MEMORANDUM:

DATE: 4 September 1998

SUBJECT: Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

FROM: Combustion Turbine Work Group

TO: ICCR Coordinating Committee

The Combustion Turbine Work Group (CTWG) formed a task group to develop a white paper on the cost-effectiveness of oxidation catalysts in controlling HAP emissions from combustion turbines. The attached document is the white paper developed by this task group.

The CTWG concurs that this information may be valuable to EPA in developing regulations for combustion turbines and requests that the ICCR Coordinating Committee pass it to EPA as a Closure Item.

Attachment: Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions From Stationary Combustion Turbines

Prepared By the

Combustion Turbine Work Group
Of the Industrial Combustion Coordinated Rulemaking

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I. Introduction

This paper presents the assessment of the Combustion Turbine Work Group (CTWG) with regard to the potential cost-effectiveness of oxidation catalysts used to control hazardous air pollutant (HAP) emissions from combustion turbines. This assessment is made in the context of the Coordinating Committee providing recommendations that contribute to EPA's evaluation of "above-the-floor" MACT options for existing combustion turbines. In accordance with Section 112(d) of the Clean Air Act, EPA must consider costs in evaluating above-the-floor options for MACT, along with any non-air quality health and environmental impacts and energy requirements.

In previous materials, the Coordinating Committee recommended to EPA, based on available information, that it is not possible to identify a best performing subset of existing combustion turbines, and as a result, there is no MACT floor for the existing population of combustion turbines in the United States. Therefore, to determine MACT, EPA may evaluate emission reduction technologies above the floor for existing combustion turbines. The CTWG has reviewed emission reduction technologies for existing turbines to identify controls that may be considered in the above-the-floor MACT analysis. Based on the CTWG's review, oxidation catalysts for the reduction of carbon monoxide (CO) may reduce emissions of organic HAPs from combustion turbines. The CO oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct and serves to oxidize CO and hydrocarbons to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the fuel gas stream (EPA, 1993a). Oxidation catalysts are used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust (EPA 1993a, Chen et al., 1993). Therefore, EPA may evaluate oxidation catalysts as an "above-the floor" MACT option for existing combustion turbines. This paper addresses the costs and the HAP air emissions reductions that may be achieved with oxidation catalysts. The CTWG recognizes that EPA may consider other factors, such as non-air quality environmental impacts, energy requirements, and secondary pollutants, in assessing above-the-floor MACT

The approach taken in this paper is to present a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for model combustion turbine units, which range in size from 1.13 megawatts (MW) to 170 MW. To determine cost-effectiveness for the base case analysis, the CTWG developed quantitative estimates for the three inputs required to estimate cost-effectiveness:

1. the baseline HAP emissions of combustion turbines before emissions control,
2. the costs of acquiring and operating oxidation catalysts, and,
3. the performance of oxidation catalysts in reducing HAP emissions.

For each of these inputs this paper presents the key factors that the CTWG considers important. In assessing these three areas the CTWG presents a base case quantitative estimate of the cost-effectiveness of oxidation catalysts for each model turbine. The quantitative cost-effectiveness for each model was calculated by dividing the total annual cost by the mass of annual HAP emission reductions. Cost-effectiveness is expressed as dollars per megagram of HAP emission reduction. A megagram (Mg) is one metric ton, or approximately 1.1 U.S. tons. The paper also presents a qualitative discussion of the CTWG's views on complicating factors that could cause the estimated cost-effectiveness base case to be different in real-world situations.

Section II provides a summary of the base case assumptions. Sections III, IV, and V present the quantitative estimates and complicating factors for each of the three inputs for cost-effectiveness: baseline HAP emissions, control costs, and emission reduction. The range of cost-effectiveness values and the base case cost-effectiveness for each model turbine are presented in Section VI. The CTWG's conclusions and recommendations are presented in Section VII.

II. Summary of Base Case Assumptions

For the base case cost-effectiveness analysis, the CTWG selected seven model turbines that range in size from 1.13 megawatts (MW) to 170 MW:

- Model 1 -- GE PG 7121EA, 85.4 MW
- Model 2 -- GE PG 7231FA, 170 MW
- Model 7 -- GE PG 6561B, 39.6 MW
- Model 9 -- GE LM2500, 27 MW
- Model 13 -- Solar Centaur 40, 3.5 MW
- Model 15 -- Solar Mars T12000, 9 MW
- Model 17 -- Solar Saturn T1500, 1.13 MW

These seven model turbines were selected from the 32 model turbines developed by the CTWG to provide the basis to estimate the national impacts associated with any future combustion turbine MACT standard. A complete list of the 32 model turbines is provided as **Appendix A.**

As originally developed, the list of model turbines incorporates the fuels used, the typical hours of operation for a unit, the industry sector that may use a turbine, the presence of a duct burner, and information about space limitations. For the base case analysis, the CTWG simplified the model turbines selected. The base case assumes that each turbine is operated for 8,000 hours annually and operates at 80% rated load or greater.
The CTWG also limited the base case analysis to natural gas-fired model turbines. Natural gas is the predominant fuel used by combustion turbines in the ICCR database. 54.3% of the turbines in ICCR Inventory Database Version 3 were reported as firing natural gas exclusively. In addition, 14.5% were reported as being dual fuel units, and it is expected that these units primarily use natural gas. The CTWG has assembled quantitative information available on baseline emissions, catalyst costs and catalyst performance for natural gas-fired turbines. In addition, the CTWG decided to focus the quantitative analysis on natural gas-fired turbines because fuels other than natural gas introduce complicating factors. For example, a catalyst vendor indicated that for turbines

that operate continuously on fuel oil, it is preferable to use a special catalyst formulation that is unaffected by sulfur exposure (Chen et al., 1993). The CTWG has no data on the specially formulated catalysts.

In addition, the CTWG limited the base case quantitative analysis to uncomplicated retrofit installations. Although the CTWG identified a number of situations that would complicate a retrofit installation of an oxidation catalyst, especially complications due to space limitations, time did not permit the CTWG to develop quantitative estimates for these complications. Therefore, the base case includes only a qualitative description of retrofit complications, and no costs for retrofit complications are included in the cost-effectiveness values. Based on the experience of the CTWG members, most retrofit installations for existing turbines would involve some complicating factors and, therefore, the costs to retrofit the units with oxidation catalysts would be higher in general, and in some cases much higher, than the costs presented in this base case analysis.

III. Baseline HAP Emissions from Combustion Turbines

The CTWG used emissions data included in the ICCR Emissions Database to identify HAPs emitted by natural gas-fired combustion turbines and to estimate baseline emission rates. Only emissions tests that met the criteria established by the CTWG for this analysis were considered. Mass emissions for each HAP were calculated using emission factors (lb/MMBtu) from those emission tests that met the CTWG's criteria. Since the rate of emissions reported for natural gas-fired combustion turbines varies, the CTWG used two emission factors to estimate baseline emissions -- the highest emission factor and the average emission factor.

Further discussion of the baseline emissions data used in this analysis and complicating factors is provided below.

A. Source of Baseline HAP Emissions Data

The information available to the CTWG about the emissions of HAPs from combustion turbines is included in the ICCR Emissions Database. The CTWG believes that the emissions database adequately represents the turbine population, and that these source test data are a sufficient basis for emission factors for a cost-effectiveness analysis.

The current version of the emissions database includes over 70 source tests collected by EPA, many of which involve replicate sampling and analysis runs. For each test report EPA has calculated consistent emission factors for measured HAPs based on the emissions concentration reported. A description of the development of the emissions database, including assumptions used in the calculations, is provided as **Appendix B**. Also, EPA and the CTWG have performed a quality assurance review of each test report and determined which reports should be considered adequate for general assessment of HAP emissions from combustion turbines. These review criteria are included in **Appendix C**. When possible, pertinent information identified as missing from test reports was obtained by contacting the tested facilities. Only those source test data considered appropriate for use in evaluating HAP emissions were used to calculate emission factors.

B. Criteria to Include Emission Test Data in Baseline Emissions

The CTWG identified a subset of combustion turbine emission tests from the ICCR Emissions Database to develop the baseline emission factors for this cost-effectiveness analysis, based on the following criteria:

1. Because the baseline emissions estimate is to be done only for natural gas, emission factors were included only from tests of combustion turbines firing natural gas. [42 of the 70 test reports in the database are for natural gas.]
2. Only test reports that were judged to be complete and to have met quality assurance criteria were included. [Of the 42 tests for natural gas, 8 reports were not complete or did not meet QA\QC criteria.]
3. Because combustion turbines typically operate near full load, emission factors were extracted only for combustion turbine tests that were

conducted at above 80% of rated load. [Of the 42 tests for natural gas, 11 reports were conducted at less than 80% rated load.]

A list of the tests excluded based on the above criteria is provided in **Appendix D**.

C. Emission Factors for Baseline HAP Emissions

For those test reports in the ICCR Emissions Database that met the criteria discussed above, emission factors were included in this cost-effectiveness analysis for those HAPs measured at concentrations above the test method's detection limit in at least one run. Therefore, none of the emission factors are based solely on non-detects. This criterion is consistent with the ICCR Testing and Monitoring Work Group's recommendations that regulatory decisions should not be based solely on non-detects (ICCR Testing and Monitoring Work Group, 1997).

For natural gas-fired turbines, nine HAPs were measured above the detection limits in at least one run. Both the highest emission factor and the average emission factor were used for the base case analysis. The emission factors are presented in **Table 1**. Baseline annual emissions for each model turbine were calculated using these emission factors. The heat input was calculated by converting the model turbine rating (MW) to MMBtu/hr and dividing by the turbine efficiency, assumed to be 35%. The baseline annual emissions were then calculated using the heat input (MMBtu/hr), the emission factor (lb/MMBtu), and the annual operating hours (hr/yr). The baseline emissions (megagrams/year) for each model turbine are presented in **Table 2**. [Note: The emission estimates used in this analysis are presented as emissions at the stack outlet. The emissions estimates do not address ambient air dispersion of the pollutants, nor ground-level concentrations.]

