frac{\text{g}}{\text{hp*hr}}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

RM 7E, (08-15-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

ACE = Analyzer calibration error, percent of calibration span.
B_{WS} = Moisture content of sample gas as measured by Method 4 or other approved method, percent/100.
C_{Avg} = Average unadjusted gas concentration indicated by data recorder for the test run.
C_D = Pollutant concentration adjusted to dry conditions.
C_{Dir} = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode.
C_{Gas} = Average effluent gas concentration adjusted for bias.
C_M = Average of initial and final system calibration bias (or 2-point system calibration error) check responses for the upscale calibration gas.
C_{MA} = Actual concentration of the upscale calibration gas, ppmv.
C_O = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas.
C_S = Measured concentration of a calibration gas (low, mid, or high) when introduced in system calibration mode.
C_{SS} = Concentration of NOx measured in the spiked sample.
C_{Spike} = Concentration of NOx in the undiluted spike gas.
C_{Calc} = Calculated concentration of NOx in the spike gas diluted in the sample.
C_V = Manufacturer certified concentration of a calibration gas (low, mid, or high).
C_W = Pollutant concentration measured under moist sample conditions, wet basis.
CS = Calibration span.
D = Drift assessment, percent of calibration span.
E_p = The predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response.
Eff_{NO2} = NO_2 to NO converter efficiency, percent.
H = High calibration gas, designator.
L = Low calibration gas, designator.
M = Mid calibration gas, designator.
NOFinal = The average NO concentration observed with the analyzer in the NO mode during the converter efficiency test in Section 16.2.2.
NOxCorr = The NOx concentration corrected for the converter efficiency.
NOxFinal = The final NOx concentration observed during the converter efficiency test in Section 16.2.2.
NOxPeak = The highest NOx concentration observed during the converter efficiency test in Section 16.2.2.
Q_{Spike} = Flow rate of spike gas introduced in system calibration mode, L/min.
Q_{Total} = Total sample flow rate during the spike test, L/min.
R = Spike recovery, percent.
SB = System bias, percent of calibration span.
SB_i = Pre-run system bias, percent of calibration span.
SB_f = Post-run system bias, percent of calibration span.
SB / D_{Alt} = Alternative absolute difference criteria to pass bias and/or drift checks.
SCE = System calibration error, percent of calibration span.
SCE_i = Pre-run system calibration error, percent of calibration span.
SCE_{final} = Post-run system calibration error, percent of calibration span.
Z = Zero calibration gas, designator.

40CFR60.355(b)(1), (09-20-06), Nomenclature. The terms used in the equations are defined as follows:

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
P_o = observed combustor inlet absolute pressure at test, mm Hg
H_o = observed humidity of ambient air, g H_2O/g air
e = transcendental constant, 2.718
T_a = ambient temperature, K

Small Engine and FTIR Nomenclature. The terms used in the equations are defined as follows:

bhp = brake horsepower
hp = horsepower
Q_{sys} = system flow (lpm)
Q_m = matrix spike flow (lpm)

RM 19, (07-29-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

AdjFactor = percent oxygen or carbon dioxide adjustment applied to a target polltant
B_{wa} = Moisture fraction of ambient air, percent.
Btu = British thermal unit
$\%_C$ = Concentration of carbon from an ultimate analysis of fuel, weight percent.
$\%_{CO2d}$, $\%_{CO2w}$ = Concentration of carbon dioxide on a dry and wet basis, respectively, percent.
CIP / CDP = Combustor inlet pressure / compressor discharge pressure (mm Hg); note, some manufactures reference as PCD.
E = Pollutant emission rate, ng/J (lb/million Btu).
E_a = Average pollutant rate for the specified performance test period, ng/J (lb/million Btu).
E_{ao}, E_{ai} = Average pollutant rate of the control device, outlet and inlet, respectively, for the performance test period, ng/J (lb/million Btu).
E_{bi} = Pollutant rate from the steam generating unit, ng/J (lb/million Btu).
E_{bo} = Pollutant emission rate from the steam generating unit, ng/J (lb/million Btu).
E_{ci} = Pollutant rate in combined effluent, ng/J (lb/million Btu).
E_{co} = Pollutant emission rate in combined effluent, ng/J (lb/million Btu).
E_d = Average pollutant rate for each sampling period (e.g.,24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g., amount of fuel bunkered), ng/J (lb/million Btu).
E_{di} = Average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu).
E_g = Pollutant rate from gas turbine, ng/J (lb/million Btu).
E_{ga} = Daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent O_2.
E_{jo}, E_{ji} = Matched pair hourly arithmetic average pollutant rate, outlet and inlet, respectively, ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.
E_h = Hourly average pollutant, ng/J (lb/million Btu).
E_{hj} = Hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.
EXP = Natural logarithmic base (2.718) raised to the value enclosed by brackets.
Fc = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19
F_d, F_w, F_c = Volumes of combustion components per unit of heat content, scm/J (scf/million Btu).
ft^3 = cubic feet
G = ideal gas conversion factor
(385.23 SCF/lb-mol at 68 deg F & 14.696 psia)
GCM = gross Btu per SCF (constant, compound based)
GCV = Gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).
GCV_p, GCV_r = Gross calorific value for the product and raw fuel lots, respectively, dry basis, kJ/kg (Btu/lb).
$\%_H$ = Concentration of hydrogen from an ultimate analysis of fuel, weight percent.
H_b = Heat input rate to the steam generating unit from fuels fired in the steam generating unit, J/hr (million Btu/hr).
H_g = Heat input rate to gas turbine from all fuels fired in the gas turbine, J/hr (million Btu/hr).
$\%_{H2O}$ = Concentration of water from an ultimate analysis of fuel, weight percent.
H_r = Total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).
K = volume of combustion component per pound of component (constant)
K = Conversion factor, 10^{-5} (kJ/J)/(%) [10^6 Btu/million Btu].
K_c = (9.57 scm/kg)/% [(1.53 scf/lb)/%].
K_{cc} = (2.0 scm/kg)/% [(0.321 scf/lb)/%].
K_{hd} = (22.7 scm/kg)/% [(3.64 scf/lb)/%].
K_{hw} = (34.74 scm/kg)/% [(5.57 scf/lb)/%].
K_n = (0.86 scm/kg)/% [(0.14 scf/lb)/%].
K_o = (2.85 scm/kg)/% [(0.46 scf/lb)/%].
K_s = (3.54 scm/kg)/% [(0.57 scf/lb)/%].
K_{sulfur} = $2x10^4$ Btu/wt%-MMBtu
K_w = (1.30 scm/kg)/% [(0.21 scf/lb)/%].
lb = pound
ln = Natural log of indicated value.
L_p, L_r = Weight of the product and raw fuel lots, respectively, metric ton (ton).
$\%_N$ = Concentration of nitrogen from an ultimate analysis of fuel, weight percent.
$M_{\%}$ = mole percent
mol = mole
MW = molecular weight (lb/lb-mol)
MW_{AIR} = molecular weight of air (28.9625 lb/lb-mole)[1]
NCM = net Btu per SCF (constant based on compound)
$\%_O$ = Concentration of oxygen from an ultimate analysis of fuel, weight percent.
$\%_{O2d}$, $\%_{O2w}$ = Concentration of oxygen on a dry and wet basis, respectively, percent.
P_B = barometirc pressure, in Hg
P_s = Potential SO2 emissions, percent.
$\%_S$ = Sulfur content of as-fired fuel lot, dry basis, weight percent.
S_e = Standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).
$\%_{Sf}$ = Concentration of sulfur from an ultimate analysis of fuel, weight percent.
S(wt%) = weight percent of sulfur, per lab analysis by appropriate ASTM standard
S_i = Standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).
S_o = Standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).
$\%S_p$, $\%S_r$ = Sulfur content of the product and raw fuel lots respectively, dry basis, weight percent.
SCF = standard cubic feet
SH = specific humidity, pounds of water per pound of air
$t_{0.95}$ = Values shown in Table 19-3 for the indicated number of data points n.
T_{amb} = ambient temperature, °F
W/D Factor = 1.0236 = conv. at 14.696 psia and
68 deg F (ref. Civil Eng. Ref. Manual, 7th Ed.)
X_{CO2}=CO_2 Correction factor, percent.
X_k = Fraction of total heat input from each type of fuel k.

Calculations, Formulas, and Constants

The following information supports the spreadsheets for this testing project.

Given Data:

Ideal Gas Conversion Factor = 385.23 SCF/lb-mol at 68 deg F & 14.696 psia

Fuel Heating Value is based upon Air Hygiene's fuel gas calculation sheet. All calculations are based upon a correction to 68 deg F & 14.696 psia

High Heating Values (HHV) are used for the Fuel Heating Value, F-Factor, and Fuel Flow Data per EPA requirements.

ASTM D 3588

Molecular Weight of NOx (lb/lb-mole) =	46.01
Molecular Weight of CO (lb/lb-mole) =	28.00
Molecular Weight of SO2 (lb/lb-mole) =	64.00
Molecular Weight of THC (propane) (lb/lb-mole) =	44.00
Molecular Weight of VOC (methane) (lb/lb-mole) =	16.00
Molecular Weight of NH3 (lb/lb-mole) =	17.03
Molecular Weight of HCHO (lb/lb-mole) =	30.03

40CFR60, App. A., RM 19, Table 19-1

Conversion Constant for NOx =	0.0000001194351
Conversion Constant for CO =	0.0000000726839
Conversion Constant for SO2 =	0.0000001661345
Conversion Constant for THC =	0.0000001142175
Conversion Constant for VOC (methane) =	0.0000000415336
Conversion Constant for NH_3 =	0.0000000442074
Conversion Constant for HCHO =	0.0000000779534

NOTE: units are lb/ppm*ft^3

Formulas:

1. Corrected Raw Average (C_{Gas}), 40CFR60, App. A, RM 7E, Eq. 7E-5 (08/15/06)

$$C_{Gas} = (C_{Avg} - C_O) \times \left(\frac{C_{MA}}{C_M - C_O} \right)$$

2. Correction to % O_2, 40CFR60, App. A, RM 20, Eq. 20-5 (11/26/02)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}} \right)$$

3. Emission Rate in lb/hr

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

4. Emission Concentration in lb/MMBtu (O_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}}$$

5. Emission Concentration in lb/MMBtu (CO_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}}$$

RATA SHEET CALCULATIONS

d = Reference Method Data - CEMS Data

S_d = Standard Deviation

CC = Confident Coefficient

n = number of runs

$t_{0.025}$ = 2.5 percent confidence coefficent T-values

RA = relative accuracy

ARA = alternative relative accuracy

BAF = Bias adjustment factor

n	t	n	t	n	t
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

1. Difference

$$d = \sum_{i=1}^{n} d_i$$

2. Standard Deviation

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i \right)^2}{n} \right]}{n-1}}$$

3. Confident Coefficient

$$CC = t_{0.025} \times \frac{S_d}{\sqrt{n}}$$

4. Relative Accuracy

$$RA = \frac{|d_{AVG}| + |CC|}{RM_{AVG}} \times 100$$

5. Alternative Relative Accuracy

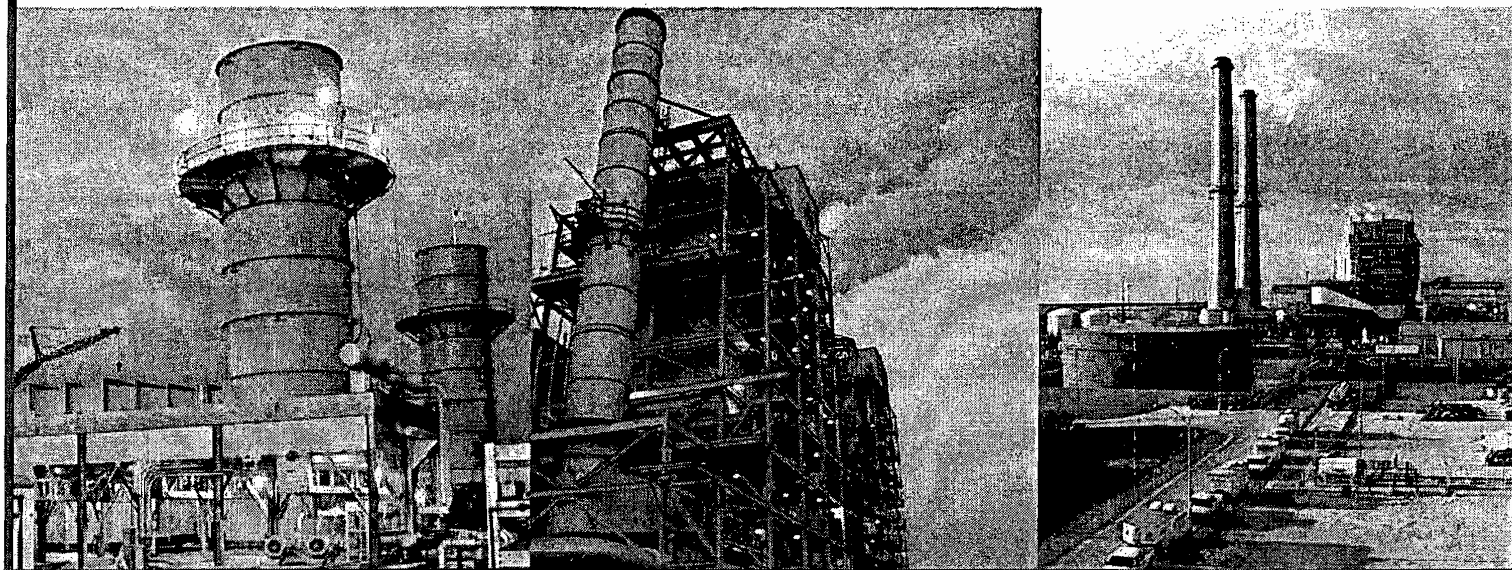
$$ARA = \frac{|d_{AVG}| + |CC|}{AS} \times 100$$

5. Bias Adjustment Factor

$$BAF = 1 + \left(\frac{|d_{AVG}|}{CEM_{AVG}} \right)$$

APPENDIX E
STATEMENT OF QUALIFICATIONS

AIR HYGIENE, INC.



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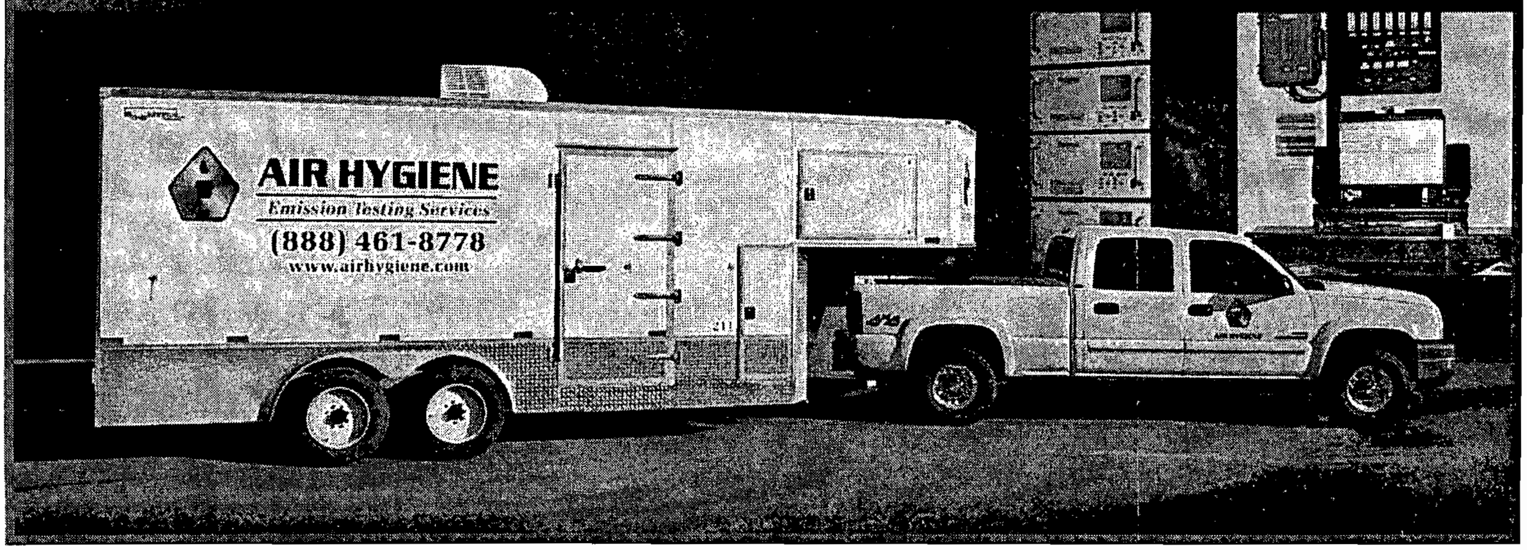


Statement of Qualifications - 2010

AIR HYGIENE, INC.

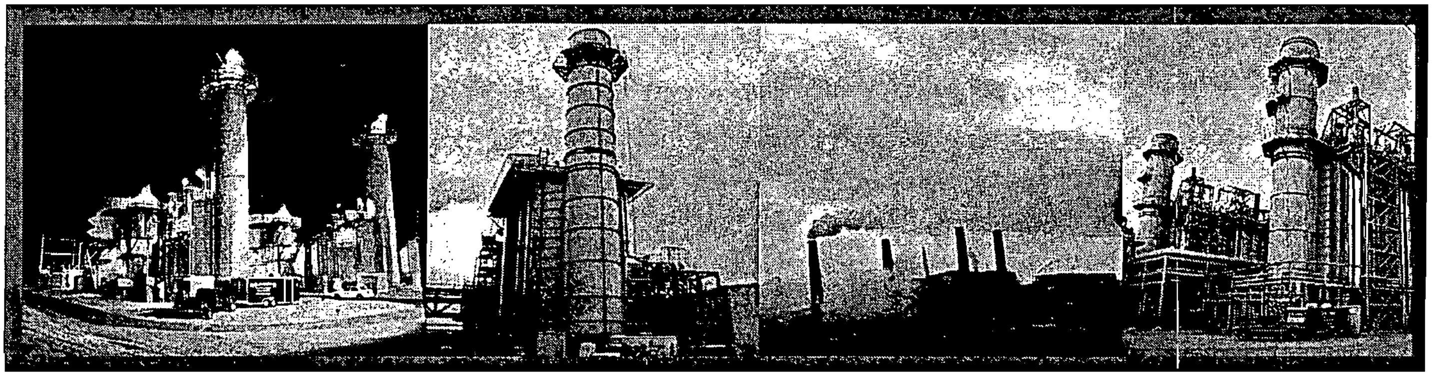
Corporate Headquarters
5634 S. 122nd E. Ave. Ste. F
Tulsa, Oklahoma 74146

West Coast Field Office
5925 E. Lake Mead Blvd.
Las Vegas, Nevada 89156

East Coast Field Office
8900 State Road
Philadelphia, Pennsylvania 19136

Gulf Coast Field Offices
Humble, Texas 77338
Ft. Worth, Texas 76028
Shreveport, Louisiana 71115

(918) 307-8865 or (888) 461-8778
www.airhygiene.com



STATEMENT OF QUALIFICATIONS

AIR HYGIENE

AIR EMISSION TESTING SERVICES

www.airhygiene.com

January, 2010

INTRODUCTION

AIR HYGIENE INTERNATIONAL, INC. (AIR HYGIENE) is a professional air emission testing services firm operating from corporate headquarters in Tulsa, Oklahoma for over 13 years. Additional field offices with ready for field use testing labs are strategically located in Houston, Texas; Las Vegas, Nevada; and Philadelphia, Pennsylvania to serve all fifty (50) United States, Mexico, and Canada. AIR HYGIENE specializes in air emission testing services for combustion sources burning multiple fuels with multiple control devices and supporting equipment.

AIR HYGIENE has testing laboratories which serve all fifty (50) of the United States and North America. Each mobile laboratory can be equipped with the following equipment and capabilities:

1. State-of-the-Art air emission analyzers, computers, and datalogging software. All designed into an efficient system to provide the fastest, most reliable data possible!
2. Dual racks for multiple source testing simultaneously or multiple points on a single source (in/out SCR, etc.)!
3. NIST traceable gases for the most accurate calibration. Ranges as low as five (5) ppm!
4. PM_{10}, NH_3, mercury (Hg), sulfuric acid mist (H_2SO_4), SO_3, and formaldehyde sampling equipment!
5. VOC testing with on-board gas chromatograph to remove methane and ethane!
6. On-board printers to provide hard copies of testing information on-site!
7. Networking capabilities to provide real-time emission data directly into the control room!

AIR HYGIENE is known for providing professional services which include the following:

- Superior, cost saving services to our clients!
- High quality emission testing personnel with service oriented, friendly attitude!
- Meeting our client's needs whether it is 24 hour a day testing or short notice mobilization!
- Using great equipment that is maintained and dependable!
- Understanding the unique startup and operational needs associated with combustion sources!

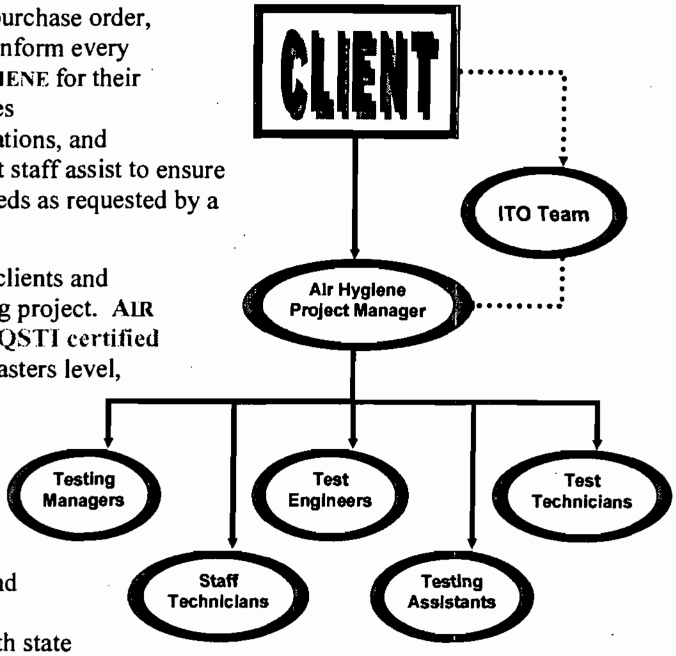
MISSION STATEMENT

Our mission is to provide innovative, practical, top-quality services allowing our clients to increase operating efficiency, save money, and comply with federal/state requirements. We believe our first responsibility is to the client. In providing our unique services, the owners of AIR HYGIENE demand ethical conduct from each employee of the company. The character and integrity of AIR HYGIENE employees allows our clients to feel confidence in the air testing services of AIR HYGIENE. Through a long-term commitment to this mission, AIR HYGIENE is known as a company committed to improving our clients' operations.

AIR HYGIENE ... Does work worth paying for every time!
... Is well known for our emission testing services and uncompromising efforts to serve our clients!
... Does work that matters!
... Is proud of our emission testing capabilities!
... Provides exciting growth opportunities for energetic individuals!

EMISSION TESTING TEAM

Air Hygiene International, Inc. (AIR HYGIENE) intends to exceed your expectations on every project. From project management to field-testing teams, we're committed to hard work on your behalf. The job descriptions and flowchart below outline AIR HYGIENE's client management strategy for your testing services.



From the initial request through receipt of the purchase order, the Inquisition To Order (ITO) team strives to inform every client of the benefits gained by using AIR HYGIENE for their emission testing project. The ITO team includes representatives from the sales, marketing, operations, and contracts divisions. In addition, several support staff assist to ensure the ITO team provides the support for client needs as requested by a client or project manager.

Project Managers are the primary contact for clients and ultimately responsible for every emission testing project. AIR HYGIENE's Project Managers include ten (10) QSTI certified testing experts with experience ranging from masters level, professional engineers to industry experts with over 5,000 testing projects completed. Each project is assigned a Project Manager based primarily upon geographic location, then industry experience, contact history, and availability. The Project Manager prepares the testing strategy and organization for the project. This includes preparation of testing protocol; coordination with state agencies, client representatives, and any interested third parties. The site testing and report preparation are executed under the direction of the Project Manager from start to finish.

Testing Managers have completed Air Hygiene's rigorous demonstration of capability training program and are capable of operating all testing equipment and performing all test methods required for your testing project. Testing Managers assist Project Managers by leading the field testing when required, preparing draft reports, calibrating equipment, and overseeing testing team on-site.

Test Engineers have significant background and understanding of emission testing or related services. Test Engineers prepare pre-test drawings for port location, ensure on-site logistics for electrical and mechanical/structural needs, and conduct on site testing as directed by the Project Manager and/or Testing Manager. Test Engineers often have special understanding of process and/or regulations applicable to specific testing jobs, which provide great value to both the client and Project Manager in testing strategies.

Test Technicians experience ranges from new hire with technical degree and experience to technicians who have performed up to 500 emission tests. All test technicians have a basic understanding of emission training and are involved in daily training and under supervision to continue to develop testing skills. Test Technicians have testing experience with AIR HYGIENE equipment along with a variety of industries and source equipment. Test Technicians may operate isokinetic sampling trains or gas analyzers on-site under the direction of the Project Manager and assist with preparation of field reports and quality assurance procedures.

Staff Technicians are entry-level personnel who have performed less than 500 emission tests. Staff Technicians perform pre-test equipment preparation, on-site test preparation, and testing assistance under the direction of Project Manager and/or Testing Manager. At least one Staff Technician is assigned to every project to assist on-site. Staff Technicians connect sampling probes to ports, assist with leak checks, raise and lower equipment to and from sampling platform, and other support activities under the direction of the Project Manager and/or Testing Manager.

Testing Assistants are entry-level personnel who have performed less than 100 emission tests. Testing Assistants help with equipment set-up, teardown, and simple testing procedures (i.e. move probe, fill ice bath, clean impingers, etc.) as directed.

AIR HYGIENE, INC.

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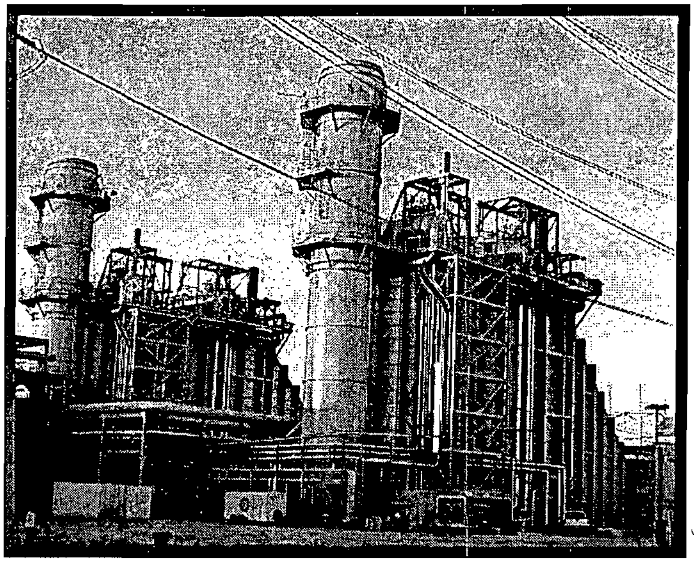
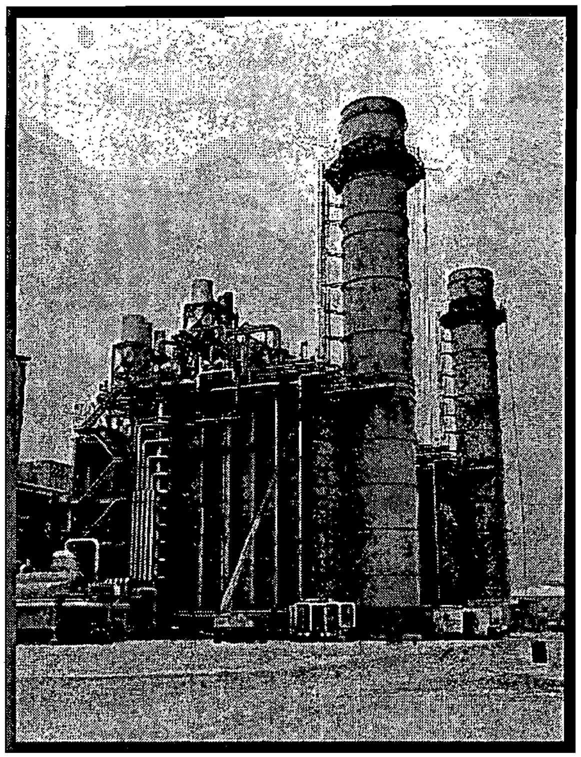
AIR HYGIENE Emission Services Summary



AIR HYGIENE is a privately-held professional services firm headquartered in Tulsa, Oklahoma with additional field offices in Las Vegas, Nevada, Houston, Texas; Ft. Worth, Texas; Shreveport, Louisiana; and Philadelphia, Pennsylvania. AIR HYGIENE specializes in emission testing services for a variety of industries including solid, liquid, & gas fired utility plants, turbines, engines, refineries, printers, glass plants, chemical plants, various manufacturers and related industries.

AIR HYGIENE provides turn-key emission testing services with fast-turnaround which include:

1. Pre-test site visit;
2. Consulting on port locations and setup;
3. Preparation of test plan for state agency;
4. Coordination with state agency for emission testing;
5. On-site emission testing services; and
6. Preparation of draft and final reports.



AIR HYGIENE has mobile laboratories that serve all 50 United States and North America. AIR HYGIENE has performed over 15,000 emission tests on a variety of sources.

AIR HYGIENE performs air emission certification compliance testing on combustion sources (natural gas, biomass, coal, fuel oil, jet fuel, etc), NSPS sources, and Title V compliance sites. Our experience ranges from emission testing for new PSD facilities, MACT and RACT required performance certification testing to Relative Accuracy Test Audits (RATA Tests) for Continuous Emission Monitoring Systems (CEMS) and Parametric Emission Monitoring Systems (PEMS).

Air Hygiene has conducted numerous emission testing projects, which involved multiple groups relying upon instantaneous reporting of important test data. These projects relied upon **Air Hygiene**'s SPIDER network. The SPIDER network provides Simultaneously Produced Information During Emission Readings (SPIDER) between the emission monitoring system and multiple locations (i.e. control room, test center, office, etc.). Hence, you can view real-time emission testing data on-demand from any location you choose using our wireless network data-logging system!

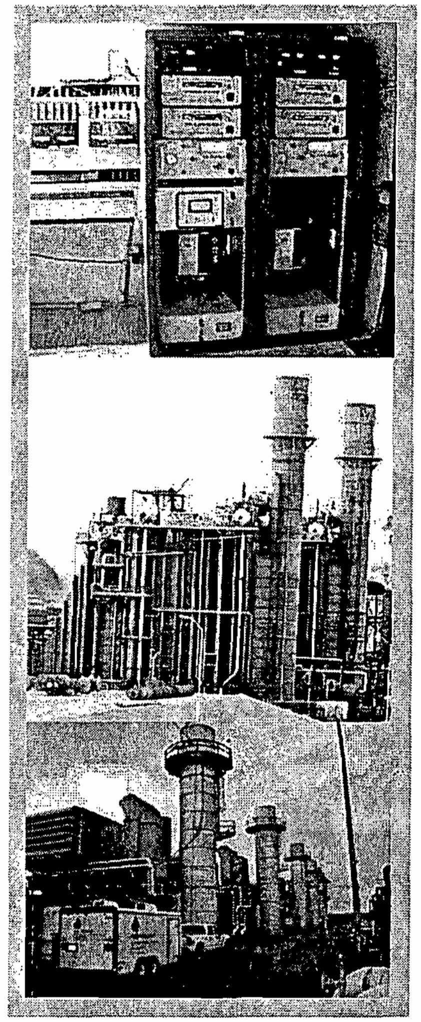
AIR HYGIENE performs FTIR testing by EPA Method 320 321, & ASTM D-6348 for Hazardous Air Pollutants (HAPS) including formaldehyde, benzene, xylene, toluene, hexane, ammonia, hydrogen chloride, etc. This methodology provides real-time analysis of these critical pollutants.

AIR HYGIENE specializes in the following types of pollutants and EPA Reference Methods (RM):

- Exhaust Flow – RM 2 &/or 19
- Carbon Dioxide (CO_2) – RM 3a
- Oxygen (O_2) – RM 3a &/or 20
- Moisture – RM 4
- Particulates (PM) – RM 5(filterable) & 202/OTM-028
- PM < 10 microns (PM_{10}) – RM 201a
- PM < 2.5 microns ($PM_{2.5}$) – RM 201b
- PM sizing (elzone analysis)
- Sulfur Dioxide (SO_2) – RM 6c
- Nitrogen Oxides (NOx) – RM 7e &/or 20
- Sulfuric Acid Mist (SO3) – RM 8a (control condensate)
- Opacity – RM 9
- Carbon Monoxide (CO) – RM 10
- Hydrogen Sulfide (H_2S) – RM 11
- Lead – RM 12
- Dioxin & Furans – RM 23
- Total Hydrocarbons (THC) – RM 25a
- Volatile Organic Compounds (VOC) RM 25a & RM 18
- Metals – RM 29
- Chrome – RM 306
- Formaldehyde – RM 320 & ASTM D-6348 (FTIR)
- HAPS – FTIR – RM 320, 321, & ASTM D-6348 (FTIR)
- Ammonia – RM 320, CTM-027, or BAAQMD ST-1B
- Mercury – RM 30b-Sorbent Tubes (both with on-site analysis, Ontario-Hydro, and RM 29

TESTING EXPERIENCE

AIR HYGIENE testing personnel include ten (10) QSTI certified test managers and account for more than one hundred (100) years of testing experience and over 18,000 emission tests. Our testing services have involved interaction with all 50 state agencies and EPA regional offices. AIR HYGIENE testing personnel are rigorously trained on EPA reference test methods from 40 CFR Part 51, 60, 63, and 75 along with ASTM methods. All testing personnel are instructed and tested on test responsibilities and must complete a "Demonstration of Capability" test per the AIR HYGIENE Quality Assurance Manual and the AIR HYGIENE Emission Testing Standard Operating Procedures Handbook.



AIR HYGIENE has completed testing on over 250 power plants including in excess of 1,000 combustion turbines and 50 coal fired boilers 100,000 megawatts (MW). ***Let us add your project to our list of satisfied customers!***

TESTING SUCCESS STORIES

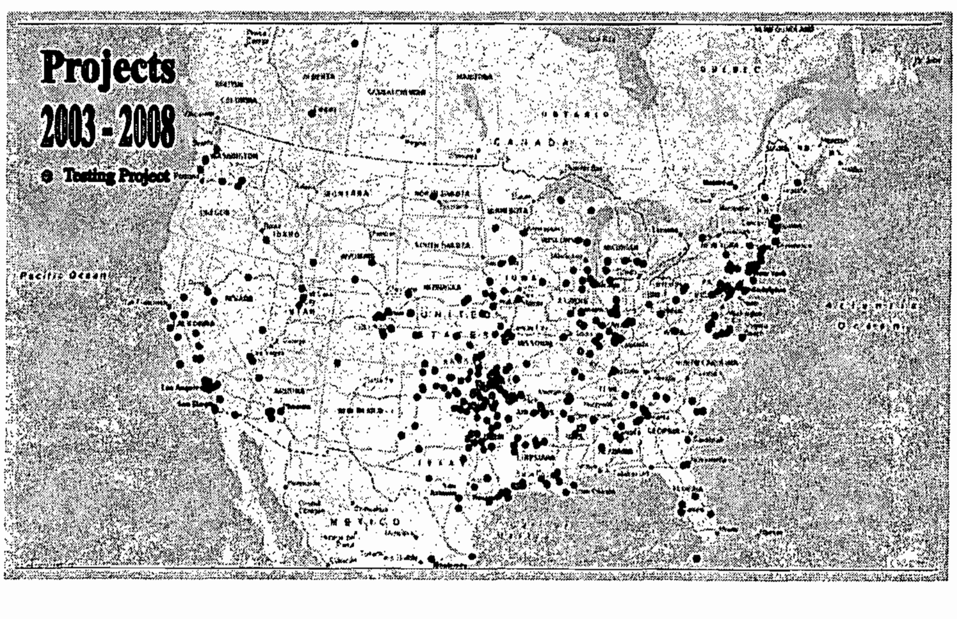
AIR HYGIENE personnel have performed thousands of testing projects which have yielded significant benefits for our clients. The following project descriptions briefly discuss some of these emission testing projects.

