UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

APR - 5 2006

Mr. Phillip Polyak
Designated Representative
Dearborn Industrial Generation
2400 Miller Road
Dearborn, MI 481216

OFFICE OF
AIR AND RADIATION

Re: Final Approval of the Predictive Emission Monitoring System (PEMS) Installed on Unit GTP1 at Dearborn Industrial Generation (Facility ID (ORISPL) 55088)

Dear Mr. Polyak:

This letter finalizes the approval of the October 24, 2002 petition submitted by Dearborn Industrial Generation (DIG) under §75.66(d) and 40 CFR Part 75, Subpart E. In that petition, DIG requested approval of a predictive emission monitoring system (PEMS) to continuously monitor nitrogen oxides (NO_x) emissions from Unit GTP1 at its Dearborn, Michigan facility (Dearborn).

On September 2, 2003, EPA issued a conditional approval of the PEMS, but the Agency reserved the right to require more stringent quality-assurance (QA) testing of the PEMS, pending the outcome of two field studies that were in progress at that time. As discussed in Attachment D to this letter, the results of those studies indicate that increasing the QA requirements is justifiable, both technically and economically. In view of this, EPA is requiring additional QA testing of the PEMS as a condition of approval.

The additional QA requirements for Unit GTP1 include: (a) the installation of a more stringent PEMS sensor alarm system; (b) monthly three-run relative accuracy audits (RAAs) of the PEMS during the ozone season; (c) quarterly RAAs in the first and fourth quarters if Unit GTP1 is affected by the Clean Air Interstate Rule; (d) three-load NO_x relative accuracy test audits (RATAs), with accompanying F-tests, correlation analyses, and t-tests, whenever the PEMS is recertified; and (e) a somewhat different daily QA/QC test.

EPA is including Attachment A to this approval in order to facilitate implementation of the final compliance requirements for the PEMS. Attachment A consolidates the provisions of EPA's September 2, 2003 conditional approval and the additional QA that the Agency is requiring based on the results of its field studies.

Note that one important change has been made to the provisions of the September 2, 2003 conditional approval. Paragraph (h) in section 4 of Attachment A, pertaining to the maximum potential NO_x emission rate (MER), supersedes paragraph (i) in section 4 of the conditional approval. The MER calculation method described in the conditional approval yields a value of 1.863 lb/mmBtu, which is unrealistically high for a gas-fired turbine. Therefore, paragraph (h) in section 4 of Attachment A replaces this calculated MER with a default value of 0.700 lb/mmBtu[1], which DIG must report whenever reporting of the MER is required by this approval. The Agency notes that in the third and fourth quarter 2005 electronic data reports (EDRs), the MER value of 0.033 lb/mmBtu for Unit GTP1 in record type 531 is incorrect and must be replaced with 0.700 lb/mmBtu.

Finally, on July 13, 2005, in accordance with §75.20(f), EPA published a notice in the Federal Register concerning DIG's request for approval of an alternative monitoring system (see 70 FR 40330, July 13, 2005). The 60-day public comment period closed on September 12, 2005. No comments were received.

This final approval relies on the accuracy of the information provided by DIG in the October 24, 2002 petition and is appealable under Part 78. If there are any further questions or concerns about this matter, please contact John Schakenbach of my staff at 202-343-9158 or at (schakenbach.john@epa.gov).

Sincerely,

Sam Napolitano, Director
Clean Air Markets Division

cc: John Schakenbach, EPA, CAMD
Louis Nichols, EPA, CAMD
Constantine Blathras, EPA Region 5
Karen Kajiya-Mills, MI DEQ

Attachments

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[1] This default value is derived from Table LM-2 in §75.19. It is a conservative (but reasonable) estimate of the maximum potential NO_x emission rate for a gas-fired turbine.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

ATTACHMENT A

Mr. Phillip Polyak
Designated Representative
Dearborn Industrial Generation
2400 Miller Road
Dearborn, MI 48121

Re: Consolidated Compliance Requirements for the NO_x Predictive Emission Monitoring System Installed on Unit GTP1 at Dearborn Industrial Generation (Facility ID (ORISPL) 55088)

Dear Mr. Polyak:

To facilitate implementation of the compliance requirements for the NO_x PEMS installed on Dearborn Industrial Generation's (DIG's) Unit GTP1, this Attachment consolidates the provisions of EPA's September 2, 2003 conditional approval with the additional quality assurance (QA) tests that EPA is requiring based on the results of its PEMS[2] and portable analyzer[3] field studies.

Background

On October 24, 2002, DIG petitioned for approval of a CMC Solutions' Smart-75_C PEMS, which is a hybrid statistical-based computer software system that utilizes turbine sensor inputs to produce outputs of estimated nitrogen oxides (NO_x) and carbon dioxide (CO_2) emissions. The PEMS is installed on Unit GTP1, which is a 170 MW GE Frame 7FA, simple cycle combustion turbine at the DIG plant in Dearborn, Michigan. Unit GTP1 was installed in 1999 to generate electricity exclusively for commercial resale. The unit combusts only pipeline natural gas and uses dry low-NO_x combustion technology to control NO_x emissions.

Unit GTP1 is subject to the Acid Rain Program regulations and in 2004 qualified as a peaking unit (as defined in 40 CFR §72.2). According to the Michigan Department of Environmental Quality, Unit GTP1 is also subject to the NO_x Budget Trading Program, under NO_x Rules 801-818 (also referred to as R336.1801 - R336.1818). NO_x Rules 801-818 require DIG to begin monitoring and reporting NO_x mass emissions and heat input for Unit GTP1 in accordance with Subpart H of 40 CFR Part 75, beginning on May 1, 2003. NO_x Rules 801-818 further require

2 "Evaluation and Field Testing of Nitrogen Oxide (NO_x) Predictive Emission Monitoring Systems (PEMS) for Gas-fired Combustion Turbines - Synthesis Report", The Cadmus Group, Inc., December 29, 2004.

3 "Evaluation of Portable Analyzers for Use in Quality Assuring Predictive Emission Monitoring Systems for NOx", The Cadmus Group, Inc., September 8, 2004.

DIG to hold NO_x allowances equal to the ozone season[4] NO_x mass emissions from Unit GTP1, beginning on May 31, 2004[5].

To meet the NO_x monitoring requirements of the Acid Rain Program, DIG elected to implement Part 75, Appendix E, which applies exclusively to gas-fired and oil-fired peaking units. The Smart-75© software was installed on the turbine in 1999 and, since that time, has been functioning as a data acquisition and handling system (DAHS) which satisfies Appendix E reporting requirements. However, note that DIG would be required to install a NO_x continuous emissions monitoring system (CEMS) and a more sophisticated DAHS on Unit GTP1 if the unit should ever lose its status as a peaking unit. Faced with this possibility, the October 24, 2002 petition requested approval of the PEMS as an alternative monitoring system (AMS) under Subpart E of Part 75. If approved as an AMS, the PEMS could be used in lieu of a NO_x CEMS if Unit GTP1's peaking unit status should ever be lost. Approval of the petition would also allow DIG to use the AMS for Part 75 reporting, regardless of Unit GTP1's peaking status.

In its certification application, DIG submitted Subpart E data for two PEMS models, a simple model and a complete model. Each model was evaluated against quality-assured data recorded by a NO_x-diluent CEMS, which was temporarily installed, certified, maintained and quality-assured according to Part 75 for the purposes of the PEMS demonstration. The two models are identical; only the training data set used for each model was different. For the simple model, the first 40 hours of quality assured data were used to train the model and the remaining 762 hours were used to test the model using Part 75, Subpart E statistics. For the complete model, all 802 hours of quality assured data were used to train and to test the model. Because it is more rigorous to test a PEMS model on a different data set than the one on which it was trained and because, typically, a PEMS may be trained on as few as 40 hours of data in practice, EPA decided to evaluate compliance with Subpart E based on the simple model.