Table 1. HAPs Emission Factors for the Base Case Analysis

Pollutant	Highest Emission Factor		Average Emission Factor	
	Test	(lb/MMBtu)	(lb/MMBtu)	No. of Tests
Formaldehyde	Test 316.1.1	5.61E-03	7.13E-04	22 Tests
Toluene	Test 28	7.60E-04	1.42E-04	7 Tests
Acetaldehyde	Test 11	3.50E-04	9.12E-05	7 Tests
Xylenes	Test 18	1.20E-04	4.59E-05	5 Tests
Ethylbenzene	Test 18	4.10E-05	4.10E-05	1 Test
Benzene	Test 315.1	3.91E-05	1.03E-05	11 Tests
PAHs	Test 7	7.32E-06	2.23E-06	4 Tests
Acrolein	Test 18	6.08E-06	5.49E-06	2 Tests
Naphthalene	Test 7	3.31E-06	1.46E-06	3 Tests

Source: ICCR Emissions Database for Combustion Turbines

Table 2. Baseline Emissions (Mg/yr) for Each Model Turbine

Baseline Emissions (Mg/yr)-- Highest Emission Factor											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	33.810	4.580	2.109	0.723	0.247	0.236	0.044	0.037	0.020	41.806
1	85.4 MW	16.984	2.301	1.060	0.363	0.124	0.118	0.022	0.018	0.010	21.001
7	39.6 MW	7.876	1.067	0.491	0.168	0.058	0.055	0.010	0.009	0.005	9.738
9	27 MW	5.370	0.727	0.335	0.115	0.039	0.037	0.007	0.006	0.003	6.640
15	9 MW	1.790	0.242	0.112	0.038	0.013	0.012	0.002	0.002	0.001	2.213
13	3.5 MW	0.696	0.094	0.043	0.015	0.005	0.005	0.001	0.001	< 0.001	0.861
17	1.13 MW	0.225	0.030	0.014	0.005	0.002	0.002	< 0.001	< 0.001	< 0.001	0.278
Baseline Emissions (Mg/yr) -- Average Emission Factor											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	4.297	0.856	0.550	0.277	0.247	0.062	0.013	0.033	0.009	6.344
1	85.4 MW	2.159	0.430	0.276	0.139	0.124	0.031	0.007	0.017	0.004	3.187
7	39.6 MW	1.001	0.199	0.128	0.064	0.058	0.014	0.003	0.008	0.002	1.478
9	27 MW	0.682	0.136	0.087	0.044	0.039	0.010	0.002	0.005	0.001	1.008
15	9 MW	0.227	0.045	0.029	0.015	0.013	0.003	0.001	0.002	< 0.001	0.336
13	3.5 MW	0.088	0.018	0.011	0.006	0.005	0.001	< 0.001	0.001	< 0.001	0.131
17	1.13 MW	0.029	0.006	0.004	0.002	0.002	< 0.001	< 0.001	< 0.001	< 0.001	0.042

D. Complicating Factors

The emission factors used for the base case cost-effectiveness analysis, as presented in **Table 1**, represent a necessary simplification of actual HAP emissions which could be expected in the existing population of combustion turbines in the United States. The following complicating factors would change the baseline emissions of certain combustion turbines in some cases:

1. The use of the highest HAP emission factors reported tends to overestimate HAP baseline emissions.
2. For the "highest" case, the highest HAP emissions factors for each pollutant were used. It has not been shown that all these "highs" would occur simultaneously from a combustion turbine. In fact, it is not likely that all the "highs" for all pollutants would occur simultaneously. Therefore, total HAP emissions are overstated in the case where the highest emission factor from all the tests is used for each HAP.
3. HAP emissions may be different for combustion turbines using fuels other than natural gas.
4. HAP emission factors used in this base case analysis tend to overestimate HAP emissions for uncontrolled turbines, since a significant portion of the emissions tests in the ICCR Emissions Database for natural gas-fired turbines were conducted on units that use steam or water injection to reduce NOx emissions, and steam or water injection may result in increased HAP emissions due to the cooling of the combustion process.
5. For some pollutants there are very few emissions test reports available. In those cases where emission averages rely on very few tests, it is unclear whether the resulting emission factor is representative of the turbine population.
6. The baseline emissions included in this analysis may underestimate annual HAP emissions from turbines that operate at less than 80% load, since the emission factors included in this base case analysis do not include the higher emission rates that may occur when turbines are operated at low loads.

IV. Oxidation Catalyst Costs

The CTWG obtained information on the costs of acquiring, installing, and operating oxidation catalysts for HAPs reduction on combustion turbines from the following sources:

- Quotes provided to EPA by catalyst vendors
- Costs gathered by the Gas Research Institute (GRI)
- Estimates provided by Work Group members

The methodology to estimate the total annual costs for oxidation catalysts was obtained from the EPA "OAQPS Control Cost Manual" (EPA, 1990). The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. The CTWG relied on the OAQPS methodology to develop the cost-effectiveness analysis because the Work Group understands that this is the methodology that EPA has used in the past to assess cost-effectiveness. The GRI study (Ferry et al., 1998) also relied on the OAQPS methodology.

The OAQPS cost manual requires direct cost inputs for certain key elements, such as control device capital costs, and then relies on default assumptions (percentages of the direct cost inputs) to estimate other costs, such as installation. The following sections describe the direct cost inputs into the OAQPS methodology and the costs estimated using the OAQPS default assumptions. A printout of the spreadsheet used to estimate costs is presented as **Appendix E**.

The OAQPS manual uses five cost categories to describe the annual incremental cost incurred by installing a control device, such as an oxidation catalyst:

- **Purchased Equipment Costs (PEC)** include the capital cost of the catalyst and auxiliary equipment, and the cost of instrumentation, sales tax, and freight.
- **Direct Costs for Installation (DCI)** are the construction-related costs associated with installing the catalyst.

- **Indirect Costs for Installation (ICI)** include expenses related to engineering and start up**.**
- **Direct Annual Costs (DAC)** include catalyst replacement and disposal costs and the annual increases in utilities and operating and maintenance costs.
- **Indirect Annual Costs (IAC)** are the annualized cost of the catalyst system and costs due to tax, overhead, insurance and administrative burdens.

The cost used in the cost-effectiveness calculation is the total annual cost, which is the sum of the DAC and IAC.

A. Cost Inputs

The CTWG developed cost estimates for the following inputs:

- Capital cost of the oxidation catalysts
- Capital cost of the catalyst housing
- Contingency for capital costs
- Catalyst life and equipment life
- Catalyst disposal costs
- Interest rate for capital recovery
- Direct annual operating & maintenance costs
- Fuel penalty costs
- Annual compliance test costs

A description of the each cost input is provided below.

<u>Capital cost of the oxidation catalysts</u>

The CTWG used cost estimates from Engelhard, a catalyst vendor, for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec to estimate the capital cost of the oxidation catalysts. The Engelhard costs were based on an oxidation catalyst that would achieve 90% CO conversion efficiency and 1” pressure drop across the catalyst panels (not total system pressure drop) and include the cost of an internal support frame and catalyst modules. Regression analysis on these cost data provided by the vendor suggested that there is a nearly linear relationship between catalyst cost and exhaust flow rate (r^2 = 0.993, when Catalyst cost=1541.8*(lb/sec)+102370). In estimating catalyst costs for the seven model turbines, the CTWG relied on the equation based on the Engelhard cost quotes, where cost is a function of turbine exhaust flow. Additional cost information reviewed by the CTWG is discussed in complicating factors.

Capital cost of the catalyst housing

The capital cost of the catalyst housing was estimated as 30% of the total cost of the catalyst system (the catalyst plus housing). This estimate is based on estimates provided orally by catalyst vendors. The CTWG contacted catalyst installers to get additional information on the costs for catalyst housings, but the data was not made available in time to include it in the base case analysis.

Contingency

A contingency of 10% of the sum of the purchased equipment costs, direct costs of installation, and indirect costs of installation was incorporated in the base case analysis. The budgeted contingency would cover costs associated with equipment redesign and modifications, cost escalations, and delays in start-up. The OAQPS Control Cost Manual recommends a 3% contingency. However, the CTWG agreed that a contingency of at least 10 percent would be appropriate for the base case analysis since the analysis is based on a preliminary vendor quote, not a guaranteed quote. Based on CTWG experience, a contingency factor of 25 percent DCI and ICI (direct and indirect installation costs) is budgeted in the early planning stages of a project and a contingency factor of at least 10 percent is budgeted once the project is under contract.

Catalyst life and equipment life

For the base case, the lifetime of purchased equipment was assumed to be fifteen years, except for the catalyst. Two scenarios were used for the catalyst life: the vendor guaranteed life (three years) and the “typical” life (six years) reported by catalyst vendors and users. The guaranteed life of the catalyst was used by EPA in the cost-effectiveness analysis for a passive catalytic device (non-selective catalytic reduction, NSCR) in the Alternative Control Techniques (ACT) document for reciprocating internal combustion engines (EPA, 1993b). In the Turbine ACT document, EPA used 5 years as the catalyst life for Selective Catalytic Reduction (SCR) (EPA, 1993a). The Turbine ACT did not specify whether the catalyst life was guaranteed life or "typical" life for SCR. However, in general, EPA prefers to rely on the useful life of equipment for cost-effectiveness calculations. The CTWG determined that the base case should evaluate the costs using both the guaranteed life and the typical life to account for the uncertainty regarding the long-term performance of oxidation catalysts. Further discussion of the issues related to catalyst life are discussed as complicating factors.

The cost of catalyst replacement is annualized by applying a capital recovery factor based on the catalyst lifetime and interest rate to the cost of the oxidation catalyst only (based on the Engelhard formula).

Catalyst Disposal Costs

For the base case analysis, costs for catalyst disposal were limited to the freight charge associated with shipping the spent modules back to the vendor. Based on the experience of CTWG members, catalyst vendors do not charge for catalyst disposal since the vendors can recover the noble metals from the spent catalysts.

Interest Rate for Capital Recovery

An interest rate of 7 percent was used in the base case to calculate capital recovery. The EPA Co-Chair of the ICCR Economics Work Group recommended this interest rate for the cost-effectiveness analysis.