- Conducted Mercury (Hg), PM, selected metals, HCl, Chlorine, and gas testing to verify status with the industrial boiler MACT on six coal fired units at three (3) locations.
- Conducted inlet/outlet baghouse emission testing for Mercury (Hg) to determine control efficiency using Ontario-Hyrdo testing methodology.
- Conducted numerous projects optimizing SCR performance by conducting inlet & outlet SCR analysis for NH_3, NOx, flow, and Oxygen. Used information to assist with flow optimization and AIG tuning.
- Conducted federal and state required compliance testing for NOx, CO, PM-10 (front & back-half), SO_2, VOC, Ammonia, Formaldehyde, Opacity, RATA testing (NOx and CO) for new and updated power plants with both simple and combined cycle turbines firing natural gas and fuel oil.
- Conducted dry low NOx burner tuning and performance testing for various models of GE, Siemens Westinghouse, Mitsubishi, Pratt & Whitney, and ABB combustion turbines to verify manufacturer's emission guarantees for clients in preparation for compliance testing.
- Performed power plant emission testing for natural gas & fuel oil fired combustion turbines. Tests included federal required testing per 40 CFR Part 75, state air permit requirements, RATA testing, and emission testing to verify manufacturer's guarantee's during electric/heat output performance testing.

TESTING LOCATIONS

AIR HYGIENE bases mobilization charges on the distance from your site to the closest of six (6) regional starting points covering all 50 United States. These include Las Vegas, Tulsa, Houston, Ft. Worth, Shreveport, and Philadelphia.

Each start point is located such that the AIR HYGIENE test teams can mobilize to your site within 24 hours at affordable costs to ensure we are price competitive to any U.S. location.



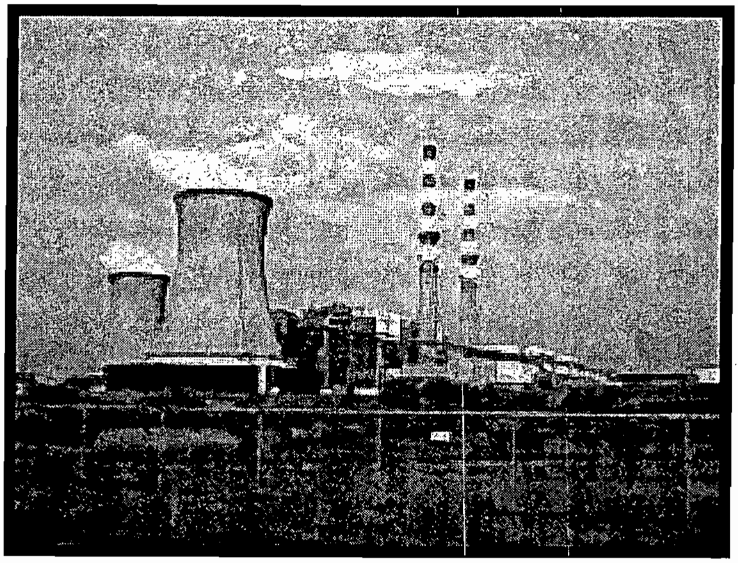
AIR HYGIENE, INC.

Testing Solutions for a Better World

COMBUSTION TESTING SERVICES SUMMARY

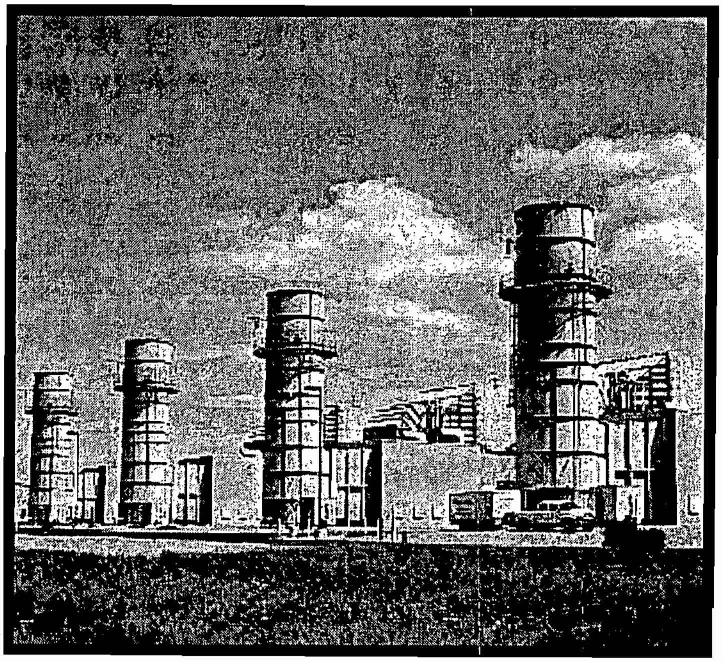
Thank you for your consideration of the combustion emission testing services of Air Hygiene International, Inc. (AIR HYGIENE). The following list details some of the testing services and extras AIR HYGIENE includes with each testing job.

Types of Air Testing Services for Combustion Sources:



- Boiler or Turbine tuning/mapping for NOx, CO, O2, CO2, flow, temperature, &/or NH_3 emissions
- Pollutant testing to verify EPC contractual emission guarantees
- Research and Development (R&D) emission data research and emissions optimization
- Mercury (Hg) testing with on-site data
- 40 CFR Part 60 Subpart GG or KKKK – Turbine Compliance Testing
- 40 CFR Part 75 – Acid Rain Classified Equipment Testing
- 40 CFR Part 75 Appendix E – Peaking Plant CEMS alternative NOx emissions versus Heat Input mapping
- RATA Testing on CEMS systems for NOx, CO, SO_2, CO_2 or O_2, Flow (3-D & Wall effects)
- QA/QC Plans, Monitoring Plans, Linearity Checks, Testing Protocols, etc. are provided with our high quality, service oriented emission testing services
- Initial permit compliance testing for PM, PM-10, PM-2.5, SO_2, NOx, CO, H2SO4, HCl, Hg, exhaust flow, moisture, O_2, CO_2, Ammonia, Formaldehyde, other HAPs

AIR HYGIENE will provide the following testing services:



- On-site, real-time test data
- Fuel F-Factor calculation data sheet
- Experienced emission testing personnel
- Flexible testing schedules to meet your needs
- Electronic reports provided on CD upon request
- Extensive experience with all 50 state agencies in the U.S., Mexico, & Canada
- EPA Protocol 1 Certified Gases (one percent accuracy) for precise calibration
- Low range (0-10 ppm) equipment calibration and measurement available
- Test protocol preparation, coordination with state agency, and site personnel
- Numerous mobile testing labs, which may be used for your projects across the U.S.
- State-of-the-art data logging technology to allow real-time examination of meaningful emission data
- Monitor your emissions data measured in our test lab from your control room via our datalogging network system

AIR HYGIENE is committed to providing testing teams that will take the time to meet your needs. We ensure the job is completed on time with the least amount of interruption to your job and site operation as possible. Thank you for considering our services.

AIR HYGIENE, INC.

Testing Solutions for a Better World

SYNERGISTIC APPROACH TO POWER PLANT CONSTRUCTION PROJECT TESTING

Power plants continue to be built, modified, and improved across the United States. These new or modified facilities are at the forefront of clean energy. Emission rates and limits continue to decrease. These units are very efficient, environmentally friendly, and meet the stringent requirements set forth by the Environmental Protection Agency (EPA) and associated state agencies. AIR HYGIENE has developed a unique strategy to help owners demonstrate compliance with testing solutions for difficult sampling locations to meet complicated requirements.

Unique Testing Strategy

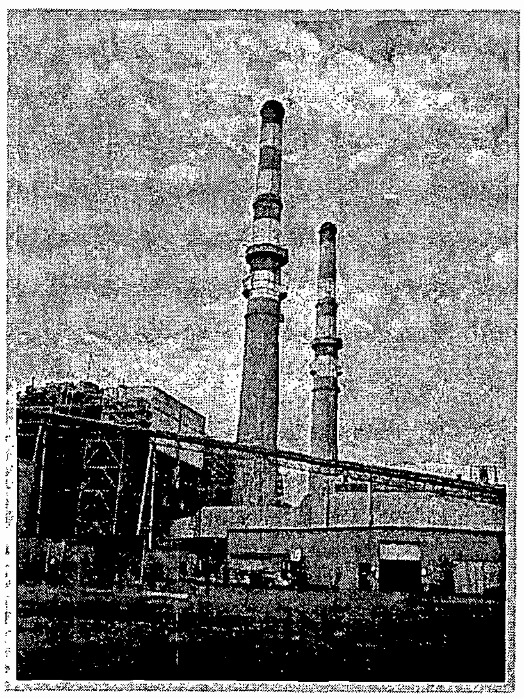
AIR HYGIENE has developed a synergistic approach to assisting the various groups involved in the completion of a commissioning/startup unit or modification project. AIR HYGIENE strives to combine the multiple testing aspects involved with bringing a combustion unit to commercial service. By conducting the various emission tests required for a new combustion unit using one test company, the following benefits are a given:

1. Save money by...
   a. Reduced mobilizations
   b. Combined tests yield reduced fuel usage and site time
   c. Bulk projects receive quantity discounts
2. Improve efficiency through familiarity with site needs
3. Site personnel and testing team are comfortable working together

These projects typically involve some or all of the following groups. There is not a defined set of responsibilities that will match every project. The table below simply suggests a typical list of testing responsibilities.

Responsible Party	**Testing Responsibilities**
Owner	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Operator	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Turbine/Boiler manufacturer	Contractual emission guarantees of unit (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
EPC & Construction Company	Contractual emission guarantees including control devices (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
CEMS Supplier	Initial RATA testing (i.e. NOx, CO, SO2, CO2, O2, flow)
Lending Party (i.e. bank)	No responsibility, but concerned with outcome of all tests
Environmental Consultant	Concerned with air permit and overall compliance; may select the test contractor and provide oversight for testing

Example Project:



A recent project provides a prime example of the synergistic benefits of using AIR HYGIENE to perform your commissioning/startup or remodification testing needs for performance and compliance. Eight GE Frame 7FA turbines were taken from performance testing through compliance testing in 20 days. The following tests were performed on each turbine:

- NOx tuning and mapping
- Contractual performance testing for NOx, CO, VOC, SO_2, NH_3, & PM_{10}
- 40 CFR Part 60 Subpart GG: testing for NOx and CO at max load
- 40 CFR Part 75: NOx & CO RATA certification on CEMS
- State required compliance testing for NOx, CO, VOC, NH_3(on-site analysis), formaldehyde (on-site analysis by FTIR), opacity and SO_2 burning natural gas

Test data was provided on-site for all tests, except PM-10. Electronic files were e-mailed for review to the turbine manufacturer, owner & operator, and environmental consultant within 24 hours following completion of site work. Complete reports including PM-10 were submitted to interested parties within 10 days following each blocks completion.

Power Plant Testing Experience

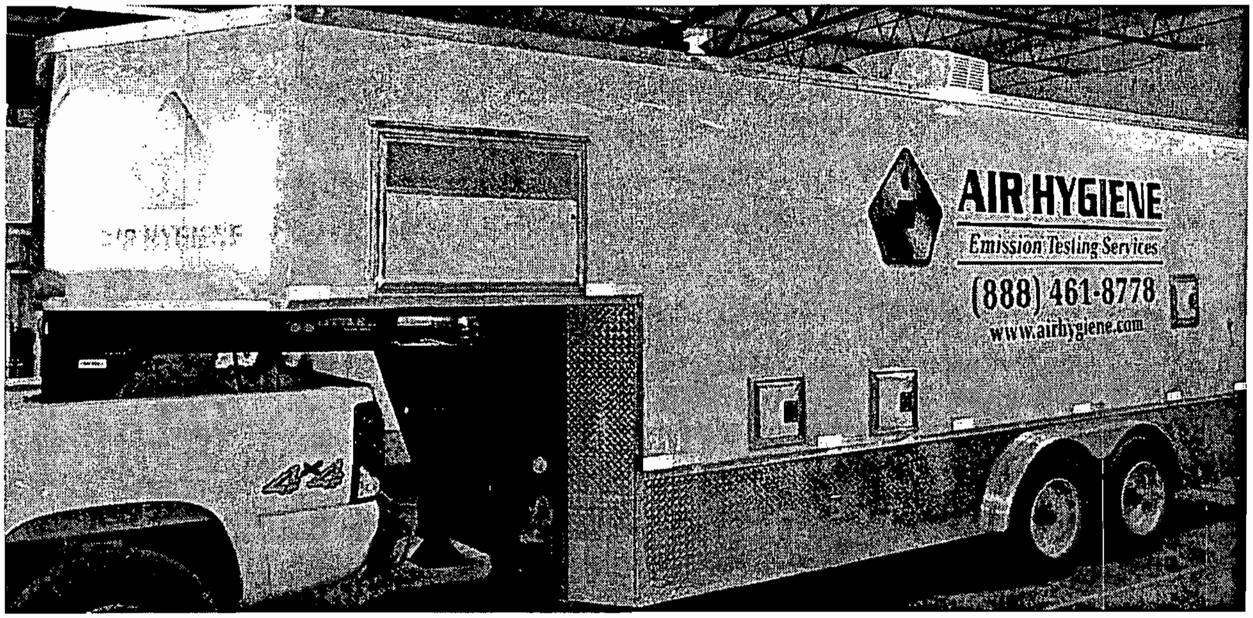
AIR HYGIENE personnel have over one hundred (100) years of testing experience on combustion turbines, coal fired boilers, gas fired boilers, landfill gas, wood fired, & diesel fired engines across the United States. AIR HYGIENE has 15 combustion labs serving all 50 states from one corporate office in Tulsa, OK and five (5) additional field offices (Houston, TX; Ft. Worth, TX; Shreveport, Louisiana; Las Vegas, NV; & Philadelphia, PA). AIR HYGIENE has tested plants ranging from 50 to 2,000 megawatts in both simple and combined cycle operation with controls including:

- Selective Catalytic Reduction - Ammonia injection
- Steam/Water injection
- Sprint injection
- Dry Low NOx burners (DLN)

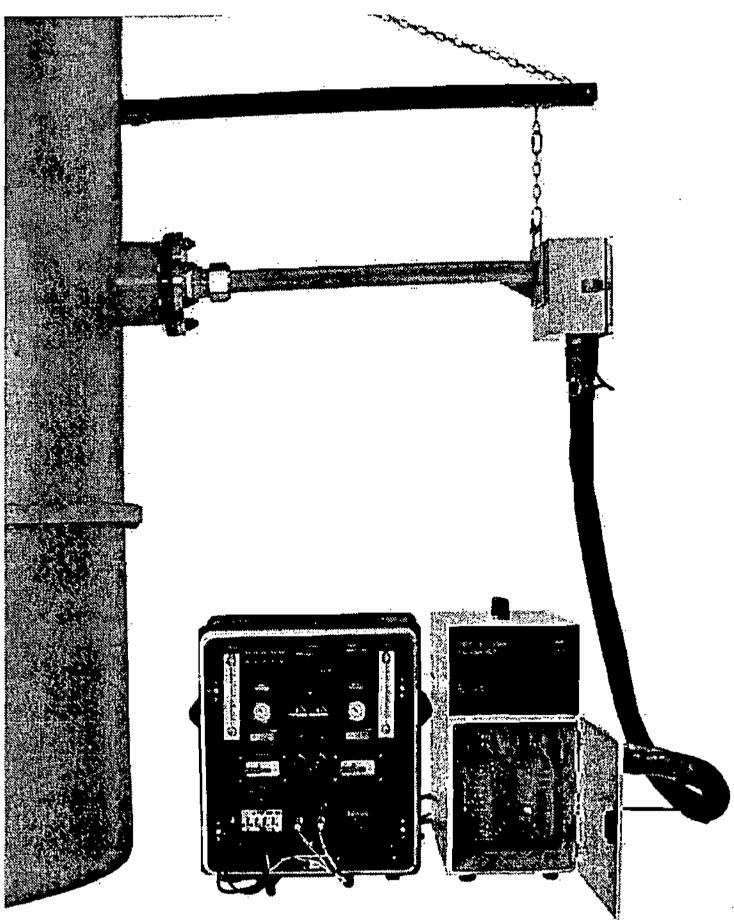
AIR HYGIENE has completed testing at over 250 plants on 1,000 combustion turbines, 50 coal fired boilers, 20 gas fired boilers, and other sources representing 100,000 plus megawatts (MW). AIR HYGIENE has proven through our numerous projects that we can be relied upon for uncompromised quality, service flexibility, and loyalty to our clients no matter where the job nor what the situation may be. ***Let us add your upcoming project to our list of satisfied customers!***

Air Hygiene Mercury Testing

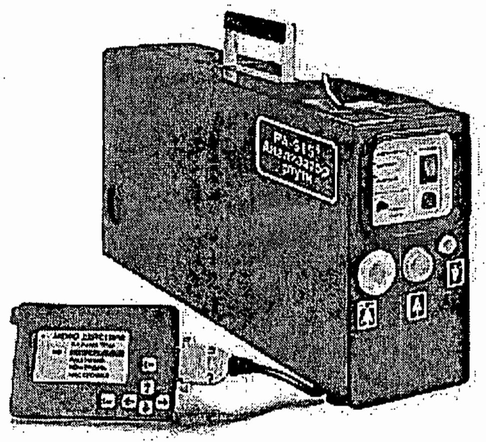
Air Hygiene Mercury Testing Lab

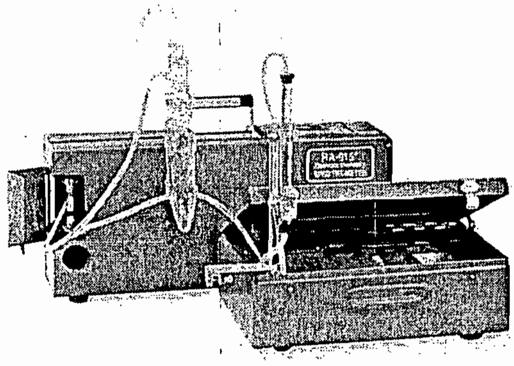


Apex 30B Console & Probe



Ohio Lumex: RA915+ Analyzer with RP-91 Attachment for Ontario Hydro or 30b sorbent trap analysis on-site





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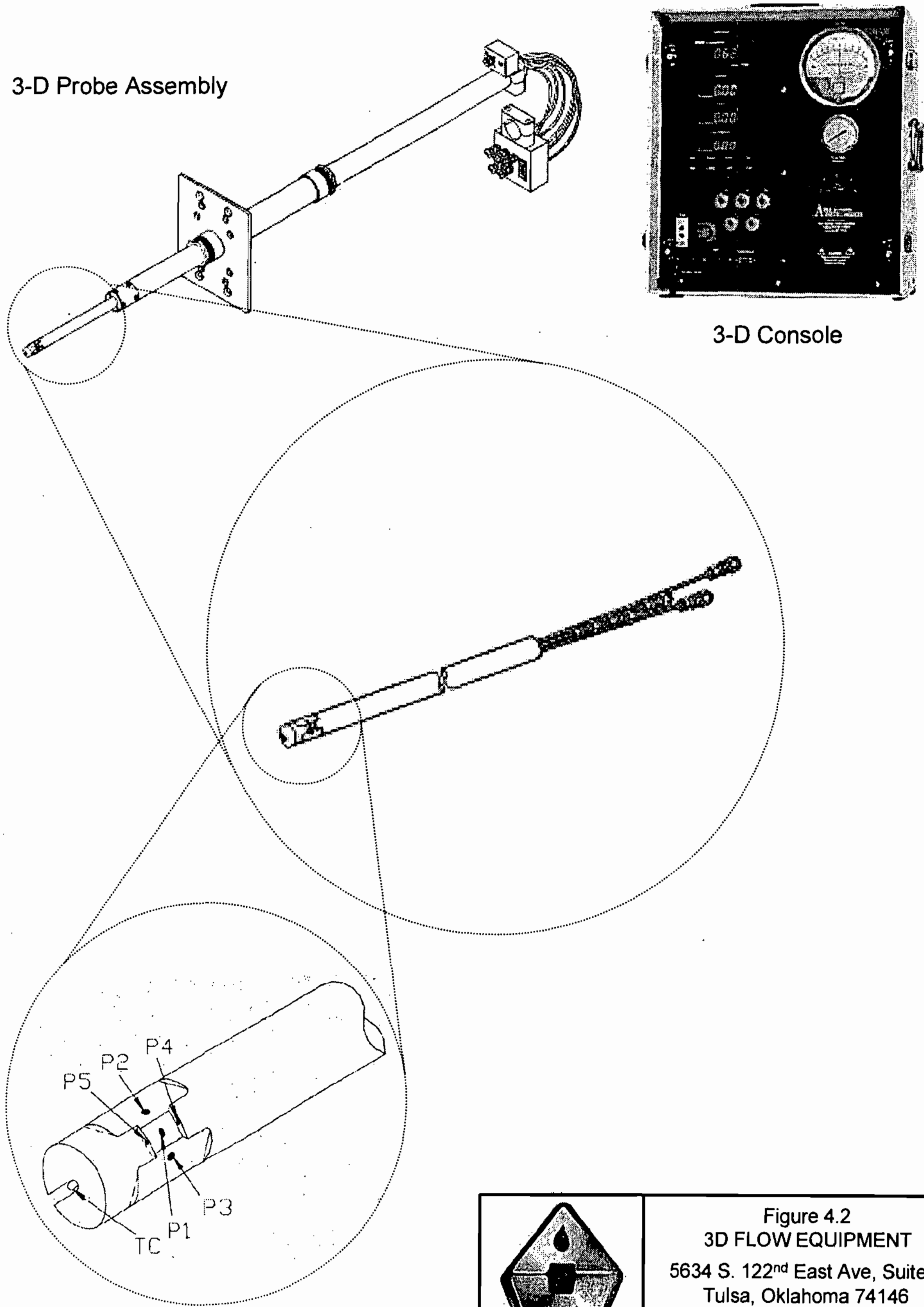

Figure 4.2
3D FLOW EQUIPMENT

AIR HYGIENE
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(888) 461-8778

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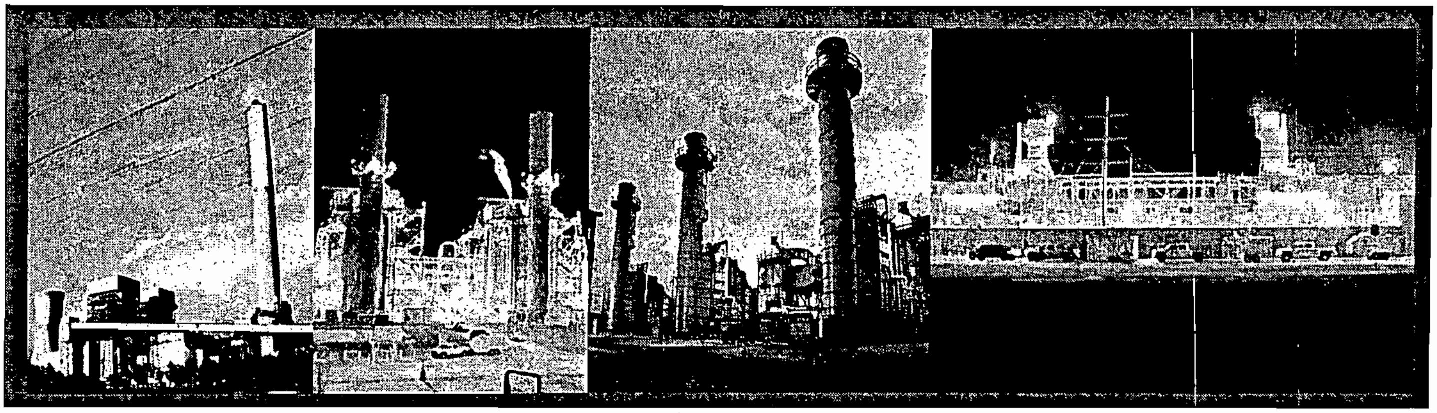

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures used by AIR HYGIENE during tests conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 3a, 6c, 7e, 10, 18, 19, 20, and 25a.

The flowchart on the next page depicts the sample system used by AIR HYGIENE for analysis of oxygen (O_2), carbon dioxide (CO_2), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC) tests. A heated stainless steel probe is inserted into the sample ports of the stack to extract gas measurements from the emission stream. The gas sample is continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample is partitioned to the O_2, CO_2, SO_2, CO, and NOx analyzers through glass and stainless steel rotameters that control the flow rate of the sample. The VOC sample is measured as a wet gas.

The flowchart shows that the sample system is also equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments are housed in an air-conditioned trailer which serves as a mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 is used to determine the cylinder concentrations where applicable (i.e. NO_x calibration gases).

All data from the continuous monitoring instruments are recorded on a Logic Beach Hyperlogger which retrieves calibrated electronic data from each instrument every second and reports an average of the collected data every 30 seconds and 10 seconds. The averaging time can be selected to meet the clients needs. **This data is available instantaneously for printout, statistical analysis, viewable by actual values, or examined by a trending graph!**

The number of test runs, test loads, and length of runs is based upon federal and state requirements for the facility. Typical run times associated with emission testing are as follows:

Type of Test	# of runs	Length of runs
O_2 Traverse (GG)	1 run @ low load (8 – 48 points)	2 minutes per point
NOx Stratification Test	1 run @ base load (12 points)	2 – 4 minutes per point
Subpart GG or KKKK	3 runs @ 4 loads (30%, 50%, 75%, & 100%)	15 – 60 minutes per run
RATA	9 – 12 runs @ normal load	21 minutes per run
State Permit Test (gases)	3 runs @ base load	1 hour per run
State Permit Test (particulates)	3 runs @ base load	2 – 4 hours per run

The stack gas analysis for O_2 and CO_2 concentrations are performed in accordance with procedures set forth in EPA Method 3a (EPA Method 20 for O_2 on combustion turbines). The O_2 analyzer uses a paramagnetic cell detector. The CO_2 analyzer uses an infrared detector.

CO emission concentrations are quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer is used for this purpose.

NOx emission concentrations are measured in accordance with procedures set fort in EPA Method 7e and/or 20. A chemiluminescence analyzer is used to determine the nitrogen oxides concentration in the gas stream.

Total hydrocarbons (THC), non-methane, non-ethane hydrocarbons also known as volatile organic compounds (VOC) are analyzed in accordance with procedures set forth in EPA Methods 18 & 25a. A flame ionization detector calibrated with methane is used to determine the THC concentration in the gas stream and VOCs analyzed by GC to determine methane, ethane, and remaining VOCs per EPA Method 18 determination with gas chromatograph using FID detector.

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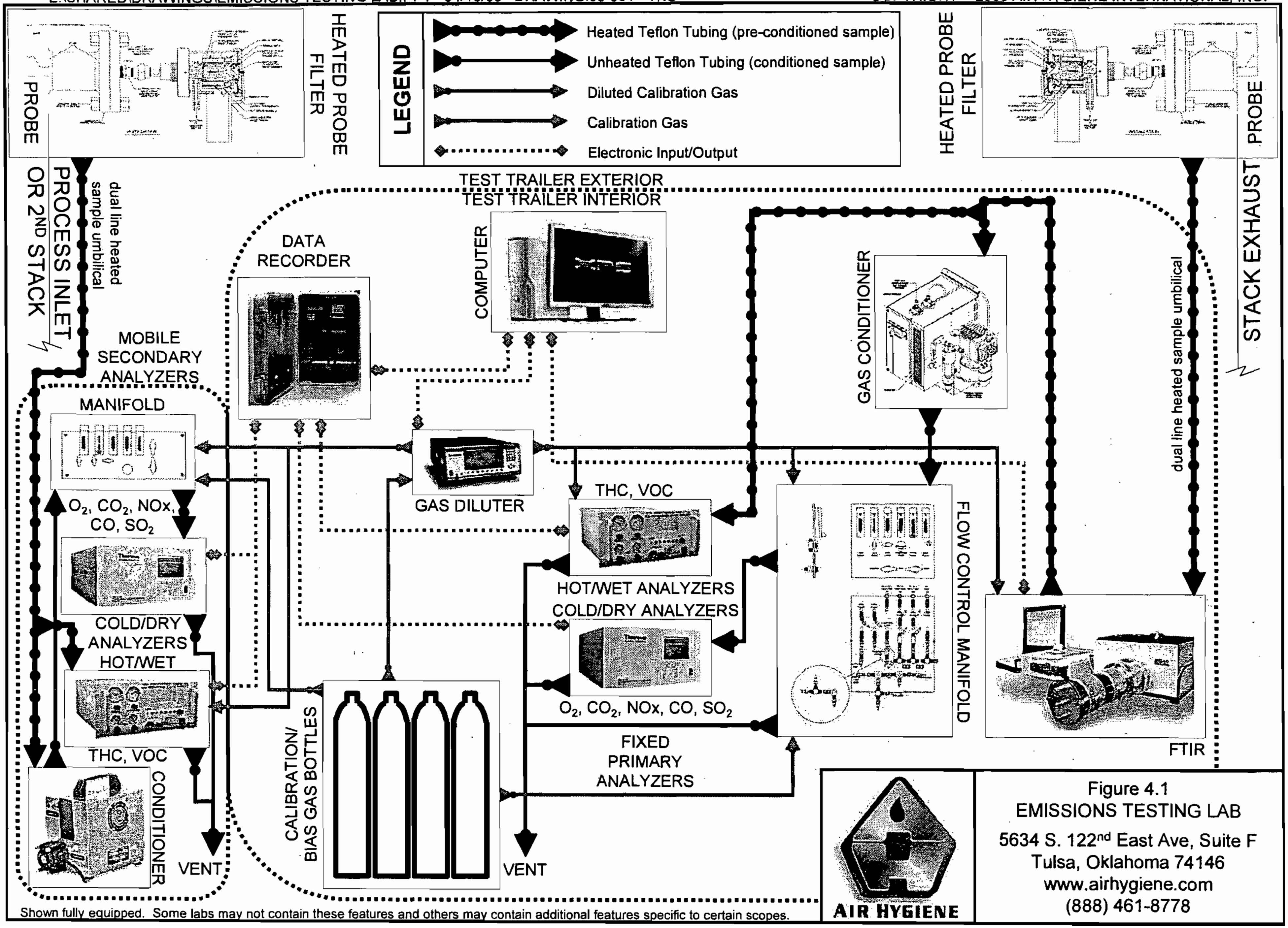
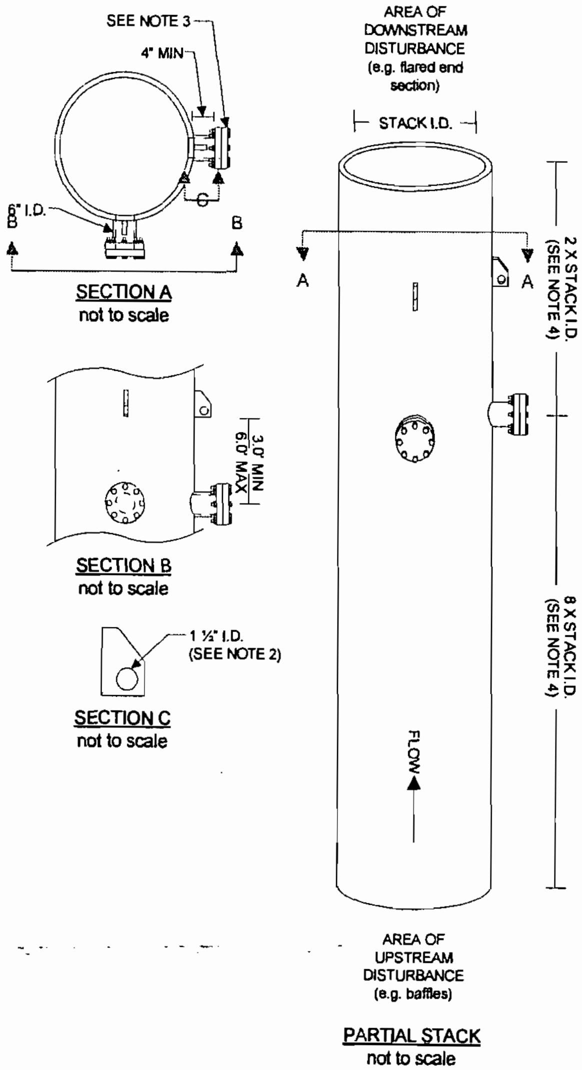


Figure 4.1
EMISSIONS TESTING LAB

5634 S. 122nd East Ave, Suite F
Tulsa, Oklahoma 74146
www.airhygiene.com
(888) 461-8778

E:\SHARED\DRAWINGS\PORT INSTALLATION.PPT 02/08/02 TKG DRW NO: 02-001



NOTES
1. TWO PORTS WITH CENTERLINES AT 90° ANGLES
2. 3/8 INCH THICK STEEL, WELDED TO STACK EXTERIOR, PROVIDES PLACE TO HOOK CHAIN FOR RAIL ASSEMBLY
3. MINIMUM THREE INCH INNER DIAMETER STEEL PIPE, WELDED TO STACK EXTERIOR, HOLE CUT INTO STACK WALL, NO POTRUSIONS OR OBSTRUCTIONS INSIDE STACK WALL
4. IF TOTAL STACK LENGTH IS NOT AVAILABLE, EPA MINIMUM REQUIREMENTS ARE ½ X STACK I.D. FROM PORTS TO TOP AND 2 X STACK I.D. FROM PORTS TO BOTTOM

AIR HYGIENE

PORT INSTALLATION DIAGRAM
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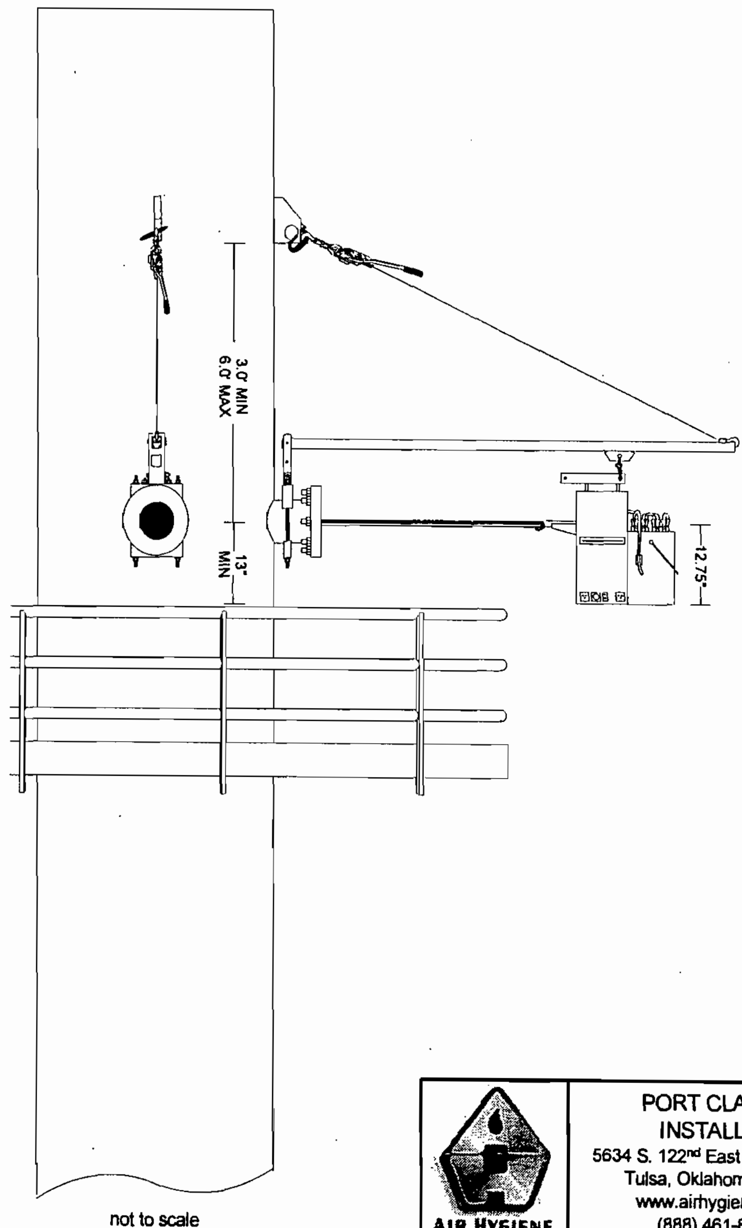
E:\SHARED\DRAWINGS\PORT INSTALLATION.PPT 02/08/02 TKG DRW NO: 02-001



AIR HYGIENE

PORT CLAMPS INSTALLED
5634 S. 122nd East Ave, Suite F
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TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after turbine testing projects. This section describes each of those activities.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± two percent of range of the predicted values.