EPA's Determination

Under Part 75, Subpart E, the owner or operator of a unit applying to the Administrator for approval of an AMS must demonstrate that the AMS has the same or better precision, reliability, accessibility, and timeliness (PRAT) as provided by a CEMS. The demonstration must be made by comparing the AMS to a contemporaneously operating, fully certified CEMS. Sections 75.41 through 75.46 discuss the criteria for evaluating PRAT, daily quality assurance, and missing data substitution for the AMS. Section 75.48 details the information that must be included in the application in order to demonstrate that the criteria in §§75.41-75.46 are met.

The following paragraphs describe how the Unit GTP1 PEMS meets the requirements of a subpart E AMS petition and present the ongoing QA and other compliance requirements for the PEMS. As detailed below, EPA's approval applies only to the Unit GTP1 when firing pipeline natural gas and for certain PEMS outputs, i.e., lb NO_x/mmBtu, and NO_x (ppm, dry). Also, if a PEMS input parameter value goes below a certain minimum or above a certain maximum value,

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4 The ozone season ends on September 30 and, for 2005 and thereafter, starts on May 1.

5 A court decision has mandated that the 2004 ozone season begin on May 31 rather than May 1 in certain states (including Michigan).

DIG must report the maximum potential NO_x emission rate (MER). Further, during startups, shutdowns, and lean/lean turbine operation, oil-fired operation, or if the PEMS alarms, DIG must report the NO_x MER.

Because the complete model was trained on a larger data set, it should be more accurate and robust than the simple model. The complete model also performed better on the Subpart E statistical tests for the same model outputs as the simple model. Therefore, EPA is approving both the simple model and the complete model, subject to the same requirements.

1. Precision

Under §75.41, for the normal unit operating level, the owner or operator must provide paired AMS and fully certified CEMS hourly data for at least 90 percent of the hours during 720 unit operating hours for the primary fuel supply and for at least 24 successive unit operating hours for all alternative fuel supplies that have significantly different sulfur content. Missing data substitution procedures must not be used to provide sample data, and the data may be adjusted to account for any lognormality and time dependency autocorrelation. Three statistical tests must be passed, i.e., a linear correlation analysis (coefficient (r) ≥ 0.8), an F-test, and a one-tailed t-test for bias, as described in Appendix A to Part 75. Further, two separate time series plots for the AMS and CEMS data must be provided. Each data plot must have a horizontal axis representing the clock hour and calendar date of the readings and must contain a separate data point for every hour for the duration of the test. One data plot must show percentage difference vs. time, and the other data plot must show AMS and CEMS readings vs. time. Finally, a plot of the paired AMS (on the vertical axis) and CEMS (on the horizontal axis) concentrations must be provided.

DIG provided 762 hours of historical, paired CEMS vs. PEMS data while pipeline natural gas was being combusted in Unit GTP1. According to DIG, the 762 hours represent more than 90% of the unit operating hours in the three-year data collection period, thereby satisfying the requirement in §75.41(a)(6). According to DIG, all 762 hours of data were quality-assured, i.e., no missing data substitution procedures were applied.

The table below shows the results of the statistical tests for the two approved PEMS outputs.[6]

PEMS (lbs NO_x/mmBtu)	PEMS (NO_x ppm, dry)
t-test: mean difference d = -0.001 abs. value of confidence coefficient cc = 0.002 **Evaluation:** Since $\lvert cc \rvert \geq d$, the model passed.	**t-test:** mean difference d = 0.024 abs. value of confidence coefficient cc = 0.438 **Evaluation:** Since $\lvert cc \rvert \geq d$, the model passed.

[6] Under §75.41(b), in preparation for conducting the required statistical tests, the data may be screened for lognormality and time dependency autocorrelation. If either is detected, certain calculation adjustments are required. DIG detected neither lognormality nor autocorrelation. Therefore, consistent with §75.41(b), no calculation adjustments were made to the data.

r-coefficient correlation: $r = 0.859$ **Evaluation:** Since $r \geq 0.8$, the model passed.	**r-coefficient correlation:** $r = 0.837$ **Evaluation:** Since $r \geq 0.8$, the model passed.
F-test: variance of PEMS = 0.001328 variance of RM = 0.001900 $F = 0.699$ $F_{critical} = 1.13$ **Evaluation:** Since $F_{critical} \geq F$, the model passed.	**F-test:** variance of PEMS = 73.216 variance of RM = 124.773 $F = 0.587$ $F_{critical} = 1.13$ **Evaluation:** Since $F_{critical} \geq F$, the model passed.

The PEMS output of NO_x emission rate in lb/mmBtu passed all three statistical tests, although EPA calculated somewhat different values for the t-test and F-test than were provided in the petition. Because the electronic paired CEMS vs PEMS data provided to EPA were in units of NO_x ppm and $\%CO_2$, EPA recalculated the NO_x lb/mmBtu values using these data before running the statistics. The NO_x emission rates were calculated using Equation F-6 and an F_c factor of 1,040 for natural gas, from Appendix F of Part 75. Although the petition did not address it, EPA also determined that the PEMS output of NO_x ppm (dry basis) passed all three statistics. EPA calculated these statistics because DIG desired this additional output based on conversations with a DIG representative. EPA also calculated the Subpart E statistics for the PEMS output of $\%CO_2$. The $\%CO_2$ output passed the F-test, but failed the "r" correlation and the t-test. Therefore, the % CO_2 PEMS output is not approvable; DIG will continue to use Part 75, Appendix G to report CO_2.

Further, DIG supplied the appropriate data plots concerning the paired AMS and CEMS data under §§75.41(a)(9) and (c)(2)(i).

2. Reliability

According to §75.42, the owner or operator must demonstrate that the PEMS is capable of providing valid hourly averages for 95.0 percent or more of unit operating hours over a one-year period and that the system meets the applicable QA requirements of Part 75, Appendix B. The October 24, 2002 petition states that the PEMS provided 98.7% data availability over the three-year data collection period. EPA therefore finds that the PEMS meets the §75.42 requirements for monitoring system data availability. By meeting the QA/QC requirements described in this letter, DIG will also meet the applicable Appendix B quality assurance and quality control (QA/QC) requirements.

3. Accessibility and Timeliness

According to §§75.43 and 75.44, the owner or operator must demonstrate that the PEMS meets the recordkeeping and reporting requirements of Subparts F and G of Part 75. According to DIG, the PEMS meets the Subpart F and G requirements. For example, the PEMS "will provide a continuous, quality assured permanent record of certified emissions data on an hourly basis," and, coupled with the selected recordkeeping and reporting system, "will be capable of issuing a record of data for the previous day within 24 hours." The PEMS has demonstrated the ability to meet

Subpart F and G requirements by providing Part 75 quarterly electronic data reports (EDRs) to EPA since 1999. The software also provides a continuous display of real-time emissions data to the operator. In view of these considerations, EPA finds that the PEMS meets the requirements of §§75.43 and 75.44 .