Direct annual operating and maintenance costs

Operating labor costs were estimated using a factor of $25 per hour operating labor and an estimate of two hours per day incremental labor. The labor costs cover costs for operator duties likely to result from installing an oxidation catalyst and complying with MACT. Those duties include 1) inspection of the continuous parameter monitoring device, 2) collection and review of continuous parameter monitoring data, 3) inspection of the control device, and 4) recordkeeping and reporting assumed to be required by the MACT standard. In developing the labor estimates, the CTWG reviewed the EPA estimates for labor for NSCR for reciprocating internal combustion engines and for SCR for turbines included in the Alternative Control Techniques (ACT) documents (EPA, 1993a and 1993b). The CTWG agreed that the labor estimates for NSCR would more closely approximate the labor associated with an oxidation catalyst, since NSCR is essentially a passive catalytic device, like oxidation catalysts. The CTWG agreed that labor costs for SCR for turbines would be greater than the labor costs for oxidation catalysts, since SCR may require frequent inspection and adjustment of the ammonia feed system. Maintenance costs, including labor and materials, were estimated as 10% of the total purchased equipment cost, based on the ACT formula for NSCR. Maintenance costs cover catalyst washing (with water), maintenance of monitoring equipment, and labor for catalyst replacement (including removal and return of old catalyst and installation of replacement).

Fuel penalty costs

Increased pressure drop in the exhaust of a gas turbine will impact both heat rate and power output. For the base case analysis, fuel penalty costs are included to compensate for the increased heat rate as a result of the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a heat rate increase of 0.105% per inch of pressure drop (measured in inches of water column) and estimates of $2 per MMBtu and a 9,000 Btu/hp-hr baseline. The heat rate increase of 0.105% was drawn from the GRI study. The

CTWG agreed that 0.105% is a very low estimate of the heat rate increase anticipated and most turbines would have higher increased heat rate due to backpressure from the catalyst. Other estimates of the heat rate increase are discussed in the complicating factors portion of this section. The estimate of $2 per MMBtu for natural gas was drawn from the GRI study. The CTWG agreed that this estimate is low compared to market value of natural gas at this time. The estimate of increased exhaust backpressure on the turbine from the catalyst was based on an assumption that the total pressure drop associated with the catalyst system is solely the pressure drop across the catalyst panels. The CTWG agreed that the total pressure drop would be higher than the pressure drop across the catalyst panels due to the pressure drop associated with the inlet and outlet ductwork for the catalyst system. Therefore, the increase in the exhaust backpressure and, therefore, the fuel penalty costs resulting from the increase in exhaust backpressure are understated in the base case analysis.

The Turbine World Handbook indicates that exhaust backpressure may result in a loss of power. The costs for loss of power were not included in the base case quantitative analysis. These costs would increase the cost of control beyond the base case costs presented in this paper. The costs for loss of power are discussed in the complicating factors portion of this section.

Annual Compliance Test Costs

Costs to perform one annual emissions compliance test are included in the base case. The costs for this annual test are estimated at $5,000. The costs were estimated based on an assumption that no continuous emissions monitoring data would be required in a MACT standard for combustion turbines. Instead, it was assumed that the MACT would require continuous monitoring for an operating parameter, such as temperature at the catalyst, along with an annual emissions test. The costs also were based on an assumption that a surrogate criteria pollutant can be measured and that HAPs would not be speciated.

B. Costs Estimated by OAQPS Control Cost Manual

The methodology outlined in the OAQPS Control Cost manual was used by the CTWG to estimate costs for the following:

- Capital cost for instrumentation (continuous parameter monitor)
- Sales tax for equipment purchases
- Freight for equipment purchases
- Direct installation costs (DCI), including foundations & supports, handling & erection, electrical, piping, insulation for ductwork, and painting.
- Indirect installation costs (ICI), including engineering, construction and field expenses, contractor fees, start-up, and performance tests.
- Indirect annual costs (IAC), including annualized equipment costs, overhead, administrative costs, property taxes, and insurance.

A description of the methodology to estimate these costs is provided below.

Costs for instrumentation, taxes and freight are estimated by applying factors from the OAQPS cost manual to the capital cost of the catalyst and auxiliary equipment. These costs (catalyst capital cost, instrumentation, taxes, and freight) are then summed to estimate the total Purchased Equipment Costs (PEC). The components of the DCI (foundations and supports, erection and handling, electrical work, piping, painting and insulation) are then calculated by applying OAQPS cost manual factors to the PEC. Likewise, the components of the ICI (engineering, construction and field expenses, contractor fees, start-up, and initial performance test) are also calculated by applying factors to the PEC.

Indirect Annual Costs (IAC) are the annualized cost of the catalyst housing and the costs for overhead, administrative tasks, property taxes, and insurance. The equipment costs are annualized by applying a capital recovery factor (based on the equipment life, 15 years, and interest rate) to the sum of the direct and the indirect equipment costs, excluding the cost of the catalyst modules. The cost of the catalyst modules is considered a direct annual cost (DAC), and is annualized separately. Factors applied to the sum of the direct and indirect equipment costs (including contingency) are used to estimate the overhead, administrative costs, property taxes, and insurance.

C. Summary of Base Case Cost Estimates

Table 3 presents the range of costs estimated for the seven model turbines included in the base case cost-effectiveness analysis. The costs for each model turbine are presented in **Appendix E**. The highest annual costs are for the largest model turbine and the lowest annual costs are for the smallest model. The $/MW are lower for the larger model turbines and higher for the smaller model turbines.

Table 3. Range of Costs Estimated for Seven Model Turbines

Cost Category	Costs for 3-Year Catalyst Life*		Costs for 6-Year Catalyst Life*	
Total Capital Cost	$360,000 -	$4,800,000	$360,000 -	$4,800,000
Direct Annual Cost	$96,000 -	$980,000	$74,000 -	$680,000
Indirect Annual Cost	$65,000 -	$700,000	$65,000 -	$700,000
Total Annual Costs (DAC + IAC)	$160,000 -	$1,700,000	$140,000 -	$1,400,000

*Costs are rounded.

D. Complicating Factors

This section presents the views of the CTWG with regard to factors that complicate the estimation of the costs of acquisition, installation, and operation of oxidation catalyst on combustion turbines. For discussion, these complicating factors are divided into five categories:

- factors related to the cost of acquiring the oxidation catalyst,
- costs associated with site installation complications,
- costs associated with performance testing,
- complicating factors associated with increased exhaust backpressure, and
- costs associated with compliance monitoring.

Factors Complicating the Estimation of Catalyst Acquisition Costs

The catalyst costs used in this base case analysis are based on a formula that was derived from one vendor's cost quotes for six different sizes of combustion turbines. The vendor's cost quotes covered a range of turbine sizes that is similar to the turbine sizes represented in the seven model turbines used in this cost-effectiveness analysis. Exhaust flow rates for the vendor's cost quotes ranged from 28.4 lb/sec to 984 lb/sec, while exhaust flow rates for the seven model turbines ranged from 14.2 lb/sec to 986 lb/sec. The formula developed by the CTWG for this cost-effectiveness analysis represents a necessary simplification of the vendor's cost quotes to facilitate estimating costs for the seven model turbines used in this analysis.

The CTWG had cost estimates for oxidation catalysts available from two other sources: 1) cost estimates provided by Mr. Marvin Schorr of General Electric (Schorr, 1998), and 2) cost estimates included in the GRI cost study (Ferry et al., 1998). Cost estimates were provided by General Electric for two large turbines (exhaust flow rates of 400 lb/sec and 1200 lb/sec). The formula calculated using the General Electric cost estimates is (0.85*(568.75*Exhaust Flow Rate (lb/hr) +172,500). For small turbines, the costs estimated using the General Electric formula are higher than the costs used in this base case analysis. For example, the General Electric formula estimates $153,490 for the catalyst for a 1.13 MW turbine, while the costs used in this base case analysis are $105,624. For a 3.5 MW turbine, the costs are similar, $166,446 estimated using the General Electric formula and $165,584 used in this analysis. For larger turbines, the costs estimated using the General Electric formula are lower than the costs used in this base case analysis. The differences in the costs estimated using the two different approaches increase with turbine size. For the 170 MW turbine, the General Electric formula estimates the cost of the catalyst as $623,294, while $1,622,585 was used in this cost-effectiveness analysis. [Note: the quote provided by Engelhard for a 170 MW turbine, exhaust flow 984.0lb/sec was $1,550,000.] The CTWG agreed not to use the General Electric cost estimates for this base case analysis for the following reasons: 1) cost estimates were provided only for two large turbines, and 2) the costs seemed to underestimate the costs when compared with the quotes received directly from a catalyst vendor.

The CTWG also reviewed the cost estimates included in the GRI study. In that case, GRI used cost quotes provided by two catalyst vendors for a 6,000 horsepower turbine. Vendors provided cost quotes for a range of VOC control estimates: 95 percent, 50 percent, 35 percent, and 22 percent. In comparing the cost quote in the GRI study for 95 percent VOC control and 98 percent CO control, the CTWG noted that the costs were similar to the costs for a 6,000 hp turbine estimated using the formula in this base case (assuming 90 percent CO control) -- $204,500 in the GRI study, and $206,796 using the base case formula. The CTWG decided not to use the GRI costs for this analysis because there was insufficient information to develop a reliable cost formula that could be applied to a wide range of turbine models, ranging in size from 1.13 MW to 170 MW.

The CTWG notes that vendor quotes that have been obtained are essentially for CO oxidation catalysts. As noted above, available emissions data indicates that CO/VOC oxidation catalysts should reduce organic HAP compounds. However, the CTWG is not aware of any actual industry experience in the acquisition of an oxidation catalyst specified to achieve a percentage reduction of formaldehyde, or the other HAPs. In the absence of such experience, the cost estimate for an oxidation catalyst designed to reduce organic HAPs from combustion turbines is uncertain. Uncertainty about the estimated cost for a HAP reduction catalyst is increased when considering that oxidation catalysts would be required for fuels other than natural gas. Oxidation catalysts for oil fired turbines may have to be formulated differently than for gas fired turbines, and may have different lifetime and degradation characteristics.

Another key uncertainty in estimating oxidation catalysts costs is the assumption regarding catalyst life. Clearly, a catalyst that can be relied upon to function for many years will have lower annual costs than a catalyst that must be replaced more often. The issue of catalyst lifetime includes estimating the probability of complete failure of the catalyst, and also estimating the degradation of catalyst performance over time.