NO_2 to NO conversion is checked via direct connect with a EPA Protocol certified concentration of NO_2 in a balance of nitrogen. Conversion is verified to be above 90 percent.

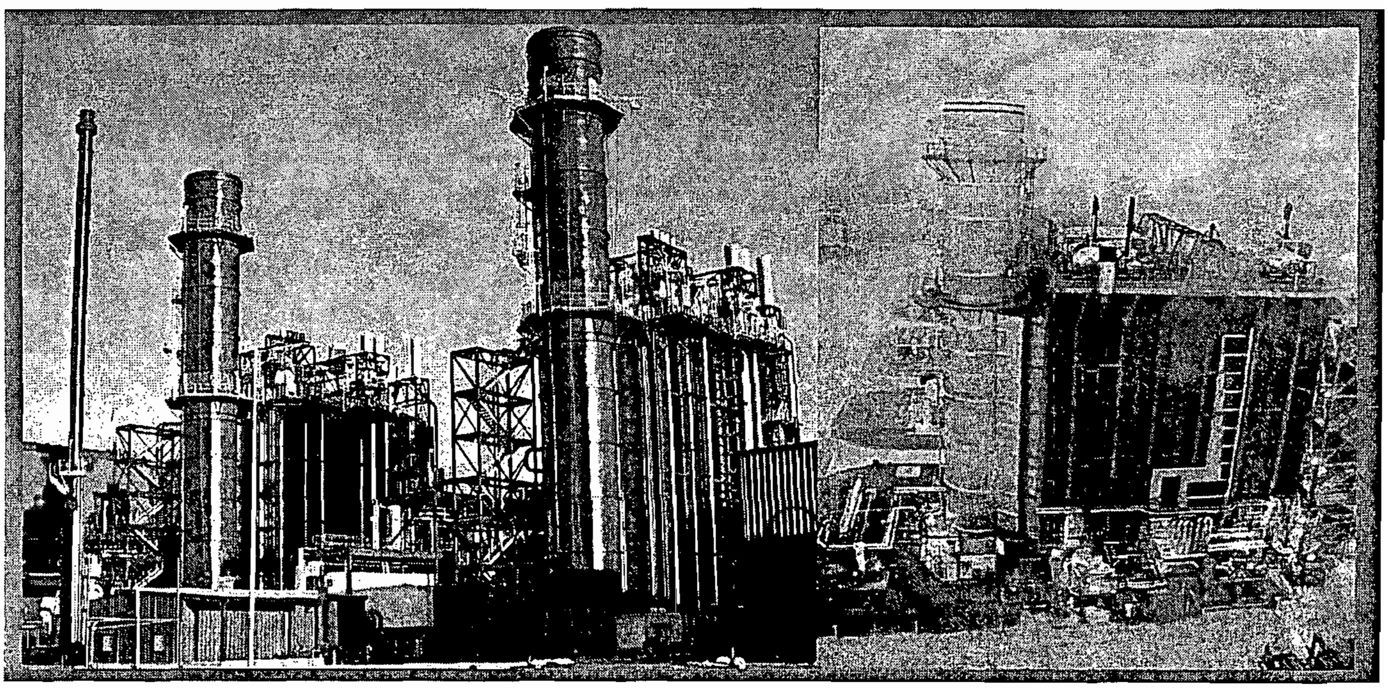
Instruments are both factory tested and periodically field challenged with interference gases to verify the instruments have less than a two percent interference from CO_2, SO_2, CO, NO, and O_2.

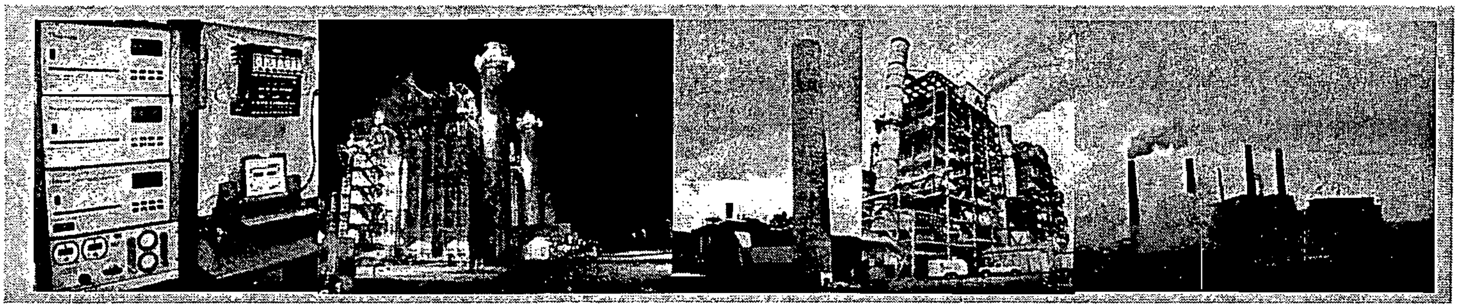
After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data collected. The criterion for acceptable data is that the instrument drift is no more than three percent of the full-scale response. Quality assurance worksheets summarize all multipoint calibration linearity checks and the zero to span checks performed during the tests are included in the test report.

The sampling systems is leak-checked by demonstrating that a vacuum greater than 10 in. Hg can be held for at least one minute with a decline of less than one in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. This test is conducted to ensure that ambient air does not dilute the sample. Any leakage detected prior to the tests is repaired and another leak check conducted before testing will commence.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the responses of the calibration gases introduced via two paths. The first path is directly into the analyzers and the second path includes the complete sample system with injection at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criterion for acceptance is agreement within five percent of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± one percent accuracy for all gases. EPA Protocol No. 1 is used, where applicable, to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM). The gas calibration sheets as prepared by the vendor are included in the test report.





QUALITY ASSURANCE PROGRAM SUMMARY

AIR HYGIENE ensures the quality and validity of its emission measurement and reporting procedures through a rigorous quality assurance (QA) program. The program is developed and administered by an internal QA team and encompasses five major areas:

1. QA reviews of reports, laboratory work, and field testing;
2. Equipment calibration and maintenance;
3. Chain-of-custody;
4. Training; and
5. Knowledge of current test methods.

QA Reviews

AIR HYGIENE's review procedure includes review of each source test report, along with laboratory and fieldwork, by the QA Team. The most important review is the one that takes place before a test program begins. The QA Team works closely with technical division personnel to prepare and review test protocols. Test protocol review includes selection of appropriate test procedures, evaluation of interferences or other restrictions that might preclude use of standard test procedures, and evaluation and/or development of alternate procedures.

Equipment Calibration and Maintenance

The equipment used to conduct the emission measurements is maintained according to the manufacturer's instructions to ensure proper operation. In addition to the maintenance program, calibrations are carried out on each measurement device according to the schedule outlined by the Environmental Protection Agency. Quality control checks are also conducted in the field for each test program. Finally, AIR HYGIENE participates in a PT gas program by analyzing blind gases semi-annually to ensure continued quality.

Chain-of-Custody

AIR HYGIENE maintains full chain-of-custody documentation on all samples and data sheets. In addition to normal documentation of changes between field sample custodians, laboratory personnel, and field test personnel, AIR HYGIENE documents every individual who handles any test component in the field (e.g., probe wash, impinger loading and recovery, filter loading and recovery, etc.). Samples are stored in a locked area to which only AIR HYGIENE personnel have access. Field data sheets are secured at AIR HYGIENE's offices upon return from the field.

Training

Personnel's training is essential to ensure quality testing. AIR HYGIENE has formal and informal training programs, which include:

1. Participation in EPA-sponsored training courses;
2. A requirement for all technicians to read and understand Air Hygiene Incorporated's QA manual;
3. In-house training relating to 40 CFR Part 60 Appendix A methods and QA meetings on a regular basis;
4. OSHA 40 hour Hazwopper Training;
5. Visible Emission (Opacity) Training; and
6. Maintenance of training records.

Knowledge of Current Test Methods

With the constant updating of standard test methods and the wide variety of emerging test procedures, it is essential that any qualified source tester keep abreast of new developments. AIR HYGIENE subscribes to services, which provide updates on EPA reference methods, rules, and regulations. Additionally, source test personnel regularly attend and present papers at testing and emission-related seminars and conferences. AIR HYGIENE personnel maintain membership in various relevant organizations associated with gas fired turbines.

AIR HYGIENE, INC.

Testing Solutions for a Better World

F-Factor Datasheet and Fuel Gas Analysis

Company: XYZ Power
Location: XYZ Power Plant
Date: April 9, 2001

Values to enter from fuel gas analysis by GPA 2166.

Font Scheme:
Blue Font = enter new data
Black Font = calculated data
Green Font = Labels for columns & rows
Red Font = Important results with notes

Gas Component		Mole (%)	Molecular Weight (lb/lb-mole)	lb Component per lb-Mole of Gas	Weight % of Component	Fuel Heat Value [HHV] (Btu/scf)[1]	Fuel Heat Value [LHV] (Btu/scf)[1]
Methane	CH4	96.491	16.04	15.477	92.97	974.27	877.20
Ethane	C2H6	2.115	30.07	0.636	3.82	37.41	34.22
Propane	C3H8	0.186	44.1	0.082	0.49	4.68	4.31
iso-Butane	iC4H10	0.019	58.12	0.011	0.07	0.62	0.57
n-Butane	nC4H10	0.023	58.12	0.013	0.08	0.75	0.69
Iso-Pentane	iC5H12	0.008	72.15	0.006	0.03	0.32	0.30
n-Pentane	nC5H12	0.005	72.15	0.004	0.02	0.20	0.19
Hexanes	C6H14	0.025	86.18	0.022	0.13	1.19	1.10
Heptanes	C7H16	0.000	100.21	0.000	0.00	0.00	0.00
Octanes	C8H18	0.000	114.23	0.000	0.00	0.00	0.00
Carbon Dioxide	CO2	0.510	44.01	0.224	1.35	0.00	0.00
Nitrogen	N2	0.618	28.01	0.173	1.04	0.00	0.00
Hydrogen Sulfide	H2S	0.000	34.08	0.000	0.00	0.00	0.00
Oxygen	O2	0.000	32	0.000	0.00	0.00	0.00
Helium	He	0.000	4	0.000	0.00	0.00	0.00
Hydrogen	H2	0.000	2	0.000	0.00	0.00	0.00
Totals (dry)		100.000		16.648	100.00	1019.44	918.57
Totals (wet)						1001.66	902.55

[1] Standardized to 60°F and 1 atm to match fuel flow data

If total is not 100.000 then the mol% data was either entered incorrectly or the gas analysis is incomplete. Sometimes small differences are due to rounding error.

High Heat Value of dry gas (HHV-dry) This is the primary fuel heat value used in emission testing calculations.

Low Heat Value of dry gas. LHV-dry

High Heat Value of wet Gas. HHV-wet

Low Heat Value of wet gas. LHV-wet

Characteristics of Fuel Gas		
Molecular Weight of gas =	16.648	lb/lb-mole
Btu per lb. of gas =	23239.7689	gross (HHV)
Btu per lb. of gas =	20940.2961	net (LHV)
wt % VOC in fuel gas =	0.83	%
Specific Gravity =	0.5749	

Value used to convert THC readings to VOC.

Component	Weight %
carbon	73.71
oxygen	0.98
hydrogen	24.27
nitrogen	1.04
helium	0.00
sulfur	0.00
Total	100.00

F-Factor (scf dry exhaust per MMBtu [HHV] = 8641.17
(Based on EPA RM-19) at 68°F and 1 atm

Fuel Specific F-Factor. Note that EPA Method 19 lists natural gas's F-factor as 8710.

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

GCV = Gross Btu per lb. of gas (HHV)

EXAMPLE TESTING DATASHEET FOR GASES
XYZ Power Plant
GE GTG Frame 7FA Combustion Turbine
Fuel: Natural Gas

Fuel Data

Fuel F-Factor	8,671.5	SCF/MMBtu
Generator Output	172.0	MW
Fuel Flow	515,040.8	SCFH
Fuel Heating Value (HHV)	1,076.5	Btu/SCF
Combustor Inlet Pressure	6,166.5	mm Hg
Heat Input (LHV)	500.6	MMBtu/hr
Stack Moisture Content	8.4	%
Stack Exhaust Flow	13,600,266.4	SCFH

Weather Data

Barometric Pressure	29.11	in. Hg
Relative Humidity	82	%
Dry Bulb Temperature	72	F
Specific Humidity	0.0142443	lb H2O/lb air
Wet Bulb Temperature	68	F

yellow - supporting information
blue - raw testing data
red - final results

Run #1 - 100% High Load

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
06/27/01 11:47:32	16770	13.57	5.05	-0.38	0.59	0.59	5.09
06/27/01 11:48:02	16800	13.57	5.85	-0.26	0.63	0.63	4.83
06/27/01 11:48:32	16830	13.55	6.37	-0.44	0.71	0.71	4.71
06/27/01 11:49:02	16860	13.54	6.83	0.60	0.83	0.83	4.33
06/27/01 11:49:32	16890	13.55	7.26	0.25	0.99	0.99	4.49
06/27/01 11:50:02	16920	13.55	6.44	-0.24	1.14	1.14	4.64
06/27/01 11:50:32	16950	13.54	6.28	-0.75	1.29	1.29	4.79
06/27/01 11:51:02	16980	13.55	5.68	-0.68	1.46	1.46	4.96
06/27/01 11:51:32	17010	13.58	6.01	-1.14	1.60	1.60	5.10
06/27/01 11:52:02	17040	13.49	5.05	1.36	1.69	1.69	5.19
06/27/01 11:52:32	17070	13.60	5.14	-0.47	1.70	1.70	5.20
06/27/01 11:53:02	17100	13.61	4.58	0.69	1.69	1.69	5.19
06/27/01 11:53:32	17130	13.62	4.93	0.90	1.65	1.65	5.15
06/27/01 11:54:02	17160	13.62	4.69	0.54	1.64	1.64	5.14
06/27/01 11:54:32	17190	13.61	4.83	0.64	1.59	1.59	5.09
06/27/01 11:55:02	17220	13.61	4.76	-0.07	1.60	1.60	5.10
06/27/01 11:55:32	17250	13.64	4.86	-0.02	1.59	1.59	5.09
06/27/01 11:56:02	17280	13.63	4.38	0.92	1.51	1.51	5.01
06/27/01 11:56:32	17310	13.61	4.94	-0.01	1.47	1.47	4.97
06/27/01 11:57:02	17340	13.61	4.89	0.27	1.47	1.47	4.97
06/27/01 11:57:32	17370	13.61	4.82	1.28	1.46	1.46	4.96
06/27/01 11:58:02	17400	13.61	4.69	1.55	1.46	1.46	4.96
06/27/01 11:58:32	17430	13.60	4.23	1.16	1.46	1.46	4.96
06/27/01 11:59:02	17460	13.59	4.69	-0.26	1.46	1.46	4.96
06/27/01 11:59:32	17490	13.57	4.89	-1.46	1.49	1.49	4.99
06/27/01 12:00:02	17520	13.58	4.86	-1.49	1.53	1.53	5.03
06/27/01 12:00:32	17550	13.59	4.79	-0.79	1.53	1.53	5.03
06/27/01 12:01:02	17580	13.58	4.76	-1.57	1.54	1.54	5.04
06/27/01 12:01:32	17610	13.57	4.65	1.17	1.53	1.53	5.03
06/27/01 12:02:02	17640	14.24	4.69	0.01	1.52	1.52	5.02
06/27/01 12:02:32	17670	13.54	4.83	1.68	1.52	1.52	5.02
06/27/01 12:03:02	17700	13.55	5.70	1.31	1.53	1.53	5.03
06/27/01 12:03:32	17730	13.55	5.66	-0.73	1.53	1.53	5.03
06/27/01 12:03:32	17760	13.55	5.04	-0.48	1.53	1.53	5.03
RAW AVERAGE		13.6	5.2	0.1	1.4	1.4	5.0

QA/QC Data Control

		O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
Bias & Drift Checks	Initial Zero	0.2	0.3	-0.2	0.0	0.1	0.1
	Final Zero	0.2	0.5	-0.2	0.2	0.2	0.1
	Avg. Zero	0.2	0.4	-0.2	0.1	0.2	0.1
	Initial UpScale	12.1	5.8	4.0	3.4	28.3	9.0
	Final UpScale	12.1	5.7	4.0	3.3	28.2	8.8
	Avg. UpScale	12.1	5.8	4.0	3.4	28.3	8.9
Upscale Cal Gas		12.0	5.7	4.0	3.5	28.0	9.0

Emissions Data

	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvd)*	SO_2 (ppmvd)	CO_2 (%)
Corrected Raw Averages	13.5	5.1	0.3	1.5	1.3	5.0
ppm @ 15% O_2	N/A	4.2	0.2	1.2	1.0	N/A
ppm @ 15% O_2 & ISO	N/A	4.7	0.2	1.4	1.1	N/A
Emission Rate (lb/MMBtu)	N/A	0.015	0.000	0.004	0.005	N/A
Emission Rate (lb/hr)	N/A	8.46	0.27	2.40	2.84	N/A
Emission Rate (ton/year) @ 8760 hr/yr	N/A	37.07	1.20	10.49	12.43	N/A
Emission Rate (g/MW*hr)	N/A	0.06	0.00	0.02	0.02	N/A

*VOC data in Emissions Data Table has been converted to dry values by the equation below.

*VOC uncorrected raw average * (100/100-stack moisture content)

CLIENT REFERENCES

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APPENDIX F
AIR PERMIT

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

PERMITTEE:

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

FP&L West County Energy Center
DEP File No. 0990646-002-AC
Permit No. PSD-FL-396
SIC No. 4911
Expires: December 31, 2013

PROJECT AND LOCATION

This permit authorizes the construction of the third nominal 1,250 megawatt combined cycle unit (Unit 3) and ancillary equipment at the Florida Power and Light Company (FP&L) West County Energy Center.

The proposed project will be located at 20505 State Road 80, Loxahatchee, Florida 33470. The UTM coordinates are Zone 17; 562.19 kilometers East; 2953.04 kilometers North.

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

7/30/08

Joseph Kahn, Director (Date)
Division of Air Resource Management

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The FP&L West County Energy Center (WCEC) was previously approved for construction as a nominal 2,500 megawatt (MW) greenfield power plant. The previously approved construction underway is for two nominal 1,250 MW gas-fired combined cycle units (Units 1 and 2) that will use ultralow sulfur diesel (ULSD) fuel oil (FO) as backup fuel.

Units 1 and 2 will each consist of: three nominal 250 megawatt (MW) Model 501G combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors; one nominal 428 mmBtu/hour (lower heating value - LHV) gas-fired duct burner (DB) located within each of the three HRSG; three 149 feet exhaust stacks; one 26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator (STG).

Previously approved ancillary equipment under construction and installation includes: four emergency generators; two natural gas fired fuel heaters; one emergency diesel fired pump; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

This permit authorizes construction of another 1,250 MW gas-fired combined cycle unit (Unit 3) identical to the description given above for Units 1 and 2. Additional ancillary equipment for Unit 3 will include two emergency generators, two natural gas fired fuel heaters and associated equipment. Unit 3 will use some of the infrastructure and ancillary equipment already under construction including the diesel storage tanks and auxiliary boilers.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
013	Unit 3A – one nominal 250 MW CTG with supplementary-fired HRSG
014	Unit 3B – one nominal 250 MW CTG with supplementary-fired HRSG
015	Unit 3C – one nominal 250 MW CTG with supplementary-fired HRSG
016	One 26 cell mechanical draft cooling tower
017	Two nominal 10 MMBtu/hr natural gas-fired process heaters
018	Two nominal 2,250 KW (~ 21 MMBtu/hr) emergency generators

REGULATORY CLASSIFICATION

The facility will be a major Prevention of Significant Deterioration (PSD) stationary source in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.). Unit 3 is subject to the PSD rules including a determination of best available control technology (BACT).

The facility will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY) or because it is a Major Source of hazardous air pollutants (HAP). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The facility under construction is subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). Unit 3 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005.

This rule also applies to duct burners (DB) that are incorporated into combined cycle projects. Two additional emergency generators are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines. Two additional process heaters are subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

The facility under construction is a major source of hazardous air pollutants (HAP) and is subject to several subparts under 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP). Unit 3 is potentially subject to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired CTG such as planned for this project.

The facility will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The facility will be subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The facility under construction was certified under the Florida Power Plant Siting Act, 403.501-518, F.S. and Chapter 62-17, F.A.C. The Unit 3 project is also subject to certification.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Subparts A from NSPS 40 CFR 60 and NESHAP 40 CFR 63; Identification of General Provisions.

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix GC: General Conditions.

Appendix Dc: NSPS Subpart Dc Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

Appendix IIII: NSPS Requirements for Compression Ignition Internal Combustion Engines (ICE).

Appendix KKKK: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart KKKK.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application and supplemental information received on December 6 and December 21, 2007;
- Department's request for additional information (RAI) January 4, 2008;
- Response to RAI received March 14, 2008; and
- Draft permit package issued on April 25, 2008.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Permitting Authority, which is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP or the Department) at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority. Telephone: (850)488-0114. Fax: (850)921-9533.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Southeast District Office. The mailing address and phone number of the Southeast District Office are: Department of Environmental Protection, Southeast District Office, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401. Telephone: (561)681-6632. Fax: (561)681-6790.

3. Appendices: The following Appendices are attached as part of this permit: Appendices A, BD, Dc, GC (General Conditions), IIII, KKKK, SC, XS, YYYY and ZZZZ.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

A. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

This section of the permit addresses the following emissions units.

Combined Cycle Unit 3 and associated equipment

Description: Combined Cycle Unit 3 will be comprised of emissions units (EU) 013, 014, and 015. Each EU will consist of: a Model M501G CTG with automated control, inlet air filtration system and evaporative cooling, a gas-fired HRSG with DB, a HRSG stack, and associated support equipment. The project also includes one STG that will serve the combined cycle unit.

Fuels: Each CTG fires natural gas as the primary fuel and ULSD fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the three CTG has a nominal generating capacity of 250 MW. The STG has a nominal generating capacity of 500 MW. The total nominal generating capacity of the "3 on 1" combined cycle unit is approximately 1,250 MW. The total nominal generating capacity of the facility is 3,750 MW.

Controls: The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_X emissions. A SCR system further reduces NO_X emissions.

Stack Parameters: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics without the DB:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,333 MMBtu/hour	59° F	195° F	1,330,197
Oil	2,117 MMBtu/hour	59° F	293° F	1,533,502

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The CTG shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards given in 40 CFR 60, Subpart KKKK. Some separate reporting and monitoring may be required by the individual subparts.

   a. *Subpart A, General Provisions*, including:

      - 40 CFR 60.7, Notification and Record Keeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements

- 40 CFR 60.19, General Notification and Reporting Requirements

b. *Subpart KKKK, Standards of Performance for Stationary Gas Turbines*: These provisions include standards for CTG and DB.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines-Electrical Generators (CTG): The permittee is authorized to install, tune, operate, and maintain three Model 501G CTG each with a nominal generating capacity of 250 MW. Each CTG shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The CTG will utilize DLN combustors. [Application and Design]

5. Heat Recovery Steam generators (HRSG): The permittee is authorized to install, operate, and maintain three new HRSG with separate exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the three CTG (3A to 3C) and deliver steam to the steam turbine-electrical generator (STG). Each HRSG may be equipped with a gas-fired duct burner (DB) having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. CTG/Supplementary-fired HRSG Emission Controls

   a. *Dry Low NO_X (DLN) Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each CTG when firing natural gas. Prior to the initial emissions performance tests required for each CTG, the DLN combustors and automated control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Wet Injection (WI)*: The permittee shall install, operate, and maintain a WI system (water or steam) to reduce NO_X emissions from each CTG when firing ULSD fuel oil. Prior to the initial emissions performance tests required for each CTG, the WI system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each CTG when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG. The permittee may install the oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 12.h.

e. *Ammonia Storage:* In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Design and Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

7. Permitted Capacity – Combustion Turbine-Electric Generators (CTG): The nominal heat input rate to each CTG is 2,333 MMBtu per hour when firing natural gas and 2,117 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, LHV of each fuel, and 100% load). Heat input rates will vary depending upon CTG characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

8. Permitted Capacity - HRSG Duct Burners (DB): The total nominal heat input rate to the DB for each HRSG is 428 MMBtu per hour based on the LHV of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. Authorized Fuels: The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. Each CTG shall fire no more than 500 hours of fuel oil, during any calendar year.
[Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Hours of Operation: Subject to the operational restrictions of this permit, the CTG may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.
[Rules 62-210.200(Definitions - PTE) and 62-212.400 (BACT), F.A.C.]

11. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTG may operate under the following methods of operation.

    a. *Combined Cycle Operation*: Each CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a three-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

    b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

    c. *Duct Burner (DB) Firing*: When firing natural gas in a CTG, the respective HRSG may fire natural gas in the DB to raise additional steam for use in the STG or in the operation of CTG components. The total combined heat input rate to the DB (all three HRSG) shall not exceed 3,697,920 MMBtu (LHV) during any consecutive 12 months.

    [Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

A. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

EMISSIONS STANDARDS

12. Emissions Standards: Emissions from each CTG/DB shall not exceed the following BACT standards. Compliance with the BACT limits also insures compliance with the emission limitations in Subpart KKKK.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr
	Gas	CTG & DB	7.6	52.5	6, 12-month
		CTG Normal Mode	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr [h]
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr [h]
		CTG Normal Mode	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal Mode	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Compliance with the 24-hour block NO_X BACT limits will insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30 day rolling average.

[Rule 62-212.400(BACT), F.A.C.; 40 CFR 60, Subpart KKKK]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

13. Operating Procedures: The BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

17. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, excess emissions of NO_X and CO resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *STG/HRSG System Cold Startup*: For cold startup of the STG/HRSG, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

       {Permitting Note: During a cold startup of the STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. *Fuel Switching*: For fuel switching, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.

18. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.
[Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

19. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

20. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

21. Initial Compliance Determinations: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the unit. Each CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Referenced method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

22. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emission standards for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$: In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition 30, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. Continuous Emissions Monitoring System(s) (CEMS): The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle CTG in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors:* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitors:* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitors:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. <u>CEMS Data Requirements</u>:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization of Standardization (ISO) conditions.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages:* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 17 and 19 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

27. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

28. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction and fuel switching). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CTG for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas:* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *ULSD Fuel Oil:* Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the CTG are defined as: a specified averaging period over which either the NO_X emissions are higher than the applicable emission limit in 60.4320; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7, and 60.4420]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. COOLING TOWER (EU 016)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
016	One 26-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 26-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 304,000 gpm; design hot/cold water temperatures of 92 °F/76 °F; a design air flow rate of 1,350,000 actual cubic feet per minute (acfm) per cell; a liquid-to-air flow ratio of 1.13; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application and Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}.

C. PROCESS HEATERS (EU 017)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
017	Two gas-fueled 10 MMBtu/hr process heaters

NSPS APPLICABILITY

1. NSPS Subpart Dc Applicability: Each process heater is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

EMISSIONS STANDARDS

2. Natural Gas Fired Process Heaters BACT Emissions Limits:

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.095 lb/MMBtu	0.08 lb/MMBtu	2 gr S/100SCF natural gas spec and 10% Opacity

3. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

   Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

EQUIPMENT SPECIFICATIONS

4. Equipment: The permittee is authorized to install, operate, and maintain two 10 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs.
   [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

6. Notification: Initial notification is required for the two small gas-fueled 10 MMBtu/hr process heaters.
   [40 CFR 60.7]

7. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3] F.A.C.]

D. EMERGENCY GENERATORS (018)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	Two nominal 2,250 kilowatts (kw) Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines (model year 2007-2010)

NESHAPS APPLICABILITY

1. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain two 2,250 kw emergency generators. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn ultralow sulfur diesel fuel oil (0.0015% sulfur). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

NO_X	CO	Hydrocarbons[1]	SO_2	PM/PM_{10}
6.9 gm/bhp-hr	8.5 gm/bhp-hr	1.0 gm/bhp-hr	0.0015% ULSD FO	0.4 gm/bhp-hr

   Note 1. Hydrocarbons are surrogate for VOC.

   {The BACT limits are equal to the values corresponding to the Table 1 values cited in 40 CFR 60, Subpart IIII}

6. Emergency Generators Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULSD fuel oil can be used to fulfill this requirement.
   [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4211]

7. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

8. Notifications: Permittee shall submit initial notification as required by 40 CFR 60.7, 40 CFR 63.9, and 40 CFR 63.6590 (b) (i) for the two 2,250 kW RICE units.

9. Reporting: The permittee shall maintain records of the amount of liquid fuel used. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3) F.A.C.].

EMISSIONS TEST PROTOCOL

FOR
THREE MITSUBISHI 501G
COMBUSTION GAS TURBINES
(UNITS 3A, 3B, AND 3C)

PREPARED FOR
BLACK AND VEATCH
AND
FLORIDA POWER AND LIGHT

AT THE
WEST COUNTY
ENERGY CENTER
LOXAHATCHEE, FLORIDA

Florida Department of
Environmental Protection
Permit No. PSD-FL-396

January 5, 2011

AIR HYGIENE, INC.

Testing Solutions for a Better World

EMISSIONS TEST PROTOCOL

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Prepared By:

Jake Fahlenkamp, QSTI, Director of Quality Assurance

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Table of Contents

1.0 INTRODUCTION

1.1 General Facility Description

Florida Power & Light (FPL) owns and operates the West County Energy Center (West County) located at 20505 State Road 80 in Loxahatchee, Florida. West County is a nominal 3,750 megawatt (MW) greenfield power plant and consists of three combined cycle units (Unit 1, 2 and 3). Each combined cycle unit consists of: three nominal 250 MW Mitsubishi Model 501G combustion turbine-electrical generator (CTGs) sets with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSGs) with selective catalytic reduction (SCR) reactors; one nominal 428 million British thermal units per hour (MMBtu/hour) based on low heat value (LHV) natural gas-fired duct burner (DB) located within each of the three HRSG's; and a common nominal 500 MW steam turbine-electrical generator (STG). The total nominal generating capacity of each of the "3 on 1" combined cycle unit is approximately 1,250 MW.

Each CTG has a nominal heat input rate of 2,333 MMBtu/hr when firing natural gas and 2,117 MMBtu/hr when firing distillate fuel oil (based on a compressor inlet air temperature of 59 degrees Fahrenheit (°F), the lower heating value (LHV) of each fuel, and 100 percent load), includes an automated gas turbine control system, and has dual-fuel capability of firing natural gas as the primary fuel or ultra-low sulfur distillate (ULSD) fuel oil as a restricted alternate fuel. Each HRSG recovers exhaust, heat energy from each of the CTGs. Each Unit delivers steam to each STG. The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of carbon monoxide (CO), particulate matter (PM), sulfuric acid mist (H_2SO_4), sulfur dioxide (SO_2) and volatile organic compounds (VOCs). Dry Low-NOx (DLN) combustors for gas firing and water injection for oil firing reduce nitrogen oxides (NOx) emissions. A selective catalyst reduction (SCR) system further reduces NOx emissions.

The 501G stacks are circular and measure 21.95 feet (ft) (263.38 inches) in diameter at the test ports which are approximately 138 ft above grade level with an exit elevation of approximately 150 ft above grade level. The test ports are located approximately 44.31 ft (531.75 inches) downstream and approximately 12 ft (144 inches) upstream from the nearest disturbances.

1.2 Reason for Testing

West County is a newly constructed plant subject to the regulatory requirements of the Florida Department of Environmental Protection (FDEP) [FDEP Permit No. PSD-FL-396, DEP File No. 0990646-001-AC, Appendix F] and the United States Environmental Protection Agency (EPA) [40 Code of Federal Regulations (CFR) Part 60, Subpart GG and Subpart KKKK] for initial compliance air emissions testing. As such, testing will include monitoring for NOx, CO, total hydrocarbons/volatile organic compounds (THC/VOC), ammonia slip (NH_3), fuel based total sulfur content (S), opacity, carbon dioxide (CO_2), and oxygen (O_2); on all units following the guidelines of 40 Code of Federal Regulations (CFR) Part 60. Each of these parameters will be monitored under one test condition, while the units are operating firing fuel oil.

This Protocol has been prepared and will be submitted to the FDEP prior to the first scheduled test date.

2.0 SUMMARY

2.1 Owner Information

Company:	Florida Power & Light
Contact:	Danny Potter
Mailing Address:	20505 State Road 80 Loxahatchee, Florida 33470
Office:	(561) 904-4910
Cell:	(561) 358-0079
Email:	Danny.Potter@fpl.com

2.2 EPC Contractor Information

Company:	Black and Veatch Energy
Contact:	William Stevenson, Air Quality Control
Mailing address:	11401 Lamar Avenue Overland Park, Kansas 66211
Telephone:	(913) 458-8549
Fax:	(913) 458-2934
Email:	StevensonWP@bv.com

2.3 Test Contractor Information

Company:	Air Hygiene International, Inc.
Contact:	Jake Fahlenkamp, Director of Quality Assurance
Mailing Address:	5634 South 122nd East Avenue, Suite F Tulsa, Oklahoma 74146
Office:	(918) 307-8865
Cell:	(918) 407-5166
Fax:	(918) 307-9131
E-mail:	jake@airhygiene.com
Website:	www.airhygiene.com

2.4 Expected Test Start Date

Test dates are yet to be determined. Further notification will be provided by Black and Veatch (BV) Energy and/or FPL as a testing schedule is determined.

2.5 Testing Schedule

The following schedule indicates specific activities required to be done each day; however, the schedule is flexible and can be extended as necessary if there are operational or testing delays. If there are no operational delays, this schedule can be completed as detailed by the testing crew. The details below describe the activities to be conducted.

Pre-test Activities	**Due Date**
1. Receive site safety training	day of arrival for setup
2. Conduct site inspection and pre-test meeting	per BV and/or Air Hygiene
3. Prepare draft electronic test protocol	prior to start of project

On-Site Pre-testing Schedule	**Time**
Day 0 – Pre-test, initial site mobilization and setup	
• Arrive at site and attend safety training class	08:00 – 09:00
• Setup on Unit 3A	09:00 – 11:00
• Conduct preliminary testing of equipment	11:00 – 13:00

Compliance Testing	**Time**
Day 1 – Compliance Testing, Unit 3A, firing fuel oil	
• Daily setup and calibrations	06:00 – 07:00
• Conduct stratification testing and preliminary flow traverse • Stratification testing for NOx and O_2 • Flow traverse for cyclonic flow profile, stack velocity, and stack temperature	07:00 – 08:00
• Conduct Testing for NOx, CO, THC/VOC, opacity, CO_2, and O_2 • NOx, CO, THC/VOC, opacity, CO_2, and O_2 testing (3, 1- hour test runs)	08:00 – 13:00
• Conduct Testing for NH_3 Slip • NH_3 testing (3, 1-hour test runs) • CO, CO_2, and O_2 will be monitored for molecular weight determinations	08:00 – 13:00
• Collect fuel gas sample for component analysis and total S	08:00 – 13:00
• Teardown from Unit 3A and setup on Unit 3B	13:00 – 17:00

Additional days will follow the same timeline of Day 1 for units 3B and 3C or test order determined by FPL and/or BV. Each unit will require one day of testing and one setup day following testing on each unit.