4. Quality Assurance

Under §75.45, the owner or operator must demonstrate either that daily tests equivalent to those in Appendix B of Part 75 can be performed on the PEMS or that such tests are unnecessary for providing quality-assured data. Sections 75.48(a)(8)-(11) require the following information to be submitted: a detailed description of the process used to collect data, including location and method of ensuring an accurate assessment of operating hourly conditions on a real-time basis; a detailed description of the operation, maintenance, and quality assurance procedures for the AMS as required in Part 75, Appendix B; a description of methods used to calculate diluent gas concentration; and results of tests and measurements necessary to substantiate the equivalency of the AMS to a fully certified CEMS. EPA finds that the Unit GTP1 PEMS will satisfy these requirements if the following QA procedures are implemented:

(a) The PEMS shall use the following input parameters: load, gas flow, PM1 (nozzle 1 fuel flow ratio), PM2 (nozzle 2 fuel flow ratio), PM3 (nozzle 3 fuel flow ratio), inlet air temperature, and burner mode. The PEMS input parameters must stay within the minimum and maximum values (inclusive) in the table below (referred to as "the PEMS operating envelope"), unless the PEMS is retrained according to paragraph (g) below, in which case, the new training values will supersede the values in the below table. Except for burner mode parameter, if any PEMS input parameter value goes below the minimum or above the maximum table value by 5 percent or more, the PEMS shall be considered out-of-control, and the NO_x MER shall be used, according to paragraph (h), starting with the hour in which the sensor value goes outside of the PEMS operating envelope and ending with the hour in which the sensor value is back within the PEMS operating envelope. Data from each PEMS input parameter shall be maintained on site in a form suitable for inspection for at least three (3) years from the date of each record. If the burner mode is not steady state (mode 6), DIG shall follow the procedures in paragraph (h).

PEMS Operating Envelope

PEMS Input Parameter	Minimum Value	Maximum Value
Load (MW)	85.5	169.1
Gas flow (hscfh)	10,275.3	15,873.7
PM1 (unitless) [a]	0.064	0.531
PM2 (unitless) [b]	0.071	0.427
PM3 (unitless) [c]	0.162	0.609
Inlet air temp (deg F)	43	103
Burner mode [d]	6	6

[a] PM1 or Premix 1 = PM1 nozzle fuel flow / total fuel flow into combustion chamber.
[b] PM2 or Premix 2 = PM2 nozzle fuel flow / total fuel flow into combustion chamber.
[c] PM3 or Premix 3 = PM3 nozzle fuel flow / total fuel flow into combustion chamber.
[d] Six burner modes: (1) Startup (0-26% load with primary gas going in and being fired) or shutdown; (2-5) Lean/Lean (27-67% load with primary and secondary gas going in and both being fired); and (6) Steady state (68-100% load with PM1, PM2, and PM3 all non-zero). Note: Burner mode 6, itself, is not necessarily a PEMS input because load, PM1, PM2, and PM3 inputs are sufficient to define burner mode 6.

(b) Ongoing QA/QC tests of the PEMS shall be performed according to the following table:

PEMS Ongoing QA/QC Tests

Test	Performance Specification	Frequency
Daily QA/QC	PEMS output - PEMS output = 0.000 lb NO_x/mmBtu (see paragraph (e))	Daily
3-run RAA	• Accuracy $\leq$ 10.0% or • For a low emitting source[7], results are acceptable if the mean value for the PEMS is within $\pm$ 0.020 lb/mmBtu of the reference mean value	Monthly during ozone season and possibly in quarters 1 and 4 (see paragraph (f))
RATA	For semiannual RATA frequency: • RA > 7.5% and $\leq$ 10.0% or • For a low emitting source[7], results are acceptable if the mean value for the PEMS is within $\pm$ 0.020 lb/mmBtu of the reference method mean value. For annual RATA frequency: • RA $\leq$ 7.5% or • For a low emitting source[7], results are acceptable if the mean value for the PEMS is within $\pm$ 0.015 lb/mmBtu of the reference method mean value	Semiannual or annual (depending on the RATA results) for routine QA. Recertification RATA is required when a RAA or a RATA is failed or when operating conditions change. $\geq$ 9 test runs are required at normal operating level for annual or semiannual QA. $\geq$ 30 test runs are required at each of 3 operating levels for recertification. (see paragraphs (f) and (g))
Sensor validation system (minimum data capture)	Check for production of at least 1 valid data point per 15 minutes (see paragraph (c))	Before each RATA (see paragraphs (f) and (g))
Sensor validation system (failed sensor alert)	Alert operator of any failed sensors (see paragraphs (c) and (d))	Hourly

[7] The unit is a low-emitting source if the mean reference value during the RATA or RAA is $\leq$ 0.200 lb/mmBtu NO_x

Bias adjustment factor	If $d_{avg} \leq \|cc\|$, bias test is passed	After each RATA. Perform bias test at the normal operating level (see paragraphs (f) and (g))
PEMS training (Linear correlation and F-test)	$r \geq 0.8$, and $F_{critical} \geq F$	According to paragraph (g)
Sensor validation system (alarm system set-up)	(see paragraphs (c) and (d))	After each PEMS training (see paragraph (g))

The sensor alarm system validation procedure is described in paragraphs (c) and (d). The daily QA/QC test is described in paragraph (e). The RATAs, 3-run RAAs, and bias adjustment factor are discussed in paragraphs (f) and (g). Recertification, including training, of the PEMS is discussed in paragraph (g).

(c) The sensors for the PEMS' input parameters must be maintained in accordance with the manufacturer's recommendations. A sensor validation system is required to identify sensor failures hourly to the operator and to reconcile failed sensors by: comparing each sensor to several other sensors, determining, based on the comparison, if a sensor has failed, and calculating a reasonable substitute value for the parameter measured by the failed sensor. DIG must ensure that the sensor validation system validates sensor data in this way every minute of PEMS operation. To comply with §75.10(d)(1), hourly averages must be computed using at least one valid data point in each fifteen minute quadrant of an hour in which the unit operates. All valid data recorded by the PEMS during the hour must be used to calculate the hourly averages.

(d) The sensor validation system shall include an alarm to inform the operator when sensors need repair and to indicate that the PEMS is out-of-control. In setting up the alarm system, a demonstration shall be performed at a minimum of four different PEMS training conditions, which must be representative of the entire range of expected turbine operations. For each of the four or more training conditions, the demonstration shall consist of the following:

(1) For all of the sensors used in the PEMS model, input a set of reference sensor values that were recorded either during the training of the PEMS or during a RATA of the PEMS (these values will all be within the PEMS operating envelope). Verify that these reference inputs produce the expected PEMS output, i.e., the expected NO_x emission rate;

(2) Perform one-sensor failure analysis, as follows. Artificially fail one of the sensors and then, using the calculated replacement value for that sensor (see paragraph (c), above), assess the effect on the accuracy of the PEMS. Calculate the percent difference between the reference NO_x emission rate from step (1) and the PEMS output. Repeat this procedure for each sensor, individually;

(3) Identify the sensor failure in step (2) that results in the worst accuracy. If the highest percent deviation exceeds ± 10.0%, then set up the PEMS to alarm when any single sensor fails. If none of the percent difference values exceeds 10.0%, proceed to step (4);

(4) Perform two-sensor failure analysis, as follows: Artificially fail the sensor from step (3) that produced the worst accuracy and also fail one of the other sensors. Then, using the calculated replacement values for both sensors, assess the accuracy of the PEMS hourly average output, as in step (2). Repeat this procedure, evaluating each sensor in turn with the sensor from step (3);

(5) Identify the combination of dual sensor failures that results in the worst accuracy. If the highest percent deviation exceeds ± 10.0%, then set up the PEMS to alarm when any two sensors fail. If none of the percent difference values exceeds 10.0%, then set up the PEMS to alarm with three sensor failures.