The CTWG notes that there may be a difference between the expected useful life of an oxidation catalyst, and the period of the vendor's performance guarantee. This raises the question of which period should be used in calculating cost-effectiveness. As noted in another section, the CTWG has elected to present a number of cost-effectiveness estimates based on different assumptions about catalyst life and performance.

Limited information was available to the CTWG on the life of the catalyst. Information from an emissions test conducted by GRI on a ten-year-old CO oxidation catalyst indicates that performance can degrade when the catalyst is used for an extended period of time (10 years in that case). The GRI test is described under **Section V** of this paper. Further information is not available that would allow the CTWG to estimate the expected rate of oxidation catalyst performance degradation, or the effect of maintenance (such as catalyst washing) on catalyst life. According to catalyst vendors, the degradation of catalyst performance over time is not linear. The CTWG has not obtained any information that would allow the Work Group to estimate the expected rate of performance degradation over the life of the catalyst.

<u>Costs associated with site installation complications</u>

Costs for retrofit complications were not available for the base case analysis. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. One of the work group members provided retrofit costs for adding a catalyst system to an ABB Type 11 gas turbine (gas flow = 580 lb/sec) (Allen, 1998a and 1998b). The retrofit costs totaled about $800,000, including $100,000 for ductwork. The cost of down time is also site specific. In the case described above, the cost cited by the work group member for down time was about $3.5 million based on a 35 day outage, a power sales price of $35/MWh, and a steam cost $4.5/thousand pounds of steam (Allen, 1998a).

Costs Associated with Performance Testing

Costs for performance testing were included in the base case quantitative analysis in accordance with the OAQPS Control Cost Manual. The costs for performance testing are estimated as 0.01% of the Purchased Equipment Costs (PEC). For the 170 MW turbine, $27,000 was calculated as the performance test costs using the OAQPS formula. For the 1.13 MW turbine, $2,095 was calculated as the performance test costs using the OAQPS formula. The CTWG agreed that the costs for stack emissions testing would be fixed, regardless of turbine size. The costs estimated for performance testing may have been underestimated for the base case analysis, especially for the small model turbines.

Complicating Factors Associated with Increased Exhaust Backpressure

For the base case quantitative analysis, fuel penalty costs were estimated assuming a 0.105% heat rate increase per inch of pressure resulting from installation of a catalyst system. The CTWG agreed that 0.105% is a very low estimate of the heat rate increase. The Gas Turbine World 1997 Handbook provides rough rule of thumb estimates of heat rate increase and power loss per inch pressure drop (Gas Turbine World 1997). For aeroderivative turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.7% (0.175% per inch) and reduce power output 0.7%. For heavy frame turbines, the Handbook indicates that every 4 inches outlet loss will increase heat rate 0.6%

(0.15% per inch) and reduce power output 0.6%. Therefore, the heat rate increase due to increased pressure drop is understated in the base case analysis.

To estimate pressure drop for the base case quantitative analysis, it was assumed that the total pressure drop associated with the catalyst system is solely the pressure drop across the panels. The CTWG agreed that the total pressure drop would be higher than the pressure drop across the catalyst panels alone due to the inlet and outlet ductwork. Therefore, the operating costs associated with the increase in exhaust backpressure are understated in the base case analysis. The fuel penalty costs associated with backpressure may be significantly higher when a more realistic estimate of the catalyst system pressure drop is used.

In addition, implementing oxidation catalyst control may result in a reduction in turbine power output caused by increased exhaust backpressure on the engine. The costs associated with the power loss depend on site-specific factors (e.g., value of lost product or capital and annual costs for equipment required to make up for the power loss). The increase in exhaust backpressure results in a loss of power sales if the unit is operating at full load. One of the work group members provided information on the loss in annual sales at different selling prices for electrical power (Allen, 1998b). For a GE Frame 7 turbine, the annual cost (i.e., lost sales) per inch of water pressure drop may be estimated using the following equation:

$$\text{Annual Cost (\$/inch)} = 1{,}160 * \text{Power Value (\$/MWh)} + 100$$

For this example turbine unit, if electricity can be sold for $40 per MWh, the annual cost per each additional inch of water pressure drop caused by the catalyst would equal $46,500.

These costs were not incorporated into the base case analysis. The cost associated with power loss would increase the costs for the control system.

Costs Associated with Compliance Monitoring

If the MACT would require speciated HAP emissions test data, the costs for the annual compliance test would increase significantly. Also, if compliance tests must be conducted more frequently than annually, the costs would increase.

V. Performance of Oxidation Catalysts in Reducing HAP Emissions

Oxidation catalysts have been installed on combustion turbines for the purposes of controlling emissions of carbon monoxide (CO) and some volatile organic compounds (VOC). The catalyst is designed to promote the oxidation of hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O). It is expected that existing catalysts similar to those in use for CO and VOC control may oxidize organic HAPs.

In order to estimate the quantitative performance of an oxidation catalyst the CTWG evaluated two emissions test reports and reviewed engineering estimates of potential oxidation catalyst performance.

A. HAP Emissions Test Data for Oxidation Catalysts

At present, no HAP emissions tests in the ICCR Emissions Database include before and after testing of a combustion turbine with an oxidation catalyst. Emissions test data on the performance of oxidation catalysts should be collected during the CTWG testing campaign.

The CTWG identified two existing emission test reports that provide some information on the performance of oxidation catalysts in reducing HAP emissions. The two emission tests are still being evaluated and may be included in the database after review. One test was conducted by the Gas Research Institute(GRI), in cooperation with the American Petroleum Institute (API) and Southern California Gas (SoCal), in March 1998, on a combustion turbine using a passive oxidation catalyst system, similar to the catalyst used for this base case cost-effectiveness evaluation. A summary of this test has been provided to the CTWG and the complete test data will be provided to EPA when it is available (Gundappa, 1998). The complete test report will be required by EPA and the report will have to undergo review prior to being included in the ICCR Emissions Database. The oxidation catalyst installed on this turbine is a precious metal catalyst, similar to the catalyst technology used as the basis for this cost-effectiveness analysis. This type of oxidation catalyst may be used over a temperature range of 450°F to 1500°F (Chen et al., 1993).

The second test was submitted to EPA for a new catalytic oxidation control system, called SCONOx™ (Bell and Finken, 1997). Although the SCONOx™ system relies on oxidation to reduce hydrocarbons, such as CO, or HAPs, such as formaldehyde, the SCONOx™ catalyst is a more complicated control system than the oxidation catalyst used for this base case cost-effectiveness evaluation. SCONOx™ may be operated over a temperature range of 300°F to 700°F (Goal Line Environmental Technologies, LLC). The cost and cost-effectiveness values presented in this paper were not based on costs for the SCONOx™ system. However, the CTWG included a discussion of the source test results as an indicator of the types of emission reductions that may be achievable for systems that rely on oxidation to reduce HAP emissions. A description of the SCONOx™ system is provided in **Appendix F**. The results from these two emissions tests are discussed below.

<u>GRI/API/SoCal Test</u>

The GRI/API/SoCal testing was conducted in March 1998. GRI, API, and SoCal added the emissions test to an existing emissions testing program in order to provide data to the CTWG on the performance of oxidation catalysts. Some members of the CTWG and EPA representatives witnessed the GRI/API/SoCal test. The test was performed on a 20 MW GE LM2500 turbine equipped with a Johnson Matthey CO oxidation catalyst. Three load conditions were tested, including full load (typical) and part loads (88% and 70% of rated load). Concentrations of HAPs, including formaldehyde, were measured before and after the oxidation catalyst. HAP and CO measurements were conducted with Fourier transform infrared (FTIR) sampling upstream and downstream of the oxidation catalyst. Aldehydes also were measured with the California Air Resources Board (CARB) Method 430, which relies on an aqueous 2,4-Dinitrophenylhydrazine solution. Complete results of the test were not available in time to incorporate them into the ICCR Emissions Database. However, the CTWG has been provided a summary of the results (Gundappa, 1998). Based on FTIR, formaldehyde emissions upstream of the catalyst were in the approximate range of 400 to 460 parts per billion by volume (ppbv) and CO emissions upstream of the catalyst were in the range of 10 to 17 parts per million by volume (ppmv). Both formaldehyde and CO emissions increased as the load decreased. With FTIR, the reduction in emissions across the oxidation catalyst was on the order of 10 to 30 percent for formaldehyde and 25 to 33 percent for CO, with the highest reduction at the lowest load condition. CARB 430 results did not agree with the FTIR data. In some cases, the CARB 430 results indicated that levels of aldehydes (formaldehyde and acetaldehyde) increased after the catalyst.

SCONOx™ Test

A unit equipped with a SCONOx™ catalyst system was tested on March 14, 1997, by Delta Air Quality Services (Bell and Finken, 1997). Samples were collected at the inlet to the catalyst and at the exhaust from the cogeneration unit (turbine exhaust stack) and analyzed for the following three HAPs: formaldehyde, acetaldehyde, and benzene. Formaldehyde and acetaldehyde reportedly were reduced by 97% and 94%, respectively, based on the catalyst inlet and turbine exhaust concentrations. No conclusion regarding the control efficiency for benzene could be drawn since the levels before and after the catalyst were both very low and within 0.05 parts per billion of each other.

A subgroup of the CTWG reviewed the SCONOx™ report in greater detail to determine if the data from this test should be included in the emissions database. The subgroup was concerned with the accuracy of the catalyst inlet concentrations measured during the test since isokinetic sampling was not conducted nor was a multi-point probe used to collect the samples. However, the catalyst inlet concentrations were consistent with other source tests involving the same model turbine (GE LM 2500), using water injection. Also, even if the catalyst inlet concentrations were one-half to one-third of the average concentration measured during the source test, the efficiency of the SCONOx™ would still exceed 90% for formaldehyde. Therefore, the subgroup decided to support inclusion of the data from this test in the emissions database, with the caveat that EPA may want to retest this unit to address some of the specific concerns identified during the subgroup's review.