Activities after Testing	**Sequential Days**
• Demobilization of Testing Crew	Day 1
• Preparation of draft hard copy test report	Days 2 – 9
• Submit for review to BV	Day 10
• Review and comment on draft by BV	Days 11 – 14
• Incorporate BV comments into draft copy	Days 15 – 19
• Submit for review to FPL	Day 20
• Review and comment on draft by FPL	Days 21 – 24
• Incorporate FPL comments into draft copy	Days 25 – 29
• Final reports delivered to FPL	Day 30

2.6 Hardcopy Compliance Report Content

The hard-copy compliance reports will be submitted to BV within 30 days of completion of testing and meet the requirements of the FDEP and the United States Environmental Protection Agency (EPA) for stack emissions testing. The reports will include discussion of the following:

- Introduction
- Plant and Sampling Location Description

- Summary and Discussion of Test Results Relative to Acceptance Criteria
- Sampling and Analytical Procedures
- QA/QC Activities
- Test Results and Related Calculations
- Sampling Log and Chain-of-Custody Records
- Audit Data Sheets

2.7 Equipment and Procedures

Reference methods (RM) and parameters to satisfy 40 CFR Part 51, 60, and 63 will include:

40 CFR Part 60, EPA RM 1 for sample location
40 CFR Part 60, EPA RM 2 for stack gas velocity
40 CFR Part 60, EPA RM 3a for O_2 and CO_2
40 CFR Part 60, EPA Method 4 for stack gas moisture content
40 CFR Part 60, EPA RM 7e for NOx
40 CFR Part 60, EPA RM 9 for opacity
40 CFR Part 60, EPA RM 10 for CO
40 CFR Part 60, EPA RM 18 for methane/ethane analysis, as required
40 CFR Part 60, EPA RM 19 for F-Factor determination of stack exhaust flow
40 CFR Part 60, EPA RM 25a for VOC
40 CFR Part 63, EPA Conditional Test Method (CTM) – 027 for NH_3 slip
EPA Report #600/4-79-020 Method 350.3 for NH_3 analysis
American Society of Testing Materials (ASTM) D420 for heat of combustion of liquid fuel (LF)
ASTM D5002 for American Petroleum Institute (API) gravity, density, and specific gravity of LF
ASTM D5453-00 for sulfur content of LF

2.8 Proposed Variations

The NO_2 to NO converter check will be verified using the Emission Measurement Center's ALT-013 acceptable alternative procedure to section 8.2.4 of EPA Method 7e in Appendix A of 40 CFR Part 60 utilizing a NO_2 concentration around 50 parts per million.

In lieu of borosilicate glass nozzles and probe liners, CTM-027 will utilize stainless steel and inconel to prevent breakage, particularly during port changes.

RM 19 stoichiometrically calculated stack exhaust flows will be used to convert all gaseous, NH_3 concentrations to emission rates.

If measured total hydrocarbon (THC) emission rates are below the required volatile organic compound (VOC) limits, all THCs will be assumed as VOCs and RM 18 analysis for methane and ethane will not be conducted.

2.9 Compliance Sampling Strategy

Testing will be performed on each CTG, at one load condition, while the units are combusting fuel oil. The emission compliance tests will follow the requirements of 40 CFR Part 51, 60, 63, and the FDEP permit. The tests for NOx, CO, THC/VOC, opacity, NH_3, CO_2, and O_2 will include at least three runs, approximately 60-minutes in duration.

During each test run the following parameters will be recorded, based on availability, by the system operators from the system PLC and/or DAHS: water injection (gal/min), load (megawatts), heat input (MMBtu/hr), fuel flow (scfh), combustor inlet / compressor discharge pressure (psig), ambient temperature (^{o}F), ambient pressure (in. Hg), and ambient relative humidity (%).

Gas Testing – EPA RM 3a, 7e, 10, 19, and 25a

A stratification test will be performed prior to air permit testing to determine the proper sample location(s). The air permit emissions test will include three test runs with analysis for NOx, CO, VOC, CO_2, and O_2 on the CTGs at each load. EPA RM 19 will be used to determine exhaust flow and calculate emission rates in pounds per million British thermal units (lb/MMBtu), lb/hr, and tons per year (tpy) at each load.

Opacity Observations – EPA RM 9

Visual observations for opacity from each CTG at each load and from the AB will be determined using EPA RM 9. This method determines the level of any visible emissions that occur during the observation period. It requires that the opacity of emission be determined by a trained and certified individual. Three 60-minute runs will be observed from the proper location(s) on the CTG exhaust stack. The opacity level will be recorded every 15 seconds.

Ammonia Slip Testing and Analysis – CTM 027

Ammonia slip testing will be conducted on each CTG at each load. Each test run will be approximately 60 minutes. An S-type pitot tube will be used to measure cyclonic flow and velocity pressure in accordance with EPA RM 2. This data will be correlated with meter coefficients, temperatures, barometric pressure, and exhaust gas moisture (EPA RM 4) to determine the exhaust gas dry flow rate. NH_3 samples will be collected following CTM 027 with an isokinetic sampling train utilizing a stainless steel nozzle and inconel probe liner. A scale will be used to measure net weight gain from each impinger to determine moisture gain.

The exit of the filter holder is connected to a series of four full size impingers. The first two impingers (Greensburg Smith) each contain 100 mL of 0.1 N H_2SO_4 which absorbs the ammonia when the sample is drawn through. The third impinger (Modified) is empty. The fourth contains a tared quantity of silica gel. The impingers are maintained at a temperature below 68^{o}F for the duration of each test.

Procedures for selecting sampling locations and for operation of the apparatus are derived from CTM 027 and associated EPA RMs 1 though 4. The sampling apparatus is leak-checked before and after each test run. Sampling is performed at an isokinetic rate greater than 90 percent and less than 110 percent.

The first impinger catch is measured, its weight recorded and the catch transferred to container No. 1. The second and third impinger catches are measured, their weights recorded and the catches transferred to container No. 2. The weight gain is added to the silica gel weight gain of the forth impinger to determine the stack gas moisture content. The connective glassware from the filter to the first impinger is rinsed with de-ionized water into container No. 1. The connective glassware from the back of impinger 1 to the front of impinger 4 is rinsed with de-ionized water into container No. 2.

Container contents are poured into a graduated cylinder and their volume recorded. After recording the volume the samples are returned to their respective containers, sealed, shaken and labeled, and the liquid level is marked. The samples are then refrigerated at approximately 39°F and allowed to slowly warm to laboratory room temperature before analysis.

NH_3 analysis is conducted using EPA Report #600/4-79-020 Method 350.3 on site by AHI. The ammonia is determined potentiometrically using an ion selective ammonia electrode and a pH meter having an expanded millivolt scale or a specific ion meter. The ammonia electrode uses a hydrophobic gas-permeable membrane to separate the sample solution from an ammonium chloride internal solution. Ammonia in the sample diffuses through the membrane and alters the pH of the internal solution, which is sensed by a pH electrode. The constant level of chloride in the internal solution is sensed by a chloride selective ion electrode which acts as the reference electrode.

A series of standard solutions covering the concentration range of the samples by diluting either the stock or standard solutions of ammonium chloride are prepared. The electrometer is calibrated by placing 100 mL of each standard solution in clean 150 mL beakers. The electrode is then immersed into standard of lowest concentration and 1 mL of 10N sodium hydroxide (NaOH) solution is added while mixing. The electrode is kept in the solution until a stable reading is obtained. This procedure is repeated with the remaining standards, going from lowest to highest concentration. The samples are then analyzed at room temperature following the same procedure as measuring the standards.

APPENDIX A
QA/QC PROGRAM

TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after each testing project. The following paragraphs detail the quality control techniques, which are rigorously followed during testing projects.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range of the predicted values.

After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data just collected. The criteria on acceptable data is that the instrument drift shall be no more than 3 percent of the full-scale response. Quality assurance worksheets are prepared to document the multipoint calibration checks and zero to span checks performed during the tests (**See Appendix D**).

The sampling systems are leak checked by demonstrating that a vacuum greater than 10 in Hg could be held for at least 1 minute with a decline of less than 1 in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. These checks are performed to ensure that ambient air has not diluted the sample. Any leakage detected prior to the tests would be repaired and another leak check conducted before testing commenced.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the calibration gases introduced via two paths. The first path is directly into the analyzer and the second path via the sample system at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criteria for acceptance is agreement within 5% of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± 1% accuracy for all gases. EPA Protocol No. 1 gases will be used where applicable to assign concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials.

AIR HYGIENE maintains a large variety of calibration gases to allow the flexibility to accurately test emissions over a wide range of concentrations.

APPENDIX B
TEST EQUIPMENT CONFIGURATION AND DESCRIPTION

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures to be used conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 2, 3a, 4, 7e, 10, 18, 19, 25a; 40 CFR Part 63; and CTM-027.

Figure 1 depicts the sample system that will be used for the NOx, CO, THC, CO_2, and O_2 tests. A stainless steel probe will be inserted into the sample ports of the stack to extract gas measurements from the emission stream at multiple points or a single point determined after conducting an initial stratification test. The gas sample will be continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample and through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample will be partitioned to the NOx, CO, CO_2, and O_2 analyzers through rotameters that control the flow rate of the sample. Exhaust samples will be routed to the THC analyzer prior to gas conditioning.

The schematic (Figure 1) shows that the sample system will also be equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments will be housed in an air-conditioned, trailer-mounted mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor according to EPA Protocol No. 1.

This general schematic also illustrates the analyzers to be used for the tests (i.e., NOx, CO, and O_2). All data from the Reference Method continuous monitoring instruments are recorded on a Logic Beach Hyperlogger. The Hyperlogger retrieves calibrated emissions data from each instrument every second. An average value is recorded every 30 seconds.

The stack gas analysis for O_2 and CO_2 concentrations will be performed in accordance with procedures set forth in EPA Method 3a. The O_2 analyzer uses a paramagnetic cell detector and the CO_2 analyzer uses a continuous nondispersive infrared analyzer.

EPA Method 7e will be used to determine concentrations of NOx. A chemiluminescence analyzer will be used to determine the nitrogen oxides concentration in the gas stream. A NO_2 in nitrogen certified gas cylinder will be used to verify at least a 90 percent NO_2 conversion on the day of the test.

CO emission concentrations will be quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer will be used for this purpose.

THC emission concentrations will be quantified in accordance with procedures set forth in EPA Method 25a. A continuous flame ionization (FID) analyzer will be used for this purpose. All THC results will be assumed as VOCs. If results are greater than the permit limits a Tedlar bag sample will be taken and analyzed according to Method 18 for methane and ethane content. These results will then be subtracted from the THC concentrations to determine the VOC concentrations.

Figure 2 represents the sample system used for the NH_3 tests. For NH_3 a heated stainless steel probe sheath with an inconel liner will be inserted into a single sample point of the stack to extract gas measurements from the emission stream through a filter and glass impinger train in a constant flow rate fashion. Flow rates will be monitored with rotameters and total sample volumes will be measured with dry gas meters.

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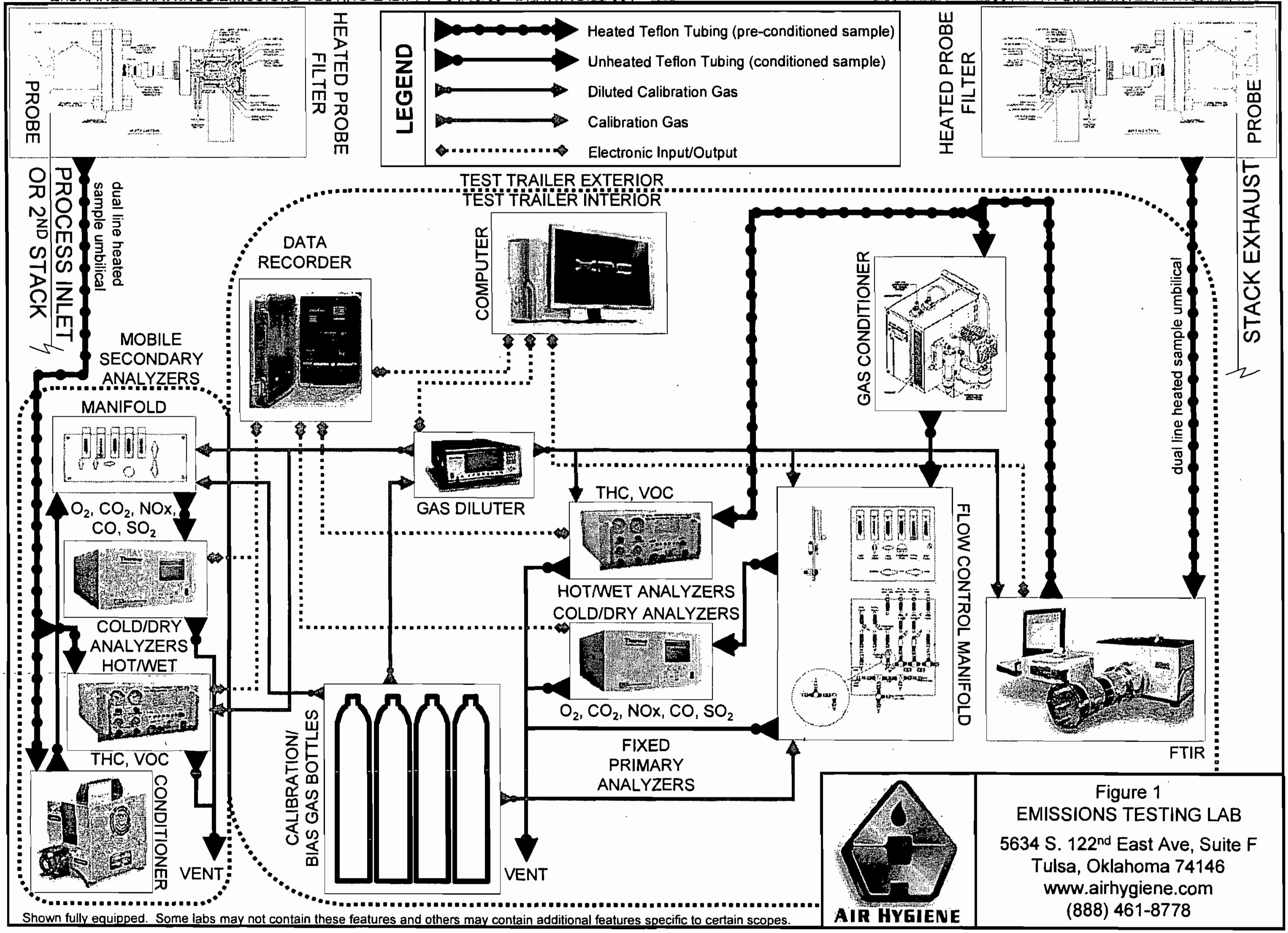

Figure 1
EMISSIONS TESTING LAB

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Tulsa, Oklahoma 74146
www.airhygiene.com
(888) 461-8778

Shown fully equipped. Some labs may not contain these features and others may contain additional features specific to certain scopes.

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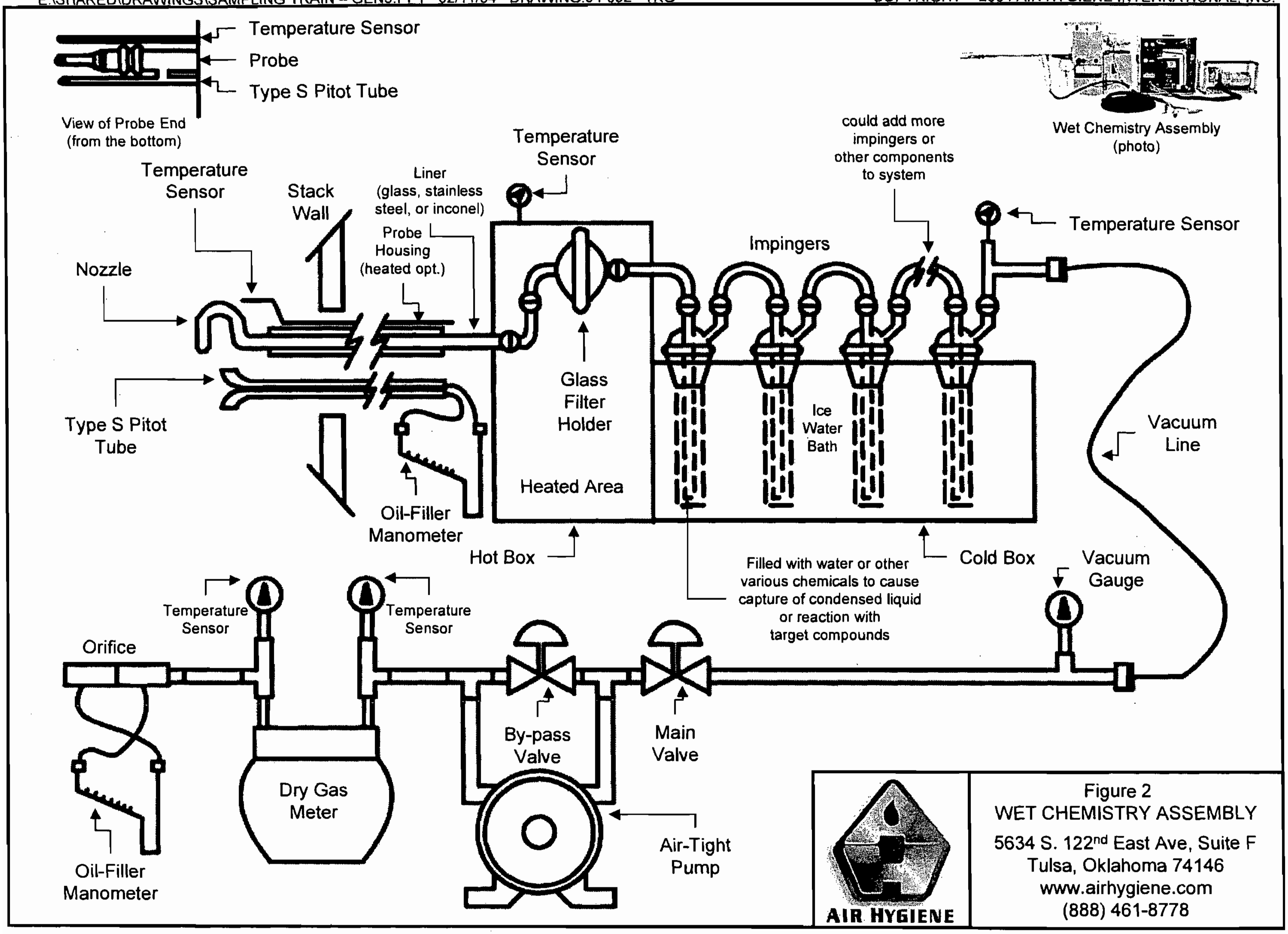

Figure 2
WET CHEMISTRY ASSEMBLY

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TABLE #1: TESTING MATRIX

Parameter	Source	Fuel	Load	No. Runs and Duration
NOx	CTG	Oil	100%	1 Strat Test (30 minutes)
	CTG	Oil	100%	3, 60 minute test runs
O_2	CTG	Oil	100%	1 Strat Test (30 minutes)
	CTG	Oil	100%	3, 60 minute test runs
CO_2	CTG	Oil	100%	during NH_3
CO	CTG	Oil	100%	3, 60 minute test runs
VOC	CTG	Oil	100%	3, 60 minute test runs
NH_3	CTG	Oil	100%	3, 60 minute test runs
Opacity	CTG	Oil	100%	3, 60 minute test runs
Fuel Analysis	CTG	Oil	100%	3, 60 minute test runs

TABLE #2: ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Max. Ranges	Sensitivity	Detection Principle
NOx	API 200AH or equivalent (1)	User may select up to 5,000 ppm	0.1 ppm	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear for listed ranges.
CO	API 300 or equivalent	User may select up to 3,000 ppm	0.1 ppm	Infrared absorption, gas filter correlation detector, microprocessor based linearization.
CO_2	FUJI 3300 or equivalent	0-20%	0.1%	Nondispersive infrared
THC	THERMO 51 or equivalent	User may select up to 10,000 ppm	0.1 ppm	Flame Ionization Detector
O_2	CAI 200 or equivalent	0-25%	0.1%	Paramagnetic cell, inherently linear.

TABLE #3: ANALYTICAL INSTRUMENTATION TESTING CONFIGURATION

Parameter	Sample Methodology	Example Range	Sensitivity	Calibration Gases (based on example range)
NOx	7e	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 4-6 ppm High = 10 ppm
CO	10	0-50 ppm	0.1 ppm	Zero = 0 ppm nitrogen Mid = 20-30 ppm High = 50 ppm
CO_2	3a	0-20%	0.1%	Zero = 0 ppm nitrogen Mid = 8-12% High = 20%
THC	25a	0-10 ppm	0.1 ppm	Zero = 0 ppm nitrogen Low = 2.5-3.5 ppm Mid = 4.5-5.5 ppm High = 8-9 ppm
O_2	3a	0-21%	0.1%	Zero = 0 ppm nitrogen Mid = 8.4-12.6% High = 21%

TABLE #4: PERMIT LIMITS

Parameter	Source	Fuel	Limit
NOx	CTG	Oil	8.0 ppmvd@15%O_2 / 82.4 lb/hr
CO	CTG	Oil	8.0 ppmvd@15%O_2 / 42.0 lb/hr
VOC	CTG	Oil	6.0 ppmvd@15%O_2 / 19.6 lb/hr
NH_3	CTG	Oil	5.0 ppmvd@15%O_2
Opacity	CTG	Oil	10%
Fuel Analysis	CTG	Oil	0.0015% sulfur

APPENDIX C
STACK DRAWINGS

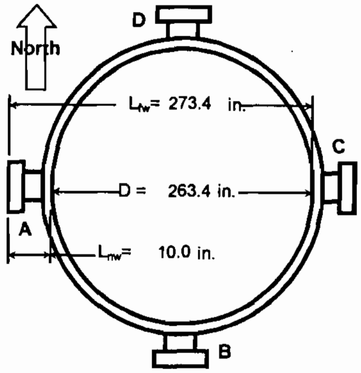
METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company	Black and Veatch Energy	**Date**	TBD
Plant Name	West County Energy Center	**Project #**	bv-10-westcounty.fl-comp#2
Equipment	Mitsubishi 501G	**# of Ports Available**	4
Location	Loxahatchee, Florida	**# of Ports Used**	4

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})	273.38	in.
Distance to Near Wall of Stack	(L_{nw})	10.00	in.*
Diameter of Stack	(D)	263.38	in.
Area of Stack	(A_s)	378.41	ft^2

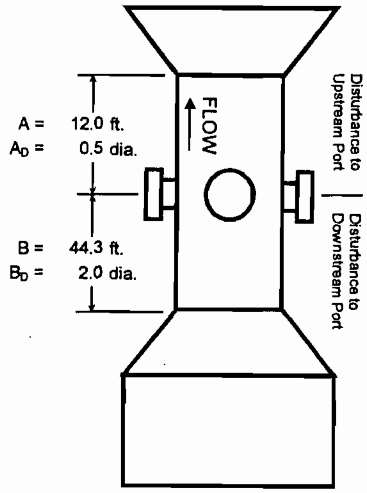
*assume 10 in. reference (must be measured and verified in field)

Distance from Disturbances to Port			
Distance Upstream	(A)	144.00	in.
Diameters Upstream	(A_D)	0.55	diameters
Distance Downstream	(B)	531.75	in.
Diameters Downstream	(B_D)	2.02	diameters



Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		**Minimum Number of Traverse Points**	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	**Comp Stratification**	
				Criteria	**Points**
2.00-4.99	0.50-1.24	24	16	● RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	○ Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12	12 points	
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	Minimum Number of Traverse Points	
Upstream Spec		24	16		
Downstream Spec		24	16	RATA Stratification	
Traverse Pts Required		24	16	Criteria	Points
				○ Part75/60	12 RM1 pts
				○ 75 abrv (a)	3 points
				○ 75 abrv (b)	6 points

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.
[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
4	**Ports by**	3	**Pts / port**	**Stratification Traverse**
12	**Pts Used**	12	**Required**	**(Compliance Test)**

Traverse Point Locations			
Traverse Point Number	**Percent of Stack Diameter**	**Distance from Inside Wall**	**Distance Including Reference Length**
	%	in.	in.
1	4.4%	11 5/8	21 5/8
2	14.6%	38 4/8	48 4/8
3	29.6%	78	88
4			
5			
6			
7			
8			
9			
10			
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13			
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17			
18			
19			
20			
21			
22			
23			
24			

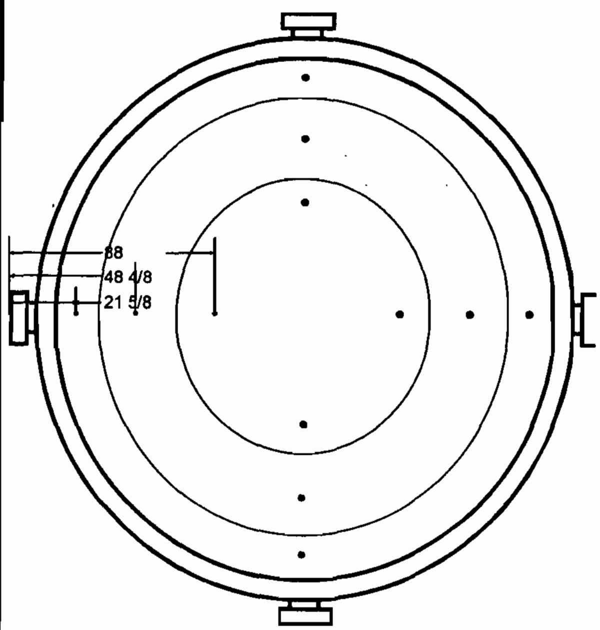


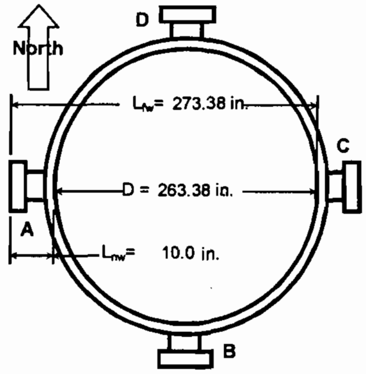
Figure 4 – CTG Gas Traverse Points

METHOD 1 - ISOKINETIC TRAVERSE FOR A CIRCULAR SOURCE			
Company	Black and Veatch Energy	Date	TBD
Plant Name	West County Energy Center	Project #	bv-10-westcounty.fl-comp#2
Equipment	Mitsubishi 501G	# of Ports Available	4
Location	Loxahatchee, Florida	# of Ports Used	4

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})	273.38	in.
Distance to Near Wall of Stack	(L_{nw})	10.00	in.*
Diameter of Stack	(D)	263.38	in.
Area of Stack	(A_s)	378.41	ft^2

*assume 10 in. reference (must be measured and verified in field)

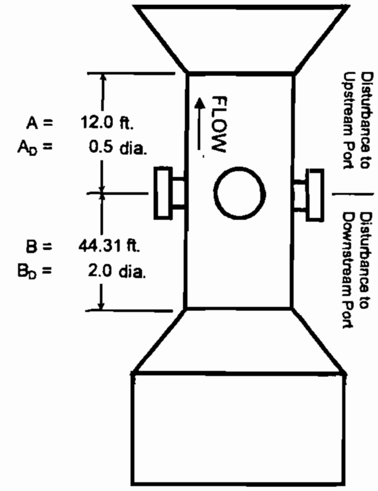
Distance from Disturbances to Port			
Distance Upstream	(A)	144.00	in.
Diameters Upstream	(A_D)	0.55	diameters
Distance Downstream	(B)	531.75	in.
Diameters Downstream	(B_D)	2.02	diameters



Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		Minimum Number of Traverse Points Comp Stratification	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	Criteria	Points
2.00-4.99	0.50-1.24	24	16	○ RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	○ Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	Minimum Number of Traverse Points RATA Stratification	
Upstream Spec		24	16		
Downstream Spec		24	16		
Traverse Pts Required		24	16	Criteria	Points
				○ Part75/60	12 RM1 pts
				○ 75 abrv (a)	3 points
				○ 75 abrv (b)	6 points

[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.

[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
4	Ports by	6	Pts / port	Isokinetic Traverse (Wet Chemistry
24	Pts Used	24	Required	

Traverse Point Locations			
Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
	%	in.	in.
1	2.1%	5 4/8	15 4/8
2	6.7%	17 5/8	27 5/8
3	11.8%	31 1/8	41 1/8
4	17.7%	46 5/8	56 5/8
5	25.0%	65 7/8	75 7/8
6	35.6%	93 6/8	103 6/8
7			
8			
9			
10			
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17			
18			
19			
20			
21			
22			
23			
24			

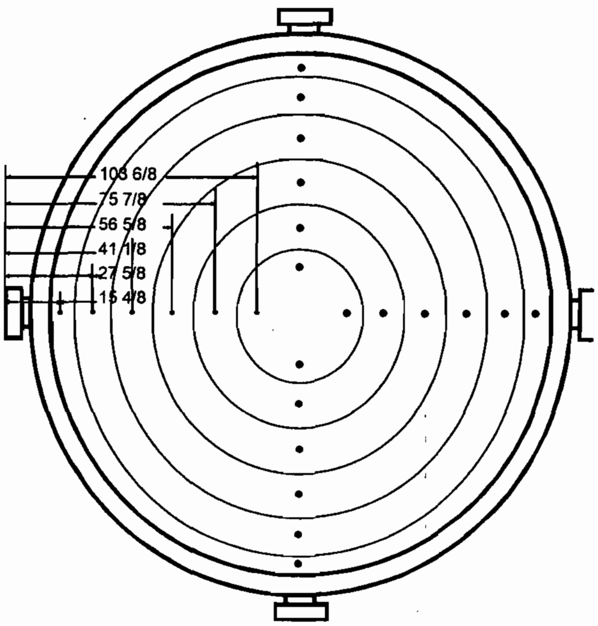


Figure 5 - CTG Wet Chemistry Points

APPENDIX D
EXAMPLE TEMPLATES AND CALCULATIONS

SINGLE LOAD TEST - FIELD DATA SHEET

AIR HYGIENE

Company:	
Location:	
Date:	
Unit Make and Model:	
Unit Number:	
Serial Number:	
Data Recorded By:	
Tested With AHI Unit(s):	Truck(s): Trailer(s):
LDEQ Warmup/Cal Req:	On (Day/Time): Cal (Day/Time):

CYLINDER SERIAL NUMBERS		O_2	NOx	CO
	Low			
	Mid			
	High			

CYLINDER SERIAL NUMBERS		THC	CO_2	SO_2
	Low			
	Mid			
	High			

RUN INFORMATION	Load		
	______% #1	______% #2	______% #3
Time Start (hh:mm:ss)			
Time Stop (hh:mm:ss)			
Rated Power (MW or hp)			
Actual Power (MW or hp)			
Barometric Pressure (in. Hg)			
Ambient Temperature (°F)			
Relative Humidity (%)			
Fuel Flow (lb/min)			
Fuel Flow (SCF/hr)=(lb/min)*21.7			
Specific Humidity (gr/lb)			
Spec. Hum. (lb H_2O/lb air)=(gr/lb)/7000			
PCD (psi)			
PCD (mm Hg)=(psi+14.24)*51.71493			
NOx Water Injection (gpm)			

NO_2 CONVERSION	
NO_2 Gas (ppm)	
NO Reading (ppm)	
NOx Reading (ppm)	
Cylinder Num	

REPORT INFORMATION		
	INSTRUMENT	SERIAL #
O_2		
NOx		
CO		
THC		
CO_2		
SO_2		

RESPONSE TIME		
	TIME (hh:mm)	RESP (min)
1st Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		
2nd Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		
3rd Gas Inject		
1st Inst. @ 95%		
2nd Inst. @ 95%		
3rd Inst. @ 95%		

CALIBRATION	O_2		NOx		CO		THC		CO_2		SO_2	
	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual	Conc.	Actual
Zero Gas												
Low Gas												
Mid Gas												
High Gas												

BIAS	O_2		NOx		CO		THC		CO_2		SO_2	
	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid	Zero	Mid
Initial Run #1												
Run #1 / Run #2												
Run #2 / Run #3												
Run #3 / Final												
Bias Gas Actual Conc.		______		______		______		______		______		______

Source Information	
Company	
Plant Name	
Equipment	
Location	

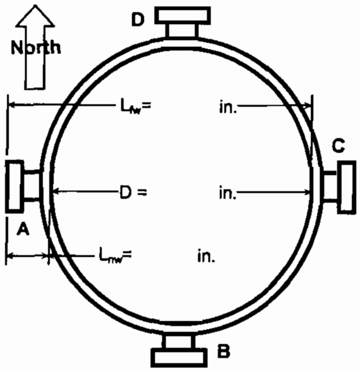
Test Information	
Date	
Project #	
Unit Number	
Load	
Number of Ports Available	
Number of Ports Used	

Stack and Test Type			
○	Isokinetic Traverse (Wet Chemistry Testing)		**Circular Stack**
○	Velocity Traverse (Flow and Flow RATA Test)		
○	Stratification Traverse (Compliance Test)	☐ RM 20	
◉	**Stratification Traverse (RATA)**	☐ Part 60 ☑ Part 75	

METHOD 1 - STRATIFICATION TEST FOR A CIRCULAR SOURCE

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Circular Stack or Duct Diameter			
Distance to Far Wall of Stack	(L_{fw})		in.
Distance to Near Wall of Stack	(L_{nw})		in.
Diameter of Stack	(D)		in.
Area of Stack	(A_s)		ft^2

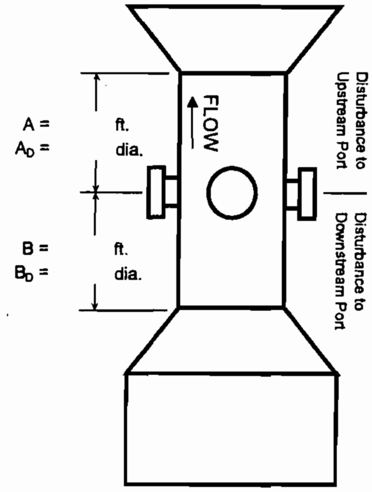


Distance from Disturbances to Port			
Distance Upstream	(A)		in.
Diameters Upstream	(A_D)		diameters
Distance Downstream	(B)		in.
Diameters Downstream	(B_D)		diameters

Number of Traverse Points Required					
Diameters to Flow Disturbance		Minimum Number of[1] Traverse Points		Minimum Number of Traverse Points Comp Stratification	
Down (B_D) Stream	Up (A_D) Stream	Particulate Points	Velocity Points	Criteria	Points
2.00-4.99	0.50-1.24	24	16	O RM 7E 8.1.2	12 RM1 pts
5.00-5.99	1.25-1.49	20	16	O Alt 7E 8.1.2	3 points
6.00-6.99	1.50-1.74	16	12		
7.00-7.99	1.75-1.99	12	12		
>= 8.00	>=2.00	8 or 12[2]	8 or 12[2]	**Minimum Number of**	
Upstream Spec				**Traverse Points**	
Downstream Spec				**RATA Stratification**	
Traverse Pts Required				**Criteria**	**Points**
				O Part75/60	12 RM1 pts
				O 75 abrv (a)	3 points
				O 75 abrv (b)	6 points

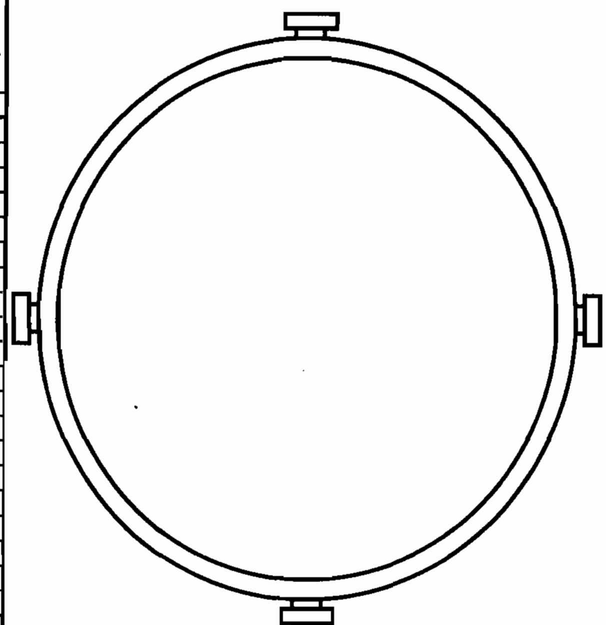
[1] Check Minimum Number of Points for the Upstream and Downstream conditions, then use the largest.