The results of this demonstration shall be maintained on site in a form suitable for inspection. For every hour of PEMS operation, the PEMS shall check for failed sensors and provide an alarm to alert the operator of any sensors needing repair. When the PEMS alarms, the PEMS is out-of-control, and DIG shall report the NO_x MER, calculated according to paragraph (h), starting with the hour after the sensor validation alarm system alarms and ending with the hour after the sensor value is back within the expected range.

(e) A daily QA/QC test must be performed whenever the unit operates for any portion of the day. DIG shall input to the PEMS a set of turbine operating parameters used by the PEMS during a passed PEMS RATA or the most recent PEMS training. (Note: It is important that the same number of decimal places for the PEMS inputs be used here as was used in the passed PEMS RATA or most recent PEMS training) The resulting PEMS NO_x lb/mmBtu output divided by the BAF (this resets the BAF to 1.000 as it was during the passed PEMS RATA or most recent PEMS training) shall be compared to the corresponding PEMS NO_x lb/mmBtu output produced at the time of the passed PEMS RATA or most recent PEMS training (with no BAF applied). If the difference between the two PEMS NO_x outputs is within ± 0.002 lb NO_x/mmBtu, the daily QA/QC test is passed. If a daily QA/QC test is failed or not performed, the PEMS is out-of-control. Subpart D missing data procedures shall be followed starting with the hour of the failed test or, if the test was not performed, the hour after the test due date, and ending with the hour in which a daily QA/QC test is passed. No grace periods are allowed. The results of this check (pass/fail) shall be reported in RT 624 in EDR version 2.2. (Note: Use code "04" in start column 53 (QA test code) for the daily QA/QC check.)

(f) Ongoing semiannual or annual RATAs shall be performed at the normal operating level according to the procedures in Part 75, Appendix B, section 2.3.1 and shall be calculated on a lb/mmBtu basis. The reference method traverse point selection shall be consistent with Part 75, Appendix A, section 6.5.6. Notification of ongoing

RATAs shall be provided according to §75.61(a)(5). Immediately prior to a RATA, the BAF shall be set to 1.000. Before each RATA, DIG shall ensure that the sensor validation system is set to provide at least one valid data point per 15 minute period, as discussed in paragraph (c). After the RATA, DIG shall calculate and apply a bias adjustment factor at the normal operating level according to Part 75, Appendix A, section 7.6. Report the RATA data and results in EDR record types 610 and 611 and report the bias test results in record type 611.

Ozone season, monthly, 3-run (minimum) relative accuracy audits (RAAs), described below, shall commence in May 2006. An RAA shall be performed in every calendar month of the ozone season (May through September) in which the unit operates for at least 56 hours, except for a month in which a full 9-run RATA or PEMS recertification is performed. Justification for these ozone season RAAs is provided in Attachment D.

Commencing on January 1, 2008, if Unit GTP1 is affected under the Clean Air Interstate Rule (CAIR), two additional RAAs are required to provide year round QA for the PEMS because of the year round monitoring requirements of CAIR. The RAAs are required in the first and fourth calendar quarters of each year, except for quarters in which: (a) the unit operates for less than 168 hours; (b) a full 9-run RATA is performed; or (c) the PEMS is recertified. Further justification for these two quarterly RAAs is provided in Attachment D.

The RAAs shall be done on a lb NO_x/mmBtu basis, and shall be performed using either EPA Reference Methods 7E and 3A in Part 60, Appendix A-4 or a portable analyzer. To the extent practicable, each RAA shall be done at different operating conditions from the previous one. Follow the portable analyzer manufacturer's recommended maintenance procedures.

The minimum time per RAA run shall be 20 minutes. The reference method traverse point selection shall be consistent with Part 75, Appendix A, section 6.5.6. Alternatively, a single measurement point located at least 1.0 meter from the stack or duct wall may be used without performing a stratification test.

Results of the RAA shall be calculated using Equation 1-1 in Appendix F to Part 60. Bias-adjusted data from the PEMS (using the bias adjustment factor from the most-recent RATA) shall be used in the calculations. The results of the RAA are acceptable if the performance specifications in the "PEMS Ongoing QA/QC Tests" table in paragraph (b) are met. If the RAA is failed, follow the provisions in paragraph (g). No grace periods are allowed.

Report the results of all RAAs in the appropriate quarterly electronic data report. Use EDR record type 624, and report the results of each test as either "pass" or "fail". Report the QA test code in column 53 of RT 624 as "05".

If a portable chemiluminescent NO_x analyzer is used to perform the required RAAs, the procedures of Method 7E in Part 60, Appendix A-4 shall be followed. The analyzer performance specifications in Method 7E for calibration error, system bias, and calibration drift shall be met.

If a portable electrochemical analyzer is used to perform the required RAAs, ASTM Method D6522-00[8], as modified below, shall be followed. ASTM D6522-00 applies to the measurement of NO_x (NO and NO_2), CO, and O_2 concentrations in emissions from natural gas-fired combustion systems using electrochemical analyzers. The method was developed based on studies sponsored by the Gas Research Institute (GRI)[9]. It has also been peer-reviewed, approved by ASTM Committees D22.03 and D22, and accepted by EPA as a conditional test method (CTM-030). ASTM D6522-00 prescribes analyzer design specifications, test procedures, and instrument performance requirements that are similar to the checks in EPA's instrumental test methods (e.g., Methods 7E and 20). These checks include linearity, interference, stability, pre-test calibration error, and post-test calibration error.

Based on the results of EPA's portable analyzer study[10], the following modifications to ASTM D6522-00 are required to make the method more practical without sacrificing accuracy: (a) NO_x analyzers must provide readings to 0.1 ppm to improve the likelihood of passing the performance specifications for sources with low NO_x levels; (b) an alternative performance specification (e.g., $\pm$ 1 ppm difference from reference value) will be applied to take account of sources with low concentrations of NO_x; and (c) the measurement system must be purged with ambient air between gas injections during the stability check, to reduce degradation of electrochemical cell performance (see footnote 11 below).

The measurement system performance specifications as modified by the EPA portable analyzer study are shown in the following table.

ASTM Method D6522-00 Measurement System Performance Specifications (as Modified by EPA Portable Analyzer Study)

Performance Check	Gas	Acceptance Criteria
Zero Calibration Error	NO, NO_2	$\leq$ 3 percent of span gas value or $\pm$ 1.0 ppm difference, whichever is less restrictive
	O_2	$\leq$ 0.3 percent O_2
Span Calibration Error	NO, NO_2	$\leq$ 5 percent of span gas value or $\pm$ 1.0 ppm difference, whichever is less restrictive
	O_2	$\leq$ 0.5 percent O_2

8 ASTM D6522-00, "Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers".

9 GRI (Gas Research Institute), "Topical Report, Development of an Electrochemical Cell Emission Analyzer Test Method", July, 1997.

10 "Evaluation of Portable Analyzers for Use in Quality Assuring Predictive Emission Monitoring Systems for NOx", The Cadmus Group, Inc., September 8, 2004.

Interference	NO, NO_2, O_2	≤ 5 percent of average stack NO concentration for each test run (using span gas checks)
Linearity	NO, O_2	≤ 2.5 percent of span gas concentration or ± 1.0 ppm difference, whichever is less restrictive
	NO_2	≤ 3.0 percent of span gas concentration or ± 1.0 ppm difference, whichever is less restrictive
Stability [11]	NO, NO_2 O_2	≤ 2.0 percent of span gas concentration or ± 1.0 ppm max-min difference, whichever is less restrictive, for 30-minute period ≤ 1.0 percent of span gas concentration or ± 1.0 ppm max-min difference, whichever is less restrictive, for 15-minute period
Cell Temperature		± 5 °F from initial temperature

(g) If a RAA or a RATA is failed due to a problem with the PEMS, or if changes occur that result in a significant change in NO_x emission rate relative to the previous PEMS training conditions (e.g., turbine aging, process modification, new process operating modes, or changes to emission controls), the following tests and procedures shall be performed to recertify the PEMS, in this order:

(1) Ensure that the Sensor Validation System meets the requirements of paragraph (c).