Based on a review of the two emissions tests available, the CTWG concluded that organic HAPs, such as formaldehyde and acetaldehyde, may be reduced using after-treatment controls that rely on catalytic oxidation. The Work Group also concluded that, in some cases, a high percent reduction may be possible for certain pollutants. However, the CTWG noted that the limited data available is not sufficient to draw conclusions about the achievability of high emission reductions over the life of catalytic devices. In addition, the CTWG noted that although there is some data that suggests catalysts degrade over time, the rate and the extent of the degradation cannot be determined based on the limited data.

B. Engineering Estimates of HAP Reduction Performance for Oxidation Catalysts

The CTWG reviewed information available in the literature on the HAP reduction performance of oxidation catalysts on organic HAPs, such as formaldehyde. In particular, the Work Group reviewed an article prepared by Engelhard, the catalyst vendor that supplied the cost quotes for this base case cost-effectiveness analysis (Chen et al., 1993). In the article, Engelhard notes that oxidation catalysts for combustion turbines are typically designed to achieve between 80 and 95 percent CO removal. In addition, the article indicates the conversion level for each species of hydrocarbon will depend on its diffusion rate in the exhaust gas. In general, larger, heavier molecules will diffuse more slowly than smaller, lighter molecules. As the size of the hydrocarbon molecule increases, hydrocarbon conversion decreases due to decreased gas diffusivity. According to the article, an oxidation catalyst designed for 90 percent CO removal will achieve 77 percent reduction of formaldehyde, 72 percent reduction of benzene, and 71 percent reduction of toluene. The article notes that the relative conversion rates do not depend on geometry and that reduction for molecules larger than formaldehyde will be lower than rates achievable for formaldehyde.

C. Summary of Base Case Performance Estimate

The CTWG has agreed to use two performance values for the base case cost-effectiveness analysis -- 80 percent emissions reduction and 50 percent emissions reduction. 80 percent emissions reduction is used for both the 3-year and 6-year catalyst life assumptions. 50 percent emissions reduction is evaluated for a 6-year catalyst life.

The CTWG believes these levels of reduction represent appropriate levels of reduction for the base case cost-effectiveness analysis, covering both high and moderate levels of emission reduction. The Work Group relied on the Engelhard engineering estimates for formaldehyde to select 80% reduction as the catalyst performance in the base case analysis (77% rounded up to 80%). Although the Engelhard article indicates that emission reductions for larger molecules, such as PAHs, may be less than the reduction achieved for formaldehyde, the HAP reduction performance for the base case analysis was set to 80 percent for all pollutants. The Work Group selected 50% reduction as a moderate level of emission reduction to examine the sensitivity of the cost-effectiveness to any significant degradation of the catalyst performance that might occur over time. Additional emissions test data before and after oxidation catalysts would be necessary to determine whether the levels of reductions are achievable for combustion turbines, considering the full range of operating conditions and catalyst degradation.

The emission reductions achieved for each model turbine assuming 80 percent reduction and 50 percent reduction are presented in **Tables 4** and **5.**

Table 4. Emissions Reductions for Each Model Turbine Assuming 80% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 80% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	27.048	3.664	1.687	0.579	0.198	0.189	0.035	0.029	0.016	33.445
1	85.4 MW	13.587	1.841	0.848	0.291	0.099	0.095	0.018	0.015	0.008	16.801
7	39.6 MW	6.301	0.854	0.393	0.135	0.046	0.044	0.008	0.007	0.004	7.791
9	27 MW	4.296	0.582	0.268	0.092	0.031	0.030	0.006	0.005	0.003	5.312
15	9 MW	1.432	0.194	0.089	0.031	0.010	0.010	0.002	0.002	0.001	1.771
13	3.5 MW	0.557	0.075	0.035	0.012	0.004	0.004	0.001	0.001	< 0.001	0.689
17	1.13 MW	0.180	0.024	0.011	0.004	0.001	0.001	< 0.001	< 0.001	< 0.001	0.222
Emissions Reductions (Mg/yr)-- Average Emission Factor -- 80% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	3.438	0.685	0.440	0.221	0.198	0.050	0.011	0.026	0.007	5.075
1	85.4 MW	1.727	0.344	0.221	0.111	0.099	0.025	0.005	0.013	0.004	2.549
7	39.6 MW	0.801	0.159	0.102	0.052	0.046	0.012	0.003	0.006	0.002	1.182
9	27 MW	0.546	0.109	0.070	0.035	0.031	0.008	0.002	0.004	0.001	0.806
15	9 MW	0.182	0.036	0.023	0.012	0.010	0.003	0.001	0.001	< 0.001	0.269
13	3.5 MW	0.071	0.014	0.009	0.005	0.004	0.001	< 0.001	0.001	< 0.001	0.104
17	1.13 MW	0.023	0.005	0.003	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.034

Table 5. Emissions Reductions for Each Model Turbine Assuming 50% HAPs Reduction Performance

Emissions Reductions (Mg/yr)-- Highest Emission Factor -- 50% Reduction Performance										
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	16.905	2.290	1.055	0.362	0.124	0.118	0.022	0.018	0.010	20.903
1	85.4 MW	8.492	1.150	0.530	0.182	0.062	0.059	0.011	0.009	0.005	10.501
7	39.6 MW	3.938	0.533	0.246	0.084	0.029	0.027	0.005	0.004	0.002	4.869
9	27 MW	2.685	0.364	0.168	0.057	0.020	0.019	0.004	0.003	0.002	3.320
15	9 MW	0.895	0.121	0.056	0.019	0.007	0.006	0.001	0.001	0.001	1.107
13	3.5 MW	0.348	0.047	0.022	0.007	0.003	0.002	< 0.001	< 0.001	< 0.001	0.430
17	1.13 MW	0.112	0.015	0.007	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	0.139
Emissions Reductions (Mg/yr)-- Average Emission Factor -- 50% HAPs Reduction Performance											
Model Turbine		Formaldehyde	Toluene	Acetaldehyde	Xylenes	Ethylbenzene	Benzene	PAHs	Acrolein	Naphthalene	Total HAPs
2	170 MW	2.149	0.428	0.275	0.138	0.124	0.031	0.007	0.017	0.004	3.172
1	85.4 MW	1.079	0.215	0.138	0.069	0.062	0.016	0.003	0.008	0.002	1.593
7	39.6 MW	0.500	0.100	0.064	0.032	0.029	0.007	0.002	0.004	0.001	0.739
9	27 MW	0.341	0.068	0.044	0.022	0.020	0.005	0.001	0.003	0.001	0.504
15	9 MW	0.114	0.023	0.015	0.007	0.007	0.002	< 0.001	0.001	< 0.001	0.168
13	3.5 MW	0.044	0.009	0.006	0.003	0.003	0.001	< 0.001	< 0.001	< 0.001	0.065
17	1.13 MW	0.014	0.003	0.002	0.001	0.001	< 0.001	< 0.001	< 0.001	< 0.001	0.021

D. Complicating Factors

This section presents the views of the CTWG with regard to factors that complicate the estimation of the performance of oxidation catalysts in the reduction of organic HAP in the exhaust of combustion turbines.

Uncertainty About the Real World Performance of Oxidation Catalysts for HAPs

As noted earlier in this paper, although there are oxidation catalysts installed on existing turbines for control of CO and some VOCs, there are not conclusive emissions data available regarding the HAP reduction performance of those oxidation catalysts over time. CO catalysts systems in use operate on far higher levels of CO than the expected concentration of HAPs. The cost-effectiveness estimates used for this base case analysis are derived from engineering judgement rather than actual data. It is possible that it may be more difficult than anticipated to achieve a consistent 80% reduction of HAPs across a real world population of combustion turbines running under various ambient conditions and operating points.

Differential Performance for Various HAPs

The assumption used in this base case analysis that oxidation catalysts will have the same HAP reduction performance for all organic HAPs was necessary because there was insufficient emissions data to estimate HAP reduction performance for specific species of HAPs. The CTWG is aware that this assumption is incorrect, based on engineering estimates performed by Engelhard, a catalyst vendor (Chen et al., 1993). Engelhard indicates that individual HAPs will be oxidized at different rates due to differences in the size of the hydrocarbons and that the HAP reduction performance for each HAP will depend on its diffusion rate. In general, larger, heavier molecules (like PAHs) will diffuse more slowly than smaller, lighter molecules (like CO).

The CTWG notes that the assumptions used in this base case analysis tend to overestimate HAP reduction efficiencies for HAPs other than formaldehyde, especially HAPs like PAHs that are larger, heavier molecules.

Decreased Catalyst Performance Over Time

This effect was discussed as a part of the evaluation of catalyst life for costing purposes. A decline in catalytic activity also would impact the performance side of the equation in that fewer metric tons of HAPs would be removed from the turbine exhaust. Again, the CTWG does not have sufficient information to estimate the rate at which catalytic activity would decline in a real-world installation.

VI. Cost-Effectiveness Results

A breakdown of the total HAP reductions achieved for individual pollutants is provided in **Tables 4** and **5**. The cost-effectiveness values based on total HAP reductions are presented in **Table 6** for each model turbine**.** The cost-effectiveness for total HAPs is provided to more fully demonstrate the benefit achieved in terms of total reduction of HAPs for the costs required to install oxidation catalysts. Cost-effectiveness for individual HAPs, calculated as the total annual costs by the mass emissions for each individual HAP, is presented in **Appendix G**. The cost-effectiveness for individual HAPs is presented to show the cost-effectiveness sensitivity for individual HAPs.

In general, the cost per metric ton of reduced HAP emissions is higher for small turbines, because capital costs, on a per-megawatt basis, are highest for these units and the annual HAP emissions are low. The costs per metric ton also would increase for small and large turbines as operating hours decrease because capital costs remain unchanged while annual HAP emissions are lower.