[2] 8 for Circular Stacks 12 to 24 inches
12 for Circular Stacks over 24 inches



Number of Traverse Points Used				
	Ports by Pts Used		Pts / port Required	Stratification Traverse (RATA)

Traverse Point Locations			
Traverse Point Number	**Percent of Stack Diameter**	**Distance from Inside Wall**	**Distance Including Reference Length**
	%	in.	in.
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			



STRATIFICATION TRAVERSE (RATA) RESULTS

Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

Traverse Point	Time Per Point	Point Start Time	Point Stop Time (Reading)	Diluent 1	Percent Difference	Pollutant 1	Percent Difference
	min.	hh:mm:ss	hh:mm:ss	%	%	ppm	%
Average							

RATA SAMPLE POINTS FOR CIRCULAR STACK

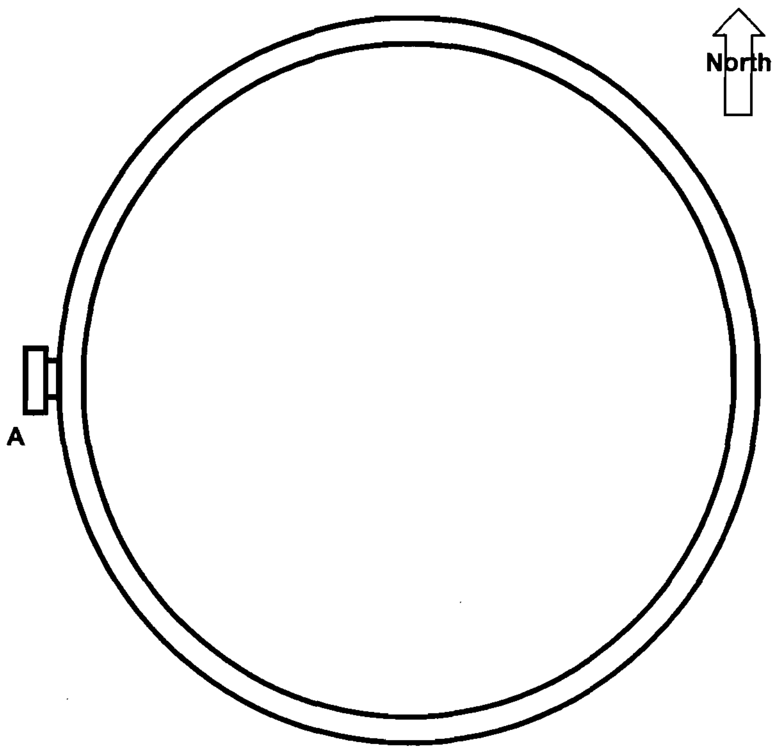
Company		Date	
Plant Name		Project #	
Equipment		# of Ports Available	
Location		# of Ports Used	

Stack Dimensions				Traverse Data			
Diameter or Length of Stack	(D)		in.		Ports by		Pts / port
Width of Stack	(W)		in.		Pts Used		Required
Area of Stack	(A_s)		ft^2	Run Start		Run End	

40 CFR 75 Criteria					
Stratification Results		Traverse Point Number	Percent of Stack Diameter	Distance from Inside Wall	Distance Including Reference Length
Maximum Percent Difference	No Test				
Maximum Pollutant Conc. Diff.	No Test				
Maximum Diluent Conc. Diff.	No Test				
Stack Diameter	in.		%	in.	in.
Stratification Conclusions		1			
Maximum % Diff.	No Stratification Anticipated	2			
Maximum Conc. Diff.	No Stratification Anticipated	3			
Stack Diameter	D > 93.6 in.				

Use Short RM Measurement Line

Test Type
- ☐ Moisture, for MW
- ☐ Moisture, for wet-to-dry
- ☑ Gas
- ☐
- ☐ 6.5.6(b)(2) alt. points could apply



DRIFT AND BIAS CHECK		
Strat Test Pre and Post QA/QC Check	Diluent 1	Pollutant 1
Initial Zero		
Final Zero		
Avg. Zero		
Initial UpScale		
Final UpScale		
Avg. UpScale		
Sys Resp (Zero)		
Sys Resp (Upscale)		
Upscale Cal Gas		
Initial Zero Bias		
Final Zero Bias		
Zero Drift		
Initial Upscale Bias		
Final Upscale Bias		
Upscale Drift		
Alternative Specification Abs Diff Initial Zero		
Final Zero		
Initial Upscale		
Final Upscale		
Calibration Span		
3% of Range (drift)		
5% of Range (bias)		

Respone Time (min)		
Sys. Response (min)		

Date/Time mm/dd/yy hh:mm:ss z s z s

INJECTIONS

x

Client:
Location:
Date:
Project #:

Natural Gas - Fuel Analysis

Standardized to 68 deg F and 14.696 psia - EPA Standards

Gas Component		Mole (%)	Molecular[1] Weight (lb/lb-mole)	Lbs Component per Lb-Mole of Gas	Wt. % of Component	Ideal Gross[1,3] Heating Value (Btu/ft^3)	Fuel Heat Value [HHV] (Btu/SCF)	Ideal Net[1,3] Heating Value (Btu/ft^3)	Fuel Heat Value [LHV] (Btu/SCF)
Methane	CH_4								
Ethane	C_2H_6								
Propane	C_3H_8								
iso-Butane	iC_4H_{10}								
n-Butane	nC_4H_{10}								
Iso-Pentane	iC_5H_{12}								
n-Pentane	nC_5H_{12}								
Hexanes	C_6H_{14}								
Heptanes	C_7H_{16}								
Octanes	C_8H_{18}								
Carbon Dioxide	CO_2								
Nitrogen	N_2								
Hydrogen Sulfide	H_2S								
Oxygen	O_2								
Helium	He								
Hydrogen	H_2								
Totals						dry		dry	
						wet[2,5]		wet[2,5]	

Characteristics of Fuel Gas		
Molecular Weight of gas =		lb/lb-mole
Btu per lb. of gas[4] =		gross (HHV)
Btu per lb. of gas[4] =		net (LHV)
Density of fuel gas[2] =		lb/cu. ft
Wt % VOC in fuel gas =		%
Specific Gravity[1] =		

Component	Wt%
carbon	
oxygen	
hydrogen	
nitrogen	
helium	
sulfur	
Total	

F-Factor (SCF dry exhaust per MMBtu [HHV]) =
(Based on EPA RM-19) at 68 deg F and 14.696 psia

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of natural gas based on specific gravity multiplied by density of air at 68 deg F and 14.696 psia.

References:

[1] ASTM D 3588
[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg
[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III
[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna
[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

Air Permit # :	
Plant Name or Location:	
Date:	
Project Number:	
Manufacturer & Equipment:	
Model:	
Serial Number:	
Unit Number:	
Test Load:	
Tester(s) / Test Unit(s):	

		RUN																	
	UNITS	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Start Time	hh:mm:ss																		
End Time	hh:mm:ss																		
Bar. Pressure	in. Hg																		
Amb. Temp.	°F																		
Rel. Humidity	%																		
Spec. Humidity	lb water / lb air																		
Comb. Inlet Pres.	psig																		
NOx Water Inj.	gpm																		
Total Fuel Flow	SCFH																		
Heat Input	MMBtu/hr																		
Power Output	megawatts																		
Steam Rate	lb/hr																		

Client:
Location:
Date:
Project #:

Fuel Oil - Fuel Analysis

Characteristics of Fuel Gas		
Molecular Weight of oil =		lb/lb-mole
Btu per lb. of oil =		gross (HHV)
Btu per lb. of oiil =		net (LHV)
Density of fuel oil[2] =		lb/cu. ft
Density of fuel oil[2] =		lb/gal
Specific Gravity =		@ 68 deg F

Standardized to 68 deg F and 14.696 psia

Component	Wt%
carbon	
oxygen	
hydrogen	
nitrogen	
helium	
sulfur	
Total	

Fuel Oil HHV Conv.	
HHV (Btu/lb)	
HHV (Btu/SCF)	

Fuel Oil LHV Conv.	
LHV (Btu/lb)	
LHV (Btu/SCF)	

F-Factor (SCF dry exhaust per MMBtu [HHV]) =
(Based on EPA RM-19) at 68 deg F and 14.696 psia

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

GCV = Gross Btu per lb. of gas (HHV)

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

Density of fuel oil based on lab analysis or specific gravity multiplied by density of water at 68 deg F and 14.696 psia.

References:

[1] ASTM D 3588

[2] Civil Engineering Reference Manual, 7th ed. - Michael R. Lindeburg

[3] Mark's Standard Handbook for Mechanical Engineers, 10th ed. - Eugene A. Avallone, Theodore Baumeister III

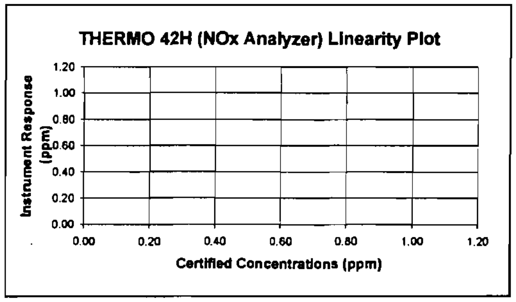
[4] Introduction to Fluid Mechanics, 3rd ed. - William S. Janna

[5] GPA Reference Bulletin 181-86, revised 1986, reprinted 1995

Calibration Date:
Client:

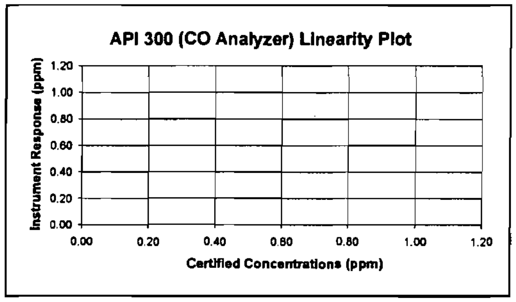
NOx Span (ppm) =

THERMO 42H (NOx Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5ppm)
Linearity =				



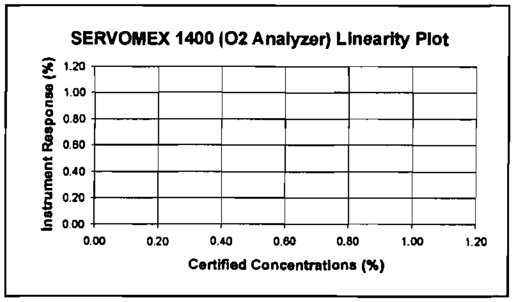
CO Span (ppm) =

API 300 (CO Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5ppm)
Linearity =				



O2 Span (%) =

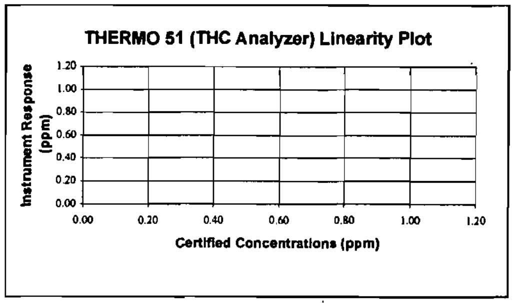
SERVOMEX 1400 (O_2 Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5%)
Linearity =				



THC Range (ppm) =

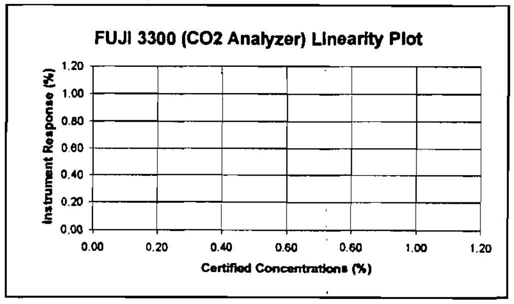
THERMO 51 (THC Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Estimated Point (ppm)	Pass or Fail (±2,5%)[1]
Linearity =				

[1]-zero/high based on 2% of span,low/mid based on 5% of concentration



CO2 Span (%) =

FUJI 3300 (CO_2 Analyzer)				
Certified Concentration (ppm)	Instrument Response (ppm)	Calibration Error (%)	Absolute Conc. (ppm)	Pass or Fail (±2%, ≤0.5%)
Linearity =				



NOx Converter Efficiency

Date:

Analyzer:

RM 7E, (08-15-06), 8.2.4.1 Introduce a concentration of 40 to 60 ppmv NO_2 to the analyzer in direct calibration mode and record the NOx concentration displayed by the analyzer. ... Calculate the converter efficiency using Equation 7E-7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. ... The NO_2 must be prepared according to the EPA Traceability Protocol and have an accuracy within 2.0 percent.

Audit Gas: NO_2 Concentration (C_v), ppmvd

Converter Efficiency Calculations:

Analyzer Reading, NO Channel, ppmvd

Analyzer Reading, NOx Channel, ppmvd

Analyzer Reading, NO_2 Channel ($C_{Dir(NO2)}$), ppmvd

Converter Efficiency, %

RM 7E, (08-15-06), 13.5 NO2 to NO Conversion Efficiency Test (as applicable). The NO2 to NO conversion efficiency, calculated according to Equation 7E-7 or Equation 7E-9, must be greater than or equal to 90 percent.

$$Eff_{NO2} = \left(\frac{C_{Dir}}{C_V}\right) \times 100 \qquad \text{Eq. 7E-7} = \frac{\text{ppmvd}}{\text{ppmvd}} \times 100 =$$

Date/Time	Elapsed Time	NOx	NO
mm/dd/yy hh:mm:ss	Seconds	ppmvd	ppmvd

Fuel Data

Fuel F_d factor		SCF/MMBtu
Fuel Heating Value (HHV)		Btu/SCF

Weather Data

Barometric Pressure		in. Hg
Relative Humidity		%
Ambient Temperature		°F
Specific Humidity		lb H_2O / lb air

Unit Data

Unit Load		megawatts
Heat Input		lb/MMBtu
Steam Rate		Steam lb/hr
Combustor Inlet Pres.		psig
NOx Control Water Injection		gpm
Est. Stack Moisture		%
Stack Exhaust Flow (M2)		SCFH
Stack Exhaust Flow (M19)		SCFH

Run - 1

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)

RAW AVERAGE

		O_2	NOx	CO
	Serial Number:			
		(%)	(ppmvd)	(ppmvd)
Bias	Initial Zero			
	Final Zero			
	Avg. Zero			
	Initial UpScale			
	Final UpScale			
	Avg. UpScale			

Upscale Cal Gas

EMISSIONS DATA	O_2	NOx	CO
Corrected Raw Average (ppm/% dry basis)			
Corrected Raw Average (ppm/% wet basis)			
Concentration (ppm@ %O_2)			
Concentration (ppm@ %O_2 &ISO)			
Emission Rate (lb/hr)			
Emission Rate (tons/day) at 24 hr/day			
Emission Rate (tons/year) at 8760 hr/yr			
Emission Rate (lb/MMBtu)			
Emission Rate (g/hp*hr)			

DRIFT AND BIAS CHECK			
Run - 1	O2	NOx	CO
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff: Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

DRIFT AND BIAS CHECK			
Run - 2	O2	NOx	CO
Raw Average			
Corrected Average			
Initial Zero			
Final Zero			
Avg. Zero			
Initial UpScale			
Final UpScale			
Avg. UpScale			
Sys Resp (Zero)			
Sys Resp (Upscale)			
Upscale Cal Gas			
Initial Zero Bias			
Final Zero Bias			
Zero Drift			
Initial Upscale Bias			
Final Upscale Bias			
Upscale Drift			
Alternative Specification Abs Diff: Initial Zero			
Final Zero			
Initial Upscale			
Final Upscale			
Calibration Span			
3% of Range (drift)			
5% of Range (bias)			

TABLE A.2
LOAD 1 DATA SUMMARY

Parameter	Run - 1	Run - 2	Run - 3	Average
Start Time (hh:mm:ss)				
End Time (hh:mm:ss)				
Run Duration (min)				
Bar. Pressure (in. Hg)				
Amb. Temp. (°F)				
Rel. Humidity (%)				
Spec. Humidity (lb water / lb air)				
Turbine Fuel Flow (SCFH)				
Stack Flow (RM19) (SCFH)				
Power Output (megawatts)				
NOx (ppmvd)				
NOx (lb/hr)				
NOx (lb/MMBtu)				
NOx (g/hp*hr)				
CO (ppmvd)				
CO (lb/hr)				
CO (lb/MMBtu)				
CO (g/hp*hr)				
O_2 (%)				

TABLE A.3
LOAD 2 DATA SUMMARY

Parameter	Run - 4	Run - 5	Run - 6	Average
Start Time (hh:mm:ss)				
End Time (hh:mm:ss)				
Run Duration (min)				
Bar. Pressure (in. Hg)				
Amb. Temp. (°F)				
Rel. Humidity (%)				
Spec. Humidity (lb water / lb air)				
Turbine Fuel Flow (SCFH)				
Stack Flow (RM19) (SCFH)				
Power Output (megawatts)				
NOx (ppmvd)				
NOx (lb/hr)				
NOx (lb/MMBtu)				
NOx (g/hp*hr)				
CO (ppmvd)				
CO (lb/hr)				
CO (lb/MMBtu)				
CO (g/hp*hr)				
O_2 (%)				

EXAMPLE CALCULATIONS (FFACTOR)

RM 19, (07-19-06),
2.0 Summary of Method,
2.1 Emission Rates. Oxygen (O_2) or carbon dioxide (CO_2) concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant co

RM 19, (07-19-06),
12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in lb/MMBtu. The pollutant concentration must be in lb/scf and the F factor must be in scf/MMBtu. If the pollutant concentration (C) is not in the appropriate units, use Table 19–1 in Section 17.0 to make the proper conversion. An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry F factor (F_d) includes all components of combustion less water, the wet F factor (F_w) includes all components of combustion, and the carbon F factor (F_c) includes only carbon dioxide.

Mark's Std Hdbk, 10th ed.,pg 4-26
High Heat Value Dry (HHV_{dry}), calc for Methane (single component for the fuel gas)

$$HHV_{dry}(Btu/SCF)=\left[\left(\frac{M_{\%}}{100}\right)\times GCM\right]$$

$HHV_{dry} = \frac{\%}{100.00} \times \frac{Btu}{SCF} = \frac{Btu}{SCF}$

Mark's Std Hdbk, 10th ed., pg 4-26
Low Heat Value Dry (LHV_{dry}), calc for Methane (single component for the fuel gas)

$$LHV_{dry}(Btu/SCF)=\left[\left(\frac{M_{\%}}{100}\right)\times NCM\right]$$

$LHV_{dry} = \frac{\%}{100.00} \times \frac{Btu}{SCF} = \frac{Btu}{SCF}$

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
High Heat Value Wet (HHV_{wet}), calc for entire sample (all components of the fuel gas)

$$HHV_{wet}(Btu/SCF)=\frac{HHV_{dry}}{W/D.factor}$$

$HHV_{wet} = \frac{Btu/SCF}{\quad} =$ Btu/SCF

Civil Eng. Ref. Man.,7th Ed.,pg 14-9/GPA Ref. Bulletin 181-86, App. C
Low Heat Value Wet (LHV_{wet}), calc for entire sample (all components of the fuel gas)

$$LHV_{wet}(Btu/SCF)=\frac{LHV_{dry}}{W/D.factor}$$

$LHV_{wet} = \frac{Btu/SCF}{\quad} =$ Btu/SCF

Lbs Component per Lb-Mol of Gas (CM), calc for Methane (single component for the fuel gas)

$$CM(lb/lb-mol)=\left[\left(\frac{M_{\%}}{100}\right)\times MW\right]$$

$CM = \frac{\%}{100.00} \times \frac{lb}{lb\text{-}mol} =$ ____ lb/lb-mol

ASTM D 3588
Fuel Molecular Weight (MW_{Fuel})

$$MW_{Fuel}(lb/lb\cdot mol)=\left[\sum(CM)\right]$$

$MW_{Fuel} =$ lb/lb-mol
\+ lb/lb-mol
\+ etc. = lb/lb-mol

Btu per Lb of Gas Gross (**GCV**)

$$GCV(Btu/lb)=\left[\frac{HHV_{dry}\times G}{MW_{Fuel}}\right]$$

$GCV = \frac{Btu/SCF \times ft^3/lbmol}{lb/lb\text{-}mol} =$ Btu/lb

ASTM D 3588 (SG)
Specific Gravity

$$SG=\left[\frac{MW_{Fuel}}{MW_{AIR}}\right]$$

$SG = \frac{lb/lb\text{-}mol}{28.96\ lb/lb\text{-}mol} =$

Btu per Lb of Gas Net (**NCV**)

$$NCV(Btu/lb)=\left[\frac{LHV_{dry}\times G}{MW_{Fuel}}\right]$$

$NCV = \frac{Btu/SCF \times ft^3/lbmol}{lb/lb\text{-}mol} =$ Btu/lb

Weight Percent of Component ($C_{\%}$), methane

$$C_{\%}(\%)=\left[\left(\frac{CM}{MW_{Fuel}}\right)\times 100\right]$$

$C_{\%} = \frac{lb/lb\text{-}mol}{lb/lb\text{-}mol} \times 100 =$ %

RM 19, (07-19-06), **Weight Percent of Volatile Organic Compounds** ($VOC_{\%}$)

$$VOC_{\%}(\%)=\left[\sum_{C_3H_8}^{C_6H_{14}} M_{\%}\right]$$

$VOC_{\%} =$ % + % + % + etc. = %

RM 19, (07-19-06), 12.3.2 Determined **F Factors**. If the fuel burned is not listed in Table 19–2 or if the owner or operator chooses to determine an F factor rather than use the values in Table 19–2, use the procedure below: 12.3.2.1 Equations. Use the eq

RM 19, (07-19-6),
12.1 Nomenclature

$$F_d=\frac{K(K_{hd}\%H+K_c\%C+K_s\%S+K_n\%N-K_o\%O)}{GCV} \qquad \text{Eq. 19-13}$$

K (scf/lb)/%	
H	3.64
C	1.53
S	0.57
N_2	0.14
O_2	0.46

$$F_d=\frac{10^6 Btu}{MMBtu}\times\left\{\frac{3.64\ SCF}{lb\cdot\%}\times\ \%+\frac{1.53\ SCF}{lb\cdot\%}\times\ \%+\frac{0.57\ SCF}{lb\cdot\%}\times\ \%+\frac{0.14\ SCF}{lb\cdot\%}\times\ \%-\frac{0.46\ SCF}{lb\cdot\%}\times\ \%\right\}\times\frac{lb}{Btu}=\frac{SCF}{MMBtu}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (INFORMATION)

Specific Humidity (RH_{sp})

Note: RHsp (gr/lb) calculated using temperature, relative humidity, and barometric pressure with psychrometric chart, psychrometric calculator, or built in psychrometric algorithm.

$$RH_{sp}(lb/lb) = \left[\left(\frac{gr}{lb}\right) \times \frac{lb}{7000\,gr}\right]$$

$$RH_{sp} = \frac{gr}{lb} \times \frac{1\,lb}{7000\,gr} = \frac{lb\ H_2O}{lb\ Air}$$

Fuel Flow Conversion (Q_f)

Note: Qf(lb/min) is a value uptained from the source operator.

$$Q_f = \left[Q_f \times G \times \left(\frac{1}{MW_{Fuel}}\right)\right]$$

$$Q_f = \frac{lb}{min} \times \frac{60\ min}{hr} \times \frac{ft^3}{lb\text{-}mol} \times \frac{lb\text{-}mol}{lb} = SCFH$$

Combustor Inlet Pressure / Compressor Discharge Pressure (CIP / CDP)
(corrected from gauge to atmospheric pres. and conv. to mm Hg.)

Note: CIP / CDP (psig) is a value obtained from the source operator.

$$CIP/CDP = \left[(psig + P) \times \frac{51.71493\ mmHg}{1 psi}\right]$$

$$CIP/CDP = (\quad psig + \quad) \times \frac{51.71493\ mmHg}{1\ psia} = \quad mmHg\ (abs)$$

Heat Rate (MMBtu/hr)

$$HR = \frac{HHV_{DRY} \times Q_f}{1{,}000{,}000}$$

$$\text{Heat Rate} = \frac{Btu}{SCF} \times \frac{SCF}{hr} \times \frac{MMBtu}{10^6\ Btu} = \frac{MMBtu}{hr}$$

Estimated Stack Gas Moisture Content (B_{ws})

$$B_{ws}(\%) = \frac{2 \times Q_f}{Q_s} \times 100$$

$$B_{ws} = 2 \times \frac{SCF}{hr} \times \frac{hr}{SCF} \times 100 = \quad \%$$

Note: Lack of significant figures may cause rounding errors between actual calculations and exemple calculations.

EXAMPLE CALCULATIONS (CALIBRATION)

Analyzer Calibration Error

RM 7E, (08-15-06), 12.2 Analyzer Calibration Error. For non-dilution systems, use Equation 7E-1 to calculate the analyzer calibration error for the low-, mid-, and high-level calibration gases. (calc for analyzer mid gas, if applicable)

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100 \qquad \text{Eq. 7E-1}$$

$$ACE = \frac{ppm - \quad ppm}{ppm} \times 100 = \quad \%$$

Calibration Error and Estimated Point, RM 25A, THC Analyzer

RM 25A, (07-19-06), 8.4 Calibration Error Test. Immediately prior to the test series (within 2 hours of the start of the test), introduce zero gas and high-level calibration gas at the calibration valve assembly. Adjust the analyzer output to the appropriate levels, if necessary. Calculate the predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response. Then introduce low-level and mid-level calibration gases successively to the measurement system. ... These differences must be less than 5 percent of the respective calibration gas value. (calc for THC analyzer mid gas, if applicable)

$$E_p = \frac{C_{Dir(H)} - C_{Dir(Z)}}{C_{V(H)} - C_{V(Z)}} \times C_{Dir(M)} + C_{Dir(Z)}$$

Eq. of a line
y=mx+b

$$E_p = \frac{ppm - \quad ppm}{ppm - \quad ppm} \times \quad ppm + \quad = \quad ppm$$

$$ACE = \left(\frac{C_{Dir} - C_V}{CS}\right) \times 100 \qquad \text{Eq. 7E-1}$$

$$ACE_{THC} = \frac{ppm - \quad ppm}{ppm} \times 100 = \quad \%$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (BIAS, DRIFT, AND CORRECTED RAW AVERAGE)

System Bias

RM 7E, (08-15-06), 12.3 System Bias. For non-dilution systems, use Equation 7E-2 to calculate the system bias separately for the low-level and upscale calibration gases. (calc for analyzer upscale gas, Run 1 initial bias, if applicable)

$$SB = \left(\frac{C_S - C_{Dir}}{CS}\right)\times 100$$ Eq. 7E-2

SB = (ppm - ppm) / ppm x 100 = %

Drift Assessment

RM 7E, (08-15-06), 12.5 Drift Assessment. Use Equation 7E-4 to separately calculate the low-level and upscale drift over each test run. (calc for analyzer upscale drift, Run 1, if applicable)

$$D = \left|SB_{final} - SB_i\right|$$ Eq. 7E-4

D = | % - % | = %

Alternative Drift and Bias

RM 7E, (08-15-06), 13.2 / 13.3 System Bias and Drift. Alternatively, the results are acceptable if |Cs – Cdir| is≤ 0.5 ppmv or if |Cs – Cv| is ≤ 0.5 ppmv (as applicable). (calc for analyzer initial upscale, Run 1, if applicable)

$$SB / D_{Alt} = \left|C_S - C_{Dir}\right|$$ Eq. Section 13.2 and 13.3

SB / D_{Alt} = | ppm - ppm | = ppm

Bias Adjusted Average

RM 7E, (08-15-06), 12.6 Effluent Gas Concentration. For each test run, calculate Cavg, the arithmetic average of all valid concentration values (e.g., 1-minute averages). Then adjust the value of Cavg for bias, using Equation 7E-5. (calc for analyzer, Run 1, if applicable)

$$C_{Gas} = \left(C_{Avg} - C_O\right)\times\left(\frac{C_{MA}}{C_M - C_O}\right)$$ Eq. 7E-5

C_{Gas} = (ppm - ppm) x (ppm / (ppm - ppm)) = ppm

EXAMPLE CALCULATIONS (BSFC)

Using LHV with Q_f (Btu/hp*hr)

$$BSFC\,(Btu / hp \cdot hr) = Q_f$$

BSFC = Btu / hp*hr = Btu / hp*hr

Using HHV with Q_f (SCFH)

$$BSFC\,(Btu / hp \cdot hr) = \frac{HHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using LHV with Q_f (SCFH)

$$BSFC\,(Btu / hp \cdot hr) = \frac{LHV \times Q_f}{bhp}$$

BSFC = Btu / SCF x SCF / hr x 1 / hp = Btu / hp*hr

Using HHV with Q_f (Btu/hp*hr)

$$BSFC\,(Btu / hp \cdot hr) = \frac{Q_f \times HHV}{LHV}$$

BSFC = N/A Btu / hp*hr x Btu / SCF x scf / Btu = Btu / hp*hr

EXAMPLE CALCULATIONS (Emissions based on Table 29 values)

Emission Rate (lb/hr)
Q_f (Btu/hp*hr))

$$E(lb / hr) = \frac{E_{g / hp \cdot hr} \times bhp}{453.6}$$

E (lb/hr) = g / hp*hr x lb / 453.6 g x hp = lb / hr

Emission Rate (g/hp-hr)
Q_f (Btu/hp*hr))

$$E(g / hp \cdot hr) = CRA \times Q_f \times FFactor \times MW \times \frac{1}{10^6}\times\frac{1}{10^6}\times\frac{453.6}{G}\times\frac{20.9\%}{20.9\% - CRA_{O_2}}$$

E (g/hp-hr) = ppm x Btu / hp*hr x SCF / MMBtu x lb / lb-mol x 1 parts / 10^6 ppm x 1 MMBtu / 10^6 Btu

x 453.6 g / lb x lb-mol / SCF x 20.9% / (20.9% - %) = g / hp*hr

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Stack Exhaust Flow (Q_S) - RM19

$$Q_S = \left(\frac{FFactor \times Q_f \times HHV}{1{,}000{,}000}\right) \times \left(\frac{20.9\%}{20.9\% - C_{Gas(O2)}}\right)$$

$$Q_S = \frac{SCF}{MMBtu} \times \frac{SCF}{hr} \times \frac{Btu}{SCF} \times \frac{MMBtu}{10^6\ Btu} \times \left[\frac{20.90\%}{20.9\% - \quad \%}\right] = \quad SCFH$$

NO_2 Conversion Efficiency Correction

RM 7E, (08-15-06), 12.8 NO2 - NO Conversion Efficiency Correction. If desired, calculate the total NOX concentration with a correction for converter efficiency using Equations 7E-8. (calc for non-bias corrected (raw) NOx gas, Run 1, if applicable)

$$NOx_{Corr} = NO + \frac{NOx - NO}{Eff_{NO2}} \times 100 \qquad \text{Eq. 7E-8}$$

$$NOx_{Corr} = \quad ppm + \frac{ppm - \quad ppm}{\%} \times 100 = \quad ppm$$

Moisture Correction

RM 7E, (08-15-06), RM7E, (08-15-06), 12.10 Moisture Correction. Use Equation 7E-10 if your measurements need to be corrected to a dry basis. (calc for THC analyzer, Run 1, if applicable) Note: Calculations may not match as Run 1 results are typically also bias adjusted

$$C_D = \frac{C_W}{1 - B_{WS}} \qquad \text{Eq. 7E-10}$$

$$C_D = \frac{ppmvw}{1 -} = \quad ppmvd$$

Diluent-Corrected Polutant Concentration, O_2 Based

RM 20, (11-26-02), 7.3.1 Correction of Pollutant Concentration Using O2 Concentration. Calculate the O2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right) \qquad \text{Eq. 20-4}$$

$$C_{adj} = \quad ppm \times \left(\frac{20.9\% - \quad \%}{20.9\% - \quad \%}\right) = \quad ppm@\%O_2$$

Diluent-Corrected Polutant Concentration, CO_2 Based

RM 20, (11-26-02), 7.3.2 Correction of Pollutant Concentration Using CO2 Concentration. Calculate the CO2 corrected pollutant concentration, as follows: (calc for gas, Run 1, if applicable)

$$C_{adj} = C_{Gas(Target)} \times \frac{X_{CO2}}{C_{Gas(CO2)}} \qquad \text{Eq. 20-5}$$

$$C_{adj} = \quad ppm \times \frac{\%}{\%} =$$

7.2 CO_2 Correction Factor. If pollutant concentrations are to be corrected to percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as follows: 7.2.1 Calculate the fuel specific F_o, as follows:

$$F_0 = \frac{0.209\, F_d}{F_c} \qquad \text{Eq. 20-2}$$

$$F_0 = \frac{0.209 \times \quad SCF/MMBtu}{SCF/MMBtu} =$$

7.2.2. Calculate the CO_2 correction factor for correcting measurement data to percent oxygen, as follows:

$$X_{CO2} = \frac{20.9\% - AdjFactor}{F_0} \qquad \text{Eq. 20-3}$$

$$X_{CO2} = \frac{20.9\% - \quad \%}{} = \quad \%$$

Diluent-Corrected Polutant Concentration Corrected to ISO Conditions

40CFR60.335(b)(1), Conversion for conc. at ISO Conditions (68°F, 1 atm). Calculate, as follows: (calc for @% with Run 1 data, if applicable)

$$C_{ISO} = C_{Adj} \times \sqrt{\frac{P_r}{P_o}} \times e^{(19 \times (H_O - 0.00633))} \times \left(\frac{288}{T_a}\right)^{1.53}$$

$$C_{ISO} = \quad ppm@\%O_2 \times \left(\sqrt{\frac{\dfrac{psig + 14.69232\ psi}{0.01933677\ psi/mm\ Hg.}}{\dfrac{psig + \quad psi}{0.01933677\ psi/mm\ Hg.}}}\right) \times 2.718^{(19 \times (\quad lb/lb - 0.00633))} \times \left(\frac{288\ K}{K}\right)^{1.53} = \quad ppm@\%\ and\ ISO$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

EXAMPLE CALCULATIONS (RUNS)

Emissions Rate (lb/hr)

Calculation for pound per hour emission rate. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

$$E_{lb/hr} = \frac{\text{ppm}}{10^6\ \text{ppm/part}} \times \frac{\text{SCFH x} \qquad \text{lb/lb-mol}}{\text{SCF/lb-mol}} = \frac{\text{lb}}{\text{hr}}$$

Emissions Rate (ton/year)

Calculation for tons per year emission rate based on 8760 hours per year. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{ton/yr} = \frac{E_{lb/hr} \times hr_{year}}{2000}$$

$$E_{ton/yr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{hr}}{\text{year}} \times \frac{\text{ton}}{\text{2000 lb}} = \frac{\text{ton}}{\text{year}}$$

Emissions Rate (lb/MMBtu)

RM 19, (07-19-06), 12.2 Emission Rates of PM, SO2, and NOx. Select from the following sections the applicable procedure to compute the PM, SO2, or NOx emission rate (E) in ng/J (lb/million Btu). (calc for gas Run 1, if applicable)

Oxygen Based

12.2.1 Oxygen-Based F Factor, Dry Basis. When measurements are on a dry basis for both O_2 (%O_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}} \qquad \text{Eq. 19-1}$$

$$E_{lb/MMBtu} = \frac{\text{ppm x} \qquad \text{SCF/MMBtu x} \qquad \text{lb/ppm*ft}^3\ \text{x 20.9\%}}{\text{20.9\% -} \qquad \text{\%}} = \frac{\text{lb}}{\text{MMBtu}}$$

Carbon Dioxide Based

12.2.4 Carbon Dioxide-Based F Factor, Dry Basis. When measurements are on a dry basis for both CO_2 (%CO_2d) and pollutant (Cd) concentrations, use the following equation:

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}} \qquad \text{Eq. 19-6}$$

$$E_{lb/MMBtu} = \frac{\text{ppm x} \qquad \text{SCF/MMBtu x} \qquad \text{lb/ppm*ft}^3\ \text{x 100\%}}{\text{\%}} = \frac{\text{lb}}{\text{MMBtu}}$$

Conversion Constant

Convc for

$$Conv_c(lb/ppm \cdot ft^3) = \frac{\frac{MW}{G}}{10^6}$$

$$Conv_c = \frac{\frac{\text{lb}}{\text{lb•mole}} \times \frac{\text{lb•mole}}{\text{SCF}}}{10^6} = \frac{\text{lb}}{\text{ppm-ft}^3}$$

Sulfur Dioxide Rate (lb/MMBtu), 40CFR60, App. A, RM 19, Eq. 19-25 (11/20/03)

$$SO_2(lb/MMBtu) = 0.97 \times K \times \frac{S(wt\%)}{GCV}$$

$$SO_2 = 0.97 \times \frac{2\text{x}10^4\ \text{Btu}}{\text{wt\%•MMBtu}} \times \frac{\text{wt\%}}{\text{Btu/lb}} = \frac{\text{lb}}{\text{MMBtu}}$$

Emissions Rate (g/hp-hr)

Calculation for grams per horsepower-hour. Calculate, as follows: (calc for gas Run 1, if applicable)

$$E_{g/hp\cdot hr} = \frac{E_{lb/hr} \times 453.6}{mw \times 1314.022}\ or\ \frac{E_{lb/hr} \times 453.6}{hp}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{453.6 g}}{\text{lb}} \times \frac{1}{\text{mw}} \times \frac{\text{mw}}{\text{1314.022 hp}} = \frac{\text{g}}{\text{hp*hr}}$$

$$E_{g/hp\text{-}hr} = \frac{\text{lb}}{\text{hr}} \times \frac{\text{453.6 g}}{\text{lb}} \times \frac{1}{\text{hp}} = \frac{\text{g}}{\text{hp*hr}}$$

Note: Lack of significant figures may cause rounding errors between actual calculations and example calculations.