(2) Re-train the PEMS according to the manufacturer's recommendations.[12]

(3) Ensure that the requirements in paragraph (d) are met.

(4) Ensure that requirements in paragraph (e) are met.

(5) Perform a RATA, following the procedures in Part 75, Appendix A, section 6.5, except use three different operating levels (low, mid, and high) as defined in section 6.5.2.1 of Part 75, Appendix A. However, because the PEMS is only approved for use at 68 to 100 percent load, use 68 percent load as the lower boundary of the range of operation and 100 percent load as the upper boundary of the range of operation. Use paired PEMS and reference method data to calculate the results on a lb NO_x/mmBtu basis. Calculations shall be based on a minimum of 30 runs at each operating level. DIG shall apply to each operating level the RATA performance specifications contained in the "PEMS Ongoing QA/QC Tests" table in paragraph (b). Report the RATA data and results of only the normal operating level in EDR record types 610 and 611 and keep the data and results for the other two operating levels on-site, available for inspection. The RATA result for the normal operating level determines when the next RATA is due.

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[11] When conducting this check for three cells in an analyzer, the system must be purged with ambient air between gas injections to minimize the possibility of problems with the electrochemical cells. Otherwise, the cells will be exposed to high NO and NO_2 concentrations for prolonged periods of time, which can cause degradation in the cell's performance (i.e., the so-called "O_2-starved exposure").

[12] If a reference method is used to provide training data for the PEMS, the training data may be used to calculate the relative accuracy at each operating level and the normal level bias, and to set up the alarm system.

(6) Conduct an F-test, and a correlation analysis using Part 75, Subpart E equations at low, mid, and high operating levels. The F-test is to be applied to data at each operating level separately. The correlation analysis shall be performed using all data collected at the three operating levels combined. If the standard deviation of the reference method NO_x data at any operating level is less than either 3 percent of the span or 5 ppm, a reference method standard deviation of either 3 percent of span or 5 ppm may be used at that operating level when applying the F-test. At any operating level, if the mean value of the reference method NO_x data is less than 5 ppm, the correlation analysis (r-test) may be performed at the remaining operating levels, combined rather than at all three operating levels combined. Report the F-test and r-test results in record type 641.

(7) Perform a bias test (one-tailed t-test) at the normal operating level according to Part 75, Appendix A, section 7.6. If the bias test is failed, calculate and apply a bias adjustment factor (BAF) to the subsequent NO_x emission rate data. Report the bias test results in record type 611.

(8) The tests and procedures in this paragraph (g) shall be completed by the earlier of 60 unit operating days (as defined in §72.2) or 180 calendar days after the failed RAA or failed RATA or after the change that caused a significant change in NO_x emission rate. DIG shall use the appropriate Part 75 missing data procedures (see section 5 below), starting from the hour of the failed RAA or RATA and ending with the hour of successful passage or completion of the tests and procedures, as required above. DIG shall report the maximum potential NO_x emission rate (MER) from paragraph (h) and shall use a Method of Determination Code of "55", i.e., "Other substitute data approved through petition by EPA", in RT 320 for reporting lb NO_x/mmBtu emission rate, starting with the hour after the change that caused a significant change in NO_x emission rate and ending with the hour of successful passage or completion of the tests and procedures in steps (1) through (7) above. Notification of recertification of the PEMS shall be provided according to §75.61.

(h) For any hour or partial hour of startup, shutdown, or lean/lean turbine operation (burner modes 1 - 5, in other words, if dry low-NO_x is not operating), DIG must report the NO_x MER, as defined in §72.2. For the purposes of this approval, the MER shall be 0.700 lb/mmBtu. A Method of Determination Code "55", i.e., "Other substitute data approved through petition by EPA", shall be used in RT 320 when reporting the MER.

5. Missing Data Substitution

Under §75.46, the owner or operator must demonstrate that all missing data can be accounted for in a manner consistent with the applicable missing data procedures in Subpart D (except where alternate procedures are required in this final approval). The DIG petition states that Unit GTP1 currently meets requirements of Appendix E to Part 75, including Appendix E missing data procedures. When DIG discontinues the use of Appendix E and begins to use the PEMS as an approved Part 75 AMS, all of the Subpart D missing data procedures for NO_x emission rate shall be immediately implemented (except where alternate procedures are required in this final approval).

The Subpart D missing data procedures include, but are not limited to, the initial missing data procedures in § 75.31, determination of monitor data availability (§ 75.32), and the standard missing data procedures in § 75.33. DIG shall also continue to meet the missing data substitution requirements of Appendix D to Part 75.

6. Additional Requirements

DIG shall submit the operating envelope for Unit GTP1 to the Michigan Department of Environmental Quality and to EPA Region 5 for inclusion in the hardcopy monitoring plan. Any time changes are made to the PEMS operating envelope, the complete, revised PEMS operating envelope shall be submitted in a hardcopy monitoring plan by the applicable deadline in §75.62(a)(2). More information on monitoring plan submittals, revisions and other submittals can be found at: http://www.epa.gov/airmarkets/monitoring/submissions/monplan.html.

DIG shall follow the EDR version 2.2 reporting instructions, found at: http://www.epa.gov/airmarkets/reporting/edr21/, in conjunction with the required PEMS record types, and the supplementary EDR reporting instructions attached to this petition response, to report data from the PEMS (see Attachments B and C). Monitoring Data Checking (MDC) software that can be used to quality assure the electronic reports prior to submission is found at: http://www.epa.gov/airmarkets/reporting/index.html.

Attachment B

BASIC EDR REPORTING FOR PREDICTIVE EMISSIONS MONITORING SYSTEMS (PEMS)

I. Introduction

Table A-15, below includes the essential EDR record types for units that have received approval under Subpart E of Part 75 to use PEMS to report NO_x emissions. The scope of Table A-15 is limited to affected oil and gas-fired units (i.e., boilers and combustion turbines) that:

- Have a single unit-single stack exhaust configuration; and
- Use Part 75, Appendix D methodology to quantify unit heat input; and
- Use Part 75, Appendices D and G to account for SO_2 and CO_2 mass emissions (if the units are in the Acid Rain Program); and
- Do not co-fire oil and gas.

For PEMS reporting, EDR version 2.2 must be used, since fuel-specific missing data substitution for NO_x emission rate is required. For hourly NO_x emission rate reporting, RT 320 is used. Hourly 200-level records are not reported for either NO_x concentration or diluent gas (O_2 or CO_2) concentration.

For units that burn more than one fuel type, separate PEMS are required for each fuel. Each PEMS should be reported as a separate monitoring system with a unique monitoring system ID in RT 510. Each PEMS will require its own set of certification, recertification, and quality assurance tests.

II. Interpreting Table A-15

In Table A-15, the first column identifies the record type. The second column gives a brief description of the record type. The third, fourth, and fifth columns indicate whether the record type must be reported for a particular type of submittal. The third column header, "MP," refers to monitoring plan submittals. The fourth column header, "CT," stands for certification or recertification applications. The fifth column header, "QT," refers to electronic data report submittals. The letter codes in columns 3 through 5 are defined as follows:

Y This record type is required for this type of submittal (monitoring plan, certification/recertification application or electronic data report)

N This record type is not appropriate for this type of submittal.