Table 6. Cost-Effectiveness Estimated for Each Model Turbine -- Base Case Analysis

Model Plant	Cost Effectiveness ($/Mg Total HAPs Reductions*)					
	Highest EF			Average EF		
	3-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 50% Emissions Reduction	3-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 80% Emissions Reduction	6-Year Catalyst Life 50% Emissions Reduction
Model 1 -- 85.4 MW Turbine	$69,000	$57,000	$91,000	$450,000	$380,000	$600,000
Model 2 -- 170 MW Turbine	$50,000	$41,000	$66,000	$330,000	$270,000	$440,000
Model 7 -- 39.6 MW Turbine	$81,000	$67,000	$110,000	$530,000	$440,000	$710,000
Model 9 -- 27 MW Turbine	$78,000	$66,000	$100,000	$520,000	$430,000	$690,000
Model 13 -- 3.5 MW Turbine	$290,000	$250,000	$400,000	$1,900,000	$1,700,000	$2,600,000
Model 15 -- 9 MW Turbine	$150,000	$130,000	$200,000	$1,000,000	$840,000	$1,400,000
Model 17 -- 1.13 MW Turbine	$730,000	$630,000	$1,000,000	$4,800,000	$4,100,000	$6,600,000

*Cost-effectiveness values were rounded. Annual costs estimated for each model turbine are presented in **Appendix E**. HAPs reductions estimated for each model turbine are presented in **Tables 4** and **5**. Cost-effectiveness values for individual HAPs are presented in **Appendix G**.

VII. Conclusions and Recommendations

The CTWG has assessed the various elements that are relevant to estimation of the cost-effectiveness of oxidation catalysts for control of organic HAPs emitted by combustion turbines. Base on this assessment the CTWG has reached the following conclusions.

1. Using a simplified base case, the annual costs associated with installation and operation of oxidation catalysts for the model turbines ranged from $160,000 for a 1.13 MW unit to $1,700,000 for a 170 MW unit, assuming a three-year catalyst life. Annual costs ranged from $140,000 for a 1.13 MW unit to $1,400,000 for a 170 MW unit, assuming a six-year catalyst life.
2. Based on quantified estimates of emissions, cost, and percent reduction for a simplified base case, the cost-effectiveness of oxidation catalysts for control of total HAPs from combustion turbines ranges from $41,000 per metric ton for a 170 MW unit to $1,000,000 per metric ton for a 1.13 MW unit, assuming emission rates based on the highest reported emission factors for all HAPs. The cost-effectiveness values range from $270,000 for a 170 MW unit to $6,600,000 for a 1.13 MW unit when the average emission factor is used.
3. Because of a variety of complicating factors, it is likely that the base case cost-effectiveness estimated range is lower than the actual cost-effectiveness which would be exhibited by actual application of oxidation catalysts to most combustion turbines in the United States. Key complicating factors include the catalysts life, problems with retrofitting ducts and the catalyst housing at existing facilities, differential effectiveness of the catalysts on various HAP compounds, and fuels that require pre-treatment to avoid fouling the catalyst. In addition, there is uncertainty regarding the HAPs reduction performance included in this base case analysis due to the limited emissions test data available to predict the performance of oxidation catalyst in reducing organic HAP emissions from combustion turbines. While experience with CO oxidation catalysts is useful for evaluating the potential HAP reduction performance, there may be important differences between the costs and performance of CO catalysts and the costs and performance of catalysts for reduction or organic HAPs.

Most of the complicating factors that have not been quantified in the numerical estimates would tend to increase the catalyst costs, or decrease catalyst performance. Because of this, the CTWG views the base case quantitative estimate reported in this paper as a lower range estimate of the cost-effectiveness of oxidation catalysts for HAPs control on combustion turbines.

The CTWG recommends that the Coordinating Committee forward this information to EPA and recommend that EPA consider the information presented in this paper in the Agency's assessment of above-the-floor MACT options for combustion turbines. This paper provides reasonable estimates, based on available information, of the costs and the HAP air emissions reductions that may be achieved with oxidation catalysts. The CTWG recognizes that EPA may consider other factors, such as non-air quality environmental impacts, energy requirements, and secondary pollutants (including possible CO/VOC control), in assessing above-the-floor MACT options.

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Appendix A - List of Model Turbines

Model Plant No.	Unit Size	Operating Hours Per Year	Heat Recovery (Y/N)	Existing Application (Y/N)	Clean Fuel (Y/N)	Typical Applications	Surrogate Turbine	Output MW(ISO)	Ex. Flow (lbs/sec)
1	Large	8000	Y	Y	Y	existing utility/IPP generating station	GE PG 7121EA	85.4	658
1A	Large	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 7121EA	85.4	658
1B	Large	8000	Y	Y	Y	existing utility/IPP generating station (duct burner)	GE PG 7121EA	85.4	658
2	Large	8000	Y	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
2A	Large	8000	Y	N	N	new unit with residual oil fuel	GE PG 7231FA	170	986
2B	Large	8000	Y	N	Y	new utility/IPP generating station (duct burner)	GE PG 7231FA	170	986
3	Large	2000	N	Y	Y	existing utility/IPP generating station	GE PG 7231FA	170	986
3A	Large	2000	N	Y	Y	existing utility/IPP station (space constrained)	GE PG 7231FA	170	986
4	Large	2000	N	N	Y	new utility/IPP generating station	GE PG 7231FA	170	986
5	Large	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 7121EA	85.4	658
6	Large	500	N	N	Y	new utility/IPP peaking unit	GE PG 7121EA	85.4	658
7	Medium	8000	Y	Y	Y	existing industrial power production	GE PG 6561B	39.6	318
7A	Medium	8000	Y	Y	N	existing unit with residual oil fuel	GE PG 6561B	39.6	318
7B	Medium	8000	Y	Y	Y	existing industrial power production (duct burner)	GE PG 6561B	39.6	318
8	Medium	8000	Y	N	Y	new industrial power production	GE PG 6561B	39.6	318
8A	Medium	8000	Y	N	N	new unit with residual oil fuel	GE PG 6561B	39.6	318
8B	Medium	8000	Y	N	Y	new industrial power production (duct burner)	GE PG 6561B	39.6	318
9	Medium	8000	N	Y	Y	existing pipeline compressor/ ind.- mech. drive	GE LM2500	27	178
10	Medium	8000	N	N	Y	new pipeline compressor/ ind. mech. drive	GE LM2500	27	178
11	Medium	500	N	Y	Y	existing utility/IPP peaking unit	GE PG 6561B	39.6	318
12	Medium	500	N	N	Y	new utility/IPP peaking unit	GE PG 6561B	39.6	318
13	Small	8000	Y	Y	Y	existing industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
13A	Small	8000	Y	Y	N	existing landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
13B	Small	8000	Y	Y	Y	existing ind. process plant (duct burner)	Solar Centaur 40	3.5	41
14	Small	8000	Y	N	Y	new industrial process plant (food, nat'l gas)	Solar Centaur 40	3.5	41
14A	Small	8000	Y	N	N	new landfill operation or residual oil fuel	Solar Centaur 40	3.5	41
14B	Small	8000	Y	N	Y	new ind. process plant (duct burner)	Solar Centaur 40	3.5	41
15	Small	8000	N	Y	Y	existing pipeline compressor	Solar Mars T12000	9	83.6
15A	Small	8000	N	Y	Y	existing offshore platform (space constrained)	Solar Mars T12000	9	83.6
16	Small	8000	N	N	Y	new pipeline compressor/offshore platform	Solar Mars T12000	9	83.6
17	Small	200	N	Y	Y	existing emergency power (hospital,university,etc)	Solar Saturn T1500	1.13	14.2
18	Small	200	N	N	Y	new emergency power (hospital, university, etc)	Solar Saturn T1500	1.13	14.2

Appendix B - Description of ICCR Emissions Database

MEMORANDUM

DATE :	March 6, 1998
SUBJECT :	Documentation on the Combustion Turbines Emissions Database
TO :	Combustion Turbines Project File
FROM :	Ana Rosa Alvarez and Dan Herndon

This memorandum provides a short description of the development of the emissions database for turbines, including assumptions used in the underlying calculations.

Development of the Emissions Database

The emission test reports were first carefully reviewed and summarized. Facility name, location, testing company, date of testing, make and model of turbine, manufacturer rating (and units), load, fuel type, application and control device (for emissions) were entered in a table named "Facilities." Pollutant name, sampling method, concentrations and units, detection limits and units, % oxygen, fuel factors, exhaust gas flow rates, stack temperature, fuel heating value and flow rate, % humidity, standard temperature, and pollutant molecular weight were entered in a table named "Test Data." Emission rates (lb/hr) and emission factors (lb/MMBtu) were also entered in that table for comparison with the emissions calculated in the database using the pollutant concentrations for each test run.

Test reports included in the database were identified using the following scheme: numbers from 1 to 99 were assigned to tests containing only hazardous air pollutants (HAPs), and numbers greater than 100 were allocated for tests with only criteria pollutants or with both HAPs and criteria pollutants. Exceptions are the reports numbered 10 and 15. These test reports contain both HAPs and criteria pollutant test results. They are numbered as HAPs-only type reports because criteria pollutant data were identified in these reports after the first version of the database was posted on the TTN. Test reports containing more than one turbine, multiple load conditions, different fuels, control device inlet and outlet samples (criteria pollutant data only), or more than three sampling runs were assigned the same initial number followed by an extension (for example, 1.1 or 1.1.1).

Some of the test reports in the database include an "x" symbol at the end of the test report number (e.g., test report 8x). The "x" symbol indicates that the test report does not meet the acceptance criteria developed by the CTWG. The data from these test reports are included in the database for informational purposes only.

Construction of database reports (i.e., summaries of relevant data) required the complete separation of tests with HAPs-only data from tests with only criteria pollutant data and tests with both HAPs and criteria pollutant data. The "Test Data" table was consequently divided into three tables: "Test Data - HAPs," containing all HAP data in the Test Data table; "Test Data - Criteria Pollutants," containing all criteria pollutant data in the Test Data table, and "Test Data - HAPs + Criteria," containing the tests that include data for both HAPs and criteria pollutants.

In the report section, a set of 6 different reports was built for each of the test data tables discussed above. These reports provide information about pollutant concentrations (corrected to 15% O_2) and emissions in units of lb/hr, lb/MMBtu, and lb/MW-hr. Individual sets of reports were also developed for test summaries and pollutant summaries.

<u>Treatment of non-detected or non-reported concentrations</u>

Many pollutants, especially HAPs, were not detected in some or all of the sampling runs collected during a test. In these cases, concentrations were entered in the database as "ND." Although the test reports identified those pollutants not detected for a given testing run, the detection limit (DL) values were not always provided (i.e., ND was reported rather than a detection limit concentration). Often, review of the lab report and some additional calculations were necessary to determine the DL concentration. For example, in the case of formaldehyde, detection limits were usually given in micrograms or micrograms per milliliter in the lab report. Estimation of the DL in the same units as the test data (e.g., ppb) involved the use of the sample volume collected during the test and additional unit conversions (for example, micrograms/cubic meter to ppb).