RM 7E, (08-15-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

ACE = Analyzer calibration error, percent of calibration span.
B_{WS} = Moisture content of sample gas as measured by Method 4 or other approved method, percent/100.
C_{Avg} = Average unadjusted gas concentration indicated by data recorder for the test run.
C_D = Pollutant concentration adjusted to dry conditions.
C_{Dir} = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode.
C_{Gas} = Average effluent gas concentration adjusted for bias.
C_M = Average of initial and final system calibration bias (or 2-point system calibration error) check responses for the upscale calibration gas.
C_{MA} = Actual concentration of the upscale calibration gas, ppmv.
C_O = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas.
C_S = Measured concentration of a calibration gas (low, mid, or high) when introduced in system calibration mode.
C_{SS} = Concentration of NOx measured in the spiked sample.
C_{Spike} = Concentration of NOx in the undiluted spike gas.
C_{Calc} = Calculated concentration of NOx in the spike gas diluted in the sample.
C_V = Manufacturer certified concentration of a calibration gas (low, mid, or high).
C_W = Pollutant concentration measured under moist sample conditions, wet basis.
CS = Calibration span.
D = Drift assessment, percent of calibration span.
E_p = The predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level response.
Eff_{NO2} = NO_2 to NO converter efficiency, percent.
H = High calibration gas, designator.
L = Low calibration gas, designator.
M = Mid calibration gas, designator.
NOFinal = The average NO concentration observed with the analyzer in the NO mode during the converter efficiency test in Section 16.2.2.
NOxCorr = The NOx concentration corrected for the converter efficiency.
NOxFinal = The final NOx concentration observed during the converter efficiency test in Section 16.2.2.
NOxPeak = The highest NOx concentration observed during the converter efficiency test in Section 16.2.2.
Q_{Spike} = Flow rate of spike gas introduced in system calibration mode, L/min.
Q_{Total} = Total sample flow rate during the spike test, L/min.
R = Spike recovery, percent.
SB = System bias, percent of calibration span.
SB_i = Pre-run system bias, percent of calibration span.
SB_f = Post-run system bias, percent of calibration span.
SB / D_{Alt} = Alternative absolute difference criteria to pass bias and/or drift checks.
SCE = System calibration error, percent of calibration span.
SCE_i = Pre-run system calibration error, percent of calibration span.
SCE_{final} = Post-run system calibration error, percent of calibration span.
Z = Zero calibration gas, designator.

40CFR60.355(b)(1), (09-20-06), Nomenclature. The terms used in the equations are defined as follows:

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
P_o = observed combustor inlet absolute pressure at test, mm Hg
H_o = observed humidity of ambient air, g H_2O/g air
e = transcendental constant, 2.718
T_a = ambient temperature, K

Small Engine and FTIR Nomenclature. The terms used in the equations are defined as follows:

bhp = brake horsepower
hp = horsepower
Q_{sys} = system flow (lpm)
Q_m = matrix spike flow (lpm)

RM 19, (07-29-06), 12.1 Nomenclature. The terms used in the equations are defined as follows:

AdjFactor = percent oxygen or carbon dioxide adjustment applied to a target polltant

B_{wa} = Moisture fraction of ambient air, percent.

Btu = British thermal unit

$\%_C$ = Concentration of carbon from an ultimate analysis of fuel, weight percent.

$\%_{CO2d}$, $\%_{CO2w}$ = Concentration of carbon dioxide on a dry and wet basis, respectively, percent.

CIP / CDP = Combustor inlet pressure / compressor discharge pressure (mm Hg); note, some manufactures reference as PCD.

E = Pollutant emission rate, ng/J (lb/million Btu).

E_a = Average pollutant rate for the specified performance test period, ng/J (lb/million Btu).

E_{ao}, E_{ai} = Average pollutant rate of the control device, outlet and inlet, respectively, for the performance test period, ng/J (lb/million Btu).

E_{bi} = Pollutant rate from the steam generating unit, ng/J (lb/million Btu).

E_{bo} = Pollutant emission rate from the steam generating unit, ng/J (lb/million Btu).

E_{ci} = Pollutant rate in combined effluent, ng/J (lb/million Btu).

E_{co} = Pollutant emission rate in combined effluent, ng/J (lb/million Btu).

E_d = Average pollutant rate for each sampling period (e.g.,24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g., amount of fuel bunkered), ng/J (lb/million Btu).

E_{di} = Average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu).

E_g = Pollutant rate from gas turbine, ng/J (lb/million Btu).

E_{ga} = Daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent O_2.

E_{jo},E_{ji} = Matched pair hourly arithmetic average pollutant rate, outlet and inlet, respectively, ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

E_h = Hourly average pollutant, ng/J (lb/million Btu).

E_{hj} = Hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

EXP = Natural logarithmic base (2.718) raised to the value enclosed by brackets.

Fc = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19

F_d, F_w, F_c = Volumes of combustion components per unit of heat content, scm/J (scf/million Btu).

ft^3 = cubic feet

G = ideal gas conversion factor

(385.23 SCF/lb-mol at 68 deg F & 14.696 psia)

GCM = gross Btu per SCF (constant, compound based)

GCV = Gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).

GCV_p, GCV_r = Gross calorific value for the product and raw fuel lots, respectively, dry basis, kJ/kg (Btu/lb).

$\%_H$ = Concentration of hydrogen from an ultimate analysis of fuel, weight percent.

H_b = Heat input rate to the steam generating unit from fuels fired in the steam generating unit, J/hr (million Btu/hr).

H_g = Heat input rate to gas turbine from all fuels fired in the gas turbine, J/hr (million Btu/hr).

$\%_{H2O}$ = Concentration of water from an ultimate analysis of fuel, weight percent.

H_r = Total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

K = volume of combustion component per pound of component (constant)

K = Conversion factor, 10^{-5} (kJ/J)/(%) [10^6 Btu/million Btu].

K_c = (9.57 scm/kg)/% [(1.53 scf/lb)/%].

K_{cc} = (2.0 scm/kg)/% [(0.321 scf/lb)/%].

K_{hd} = (22.7 scm/kg)/% [(3.64 scf/lb)/%].

K_{hw} = (34.74 scm/kg)/% [(5.57 scf/lb)/%].

K_n = (0.86 scm/kg)/% [(0.14 scf/lb)/%].

K_o = (2.85 scm/kg)/% [(0.46 scf/lb)/%].

K_s = (3.54 scm/kg)/% [(0.57 scf/lb)/%].

K_{sulfur} = $2x10^4$ Btu/wt%-MMBtu

K_w = (1.30 scm/kg)/% [(0.21 scf/lb)/%].

lb = pound

ln = Natural log of indicated value.

L_p,L_r = Weight of the product and raw fuel lots, respectively, metric ton (ton).

$\%_N$ = Concentration of nitrogen from an ultimate analysis of fuel, weight percent.

$M_{\%}$ = mole percent

mol = mole

MW = molecular weight (lb/lb-mol)

MW_{AIR} = molecular weight of air (28.9625 lb/lb-mole)[1]

NCM = net Btu per SCF (constant based on compound)

$\%_O$ = Concentration of oxygen from an ultimate analysis of fuel, weight percent.

$\%_{O2d}$, $\%_{O2w}$ = Concentration of oxygen on a dry and wet basis, respectively, percent.

P_B = barometirc pressure, in Hg

P_s = Potential SO2 emissions, percent.

$\%_S$ = Sulfur content of as-fired fuel lot, dry basis, weight percent.

S_e = Standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

$\%_{Sf}$ = Concentration of sulfur from an ultimate analysis of fuel, weight percent.

S(wt%) = weight percent of sulfur, per lab analysis by appropriate ASTM standard

S_i = Standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

S_o = Standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

$\%S_p$, $\%S_r$ = Sulfur content of the product and raw fuel lots respectively, dry basis, weight percent.

SCF = standard cubic feet

SH = specific humidity, pounds of water per pound of air

$t_{0.95}$ = Values shown in Table 19-3 for the indicated number of data points n.

T_{amb} = ambient temperature, °F

W/D Factor = 1.0236 = conv. at 14.696 psia and

68 deg F (ref. Civil Eng. Ref. Manual, 7th Ed.)

X_{CO2}=CO_2 Correction factor, percent.

X_k = Fraction of total heat input from each type of fuel k.

Calculations, Formulas, and Constants

The following information supports the spreadsheets for this testing project.

Given Data:

Ideal Gas Conversion Factor = 385.23 SCF/lb-mol at 68 deg F & 14.696 psia

Fuel Heating Value is based upon Air Hygiene's fuel gas calculation sheet. All calculations are based upon a correction to 68 deg F & 14.696 psia

High Heating Values (HHV) are used for the Fuel Heating Value, F-Factor, and Fuel Flow Data per EPA requirements.

ASTM D 3588

Molecular Weight of NOx (lb/lb-mole) =	46.01
Molecular Weight of CO (lb/lb-mole) =	28.00
Molecular Weight of SO2 (lb/lb-mole) =	64.00
Molecular Weight of THC (propane) (lb/lb-mole) =	44.00
Molecular Weight of VOC (methane) (lb/lb-mole) =	16.00
Molecular Weight of NH3 (lb/lb-mole) =	17.03
Molecular Weight of HCHO (lb/lb-mole) =	30.03

40CFR60, App. A., RM 19, Table 19-1

Conversion Constant for NOx =	0.0000001194351
Conversion Constant for CO =	0.0000000726839
Conversion Constant for SO2 =	0.0000001661345
Conversion Constant for THC =	0.0000001142175
Conversion Constant for VOC (methane) =	0.0000000415336
Conversion Constant for NH_3 =	0.0000000442074
Conversion Constant for HCHO =	0.0000000779534

NOTE: units are lb/ppm*ft^3

Formulas:

1. Corrected Raw Average (C_{Gas}), 40CFR60, App. A, RM 7E, Eq. 7E-5 (08/15/06)

$$C_{Gas} = (C_{Avg} - C_O) \times \left(\frac{C_{MA}}{C_M - C_O}\right)$$

2. Correction to % O_2, 40CFR60, App. A, RM 20, Eq. 20-5 (11/26/02)

$$C_{adj} = C_{Gas(Target)} \times \left(\frac{20.9\% - AdjFactor}{20.9\% - C_{Gas(O2)}}\right)$$

3. Emission Rate in lb/hr

$$E_{lb/hr} = \frac{C_{Gas}}{10^6} \times \frac{Q_S \times MW}{G}$$

4. Emission Concentration in lb/MMBtu (O_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 20.9\%}{20.9\% - C_{Gas(O2)}}$$

5. Emission Concentration in lb/MMBtu (CO_2 based)

$$E_{lb/MMBtu} = \frac{C_{Gas} \times F_d Factor \times Conv_C \times 100\%}{C_{Gas(CO2)}}$$

RATA SHEET CALCULATIONS

d = Reference Method Data - CEMS Data

S_d = Standard Deviation

CC = Confident Coefficient

n = number of runs

$t_{0.025}$ = 2.5 percent confidence coefficent T-values

RA = relative accuracy

ARA = alternative relative accuracy

BAF = Bias adjustment factor

n	t	n	t	n	t
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

1. Difference

$$d = \sum_{i=1}^{n} d_i$$

2. Standard Deviation

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

3. Confident Coefficient

$$CC = t_{0.025} \times \frac{S_d}{\sqrt{n}}$$

4. Relative Accuracy

$$RA = \frac{|d_{AVG}| + |CC|}{RM_{AVG}} \times 100$$

5. Alternative Relative Accuracy

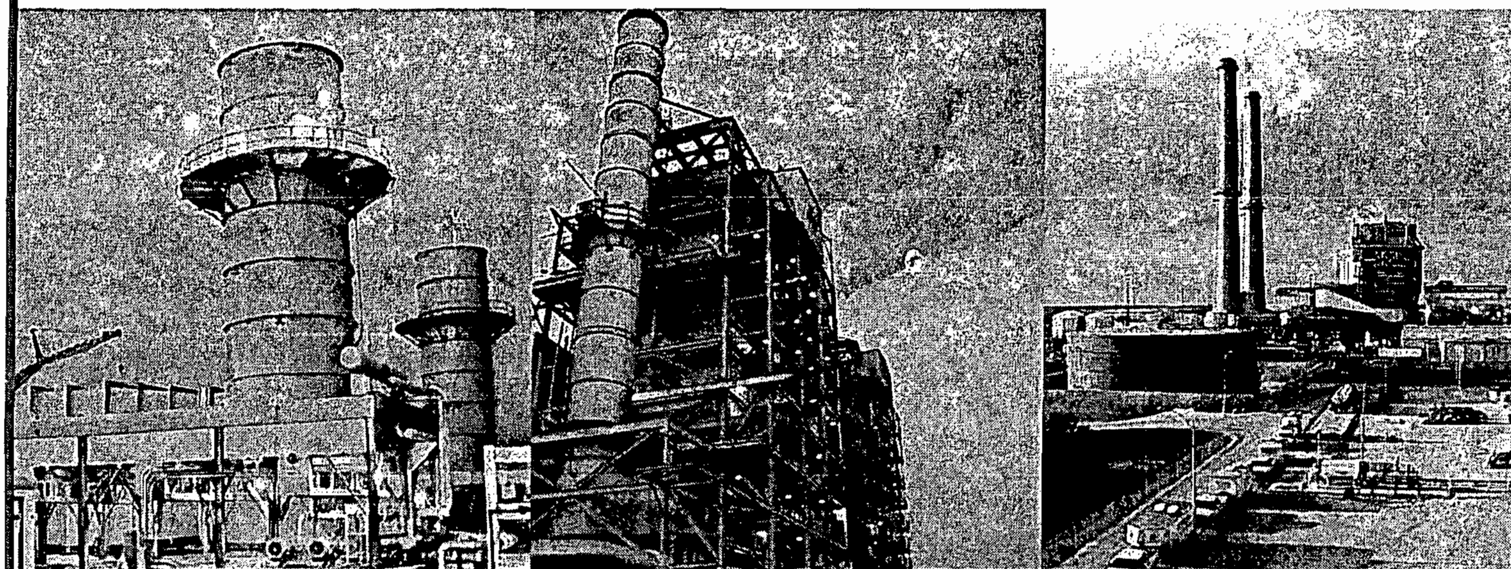
$$ARA = \frac{|d_{AVG}| + |CC|}{AS} \times 100$$

5. Bias Adjustment Factor

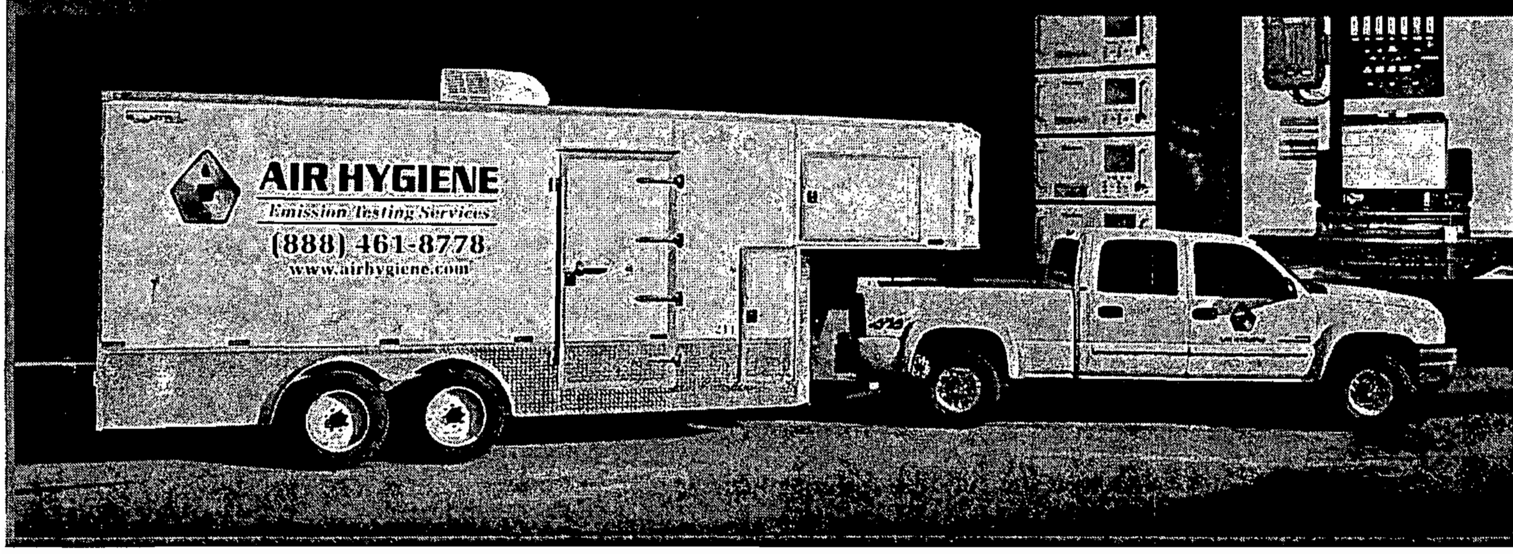
$$BAF = 1 + \left(\frac{|d_{AVG}|}{CEM_{AVG}}\right)$$

APPENDIX E
STATEMENT OF QUALIFICATIONS

AIR HYGIENE, INC.



Testing Solutions for a Better World



Statement of Qualifications - 2010

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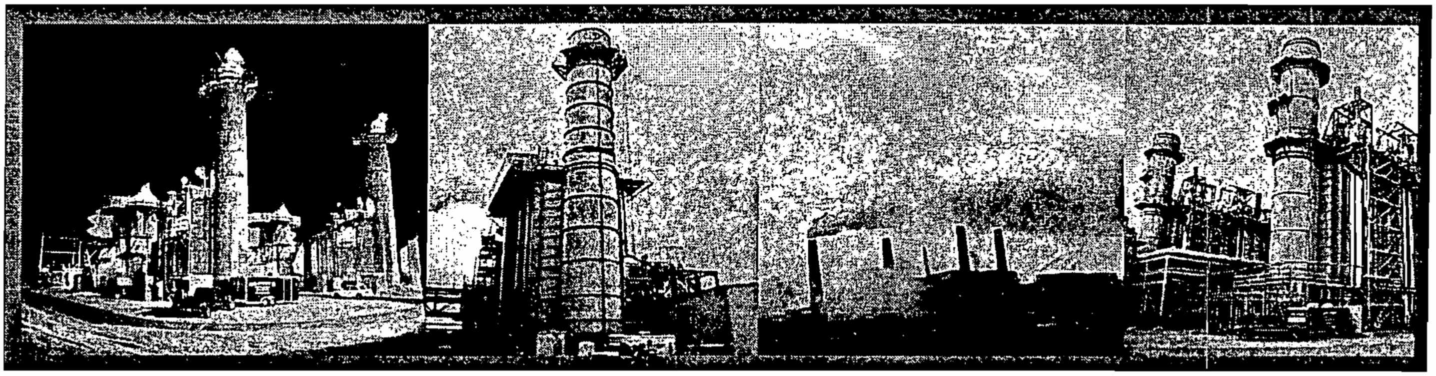


STATEMENT OF QUALIFICATIONS

AIR HYGIENE

AIR EMISSION TESTING SERVICES
www.airhygiene.com
January, 2010

INTRODUCTION

AIR HYGIENE INTERNATIONAL, INC. (AIR HYGIENE) is a professional air emission testing services firm operating from corporate headquarters in Tulsa, Oklahoma for over 13 years. Additional field offices with ready for field use testing labs are strategically located in Houston, Texas; Las Vegas, Nevada; and Philadelphia, Pennsylvania to serve all fifty (50) United States, Mexico, and Canada. AIR HYGIENE specializes in air emission testing services for combustion sources burning multiple fuels with multiple control devices and supporting equipment.

AIR HYGIENE has testing laboratories which serve all fifty (50) of the United States and North America. Each mobile laboratory can be equipped with the following equipment and capabilities:

1. State-of-the-Art air emission analyzers, computers, and datalogging software. All designed into an efficient system to provide the fastest, most reliable data possible!
2. Dual racks for multiple source testing simultaneously or multiple points on a single source (in/out SCR, etc.)!
3. NIST traceable gases for the most accurate calibration. Ranges as low as five (5) ppm!
4. PM_{10}, NH_3, mercury (Hg), sulfuric acid mist (H_2SO_4), SO_3, and formaldehyde sampling equipment!
5. VOC testing with on-board gas chromatograph to remove methane and ethane!
6. On-board printers to provide hard copies of testing information on-site!
7. Networking capabilities to provide real-time emission data directly into the control room!

AIR HYGIENE is known for providing professional services which include the following:

- Superior, cost saving services to our clients!
- High quality emission testing personnel with service oriented, friendly attitude!
- Meeting our client's needs whether it is 24 hour a day testing or short notice mobilization!
- Using great equipment that is maintained and dependable!
- Understanding the unique startup and operational needs associated with combustion sources!

MISSION STATEMENT

Our mission is to provide innovative, practical, top-quality services allowing our clients to increase operating efficiency, save money, and comply with federal/state requirements. We believe our first responsibility is to the client. In providing our unique services, the owners of AIR HYGIENE demand ethical conduct from each employee of the company. The character and integrity of AIR HYGIENE employees allows our clients to feel confidence in the air testing services of AIR HYGIENE. Through a long-term commitment to this mission, AIR HYGIENE is known as a company committed to improving our clients' operations.

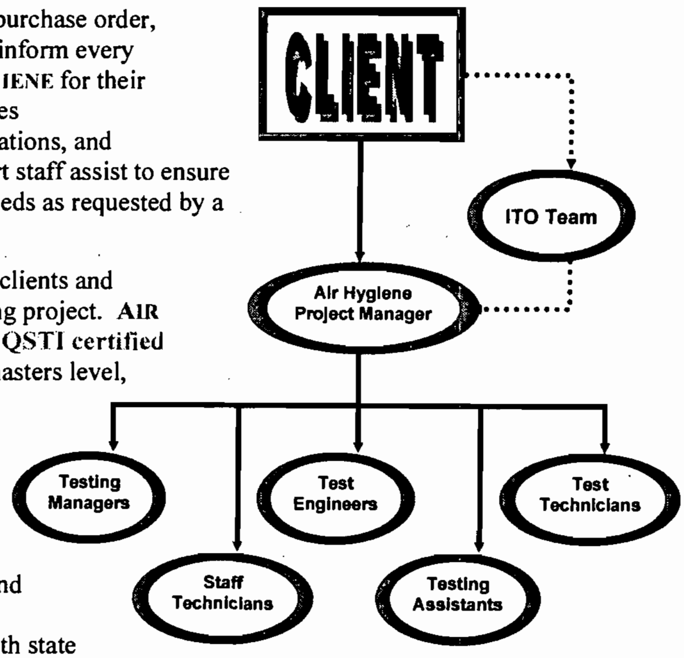
AIR HYGIENE … Does work worth paying for every time!
… Is well known for our emission testing services and uncompromising efforts to serve our clients!
… Does work that matters!
… Is proud of our emission testing capabilities!
… Provides exciting growth opportunities for energetic individuals!

Testing Solutions for a Better World

AIR HYGIENE, INC.

EMISSION TESTING TEAM

Air Hygiene International, Inc. (**AIR HYGIENE**) intends to exceed your expectations on every project. From project management to field-testing teams, we're committed to hard work on your behalf. The job descriptions and flowchart below outline **AIR HYGIENE**'s client management strategy for your testing services.



From the initial request through receipt of the purchase order, the Inquisition To Order (ITO) team strives to inform every client of the benefits gained by using **AIR HYGIENE** for their emission testing project. The ITO team includes representatives from the sales, marketing, operations, and contracts divisions. In addition, several support staff assist to ensure the ITO team provides the support for client needs as requested by a client or project manager.

Project Managers are the primary contact for clients and ultimately responsible for every emission testing project. **AIR HYGIENE**'s Project Managers include ten (10) QSTI certified testing experts with experience ranging from masters level, professional engineers to industry experts with over 5,000 testing projects completed. Each project is assigned a Project Manager based primarily upon geographic location, then industry experience, contact history, and availability. The Project Manager prepares the testing strategy and organization for the project. This includes preparation of testing protocol; coordination with state agencies, client representatives, and any interested third parties. The site testing and report preparation are executed under the direction of the Project Manager from start to finish.

Testing Managers have completed Air Hygiene's rigorous demonstration of capability training program and are capable of operating all testing equipment and performing all test methods required for your testing project. Testing Managers assist Project Managers by leading the field testing when required, preparing draft reports, calibrating equipment, and overseeing testing team on-site.

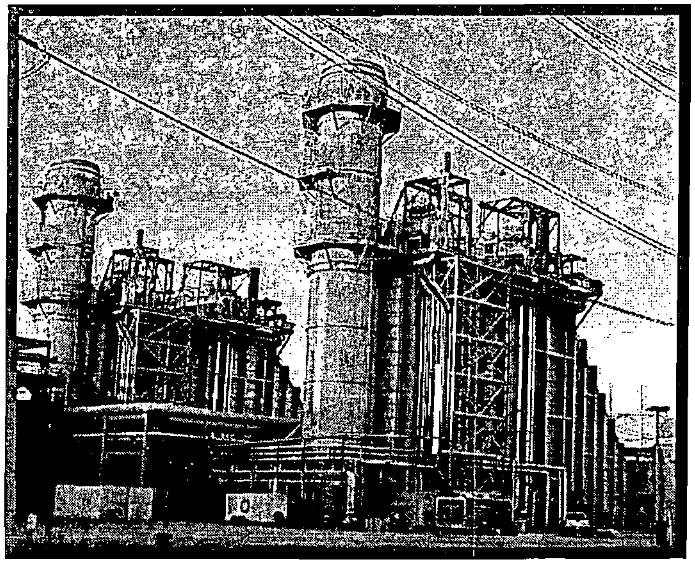
Test Engineers have significant background and understanding of emission testing or related services. Test Engineers prepare pre-test drawings for port location, ensure on-site logistics for electrical and mechanical/structural needs, and conduct on site testing as directed by the Project Manager and/or Testing Manager. Test Engineers often have special understanding of process and/or regulations applicable to specific testing jobs, which provide great value to both the client and Project Manager in testing strategies.

Test Technicians experience ranges from new hire with technical degree and experience to technicians who have performed up to 500 emission tests. All test technicians have a basic understanding of emission training and are involved in daily training and under supervision to continue to develop testing skills. Test Technicians have testing experience with **AIR HYGIENE** equipment along with a variety of industries and source equipment. Test Technicians may operate isokinetic sampling trains or gas analyzers on-site under the direction of the Project Manager and assist with preparation of field reports and quality assurance procedures.

Staff Technicians are entry-level personnel who have performed less than 500 emission tests. Staff Technicians perform pre-test equipment preparation, on-site test preparation, and testing assistance under the direction of Project Manager and/or Testing Manager. At least one Staff Technician is assigned to every project to assist on-site. Staff Technicians connect sampling probes to ports, assist with leak checks, raise and lower equipment to and from sampling platform, and other support activities under the direction of the Project Manager and/or Testing Manager.

Testing Assistants are entry-level personnel who have performed less than 100 emission tests. Testing Assistants help with equipment set-up, teardown, and simple testing procedures (i.e. move probe, fill ice bath, clean impingers, etc.) as directed.

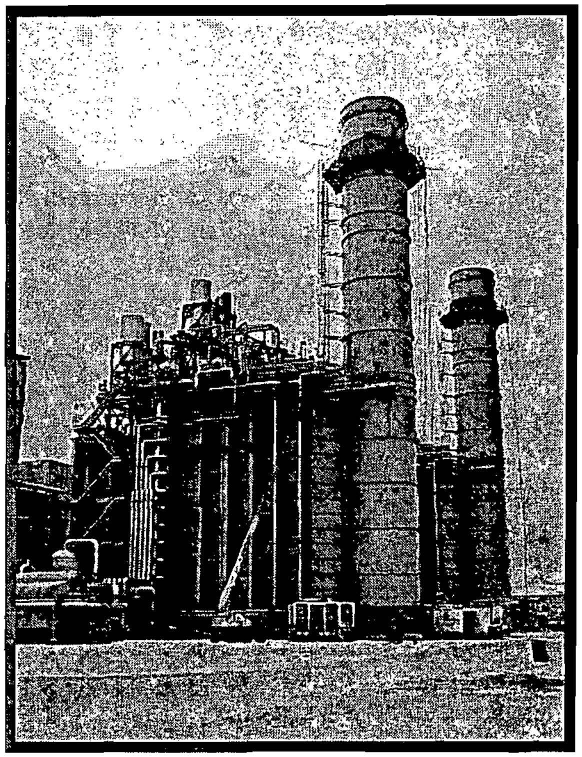
AIR HYGIENE Emission Services Summary



AIR HYGIENE is a privately-held professional services firm headquartered in Tulsa, Oklahoma with additional field offices in Las Vegas, Nevada, Houston, Texas; Ft. Worth, Texas; Shreveport, Louisiana; and Philadelphia, Pennsylvania. AIR HYGIENE specializes in emission testing services for a variety of industries including solid, liquid, & gas fired utility plants, turbines, engines, refineries, printers, glass plants, chemical plants, various manufacturers and related industries.

AIR HYGIENE provides turn-key emission testing services with fast-turnaround which include:

1. Pre-test site visit;
2. Consulting on port locations and setup;
3. Preparation of test plan for state agency;
4. Coordination with state agency for emission testing;
5. On-site emission testing services; and
6. Preparation of draft and final reports.



AIR HYGIENE has mobile laboratories that serve all 50 United States and North America. AIR HYGIENE has performed over 15,000 emission tests on a variety of sources.

AIR HYGIENE performs air emission certification compliance testing on combustion sources (natural gas, biomass, coal, fuel oil, jet fuel, etc), NSPS sources, and Title V compliance sites. Our experience ranges from emission testing for new PSD facilities, MACT and RACT required performance certification testing to Relative Accuracy Test Audits (RATA Tests) for Continuous Emission Monitoring Systems (CEMS) and Parametric Emission Monitoring Systems (PEMS).

Air Hygiene has conducted numerous emission testing projects, which involved multiple groups relying upon instantaneous reporting of important test data. These projects relied upon **Air Hygiene**'s SPIDER network. The SPIDER network provides Simultaneously Produced Information During Emission Readings (SPIDER) between the emission monitoring system and multiple locations (i.e. control room, test center, office, etc.). Hence, you can view real-time emission testing data on-demand from any location you choose using our wireless network data-logging system!

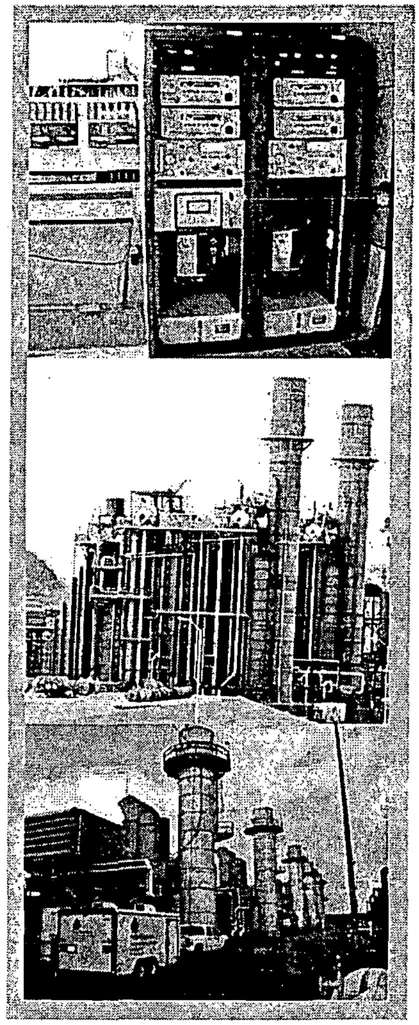
AIR HYGIENE performs FTIR testing by EPA Method 320 321, & ASTM D-6348 for Hazardous Air Pollutants (HAPS) including formaldehyde, benzene, xylene, toluene, hexane, ammonia, hydrogen chloride, etc. This methodology provides real-time analysis of these critical pollutants.

AIR HYGIENE specializes in the following types of pollutants and EPA Reference Methods (RM):

- Exhaust Flow – RM 2 &/or 19
- Carbon Dioxide (CO_2) – RM 3a
- Oxygen (O_2) – RM 3a &/or 20
- Moisture – RM 4
- Particulates (PM) – RM 5(filterable) & 202/OTM-028
- PM < 10 microns (PM_{10}) – RM 201a
- PM < 2.5 microns ($PM_{2.5}$) – RM 201b
- PM sizing (elzone analysis)
- Sulfur Dioxide (SO_2) – RM 6c
- Nitrogen Oxides (NOx) – RM 7e &/or 20
- Sulfuric Acid Mist (SO3) – RM 8a (control condensate)
- Opacity – RM 9
- Carbon Monoxide (CO) – RM 10
- Hydrogen Sulfide (H_2S) – RM 11
- Lead – RM 12
- Dioxin & Furans – RM 23
- Total Hydrocarbons (THC) – RM 25a
- Volatile Organic Compounds (VOC) RM 25a & RM 18
- Metals – RM 29
- Chrome – RM 306
- Formaldehyde – RM 320 & ASTM D-6348 (FTIR)
- HAPS – FTIR – RM 320, 321, & ASTM D-6348 (FTIR)
- Ammonia – RM 320, CTM-027, or BAAQMD ST-1B
- <u>Mercury – RM 30b-Sorbent Tubes (both with on-site analysis, Ontario-Hydro, and RM 29</u>

TESTING EXPERIENCE

AIR HYGIENE testing personnel include ten (10) QSTI certified test managers and account for more than one hundred (100) years of testing experience and over 18,000 emission tests. Our testing services have involved interaction with all 50 state agencies and EPA regional offices. AIR HYGIENE testing personnel are rigorously trained on EPA reference test methods from 40 CFR Part 51, 60, 63, and 75 along with ASTM methods. All testing personnel are instructed and tested on test responsibilities and must complete a "Demonstration of Capability" test per the AIR HYGIENE Quality Assurance Manual and the AIR HYGIENE Emission Testing Standard Operating Procedures Handbook.