O This record type is appropriate, but optional for this type of submittal.

A This record type may be required for this submittal. If any doubt exists as to the need to submit this record type, consult the appropriate EDR instructions.

T This record type is required each time a quality assurance test (e.g., a RATA) is performed.

Column 6 identifies the units covered by the record type as units subject to the Acid Rain Program ("ARP") or units subject to Part 75, Subpart H ("Subpart H").

Table A-15
EDR RECORD TYPES FOR UNITS WITH PEMS

Record Type	Description	MP	CT	QT	Program Applicability and Comments
100	Facility Identification	Y	Y	Y	ARP, Subpart H
101	Record Types Submitted	O	O	O	ARP, Subpart H
102	Facility Location and Identification Information	Y	Y	Y	ARP, Subpart H
300	Operating Data	N	N	Y	ARP, Subpart H • Report one RT 300 for each hour in the quarter, except when a unit does not operate during the entire quarter. • For each operating hour, report the fuel combusted in column 64.
301	Quarterly Cumulative Emissions	N	N	Y	ARP • Quarterly NO_x emission rate is the arithmetic average of the RT 320, col 42 values
302	Oil Fuel Flow	N	N	Y	ARP, Subpart H • For ARP units, must be paired with RT 313 when reporting SO_2 mass emissions.
303	Gas Fuel Flow	N	N	Y	ARP, Subpart H • For ARP units, must be paired with RT 314 when reporting SO_2 mass emissions.
307	Cumulative NO_x Mass Emissions	N	N	Y	Subpart H
313	SO_2 Mass Emissions (Oil)	N	N	Y	ARP
314	SO_2 Mass Emissions (Gas)	N	N	Y	ARP
320	NO_x Emission Rate Estimation	N	N	Y	ARP, Subpart H • See supplementary reporting instructions.
328	NO_x Mass Emissions	N	N	Y	Subpart H • See supplementary reporting instructions.
330	CO_2 Mass Emissions Data	N	N	A	ARP • Report RT 330 for hours in which Equation G-4 is used to determine hourly CO_2 mass emissions for gas or oil-fired units.
331	CO_2 Mass Emissions Estimation Parameters	N	N	A	ARP • Report RT 331 if you estimate CO_2 mass emissions using fuel sampling and Equation G-1
504	Unit Information	Y	Y	Y	ARP, Subpart H
505	Program Indicator for Report	Y	Y	Y	ARP, Subpart H
506	EIA Cross Reference Information	Y	Y	Y	ARP, Subpart H
507	Peaking Unit or ARP Gas-Fired Unit Qualification Data	A	A	A	ARP
508	Subpart H Reporting Frequency Change	N	N	A	Subpart H
510	Monitoring Systems/Analytical Components Table	Y	Y	Y	ARP, Subpart H • See supplementary reporting instructions.

Record Type	Description	MP	CT	QT	Program Applicability and Comments
520	Formula Table	Y	Y	Y	ARP, Subpart H • Report formulas for SO_2 and CO_2 mass emissions (ARP units,only), NO_x mass emissions (Subpart H units), and unit heat input rate.
531	Defaults and Constants	Y	Y	Y	ARP, Subpart H • See supplementary reporting instructions.
535	Unit and Stack Operating Load Data	Y	Y	Y	ARP, Subpart H Required for any unit using load-based missing data procedures for NO_x or fuel flow rate.
536	Range of Operation, Normal Load, and Load Usage	Y	Y	Y	ARP, Subpart H • Report RT 536 to define operating range and normal load for RATA testing
540	Fuel Flowmeter Data	Y	Y	Y	ARP, Subpart H
550	Reasons for Monitoring System Downtime or Missing Parameter	N	N	A	ARP, Subpart H • See supplementary reporting instructions.
556	Monitoring System Recertification, Maintenance, or Other Events	N	Y	A	ARP, Subpart H • Report RT 556 for recertification of the PEMS or fuel flowmeters • See supplementary reporting instructions.
585	Monitoring Methodology Information	Y	Y	Y	ARP, Subpart H • See supplementary reporting instructions.
586	Control Equipment Information	A	A	A	ARP, Subpart H
587	Unit Fuel Type	Y	Y	Y	ARP, Subpart H
610	RATA and Bias Test Data	N	Y	T	ARP, Subpart H • Report RTs 610 each time a RATA is performed for certification, recertification or for on-going QA/QC. • See supplementary reporting instructions.
611	RATA and Bias Test Results	N	Y	T	ARP, Subpart H • Report RT 611 each time a RATA is performed for certification, recertification or for on-going QA/QC. • See supplementary reporting instructions.
624	Other QA Activities	N	N	Y	ARP, Subpart H • Report RT 624 for PEMS daily QA/QC and for PEMS periodic accuracy checks using a reference method, or a portable analyzer. • See supplementary reporting instructions.
627	Fuel Flowmeter Accuracy Test	N	A	T	ARP, Subpart H • Report only for fuel flowmeters that are certified and quality assured by periodic accuracy tests according to Part 75, Appendix D, section 2.1.5.1 or 2.1.5.2.
628	Fuel Flowmeter Accuracy Test for Orifice, Nozzle and Venturi Flowmeter	N	A	T	ARP, Subpart H • Report only for orifice, nozzle and venturi-type flowmeters that are quality assured by periodic transmitter/transducer calibrations.
629	Fuel Flow-to-load Ratio Test Baseline Data	N	N	A	ARP, Subpart H • Report if quarterly fuel flow-to-load ratio test in Part 75, Appendix D, section 2.1.7 is used to extend fuel flowmeter accuracy test deadlines.

Record Type	Description	MP	CT	QT	Program Applicability and Comments
630	Quarterly Fuel Flow-to-load Ratio Test Results	N	N	A	ARP, Subpart H • Report if quarterly fuel flow-to-load ratio test in Part 75, Appendix D, section 2.1.7 is used to extend fuel flowmeter accuracy test deadlines.
640	Alternative Monitoring System Approval Petition Data	N	Y	A	ARP, Subpart H • Report when certifying a PEMS
641	Alternative Monitoring System Approval Petition Results and Statistics	N	Y	A	ARP, Subpart H • Report when certifying or recertifying a PEMS
696	Fuel Flowmeter Accuracy Test Extension	N	N	A	ARP, Subpart H • Use RT 696 to claim allowable extensions of fuel flowmeter accuracy test deadlines.
697	RATA Deadline Extension or Exemption	N	N	A	ARP, Subpart H • Report when claiming a RATA deadline extension under Part 75, Appendix B, section 2.3.3.
699	QA Test Extension Based on Grace Period	N	N	A	ARP, Subpart H • Report when claiming a QA test deadline extension under Part 75, Appendix B, section 2.2.4.
900	Certifications	Y	Y	Y	ARP
901	Certifications	Y	Y	Y	ARP
910	Comments	Y	Y	Y	ARP, Subpart H • See supplementary reporting instructions.
920	Comments	O	O	O	ARP, Subpart H
940	Certifications	Y	Y	Y	Subpart H
941	Certifications	Y	Y	Y	Subpart H
999	Contact Information	O	O	O	ARP, Subpart H

Attachment C

SUPPLEMENTARY EDR REPORTING INSTRUCTIONS FOR PEMS

For a unit with an approved petition to use a predictive emissions monitoring system (PEMS), use the following supplementary instructions, in conjunction with the EDR version 2.2 Reporting Instructions document, to prepare the required EDR submittals.