Unfortunately, the DL could not always be found or calculated based on the laboratory report. Whenever a pollutant was not detected in all three runs and the DL could not be determined, the pollutant was removed from the database. This procedure was used for report ID #1 for benzene and chromium (VI). Also, due to the calculations discussed above, two or three different DLs (one per testing run) were determined for the same pollutant in some tests. The protocol followed in these cases was to take the highest DL value.

In some tests, only one or two runs were conducted, or runs were eliminated during test report preparation due to sampling problems encountered during the test. Missing runs were entered as NR (not reported) in the database. Other parameters missing from the test reports, such as exhaust gas flow rates, were also entered in the database as NR.

The acronym NA sometimes appears in the DL field. This acronym is used in those cases when a pollutant was measured above the detection limit in all of the testing runs but a detection limit value was not reported in the test report.

<u>Equations</u>

Using raw test data (i.e., lab-reported pollutant concentrations and stack test parameters), calculations were performed to estimate emissions in lb/hr, lb/MW-hr and lb/MMBtu. Modules, small programs written in Visual Basic code, were built to perform the calculations. There are various modules in the emissions database that perform different tasks, but only the main modules are described in this memorandum.

The equations used in the modules were taken from EPA sampling methods 19 and 20 in 40 CFR Part 60,

$$C_{adj} = C_d * \frac{20.9 - 15}{20.9 - \% O_2}$$

Appendix A. For example, for the correction of the dry pollutant concentration to 15% O_2, Equation 20-4 from EPA method 20 is used:

where $\%O_2$ refers to the reported oxygen level during the testing and C_d to the pollutant dry concentration in ppb.

For the calculation of emission rates in lb/hr, lb/MW-hr, and lb/MMBtu, the following equations were used :

1. Pounds per hour:
When the concentration of pollutant is given in ppb :

$$M(lb/hr) = C_{ppb} * Q * 60 * \frac{MW}{T_{std} + 460} * 1.369x10^{-9}$$

where C_{ppb} is the dry concentration of pollutant in ppb; Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; MW is the pollutant molecular weight (in lb/lb-mol); T_{std} is the standard temperature in degrees Fahrenheit used in the test report; 460 is the conversion factor from degrees Fahrenheit to degrees Rankine; and $1.369x10^{-9}$ is the conversion factor from ppb to pounds per cubic feet. The conversion factor from ppb to pounds per cubic feet was derived from 40 CFR, App. A, Meth. 20, page 1026.

When the concentration of a pollutant is given in units other than ppb or ppm, the equation is :

$$M(lb/hr) = C_p * Q * 60 * A$$

where C_p is the concentration of pollutant in micrograms per dry cubic feet (ug/dscf), micrograms per dry cubic meter (ug/dscm), grams per dry cubic feet (g/dscf) or grams per dry cubic meter (g/dscm). For particulate matter, concentrations are in grains per dry cubic feet (gr/dscf), grains per dry cubic meter (gr/dscm), micrograins per dry cubic feet (ugr/dscf) and micrograins per dry cubic meter (ugr/dscm). Q is the exhaust gas flow rate in dry standard cubic feet per minute; 60 is the conversion factor from minutes to hours; and A is a conversion factor from the given units to lb/dscf.

The values for A for the different units are:

1.1 For ug/dscf, A = $2.205x10^{-8}$
1.2 For ug/dscm, A = $6.24x10^{-10}$
1.3 For g/dscf and g/dscm, multiplying 1.1 and 1.2 by $1x10^{-6}$
1.4 For ugr/dscf, A = $1.43x10^{-10}$.
1.5 For ugr/dscm, A = $4.043x10^{-12}$.
1.6 For gr/dscf and gr/dscm, multiplying 1.4 and 1.5 by $1x10^{-6}$

2. Pounds per megawatt-hour:

The emission factor is calculated by dividing the emissions rate in lb/hr by the turbine rating during the test. The manufacturer rating and the test load are necessary data for this calculation. When load was not available, it was assumed to be 100%. The equation is :

$$M(lb/MW\text{ - }hr) = \frac{M(lb/hr)}{\frac{R * L}{100}}$$

where M(lb/hr) is the emission rate in lb/hr; R is the manufacturer rating for the turbine in MW; and L is the turbine testing load in %.

The equation is :

$$M(lb/MMBtu) = C_p * F * \frac{20.9}{20.9\text{ - }\%O_2} * B * (\frac{MW}{T_{std} + 460})$$

3. Pounds per million Btu:

where C_p is the dry concentration of pollutant in any of the units already described for the calculation of emission factors (1.1 - 1.6); F is the fuel factor in dry standard cubic feet per minute per million Btu; the fraction 20.9/(20.9-%O_2) is an oxygen correction factor; and B is the conversion factor corresponding to the units in which the pollutant concentration is reported (see the units described in 1.1 - 1.6). The fraction MW/(T_{std}+460) is a conversion factor used only when the pollutant concentration was provided in ppb.

When the fuel factor or standard temperature was not available, defaults were used. These defaults are discussed in next section.

A sample of the modules used for the calculations is provided in Appendix C-1.

Defaults and Assumptions

For the estimation of emission factors from the concentrations given in ppb, gaseous pollutants were assumed to have ideal gas behavior, so that the volume occupied by an ideal gas (22.4 liters/mol) could be used for calculation of a conversion factor.

Not all of the reports contained the necessary information required for the calculation of emission factors. Important parameters are concentrations, units, detection limits, oxygen levels, exhaust gas flow rates, fuel factors, standard temperatures and molecular weights. In most cases, fuel factors and standard temperatures were missing. In some cases, exhaust gas flow rates were not provided in the report. Lack of gas flow rates still allows for the calculation of emission factors in pounds per million Btu. Consequently, tests lacking exhaust gas flow rates were kept in the database, but the emissions in pound per hour are shown as NR.

For non-methane hydrocarbons (NMHC) and total hydrocarbons (THC), a molecular weight of 16 (as methane) was assumed. Test reports in the database indicated a molecular weight of 16 for THC and, in most cases, for NMHC. However, in some test reports, the molecular weight chosen to report emission factors for NMHC was the molecular weight of hexane.

Fields with NR for fuel factors and standard temperatures were filled with default values based on Table 19-1 in 40 CFR Part 60, Appendix A. A default standard temperature of 68^{o}F was used. This standard temperature was selected because EPA sampling methods rely on this value.

As discussed earlier, some pollutants were not detected in one or more of the sampling runs conducted during a test. In these cases, the detection limit was used in the emission calculations. Reports generated in the emissions database use a “<” sign in front of the sampling run concentration, as well as the average concentration calculated for the three runs, to indicate when a pollutant was not detected in one or more of the runs. When a pollutant was not detected in all three runs, a “<<” sign is shown in front of the average concentration presented in the database reports. The DL value was used in calculating the average concentration when a pollutant was not detected in one or more of the runs.

Appendix C-1

Sample of modules used in the database

The modules shown here are the modules for the calculation of emission factors in pounds per million Btu (Module Convert) and the module that handles the criteria for the use of detection limits (Module NonDetect).

1. Module for the calculation of emission factors in pounds per million Btu

1.1 Declaring the function that will perform the calculations and return the result to the query. The parameters r, s, t, u, v, w, z refer to concentration units (r), fuel factor (s), molecular weight (t), standard temperature (u), % oxygen (v), concentration (w), and a parameter (z, set to three in the database) used to limit the number of significant digits (utilizing another module) in the result.

Function lbMMBtu (r, s, t, u, v, w, x, y, z)

1.2 Estimating the emission factor to return to the query that is calling this module. First the module identifies the units (r=ppb), then it makes sure that there are values in all necessary fields and finally performs the calculation. SigDig_ is calling another module that will perform the reduction of the result to a given number (z) of significant digits. Val calls for the numerical value of the field being processed.

```
If ((r = "ppb") And Not (s = "NR" Or t = "NR" Or v = "NR" Or w = "NR")) Then
lbMMBtu = CStr(SigDig_((Val(s) * Val(t) * (.00000000137 / (Val(u) + 460)) * (20.9 / (20.9 - Val(v))) * Val(w)), z))

ElseIf ((r = "ug/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * .000000002204 * (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "ug/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .000000002204 * (20.9 / (20.9 - Val(v)))), z))

ElseIf ((r = "gr/dscf") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * (20.9 / (20.9 - Val(v))) / 7000), z))

ElseIf ((r = "ugr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
    lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) * 0.000001 / 7000), z))
```

ElseIf ((r = "gr/dscm") And Not (s = "NR" Or v = "NR" Or w = "NR")) Then
*lbMMBtu = CStr(SigDig_((Val(s) * Val(w) * .0283 * (20.9 / (20.9 - Val(v))) / 7000), z))*

1.3 In any other case (units not recognized or necessary parameters were not reported) the function is returned with the value "NR"

```
Else
    lbMMBtu = "NR"
    End If
End Function
```

2. <u>Module Handling the use of non-detected values</u>

2.1 Declaring the function that will return the values to the query. The parameters x and y refer respectively to concentration and detection limit.