AIR HYGIENE has completed testing on over 250 power plants including in excess of 1,000 combustion turbines and 50 coal fired boilers 100,000 megawatts (MW). ***Let us add your project to our list of satisfied customers!***

TESTING SUCCESS STORIES

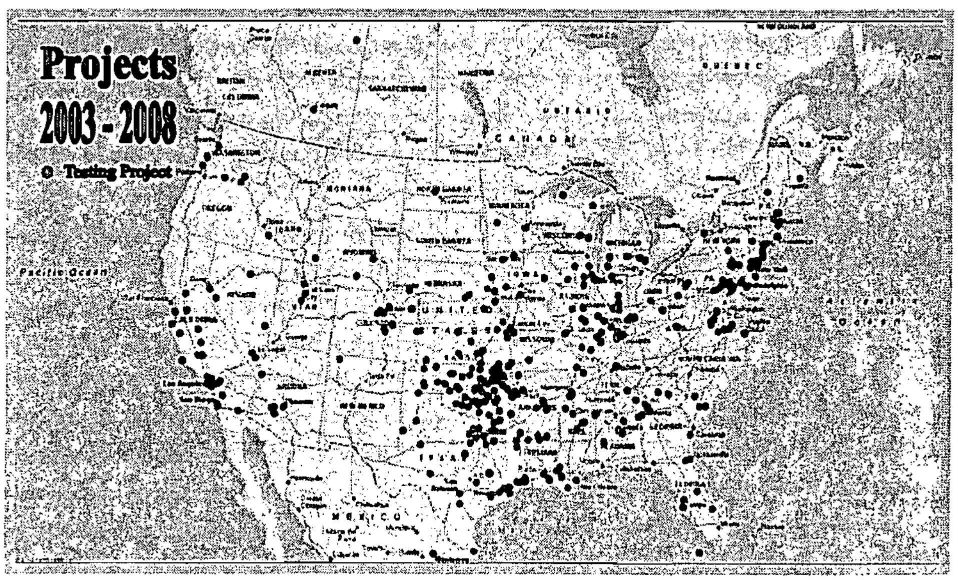
AIR HYGIENE personnel have performed thousands of testing projects which have yielded significant benefits for our clients. The following project descriptions briefly discuss some of these emission testing projects.

- Conducted Mercury (Hg), PM, selected metals, HCl, Chlorine, and gas testing to verify status with the industrial boiler MACT on six coal fired units at three (3) locations.
- Conducted inlet/outlet baghouse emission testing for Mercury (Hg) to determine control efficiency using Ontario-Hyrdo testing methodology.
- Conducted numerous projects optimizing SCR performance by conducting inlet & outlet SCR analysis for NH_3, NOx, flow, and Oxygen. Used information to assist with flow optimization and AIG tuning.
- Conducted federal and state required compliance testing for NOx, CO, PM-10 (front & back-half), SO_2, VOC, Ammonia, Formaldehyde, Opacity, RATA testing (NOx and CO) for new and updated power plants with both simple and combined cycle turbines firing natural gas and fuel oil.
- Conducted dry low NOx burner tuning and performance testing for various models of GE, Siemens Westinghouse, Mitsubishi, Pratt & Whitney, and ABB combustion turbines to verify manufacturer's emission guarantees for clients in preparation for compliance testing.
- Performed power plant emission testing for natural gas & fuel oil fired combustion turbines. Tests included federal required testing per 40 CFR Part 75, state air permit requirements, RATA testing, and emission testing to verify manufacturer's guarantee's during electric/heat output performance testing.

TESTING LOCATIONS

AIR HYGIENE bases mobilization charges on the distance from your site to the closest of six (6) regional starting points covering all 50 United States. These include Las Vegas, Tulsa, Houston, Ft. Worth, Shreveport, and Philadelphia.

Each start point is located such that the AIR HYGIENE test teams can mobilize to your site within 24 hours at affordable costs to ensure we are price competitive to any U.S. location.



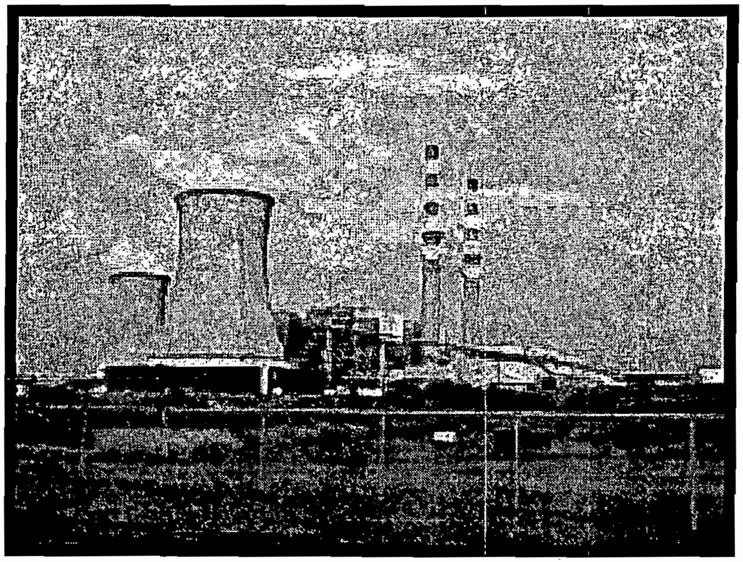
Testing Solutions for a Better World

AIR HYGIENE, INC.

COMBUSTION TESTING SERVICES SUMMARY

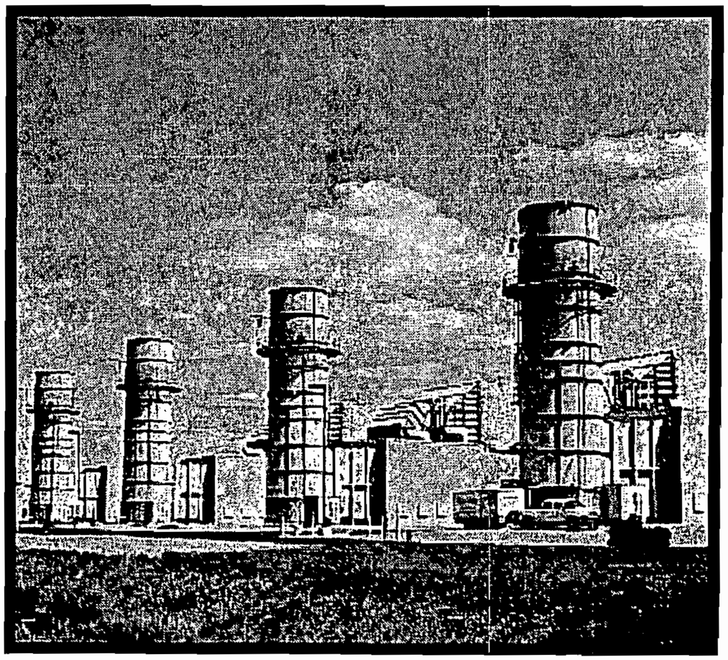
Thank you for your consideration of the combustion emission testing services of Air Hygiene International, Inc. (AIR HYGIENE). The following list details some of the testing services and extras AIR HYGIENE includes with each testing job.

Types of Air Testing Services for Combustion Sources:



- Boiler or Turbine tuning/mapping for NOx, CO, O2, CO2, flow, temperature, &/or NH_3 emissions
- Pollutant testing to verify EPC contractual emission guarantees
- Research and Development (R&D) emission data research and emissions optimization
- Mercury (Hg) testing with on-site data
- 40 CFR Part 60 Subpart GG or KKKK – Turbine Compliance Testing
- 40 CFR Part 75 – Acid Rain Classified Equipment Testing
- 40 CFR Part 75 Appendix E – Peaking Plant CEMS alternative NOx emissions versus Heat Input mapping
- RATA Testing on CEMS systems for NOx, CO, SO_2, CO_2 or O_2, Flow (3-D & Wall effects)
- QA/QC Plans, Monitoring Plans, Linearity Checks, Testing Protocols, etc. are provided with our high quality, service oriented emission testing services
- Initial permit compliance testing for PM, PM-10, PM-2.5, SO_2, NOx, CO, H2SO4, HCl, Hg, exhaust flow, moisture, O_2, CO_2, Ammonia, Formaldehyde, other HAPs

AIR HYGIENE will provide the following testing services:



- On-site, real-time test data
- Fuel F-Factor calculation data sheet
- Experienced emission testing personnel
- Flexible testing schedules to meet your needs
- Electronic reports provided on CD upon request
- Extensive experience with all 50 state agencies in the U.S., Mexico, & Canada
- EPA Protocol 1 Certified Gases (one percent accuracy) for precise calibration
- Low range (0-10 ppm) equipment calibration and measurement available
- Test protocol preparation, coordination with state agency, and site personnel
- Numerous mobile testing labs, which may be used for your projects across the U.S.
- State-of-the-art data logging technology to allow real-time examination of meaningful emission data
- Monitor your emissions data measured in our test lab from your control room via our datalogging network system

AIR HYGIENE is committed to providing testing teams that will take the time to meet your needs. We ensure the job is completed on time with the least amount of interruption to your job and site operation as possible. Thank you for considering our services.

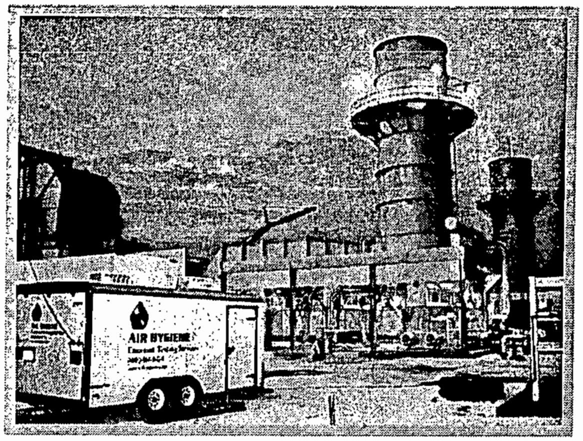
AIR HYGIENE, INC.

Testing Solutions for a Better World

SYNERGISTIC APPROACH TO POWER PLANT CONSTRUCTION PROJECT TESTING

Power plants continue to be built, modified, and improved across the United States. These new or modified facilities are at the forefront of clean energy. Emission rates and limits continue to decrease. These units are very efficient, environmentally friendly, and meet the stringent requirements set forth by the Environmental Protection Agency (EPA) and associated state agencies. AIR HYGIENE has developed a unique strategy to help owners demonstrate compliance with testing solutions for difficult sampling locations to meet complicated requirements.

Unique Testing Strategy



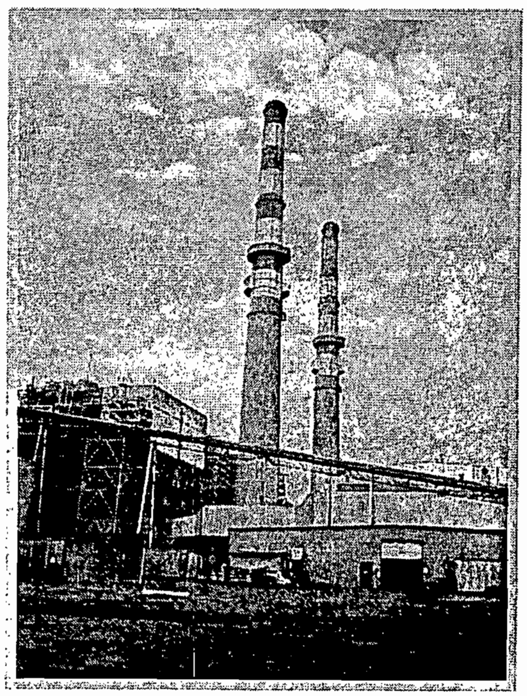
AIR HYGIENE has developed a synergistic approach to assisting the various groups involved in the completion of a commissioning/startup unit or modification project. AIR HYGIENE strives to combine the multiple testing aspects involved with bringing a combustion unit to commercial service. By conducting the various emission tests required for a new combustion unit using one test company, the following benefits are a given:

1. Save money by...
   a. Reduced mobilizations
   b. Combined tests yield reduced fuel usage and site time
   c. Bulk projects receive quantity discounts
2. Improve efficiency through familiarity with site needs
3. Site personnel and testing team are comfortable working together

These projects typically involve some or all of the following groups. There is not a defined set of responsibilities that will match every project. The table below simply suggests a typical list of testing responsibilities.

Responsible Party	**Testing Responsibilities**
Owner	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Operator	Initial and on-going federal and state compliance testing (i.e. NSPS Sub GG, Part 75, Operating Air Permit, etc.)
Turbine/Boiler manufacturer	Contractual emission guarantees of unit (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
EPC & Construction Company	Contractual emission guarantees including control devices (i.e. NOx, SO2, CO, VOC, PM-10, NH3, H2SO4)
CEMS Supplier	Initial RATA testing (i.e. NOx, CO, SO2, CO2, O2, flow)
Lending Party (i.e. bank)	No responsibility, but concerned with outcome of all tests
Environmental Consultant	Concerned with air permit and overall compliance; may select the test contractor and provide oversight for testing

Example Project:



A recent project provides a prime example of the synergistic benefits of using AIR HYGIENE to perform your commissioning/startup or remodification testing needs for performance and compliance. Eight GE Frame 7FA turbines were taken from performance testing through compliance testing in 20 days. The following tests were performed on each turbine:

- NOx tuning and mapping
- Contractual performance testing for NOx, CO, VOC, SO_2, NH_3, & PM_{10}
- 40 CFR Part 60 Subpart GG: testing for NOx and CO at max load
- 40 CFR Part 75: NOx & CO RATA certification on CEMS
- State required compliance testing for NOx, CO, VOC, NH_3(on-site analysis), formaldehyde (on-site analysis by FTIR), opacity and SO_2 burning natural gas

Test data was provided on-site for all tests, except PM-10. Electronic files were e-mailed for review to the turbine manufacturer, owner & operator, and environmental consultant within 24 hours following completion of site work. Complete reports including PM-10 were submitted to interested parties within 10 days following each blocks completion.

Power Plant Testing Experience

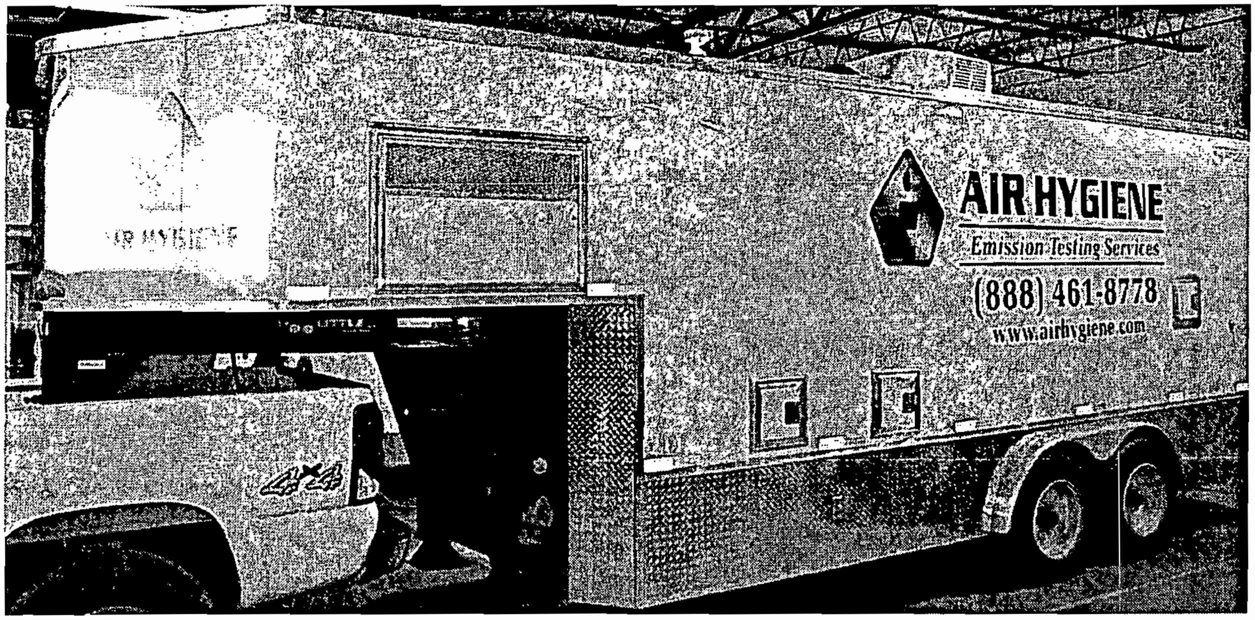
AIR HYGIENE personnel have over one hundred (100) years of testing experience on combustion turbines, coal fired boilers, gas fired boilers, landfill gas, wood fired, & diesel fired engines across the United States. AIR HYGIENE has 15 combustion labs serving all 50 states from one corporate office in Tulsa, OK and five (5) additional field offices (Houston, TX; Ft. Worth, TX; Shreveport, Louisiana; Las Vegas, NV; & Philadelphia, PA). AIR HYGIENE has tested plants ranging from 50 to 2,000 megawatts in both simple and combined cycle operation with controls including:

- Selective Catalytic Reduction - Ammonia injection
- Steam/Water injection
- Sprint injection
- Dry Low NOx burners (DLN)

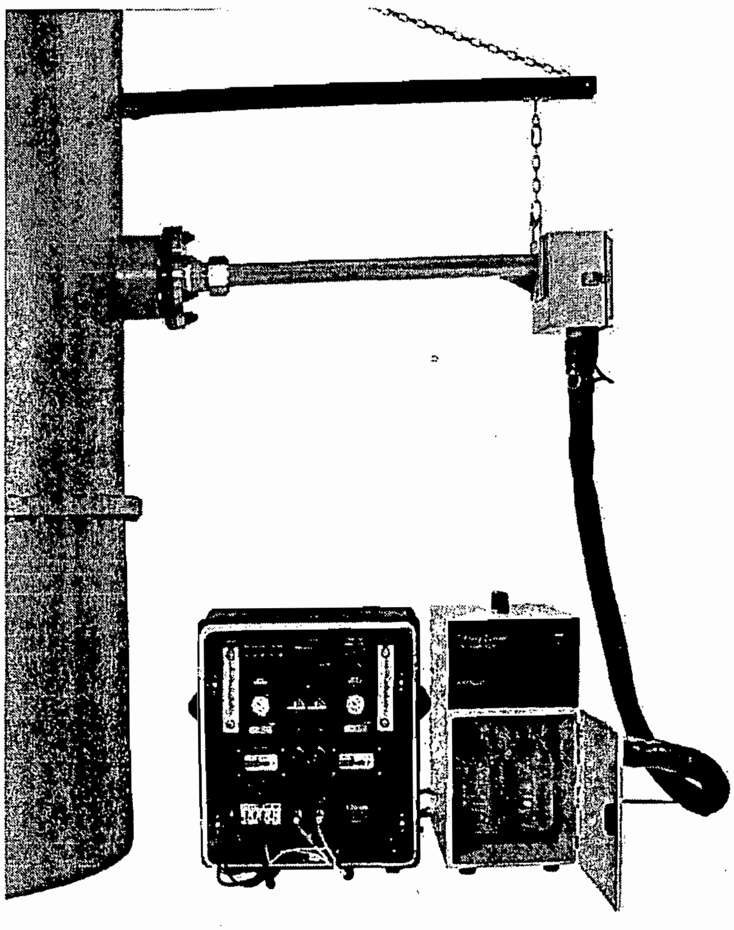
AIR HYGIENE has completed testing at over 250 plants on 1,000 combustion turbines, 50 coal fired boilers, 20 gas fired boilers, and other sources representing 100,000 plus megawatts (MW). AIR HYGIENE has proven through our numerous projects that we can be relied upon for uncompromised quality, service flexibility, and loyalty to our clients no matter where the job nor what the situation may be. ***Let us add your upcoming project to our list of satisfied customers!***

Air Hygiene Mercury Testing

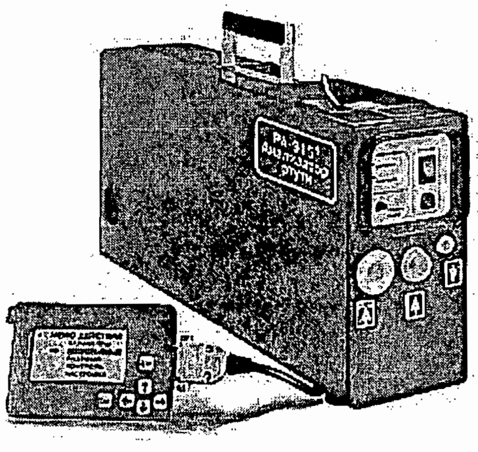
Air Hygiene Mercury Testing Lab

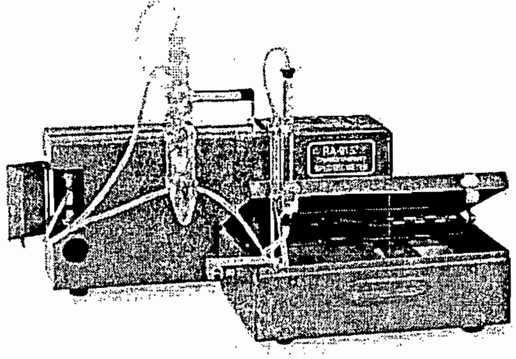


Apex 30B Console & Probe



Ohio Lumex: RA915+ Analyzer with RP-91 Attachment for Ontario Hydro or 30b sorbent trap analysis on-site





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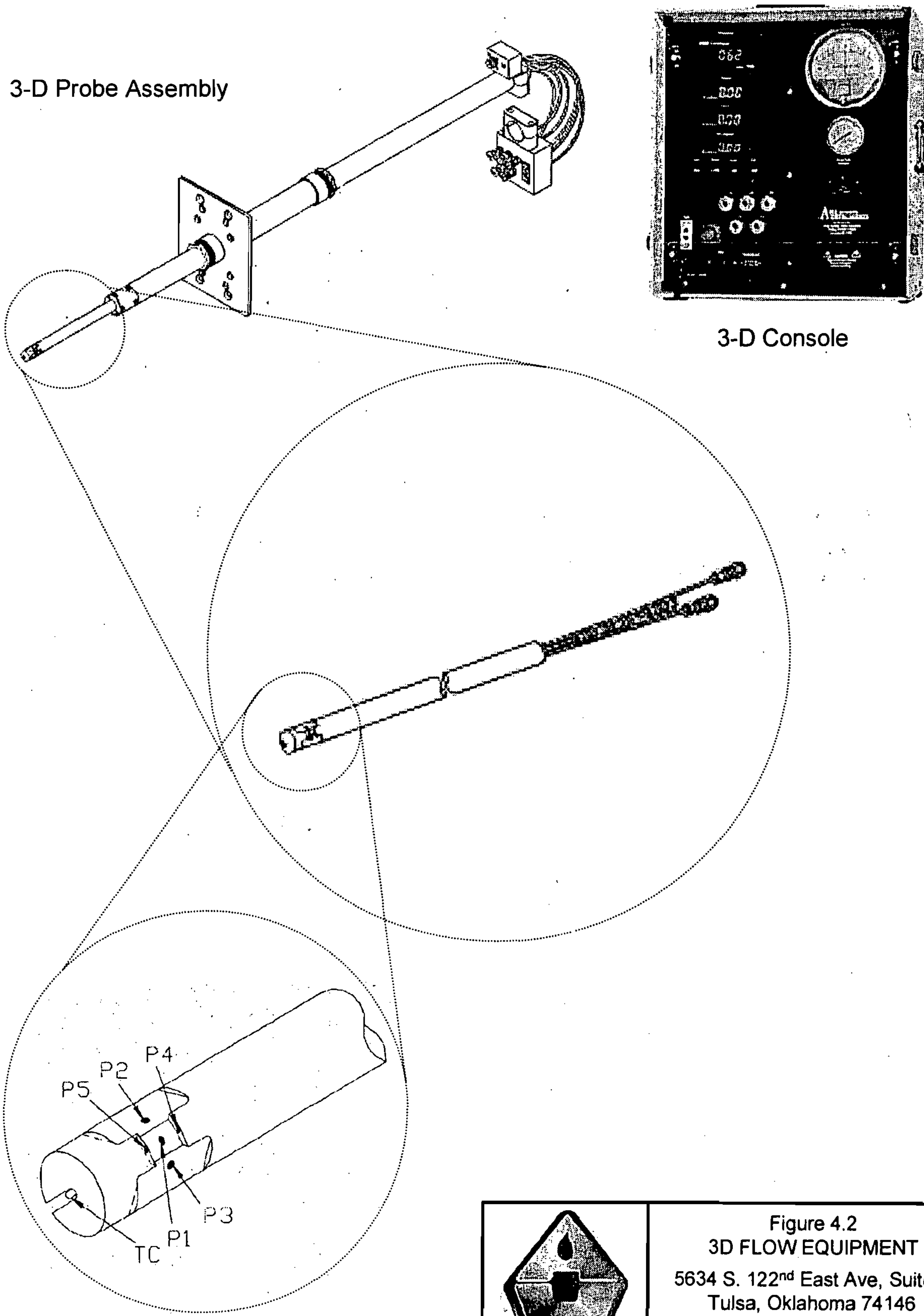

Prism Shaped 3D Pitot Head

AIR HYGIENE

Figure 4.2
3D FLOW EQUIPMENT

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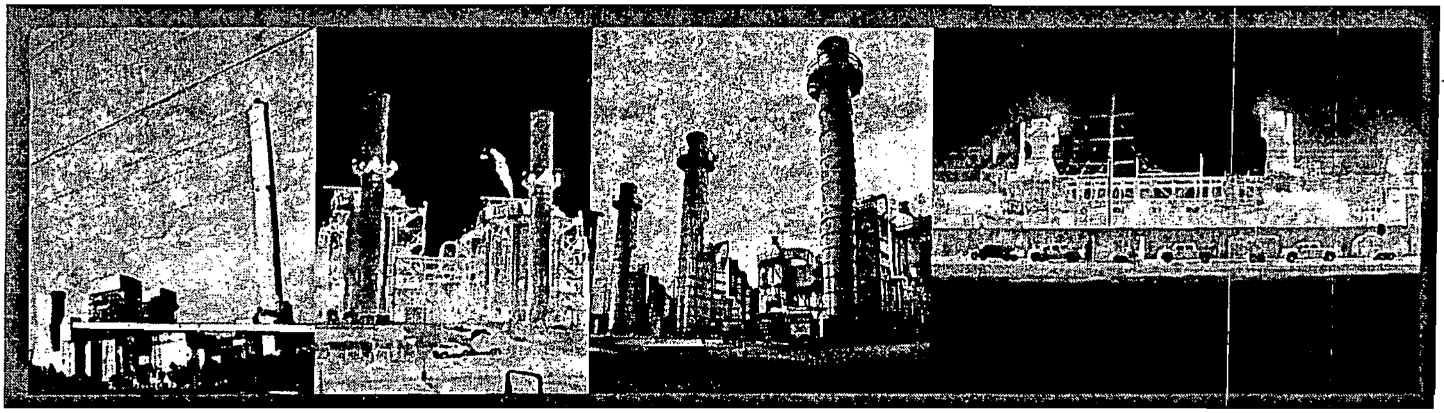

INSTRUMENT CONFIGURATION AND OPERATIONS FOR GAS ANALYSIS

The sampling and analysis procedures used by AIR HYGIENE during tests conform in principle with the methods outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 3a, 6c, 7e, 10, 18, 19, 20, and 25a.

The flowchart on the next page depicts the sample system used by AIR HYGIENE for analysis of oxygen (O_2), carbon dioxide (CO_2), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC) tests. A heated stainless steel probe is inserted into the sample ports of the stack to extract gas measurements from the emission stream. The gas sample is continuously pulled through the probe and transported via 3/8 inch heat-traced Teflon® tubing to a stainless steel minimum-contact condenser designed to dry the sample through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into the sample manifold within the mobile laboratory. From the manifold, the sample is partitioned to the O_2, CO_2, SO_2, CO, and NOx analyzers through glass and stainless steel rotameters that control the flow rate of the sample. The VOC sample is measured as a wet gas.

The flowchart shows that the sample system is also equipped with a separate path through which a calibration gas can be delivered to the probe and back through the entire sampling system. This allows for convenient performance of system bias checks as required by the testing methods.

All instruments are housed in an air-conditioned trailer which serves as a mobile laboratory. Gaseous calibration standards are provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 is used to determine the cylinder concentrations where applicable (i.e. NO_x calibration gases).

All data from the continuous monitoring instruments are recorded on a Logic Beach Hyperlogger which retrieves calibrated electronic data from each instrument every second and reports an average of the collected data every 30 seconds and 10 seconds. The averaging time can be selected to meet the clients needs. **This data is available instantaneously for printout, statistical analysis, viewable by actual values, or examined by a trending graph!**

The number of test runs, test loads, and length of runs is based upon federal and state requirements for the facility. Typical run times associated with emission testing are as follows:

Type of Test	***# of runs***	***Length of runs***
O_2 Traverse (GG)	1 run @ low load (8 – 48 points)	2 minutes per point
NOx Stratification Test	1 run @ base load (12 points)	2 – 4 minutes per point
Subpart GG or KKKK	3 runs @ 4 loads (30%, 50%, 75%, & 100%)	15 – 60 minutes per run
RATA	9 – 12 runs @ normal load	21 minutes per run
State Permit Test (gases)	3 runs @ base load	1 hour per run
State Permit Test (particulates)	3 runs @ base load	2 – 4 hours per run

The stack gas analysis for O_2 and CO_2 concentrations are performed in accordance with procedures set forth in EPA Method 3a (EPA Method 20 for O_2 on combustion turbines). The O_2 analyzer uses a paramagnetic cell detector. The CO_2 analyzer uses an infrared detector.

CO emission concentrations are quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer is used for this purpose.

NOx emission concentrations are measured in accordance with procedures set fort in EPA Method 7e and/or 20. A chemiluminescence analyzer is used to determine the nitrogen oxides concentration in the gas stream.

Total hydrocarbons (THC), non-methane, non-ethane hydrocarbons also known as volatile organic compounds (VOC) are analyzed in accordance with procedures set forth in EPA Methods 18 & 25a. A flame ionization detector calibrated with methane is used to determine the THC concentration in the gas stream and VOCs analyzed by GC to determine methane, ethane, and remaining VOCs per EPA Method 18 determination with gas chromatograph using FID detector.

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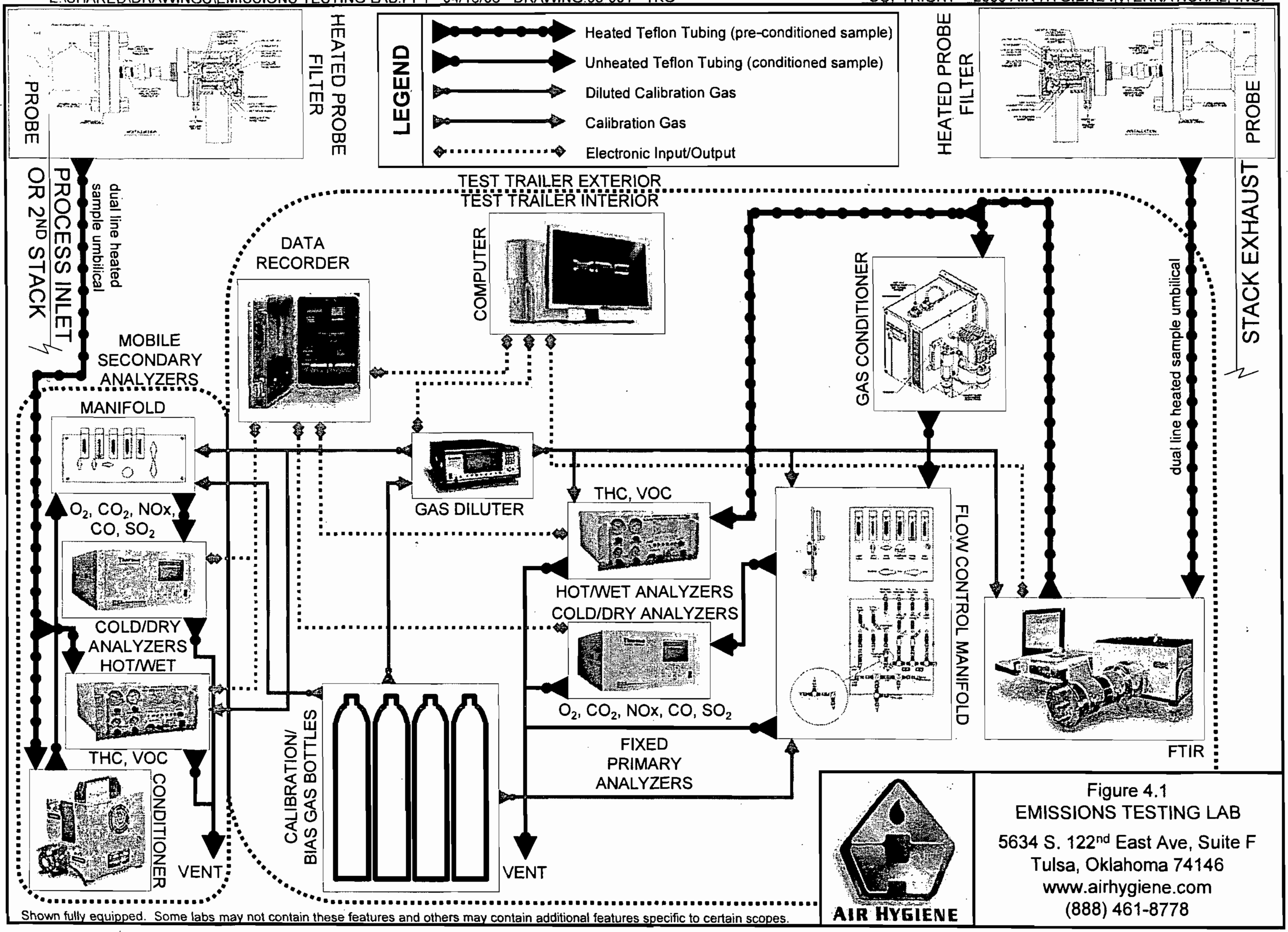

Shown fully equipped. Some labs may not contain these features and others may contain additional features specific to certain scopes.