RT 320

Monitoring System ID (10). Report the monitoring system ID (from RT 510, column 13) of the PEMS used to determine the NO_x emission rate during the hour.

F-Factor (26). Leave this field blank.

Average NO_x Emission Rate for the Hour (36). Report the average unadjusted NO_x emission rate for the hour (lb/mmBtu), rounded to three decimal places, as determined by the PEMS. For hours in which you use missing data procedures, leave this field blank.

Adjusted Average NO_x Emission Rate for the Hour (42). For each hour in which you report NO_x emission rate in column 36, apply the appropriate adjustment factor (1.000 or the BAF) to the unadjusted average emission rate, and report the result rounded to three decimal places. For each hour in which you use missing data procedures, report the appropriate substitute value.

Formula ID (50). Leave this field blank.

Method of Determination Code (53). Report "03" when you use the PEMS to determine the NO_x emissions rate. Report "12" when you report the fuel-specific maximum NO_x emission rate (e.g., during hours of startup or shutdown or when NO_x controls (if any) are not functioning properly). During hours when you use other missing data procedures, report the appropriate MODC listed in the EDR instructions.

RT 328

NOx Methodology for the Hour (45). Report "NOXR-PEMS".

RT 510

The PEMS monitoring system consists of either one or two data acquisition and handling system (DAHS) components. For single-component PEMS systems or for systems where the PEMS software and standard DAHS software have the same manufacturer/provider, model or version number, report one RT 510 for the PEMS system. If the PEMS software and the standard DAHS software have different manufacturer/providers, model or version numbers, report each as a separate RT 510 with the same PEMS monitoring system ID.

Component ID (10). Report the three-character alphanumeric ID for each DAHS component.

Monitoring System ID (13). Create a unique three-character alphanumeric ID for each PEMS monitoring

system. Define a separate NO_x PEMS system for each fuel type. For sources switching from NO_x CEMS or Part 75, Appendix E to PEMS, do not re-use the CEMS or Appendix E system ID numbers.
System Parameter Monitored (17). If your PEMS is approved for NO_x emission rate (lb/mmBtu) and if you use the NO_x emission rate to calculate NO_x mass emissions, report "NOX" for the system parameter monitored. If your PEMS is approved for NO_x concentration (ppm) and if you calculate NO_x mass emissions as the product of NO_x concentration times flow rate, report "NOXC" for the system parameter monitored.

Primary/Backup Designation (21). Report "PE" to indicate that this is a predictive emissions monitoring system.

Component Type Code (23). Report "DAHS" as the component type code.

Sample Acquisition Method (27). Leave this field blank.

Manufacturer (30). Report the name of the manufacturer or developer of the software component.

Model/Version (55). Report the model/version of the software component.

Serial Number (70). Report the serial number, if applicable—otherwise leave blank.

RT 531

Parameter (10). Report "NORX" as the parameter monitored. (You should report one 531 record for each fuel type.)

Default Value (14). Report the fuel-specific maximum potential NO_x emission rate (MER), in units of lb/mmBtu.

Units of Measure (27). Report "LBMMBTU".

Purpose or Intended Use (34). Report "MD" for missing data.

Type of Fuel (37). Report the fuel type code for the fuel. (See the EDR Instructions for RT 531 for the list of available codes.)

Indicator of Use (40). Report "A" for any hour.

Source of Value (41). Report "DEF" for default value.

RT 550

Parameter (10). Report "NOX".

Monitoring System ID (14). Report the monitoring system ID, from RT 510, of the NO_x PEMS system.

RT 556

Component ID (10). Report the PEMS component ID subject to recertification/diagnostic testing, if a specific component is involved. If the event is system, not component, specific, leave this field blank.

Monitoring System ID (13). Report the monitoring system ID, from RT 510, of the NO_x PEMS system.

Event Code (16). Report code "99" (i.e., "Other").

Code for Required Test (19). Codes for PEMS systems are:

80 PEMS sensor validation system (minimum data capture check), train or retrain (if manufacturer recommends), sensor validation system (alarm system set-up and failed sensor alert check), daily QA/QC, 3 operating level RATA, statistical tests, and normal operating level bias test;

81 PEMS daily QA/QC, and PEMS check with reference method or portable analyzer;

Beginning of Conditionally Valid Period (31, 39). If conditional data validation is used, report the date and hour that the probationary PEMS daily QA/QC test was successfully completed according to the provisions of §75.20(b)(3)(ii).

Note: For PEMS, you may only use conditional data validation if the "event" in column 16 requires RATA testing. If you elect to use conditional data validation, you must complete the RATA within the allotted time in §75.20(b)(3)(iv).

RT 585

Parameter (10). If your PEMS is approved for NO_x emission rate (lb/mmBtu) and if you use the NO_x emission rate to calculate NO_x mass emissions, report "NOXR" as the parameter code associated with the PEMS. If your PEMS is approved for NO_x concentration (ppm) and if you calculate NO_x mass emissions as the product of NO_x concentration times flow rate, report "NOXM" as the parameter code associated with the PEMS. Report one RT 585 for each generic fuel type combusted.

Monitoring Methodology (14). Report "PEMS" as the monitoring methodology for the PEMS.

Missing Data Approach for Methodology (28). Report "FSP75" for the fuel-specific missing data approach for the PEMS methodology.

RT 610

Units of Measure (33). Report "2" (lb/mmBtu) as the units of measure.

Value from CEM System Being Tested (34). Report the average value recorded by the PEMS, for each RATA run.

RT 611

Units of Measure (34). Report "2" (lb/mmBtu) as the units of measure.

Arithmetic Mean of CEM Values (35). Report the arithmetic mean of all the RTs 610 PEMS values associated with the RATA.

Number of Load Levels Comprising Test (133). Report "1" or "3" (if certification or recert).

BAF for a Multiple-Load RATA (134). Leave this field blank.

RT 624

Component ID (10). Report the PEMS software component ID from RT 510.

Monitoring System ID (13). Report the NO_x monitoring system ID from RT 510.

Parameter (16). Report "NOX".

QA Test Activity Description (30). Fill in appropriately.

Reason for Test (51). Report "Q".

QA Test Code (53). Report one of the following codes, as appropriate:

04 PEMS daily QA/QC
05 Periodic check of PEMS accuracy with a portable analyzer, or reference method

RT 640

Submit RT 640 only with the Subpart E application for initial certification of the PEMS. Do not submit RT 640 for PEMS recertification.

Component ID (10). Report the PEMS software component ID from RT 510.

Monitoring System ID (13). Report the NO_x monitoring system ID from RT 510.

RT 641

Submit RT 641 with the Part 75, Subpart E application for initial certification of the PEMS and for all recertifications of the PEMS. For initial certification, fill in all applicable data fields in RT 641. For PEMS recertification, report only the data elements in start columns 1 through13, column 95 (the F-statistic), column 108 (Critical value of F at 95% confidence level for sample size), and column 121 (Coefficient of correlation (Pearson's r) of CEM and AMS data).

Component ID (10). Report the PEMS software component ID from RT 510.

Monitoring System ID (13). Report the NO_x monitoring system ID from RT 510.

RT 910

Text (4). Briefly describe the PEMS.

Attachment D

JUSTIFICATION FOR RAA TESTING OF THE PEMS

A. Background

A NO_x PEMS is a piece of software that provides an indirect determination of NO_x emissions. It can provide an accurate indication of NO_x levels if it is properly developed, trained, and quality-assured. Normally, a PEMS is trained over a one week (or longer) time period and over a wide range of source operating conditions. However, even the best training regimen cannot include all possible operating conditions, e.g., upsets, sticky valves, or other unforeseen events, that can affect emissions but are not reflected in the PEMS output.

One safeguard against this is to implement a PEMS algorithm that identifies potentially failed sensors and PEMS input parameters that are outside of the expected range of values, by comparing the readings from each sensor to several other sensors and determining expected sensor values based on the historical sensor relationships developed during PEMS training. When unacceptable sensor values are identified, an alarm is activated, the PEMS is considered out of control, and the maximum potential NO_x emission rate must be reported until the sensor is fixed or the PEMS is retrained. Reporting standard missing data values or allowing a substitute sensor value calculated by the PEMS is not an adequate solution because the PEMS cannot determine whether the abnormal input parameter value is caused by a failed sensor or by some new region of operation not represented in the PEMS training data.

An even better safeguard against unforeseen events that can affect NO_x emissions, but may not be reflected in the PEMS output, is to periodically compare the PEMS output to a quality assured, direct measurement of stack emissions, e.g., by performing a RATA. However, RATAs are costly and are generally performed only once or twice a year. Therefore, other, less-expensive accuracy checks should be done in between the RATAs, to provide ongoing assurance of data quality. For continuous emission monitoring systems (CEMS), the RATAs are supplemented by daily calibration error checks and quarterly linearity checks, which use calibration gases. However, these tests cannot be done on a PEMS because calibration gas cannot be injected into a PEMS. Therefore, some other type of periodic accuracy check suitable for a PEMS is needed to supplement the RATAs in order to adequately quality assure the PEMS data for use in a cap and trade program.

In paragraph (e) of EPA's September 2, 2003 conditional PEMS approval for Unit GTP1 at DIG, EPA reserved the right to require the owner or operator of GTP1, i.e., DIG, to use portable NO_x and diluent gas (CO_2 or O_2) analyzers to perform periodic assessments of the accuracy of the PEMS, if and when EPA determined that portable NO_x analyzers can provide adequate PEMS accuracy checks. EPA stated that it would provide DIG with the necessary performance specifications, sampling frequency, methodology, and reporting guidance should this become a requirement. EPA also stated that over the next few months, it would test several portable electrochemical and chemiluminescent NO_x analyzers at combustion turbine sites to determine how well these analyzers work. Finally, EPA indicated that if periodic, direct checks of PEMS accuracy with portable analyzers should become a requirement, it would be implemented in such a way that the unit would be tested at different operating levels from check-to-check.

Since issuing the September 2, 2003 conditional PEMS approval, EPA has completed a field study of portable NO_x monitors, analyzed the results, and performed a cost assessment[13]. For the two natural gas-fired combustion turbines tested, the accuracy of the portable analyzers at NO_x concentration levels of 3 ppm and higher was found to be comparable to that of a certified Part 75 CEMS and to EPA Reference Method 7E. Thus, portable analyzers are suitable for periodic accuracy tests of a PEMS.

B. Monthly 3-Run Relative Accuracy Audits in the Ozone Season

EPA believes that monthly 3-run relative accuracy audits (RAAs) performed during the ozone season using a portable analyzer will provide the necessary additional QA for the PEMS installed on Unit GTP1 under the NO_x Budget Trading Program. The monthly frequency was chosen by EPA as a compromise between a daily and a quarterly check of the PEMS against a direct emission measurement. Because the NO_x Budget Trading Program is concerned with controlling ozone, EPA decided that performing monthly RAAs on the PEMS during the ozone season (May through September) is an appropriate level of quality assurance.

C. Quarterly 3-Run RAAs in First and Fourth Quarters

Starting on January 1, 2008, Unit GTP1 may need to comply with the monitoring requirements of the Clean Air Interstate Rule (CAIR). Under CAIR, certain sources in Michigan are controlled out of concern for both ozone and fine particulate concentrations. The previously discussed monthly RAAs in the ozone season cover the second and third quarters only. However, fine particulate is a year round problem. Therefore, if Unit GTP1 is affected under CAIR, two additional RAAs are required to provide year round QA for the PEMS. One of these RAAs is required in the first quarter and the other in the fourth quarter. For the first and fourth quarters, EPA has decided to provide the greater flexibility of quarterly rather than monthly RAAs out of safety concerns of performing stack tests during winter months.

D. Cost Analysis

EPA has assessed the potential cost associated with an RAA requirement. The Agency estimates that performing the additional five monthly RAAs during the ozone season and two RAAs during the non-ozone season using a portable analyzer with trained in-house staff would bring the total annual cost of operating, maintaining and quality-assuring a PEMS such as the one on Unit GTP1 to approximately \$29,850. (If outside contractors are used, instead of in-house staff, the total annual cost would be \$49,750). This cost includes \$6,000 annualized equipment cost for a portable analyzer plus \$7,750 operation and maintenance (O&M) costs associated with QA testing (including an annual 9-run RATA performed by an outside test contractor, and seven 3-run RAAs performed by in-house staff using a portable analyzer), and \$15,000 for PEMS O&M. This represents an annualized increase of about \$9,850 above the cost without the seven RAAs.

EPA believes that the cost of the additional RAAs is reasonable. According to EPA's CEM Cost Model, the next least costly option for Unit GTP1 to comply with Subpart H of Part 75 would be NO_x-diluent CEMS. The total annual cost of operating and maintaining a CEMS is estimated at \$62,700. This cost includes \$15,000 annualized equipment cost plus \$47,700 O&M costs (including an annual

[13] "Evaluation of Portable Analyzers for Use in Quality Assuring Predictive Emission Monitoring Systems for NOx", The Cadmus Group, Inc., September 8, 2004.

RATA). Thus, even with the additional RAA requirement, the estimated annual cost of operating and maintaining a PEMS at Unit GTP1 using trained in-house staff and a portable analyzer would be less than half the cost associated with CEMS. Even if outside contractors are used instead of in-house staff, the annual PEMS cost would be significantly less ($12,950 less) than the annual cost associated with a CEMS.

E. Additional Statistical Tests and 3-Load RATAs

In paragraph (j) of EPA's September 2, 2003 conditional PEMS approval for Unit GTP1, the Agency reserved the right to require new statistical procedures or to change the ones currently required. Since issuing the conditional PEMS approval, EPA has completed a field study of a hybrid neural network based PEMS at two gas-fired combustion turbines[14]. The study suggested that application of the Part 75, Subpart E statistics to a smaller data set, when coupled with a three-level RATA to evaluate the PEMS predictions across the PEMS "operating envelope", is a good measure of PEMS performance.

EPA performed a Subpart E statistical analysis of 720 hours of matched pairs of PEMS and CEMS data for one participating combustion turbine and 830 matched data pairs for another, and then performed the same statistics on 30-point subsets of these data. The results of these analyses showed that most of the 30-point subsets passed the same combination of statistical tests as the full data set. The field test data also illustrated the importance of testing the PEMS over the full operating range of the unit because of the strong correlation between NO_x emissions to certain unit operating parameters. Based on this evaluation, EPA believes that whenever the PEMS is recertified, a three load RATA (with a minimum of 30 paired data points at each load level) should be required in conjunction with input sensor failure checks and certain abbreviated Subpart E statistical tests; in particular, the F-test, the correlation analysis, and the t-test.

[14] "Evaluation and Field Testing of Nitrogen Oxide (NO_x) Predictive Emission Monitoring Systems (PEMS) for Gas-fired Combustion Turbines - Synthesis Report", The Cadmus Group, Inc., December 29, 2004 .