Figure 4.1
EMISSIONS TESTING LAB

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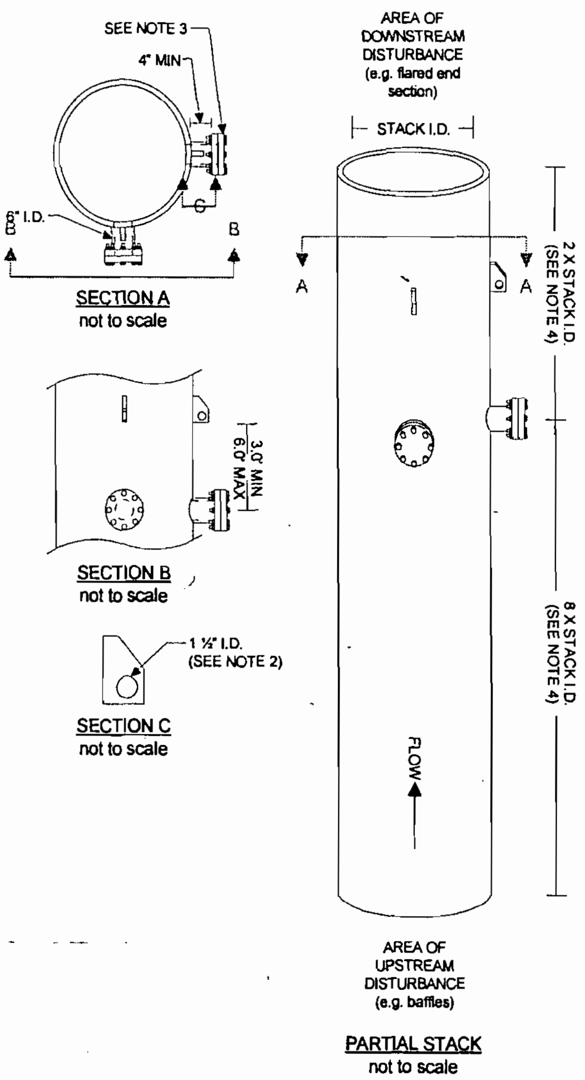

NOTES

1. TWO PORTS WITH CENTERLINES AT 90° ANGLES
2. 3/8 INCH THICK STEEL, WELDED TO STACK EXTERIOR, PROVIDES PLACE TO HOOK CHAIN FOR RAIL ASSEMBLY
3. MINIMUM THREE INCH INNER DIAMETER STEEL PIPE, WELDED TO STACK EXTERIOR, HOLE CUT INTO STACK WALL, NO POTRUSIONS OR OBSTRUCTIONS INSIDE STACK WALL
4. IF TOTAL STACK LENGTH IS NOT AVAILABLE, EPA MINIMUM REQUIREMENTS ARE ½ X STACK I.D. FROM PORTS TO TOP AND 2 X STACK I.D. FROM PORTS TO BOTTOM

AIR HYGIENE

PORT INSTALLATION DIAGRAM

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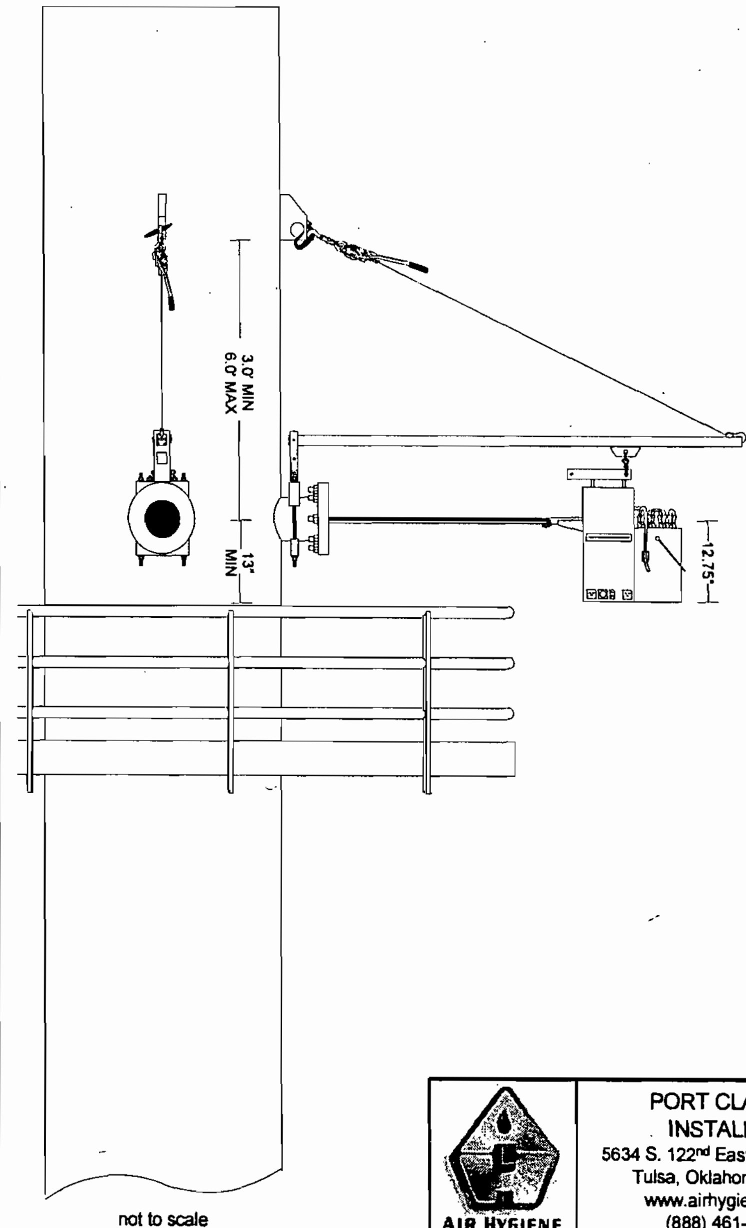

AIR HYGIENE

PORT CLAMPS INSTALLED

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Tulsa, Oklahoma 74146
www.airhygiene.com
(888) 461-8778

TESTING QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities are undertaken before, during, and after turbine testing projects. This section describes each of those activities.

Each instrument's response is checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity is checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response is then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within ± two percent of range of the predicted values.

NO_2 to NO conversion is checked via direct connect with a EPA Protocol certified concentration of NO_2 in a balance of nitrogen. Conversion is verified to be above 90 percent.

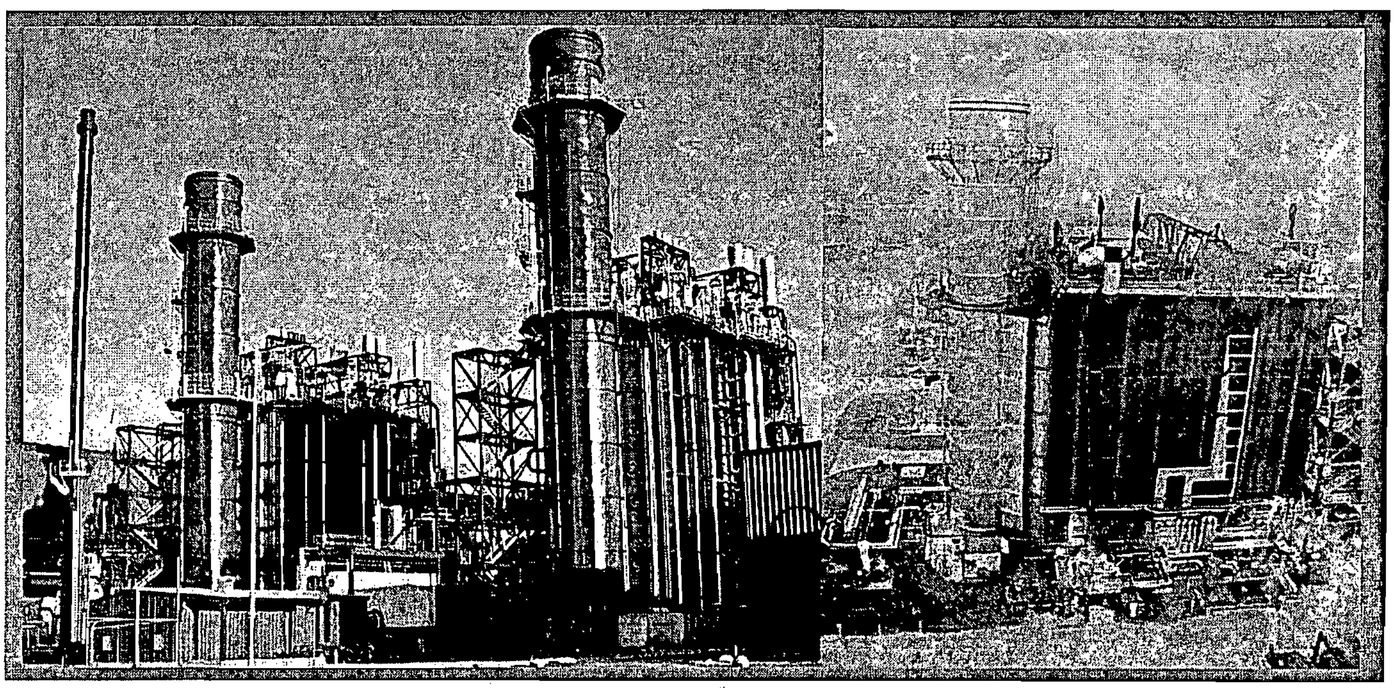
Instruments are both factory tested and periodically field challenged with interference gases to verify the instruments have less than a two percent interference from CO_2, SO_2, CO, NO, and O_2.

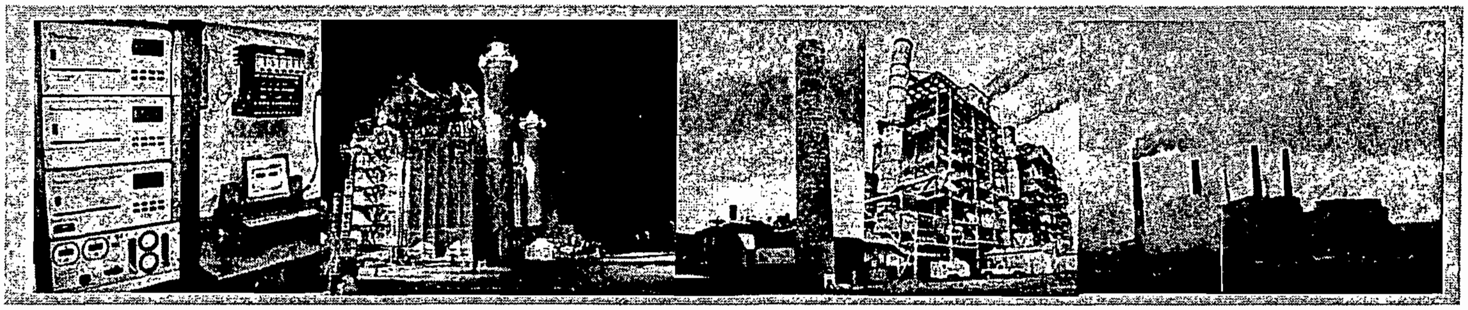
After each test run, the analyzers are checked for zero and span drift. This allows each test run to be bracketed by calibrations and documents the precision of the data collected. The criterion for acceptable data is that the instrument drift is no more than three percent of the full-scale response. Quality assurance worksheets summarize all multipoint calibration linearity checks and the zero to span checks performed during the tests are included in the test report.

The sampling systems is leak-checked by demonstrating that a vacuum greater than 10 in. Hg can be held for at least one minute with a decline of less than one in. Hg. A leak test is conducted after the sample system is set up and before the system is dismantled. This test is conducted to ensure that ambient air does not dilute the sample. Any leakage detected prior to the tests is repaired and another leak check conducted before testing will commence.

The absence of leaks in the sampling system is also verified by a sampling system bias check. The sampling system's integrity is tested by comparing the responses of the analyzers to the responses of the calibration gases introduced via two paths. The first path is directly into the analyzers and the second path includes the complete sample system with injection at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The criterion for acceptance is agreement within five percent of the span of the analyzer.

The control gases used to calibrate the instruments are analyzed and certified by the compressed gas vendors to ± one percent accuracy for all gases. EPA Protocol No. 1 is used, where applicable, to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM). The gas calibration sheets as prepared by the vendor are included in the test report.





QUALITY ASSURANCE PROGRAM SUMMARY

AIR HYGIENE ensures the quality and validity of its emission measurement and reporting procedures through a rigorous quality assurance (QA) program. The program is developed and administered by an internal QA team and encompasses five major areas:

1. QA reviews of reports, laboratory work, and field testing;
2. Equipment calibration and maintenance;
3. Chain-of-custody;
4. Training; and
5. Knowledge of current test methods.

QA Reviews

AIR HYGIENE's review procedure includes review of each source test report, along with laboratory and fieldwork, by the QA Team. The most important review is the one that takes place before a test program begins. The QA Team works closely with technical division personnel to prepare and review test protocols. Test protocol review includes selection of appropriate test procedures, evaluation of interferences or other restrictions that might preclude use of standard test procedures, and evaluation and/or development of alternate procedures.

Equipment Calibration and Maintenance

The equipment used to conduct the emission measurements is maintained according to the manufacturer's instructions to ensure proper operation. In addition to the maintenance program, calibrations are carried out on each measurement device according to the schedule outlined by the Environmental Protection Agency. Quality control checks are also conducted in the field for each test program. Finally, AIR HYGIENE participates in a PT gas program by analyzing blind gases semi-annually to ensure continued quality.

Chain-of-Custody

AIR HYGIENE maintains full chain-of-custody documentation on all samples and data sheets. In addition to normal documentation of changes between field sample custodians, laboratory personnel, and field test personnel, AIR HYGIENE documents every individual who handles any test component in the field (e.g., probe wash, impinger loading and recovery, filter loading and recovery, etc.). Samples are stored in a locked area to which only AIR HYGIENE personnel have access. Field data sheets are secured at AIR HYGIENE's offices upon return from the field.

Training

Personnel's training is essential to ensure quality testing. AIR HYGIENE has formal and informal training programs, which include:

1. Participation in EPA-sponsored training courses;
2. A requirement for all technicians to read and understand Air Hygiene Incorporated's QA manual;
3. In-house training relating to 40 CFR Part 60 Appendix A methods and QA meetings on a regular basis;
4. OSHA 40 hour Hazwopper Training;
5. Visible Emission (Opacity) Training; and
6. Maintenance of training records.

Knowledge of Current Test Methods

With the constant updating of standard test methods and the wide variety of emerging test procedures, it is essential that any qualified source tester keep abreast of new developments. AIR HYGIENE subscribes to services, which provide updates on EPA reference methods, rules, and regulations. Additionally, source test personnel regularly attend and present papers at testing and emission-related seminars and conferences. AIR HYGIENE personnel maintain membership in various relevant organizations associated with gas fired turbines.

AIR HYGIENE, INC.

Testing Solutions for a Better World

F-Factor Datasheet and Fuel Gas Analysis

Company: XYZ Power
Location: XYZ Power Plant
Date: April 9, 2001

Values to enter from fuel gas analysis by GPA 2166.

Font Scheme:
Blue Font = enter new data
Black Font = calculated data
Green Font = Labels for columns & rows
Red Font = Important results with notes

Gas Component		Mole (%)	Molecular Weight (lb/lb-mole)	lb Component per lb-Mole of Gas	Weight % of Component	Fuel Heat Value [HHV] (Btu/scf)[1]	Fuel Heat Value [LHV] (Btu/scf)[1]
Methane	CH4	96.491	16.04	15.477	92.97	974.27	877.20
Ethane	C2H6	2.115	30.07	0.636	3.82	37.41	34.22
Propane	C3H8	0.186	44.1	0.082	0.49	4.68	4.31
iso-Butane	iC4H10	0.019	58.12	0.011	0.07	0.62	0.57
n-Butane	nC4H10	0.023	58.12	0.013	0.08	0.75	0.69
Iso-Pentane	iC5H12	0.008	72.15	0.006	0.03	0.32	0.30
n-Pentane	nC5H12	0.005	72.15	0.004	0.02	0.20	0.19
Hexanes	C6H14	0.025	86.18	0.022	0.13	1.19	1.10
Heptanes	C7H16	0.000	100.21	0.000	0.00	0.00	0.00
Octanes	C8H18	0.000	114.23	0.000	0.00	0.00	0.00
Carbon Dioxide	CO2	0.510	44.01	0.224	1.35	0.00	0.00
Nitrogen	N2	0.618	28.01	0.173	1.04	0.00	0.00
Hydrogen Sulfide	H2S	0.000	34.08	0.000	0.00	0.00	0.00
Oxygen	O2	0.000	32	0.000	0.00	0.00	0.00
Helium	He	0.000	4	0.000	0.00	0.00	0.00
Hydrogen	H2	0.000	2	0.000	0.00	0.00	0.00
Totals (dry)		100.000		16.648	100.00	1019.44	918.57
Totals (wet)						1001.66	902.55

[1] Standardized to 60°F and 1 atm to match fuel flow data

If total is not 100.000 then the mol% data was either entered incorrectly or the gas analysis is incomplete. Sometimes small differences are due to rounding error.

High Heat Value of dry gas (HHV-dry) This is the primary fuel heat value used in emission testing calculations.

Low Heat Value of dry gas. LHV-dry

High Heat Value of wet Gas. HHV-wet

Low Heat Value of wet gas. LHV-wet

Characteristics of Fuel Gas		
Molecular Weight of gas =	16.648	lb/lb-mole
Btu per lb. of gas =	23239.7689	gross (HHV)
Btu per lb. of gas =	20940.2961	net (LHV)
wt % VOC in fuel gas =	0.83	%
Specific Gravity =	0.5749	

Value used to convert THC readings to VOC.

Component	Weight %
carbon	73.71
oxygen	0.98
hydrogen	24.27
nitrogen	1.04
helium	0.00
sulfur	0.00
Total	100.00

F-Factor (scf dry exhaust per MMBtu [HHV] = 8641.17
(Based on EPA RM-19) at 68°F and 1 atm

Fuel Specific F-Factor. Note that EPA Method 19 lists natural gas's F-factor as 8710.

F-Factor Calculation:

F-Factor = 1,000,000*((3.64*%H)+(1.53*%C)+(0.57*%S)+(0.14*%N)-(0.46*%O))/GCV

%H, %C, %S, %N, & %O are percent weight values calculated from fuel analysis and have units of (scf/lb)/%

GCV = Gross Btu per lb. of gas (HHV)

EXAMPLE TESTING DATASHEET FOR GASES
XYZ Power Plant
GE GTG Frame 7FA Combustion Turbine
Fuel: Natural Gas

Fuel Data

Fuel F-Factor	8,671.5	SCF/MMBtu
Generator Output	172.0	MW
Fuel Flow	515,040.8	SCFH
Fuel Heating Value (HHV)	1,076.5	Btu/SCF
Combustor Inlet Pressure	6,166.5	mm Hg
Heat Input (LHV)	500.8	MMBtu/hr
Stack Moisture Content	8.4	%
Stack Exhaust Flow	13,600,266.4	SCFH

Weather Data

Barometric Pressure	29.11	in. Hg
Relative Humidity	82	%
Dry Bulb Temperature	72	F
Specific Humidity	0.0142443	lb H2O/lb air
Wet Bulb Temperature	68	F

yellow - supporting information
blue - raw testing data
red - final results

Run #1 - 100% High Load

Date/Time (mm/dd/yy hh:mm:ss)	Elapsed Time (seconds)	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
06/27/01 11:47:32	16770	13.57	5.05	-0.38	0.59	0.59	5.09
06/27/01 11:48:02	16800	13.57	5.85	-0.26	0.63	0.63	4.83
06/27/01 11:48:32	16830	13.55	6.37	-0.44	0.71	0.71	4.71
06/27/01 11:49:02	16860	13.54	6.83	0.60	0.83	0.83	4.33
06/27/01 11:49:32	16890	13.55	7.26	0.25	0.99	0.99	4.49
06/27/01 11:50:02	16920	13.55	6.44	-0.24	1.14	1.14	4.64
06/27/01 11:50:32	16950	13.54	6.28	-0.75	1.29	1.29	4.79
06/27/01 11:51:02	16980	13.55	5.68	-0.68	1.46	1.46	4.96
06/27/01 11:51:32	17010	13.58	6.01	-1.14	1.60	1.60	5.10
06/27/01 11:52:02	17040	13.49	5.05	1.36	1.69	1.69	5.19
06/27/01 11:52:32	17070	13.60	5.14	-0.47	1.70	1.70	5.20
06/27/01 11:53:02	17100	13.61	4.58	0.69	1.69	1.69	5.19
06/27/01 11:53:32	17130	13.62	4.93	0.90	1.65	1.65	5.15
06/27/01 11:54:02	17160	13.62	4.69	0.54	1.64	1.64	5.14
06/27/01 11:54:32	17190	13.61	4.83	0.64	1.59	1.59	5.09
06/27/01 11:55:02	17220	13.61	4.76	-0.07	1.60	1.60	5.10
06/27/01 11:55:32	17250	13.64	4.86	-0.02	1.59	1.59	5.09
06/27/01 11:56:02	17280	13.63	4.38	0.92	1.51	1.51	5.01
06/27/01 11:56:32	17310	13.61	4.94	-0.01	1.47	1.47	4.97
06/27/01 11:57:02	17340	13.61	4.89	0.27	1.47	1.47	4.97
06/27/01 11:57:32	17370	13.61	4.82	1.28	1.46	1.46	4.96
06/27/01 11:58:02	17400	13.61	4.69	1.55	1.46	1.46	4.96
06/27/01 11:58:32	17430	13.60	4.23	1.16	1.46	1.46	4.96
06/27/01 11:59:02	17460	13.59	4.69	-0.26	1.46	1.46	4.96
06/27/01 11:59:32	17490	13.57	4.89	-1.46	1.49	1.49	4.99
06/27/01 12:00:02	17520	13.58	4.86	-1.49	1.53	1.53	5.03
06/27/01 12:00:32	17550	13.59	4.79	-0.79	1.53	1.53	5.03
06/27/01 12:01:02	17580	13.58	4.76	-1.57	1.54	1.54	5.04
06/27/01 12:01:32	17610	13.57	4.65	1.17	1.53	1.53	5.03
06/27/01 12:02:02	17640	14.24	4.69	0.01	1.52	1.52	5.02
06/27/01 12:02:32	17670	13.54	4.83	1.68	1.52	1.52	5.02
06/27/01 12:03:02	17700	13.55	5.70	1.31	1.53	1.53	5.03
06/27/01 12:03:32	17730	13.55	5.66	-0.73	1.53	1.53	5.03
06/27/01 12:03:32	17760	13.55	5.04	-0.48	1.53	1.53	5.03
RAW AVERAGE	-	13.6	5.2	0.1	1.4	1.4	5.0

QA/QC Data Control

		O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvw)	SO_2 (ppmvd)	CO_2 (%)
Bias & Drift Checks	**Initial Zero**	0.2	0.3	-0.2	0.0	0.1	0.1
	Final Zero	0.2	0.5	-0.2	0.2	0.2	0.1
	Avg. Zero	0.2	0.4	-0.2	0.1	0.2	0.1
	Initial UpScale	12.1	5.8	4.0	3.4	28.3	9.0
	Final UpScale	12.1	5.7	4.0	3.3	28.2	8.8
	Avg. UpScale	12.1	5.8	4.0	3.4	28.3	8.9
Upscale Cal Gas		12.0	5.7	4.0	3.5	28.0	9.0

Emissions Data

	O_2 (%)	NOx (ppmvd)	CO (ppmvd)	VOC (ppmvd)	SO_2 (ppmvd)	CO_2 (%)
Corrected Raw Averages	13.5	5.1	0.3	1.5	1.3	5.0
ppm @ 15% O_2	N/A	4.2	0.2	1.2	1.0	N/A
ppm @ 15% O_2 & ISO	N/A	4.7	0.2	1.4	1.1	N/A
Emission Rate (lb/MMBtu)	N/A	0.015	0.000	0.004	0.005	N/A
Emission Rate (lb/hr)	N/A	8.46	0.27	2.40	2.84	N/A
Emission Rate (ton/year) @ 8760 hr/yr	N/A	37.07	1.20	10.49	12.43	N/A
Emission Rate (g/MW-hr)	N/A	0.06	0.00	0.02	0.02	N/A

*VOC data in Emissions Data Table has been converted to dry values by the equation below.

*VOC uncorrected raw average * (100/100-stack moisture content)

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APPENDIX F
AIR PERMIT

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

PERMITTEE:

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

FP&L West County Energy Center
DEP File No. 0990646-002-AC
Permit No. PSD-FL-396
SIC No. 4911
Expires: December 31, 2013

PROJECT AND LOCATION

This permit authorizes the construction of the third nominal 1,250 megawatt combined cycle unit (Unit 3) and ancillary equipment at the Florida Power and Light Company (FP&L) West County Energy Center.

The proposed project will be located at 20505 State Road 80, Loxahatchee, Florida 33470. The UTM coordinates are Zone 17; 562.19 kilometers East; 2953.04 kilometers North.

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

7/30/08
(Date)

SECTION I. GENERAL INFORMATION

FACILITY DESCRIPTION

The FP&L West County Energy Center (WCEC) was previously approved for construction as a nominal 2,500 megawatt (MW) greenfield power plant. The previously approved construction underway is for two nominal 1,250 MW gas-fired combined cycle units (Units 1 and 2) that will use ultralow sulfur diesel (ULSD) fuel oil (FO) as backup fuel.

Units 1 and 2 will each consist of: three nominal 250 megawatt (MW) Model 501G combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors; one nominal 428 mmBtu/hour (lower heating value - LHV) gas-fired duct burner (DB) located within each of the three HRSG; three 149 feet exhaust stacks; one 26 cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator (STG).

Previously approved ancillary equipment under construction and installation includes: four emergency generators; two natural gas fired fuel heaters; one emergency diesel fired pump; two diesel fuel storage tanks; two auxiliary steam boilers; and other associated support equipment.

This permit authorizes construction of another 1,250 MW gas-fired combined cycle unit (Unit 3) identical to the description given above for Units 1 and 2. Additional ancillary equipment for Unit 3 will include two emergency generators, two natural gas fired fuel heaters and associated equipment. Unit 3 will use some of the infrastructure and ancillary equipment already under construction including the diesel storage tanks and auxiliary boilers.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
013	Unit 3A – one nominal 250 MW CTG with supplementary-fired HRSG
014	Unit 3B – one nominal 250 MW CTG with supplementary-fired HRSG
015	Unit 3C – one nominal 250 MW CTG with supplementary-fired HRSG
016	One 26 cell mechanical draft cooling tower
017	Two nominal 10 MMBtu/hr natural gas-fired process heaters
018	Two nominal 2,250 KW (~ 21 MMBtu/hr) emergency generators

REGULATORY CLASSIFICATION

The facility will be a major Prevention of Significant Deterioration (PSD) stationary source in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.). Unit 3 is subject to the PSD rules including a determination of best available control technology (BACT).

The facility will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY) or because it is a Major Source of hazardous air pollutants (HAP). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The facility under construction is subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). Unit 3 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005.

This rule also applies to duct burners (DB) that are incorporated into combined cycle projects. Two additional emergency generators are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines. Two additional process heaters are subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

The facility under construction is a major source of hazardous air pollutants (HAP) and is subject to several subparts under 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP). Unit 3 is potentially subject to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired CTG such as planned for this project.

The facility will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The facility will be subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The facility under construction was certified under the Florida Power Plant Siting Act, 403.501-518, F.S. and Chapter 62-17, F.A.C. The Unit 3 project is also subject to certification.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Subparts A from NSPS 40 CFR 60 and NESHAP 40 CFR 63; Identification of General Provisions.

Appendix BD: Final BACT Determinations and Emissions Standards.

Appendix GC: General Conditions.

Appendix Dc: NSPS Subpart Dc Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

Appendix IIII: NSPS Requirements for Compression Ignition Internal Combustion Engines (ICE).

Appendix KKKK: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart KKKK.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix YYYY: NESHAP Requirements for Gas Turbines, 40 CFR 63, Subpart YYYY.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application and supplemental information received on December 6 and December 21, 2007;
- Department's request for additional information (RAI) January 4, 2008;
- Response to RAI received March 14, 2008; and
- Draft permit package issued on April 25, 2008.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Permitting Authority, which is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP or the Department) at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority. Telephone: (850)488-0114. Fax: (850)921-9533.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Southeast District Office. The mailing address and phone number of the Southeast District Office are: Department of Environmental Protection, Southeast District Office, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401. Telephone: (561)681-6632. Fax: (561)681-6790.

3. Appendices: The following Appendices are attached as part of this permit: Appendices A, BD, Dc, GC (General Conditions), IIII, KKKK, SC, XS, YYYY and ZZZZ.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

This section of the permit addresses the following emissions units.

Combined Cycle Unit 3 and associated equipment

Description: Combined Cycle Unit 3 will be comprised of emissions units (EU) 013, 014, and 015. Each EU will consist of: a Model M501G CTG with automated control, inlet air filtration system and evaporative cooling, a gas-fired HRSG with DB, a HRSG stack, and associated support equipment. The project also includes one STG that will serve the combined cycle unit.

Fuels: Each CTG fires natural gas as the primary fuel and ULSD fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the three CTG has a nominal generating capacity of 250 MW. The STG has a nominal generating capacity of 500 MW. The total nominal generating capacity of the "3 on 1" combined cycle unit is approximately 1,250 MW. The total nominal generating capacity of the facility is 3,750 MW.

Controls: The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_X emissions. A SCR system further reduces NO_X emissions.

Stack Parameters: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics without the DB:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,333 MMBtu/hour	59° F	195° F	1,330,197
Oil	2,117 MMBtu/hour	59° F	293° F	1,533,502

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The CTG shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards given in 40 CFR 60, Subpart KKKK. Some separate reporting and monitoring may be required by the individual subparts.

   a. *Subpart A, General Provisions*, including:
      - 40 CFR 60.7, Notification and Record Keeping
      - 40 CFR 60.8, Performance Tests
      - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
      - 40 CFR 60.12, Circumvention
      - 40 CFR 60.13, Monitoring Requirements

- 40 CFR 60.19, General Notification and Reporting Requirements

b. *Subpart KKKK, Standards of Performance for Stationary Gas Turbines*: These provisions include standards for CTG and DB.

3. NESHAP Requirements: The combustion turbines are subject to 40 CFR 63, Subpart A, Identification of General Provisions and 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. The project must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. (Reference: Appendix YYYY and Appendix A, NESHAP Subpart A of this permit).

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines-Electrical Generators (CTG): The permittee is authorized to install, tune, operate, and maintain three Model 501G CTG each with a nominal generating capacity of 250 MW. Each CTG shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The CTG will utilize DLN combustors. [Application and Design]

5. Heat Recovery Steam generators (HRSG): The permittee is authorized to install, operate, and maintain three new HRSG with separate exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the three CTG (3A to 3C) and deliver steam to the steam turbine-electrical generator (STG). Each HRSG may be equipped with a gas-fired duct burner (DB) having a nominal heat input rate of 428 MMBtu per hour (LHV).

6. CTG/Supplementary-fired HRSG Emission Controls

   a. *Dry Low NO_X (DLN) Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each CTG when firing natural gas. Prior to the initial emissions performance tests required for each CTG, the DLN combustors and automated control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Wet Injection (WI)*: The permittee shall install, operate, and maintain a WI system (water or steam) to reduce NO_X emissions from each CTG when firing ULSD fuel oil. Prior to the initial emissions performance tests required for each CTG, the WI system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each CTG when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG. The permittee may install the oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 12.h.

e. *Ammonia Storage:* In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

[Design and Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

7. Permitted Capacity – Combustion Turbine-Electric Generators (CTG): The nominal heat input rate to each CTG is 2,333 MMBtu per hour when firing natural gas and 2,117 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, LHV of each fuel, and 100% load). Heat input rates will vary depending upon CTG characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

8. Permitted Capacity - HRSG Duct Burners (DB): The total nominal heat input rate to the DB for each HRSG is 428 MMBtu per hour based on the LHV of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

9. Authorized Fuels: The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. Each CTG shall fire no more than 500 hours of fuel oil, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Hours of Operation: Subject to the operational restrictions of this permit, the CTG may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below. [Rules 62-210.200(Definitions - PTE) and 62-212.400 (BACT), F.A.C.]

11. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTG may operate under the following methods of operation.

    a. *Combined Cycle Operation*: Each CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a three-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

    b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

    c. *Duct Burner (DB) Firing*: When firing natural gas in a CTG, the respective HRSG may fire natural gas in the DB to raise additional steam for use in the STG or in the operation of CTG components. The total combined heat input rate to the DB (all three HRSG) shall not exceed 3,697,920 MMBtu (LHV) during any consecutive 12 months.

    [Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

A. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

EMISSIONS STANDARDS

12. Emissions Standards: Emissions from each CTG/DB shall not exceed the following BACT standards. Compliance with the BACT limits also insures compliance with the emission limitations in Subpart KKKK.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr
	Gas	CTG & DB	7.6	52.5	6, 12-month
		CTG Normal Mode	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr [h]
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr [h]
		CTG Normal Mode	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal Mode	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

h. Compliance with the 24-hour block NO_X BACT limits will insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30 day rolling average.

[Rule 62-212.400(BACT), F.A.C.; 40 CFR 60, Subpart KKKK]

A. COMBINED CYCLE UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 013, 014, and 015)

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

13. Operating Procedures: The BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

17. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, excess emissions of NO_X and CO resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *STG/HRSG System Cold Startup*: For cold startup of the STG/HRSG, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

       {Permitting Note: During a cold startup of the STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. *Fuel Switching*: For fuel switching, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.

18. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.
[Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

19. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

20. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

21. Initial Compliance Determinations: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the unit. Each CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Referenced method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

22. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emission standards for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$: In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition 30, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. Continuous Emissions Monitoring System(s) (CEMS): The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle CTG in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors:* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitors:* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitors:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization of Standardization (ISO) conditions.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages:* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 17 and 19 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

27. <u>Ammonia Monitoring Requirements:</u> In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

28. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction and fuel switching). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CTG for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas:* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. *ULSD Fuel Oil:* Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the CTG are defined as: a specified averaging period over which either the NO_X emissions are higher than the applicable emission limit in 60.4320; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7, and 60.4420]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. COOLING TOWER (EU 016)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
016	One 26-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 26-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 304,000 gpm; design hot/cold water temperatures of 92 °F/76 °F; a design air flow rate of 1,350,000 actual cubic feet per minute (acfm) per cell; a liquid-to-air flow ratio of 1.13; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application and Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}.

C. PROCESS HEATERS (EU 017)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
017	Two gas-fueled 10 MMBtu/hr process heaters

NSPS APPLICABILITY

1. NSPS Subpart Dc Applicability: Each process heater is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

EMISSIONS STANDARDS

2. Natural Gas Fired Process Heaters BACT Emissions Limits:

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.095 lb/MMBtu	0.08 lb/MMBtu	2 gr S/100SCF natural gas spec and 10% Opacity

3. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

   Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

EQUIPMENT SPECIFICATIONS

4. Equipment: The permittee is authorized to install, operate, and maintain two 10 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs.
   [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

6. Notification: Initial notification is required for the two small gas-fueled 10 MMBtu/hr process heaters.
   [40 CFR 60.7]

7. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

D. EMERGENCY GENERATORS (018)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	Two nominal 2,250 kilowatts (kw) Liquid Fueled Emergency Generators – Reciprocating Internal Combustion Engines (model year 2007-2010)

NESHAPS APPLICABILITY

1. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ.

   [40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain two 2,250 kw emergency generators. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per each generator. The generators are allowed to burn ultralow sulfur diesel fuel oil (0.0015% sulfur). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

5. Emergency Generators BACT Emissions Limits:

NO_X	CO	Hydrocarbons[1]	SO_2	PM/PM_{10}
6.9 gm/bhp-hr	8.5 gm/bhp-hr	1.0 gm/bhp-hr	0.0015% ULSD FO	0.4 gm/bhp-hr

   Note 1. Hydrocarbons are surrogate for VOC.

   {The BACT limits are equal to the values corresponding to the Table 1 values cited in 40 CFR 60, Subpart IIII}

6. Emergency Generators Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of the combined cycle unit. As an alternative, an EPA Certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values and the use of ULSD fuel oil can be used to fulfill this requirement.
   [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4211]

7. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

8. Notifications: Permittee shall submit initial notification as required by 40 CFR 60.7, 40 CFR 63.9, and 40 CFR 63.6590 (b) (i) for the two 2,250 kW RICE units.
9. Reporting: The permittee shall maintain records of the amount of liquid fuel used. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3) F.A.C.].