Function Correction (x, y)

2.2 Identifying the concentration. If it is not reported, return the value "NR;" if it is not detected, take the value of the detection limit as the value for the concentration to be returned. Otherwise leave the value as it is.

```
If (x = "NR") Then
Correction = "NR"
ElseIf
If  (x = "ND") Then
        Correction = y
Else
        Correction = x
End If

End Function
```

Appendix C -- QA\QC Review Criteria for Emissions Tests

HAPS and Criteria Pollutant Source Test Checklist

	Source Test Report #____ Date__________	Source Test Report #____ Date__________
BASIC TURBINE INFORMATION		
Manufacturer	______________	______________
Model #	______________	______________
Rating (BHP or MW)	______________	______________
Operating Cycle (Simple, Regenerative, etc.)	______________	______________
FUEL DESCRIPTION		
Fuel Name(s)	______________	______________
Fuel Analysis Summary	______________	______________
Flowrate (or BTU/H, if available)	______________	______________
OPERATING CONDITIONS		
Load (during test)	______________	______________
Water or Steam Injection and/or Ammonia Mass Flowrate	______________	______________
Firing Temperature or Turbine Inlet Temperature	______________	______________
AMBIENT CONDITIONS		
Temperature	______________	______________
Relative Humidity	______________	______________
Barometric Pressure	______________	______________
Altitude	______________	______________
EXHAUST INFORMATION		
Temperature	______________	______________
Flowrate (F-Factor or Measured)	______________	______________
EMISSIONS TEST		
*Criteria Pollutants	______________	______________
HAPS	______________	______________
Oxygen or CO_2	______________	______________
Moisture	______________	______________
Averaging Time	______________	______________
METHODS USED		
CARB	______________	______________
EPA	______________	______________
Other ____________________	______________	______________
QUALITY CONTROL DOCUMENTATION		
Calibration of Instruments	______________	______________
Specialty Gases	______________	______________
CEMs	______________	______________
Dry Gas Meters	______________	______________
MISCELLANEOUS		
Limits of Detection Reporting	______________	______________
Supplemental Firing Details	______________	______________

Appendix D

Development of Emission Factors (lb/MMBtu) for Natural Gas Fired Turbines

The emission factors (lb/MMBtu) presented in Table 1 were calculated for natural gas-fired turbines from 23 source test reports in the emissions database. Emission factors from test reports that did not meet acceptance criteria established by the CTWG were not used in the calculations (4.1.2x, 8x, 10x, 29.1, 29.2, and 29.3). In addition, only test reports where the testing was conducted at high loads (greater than 80%) were included in the analysis. Test reports in which the load was not specified in the test report or could not be estimated from fuel use data were excluded.

The following test reports were used for the emission factor calculations: 2, 3.1, 4.2, 6.2, 7, 9, 11, 12.1, 13.1, 15.1, 17, 18, 22, 26, 27, 28, 313.1.1x, 313.2.1x, 314.1x, 315.1x, 316.1.1x, 316.2.1x, and 317.1x. Listed below are the source test reports that were excluded from the emission factor calculation with the reason for exclusion.

Test Report ID#	Reason for Exclusion
4.1.2x	Formaldehyde data point appears to be an outlier. Retest of the same turbine generated formaldehyde data more consistent with other formaldehyde data in the database.
8x	Report deemed inadequate by state and federal regulators according to telephone contact with the turbine operator.
10x	Missing load and fuel usage data.
29.1, 29.2, 29.3	Only summary data provided; no raw data sheets, laboratory results, etc.
16, 21, 313.1.2x, 313.2.2x, 314.2x, 314.3x, 314.4x, 315.2x, 316.1.2x, 316.2.2x, 317.2x	Testing occurred only at operating loads less than 80%.
23, 25	Load information not available.

Test data for individual HAPs that were not detected in any of the sampling runs for a source test (i.e., where the concentration was ND in all three runs) were excluded from the emission factor calculation for that HAP. This exclusion was made on a pollutant basis such that data for a subset of the HAPs analyzed for in a particular source test may have been used.

Appendix E -- Cost Spreadsheets

INPUTS AND CALCULATIONS

Model Turbine Number	1	
Turbine Exhaust Flow (lb/sec)	658	
Turbine Rating (MW)	85.4	
Turbine Rating (hp)	114523.1	
Heat Input, MMBtu/hr, including efficiency	832.5656	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	1595574	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1116874	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

			3-Year Costs	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	1595574	1595574
	Instrumentation**	0.1 EC	159557.4	159557.4
	Sales Tax	0.03 EC	47867.23	47867.23
	Freight	0.05 EC	79778.72	79778.72
	Total Purchased Equipment Cost, PEC	1.18 EC	1882778	1882778
Direct Installation Costs				
	Foundations & supports	0.08 PEC	150622.2	150622.2
	Handling & erection	0.14 PEC	263588.9	263588.9
	Electrical	0.04 PEC	75311.11	75311.11
	Piping	0.02 PEC	37655.56	37655.56
	Insulation for ductwork	0.01 PEC	18827.78	18827.78
	Painting	0.01 PEC	18827.78	18827.78
	Direct Installation Cost	0.3 PEC	564833.3	564833.3
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP + Bldg.	2447611	2447611
Indirect Costs (installation)				
	Engineering	0.1 PEC	188277.8	188277.8
	Construction and Field Expenses	0.05 PEC	94138.89	94138.89
	Contractor Fees	0.1 PEC	188277.8	188277.8
	Start-up	0.02 PEC	37655.56	37655.56
	Performance test	0.01 PEC	18827.78	18827.78
	Total Indirect Cost, IC	0.28 PEC	527177.8	527177.8
	Contingencies	0.1 DC+IC	297478.9	297478.9
	Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	3272268	3272268

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop Assume 1" backpressure		1		17320	17320
Perf. Test	Performance Test Not speciated HAPs				5000	5000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		17370.28	7806.717
	Catalyst replacement		Catalyst only cost * CRFcat		425586.9	234315.6
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	188277.8	188277.8
		Total Direct Annual Cost (DAC)			674542.4	473707.6

Indirect Annual Cost (IAC)

Overhead			0.6 O&M costs	125559.2	125559.2
Administrative			0.02 TCC	65445.36	65445.36
Property Taxes			0.01 TCC	32722.68	32722.68
Insurance			0.01 TCC	32722.68	32722.68
Capital Recovery	for catalyst: CRFequip(TCC - 1.08(Cat only))			226840.5	226840.5
		Total Indirect Annual Cost (IAC)		483290.3	483290.3
	Total Annual Cost (TAC)			1157833	956997.9

INPUTS AND CALCULATIONS

Model Turbine Number	2	
Turbine Exhaust Flow (lb/sec)	986	
Turbine Rating (MW)	170	
Turbine Rating (hp)	227973.4	
Heat Input, MMBtu/hr, including efficiency	1657.332	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	2317985	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	1622585	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS	(Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)			
Direct Costs			3-Year Costs	6-Year Costs
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	2317985	2317985
	Instrumentation**	0.1 EC	231798.5	231798.5
	Sales Tax	0.03 EC	69539.54	69539.54
	Freight	0.05 EC	115899.2	115899.2
	Total Purchased Equipment Cost, PEC	1.18 EC	2735222	2735222
Direct Installation Costs				
	Foundations & supports	0.08 PEC	218817.8	218817.8
	Handling & erection	0.14 PEC	382931.1	382931.1
	Electrical	0.04 PEC	109408.9	109408.9
	Piping	0.02 PEC	54704.44	54704.44
	Insulation for ductwork	0.01 PEC	27352.22	27352.22
	Painting	0.01 PEC	27352.22	27352.22
	Direct Installation Cost	0.3 PEC	820566.6	820566.6
Site preparation		As required, SP	0	0
Buildings		As required, Bldg.	0	0
	Total Direct Cost, DC	1.30 PEC + SP + Bldg.	3555789	3555789
Indirect Costs (installation)				
	Engineering	0.1 PEC	273522.2	273522.2
	Construction and Field Expenses	0.05 PEC	136761.1	136761.1
	Contractor Fees	0.1 PEC	273522.2	273522.2
	Start-up	0.02 PEC	54704.44	54704.44
	Performance test	0.01 PEC	27352.22	27352.22
	Total Indirect Cost, IC	0.28 PEC	765862.2	765862.2
	Contingencies	0.1 DC+IC	432165.1	432165.1
	Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	4753816	4753816

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop Assume 1" backpressure		1		34470	34470
Perf. Test	Performance Test Not speciated HAPs				5000	5000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		25235.39	11341.53
	Catalyst replacement		Catalyst only cost * CRFcat		618288.6	340411.5
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	273522.2	273522.2
		Total Direct Annual Cost (DAC)			977503.7	685732.7

Indirect Annual Cost (IAC)

Overhead			0.6 O&M costs	176705.8	176705.8
Administrative			0.02 TCC	95076.32	95076.32
Property Taxes			0.01 TCC	47538.16	47538.16
Insurance			0.01 TCC	47538.16	47538.16
Capital Recovery	for catalyst: CRFequip(TCC - 1.08(Cat only))			329540.3	329540.3
		Total Indirect Annual Cost (IAC)		696398.7	696398.7
	Total Annual Cost (TAC)			1673902	1382131

INPUTS AND CALCULATIONS

Model Turbine Number	7	
Turbine Exhaust Flow (lb/sec)	318	
Turbine Rating (MW)	39.6	
Turbine Rating (hp)	53104.39	
Heat Input, MMBtu/hr, including efficiency	386.0609	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	846662.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	592662.4	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS	(Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)		
Direct Costs		3-Year Costs	6-Year Costs
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	846662.4	846662.4
Instrumentation**	0.1 EC	84666.24	84666.24
Sales Tax	0.03 EC	25399.87	25399.87
Freight	0.05 EC	42333.12	42333.12
Total Purchased Equipment Cost, PEC	1.18 EC	999061.6	999061.6
Direct Installation Costs			
Foundations & supports	0.08 PEC	79924.93	79924.93
Handling & erection	0.14 PEC	139868.6	139868.6
Electrical	0.04 PEC	39962.47	39962.47
Piping	0.02 PEC	19981.23	19981.23
Insulation for ductwork	0.01 PEC	9990.616	9990.616
Painting	0.01 PEC	9990.616	9990.616
Direct Installation Cost	0.3 PEC	299718.5	299718.5
Site preparation	As required, SP	0	0
Buildings	As required, Bldg.	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg.	1298780	1298780
Indirect Costs (installation)			
Engineering	0.1 PEC	99906.16	99906.16
Construction and Field Expenses	0.05 PEC	49953.08	49953.08
Contractor Fees	0.1 PEC	99906.16	99906.16
Start-up	0.02 PEC	19981.23	19981.23
Performance test	0.01 PEC	9990.616	9990.616
Total Indirect Cost, IC	0.28 PEC	279737.3	279737.3
Contingencies	0.1 DC+IC	157851.7	157851.7
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	1736369	1736369

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop Assume 1" backpressure		1		8030	8030
Perf. Test	Performance Test Not speciated HAPs				5000	5000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		9217.431	4142.586
	Catalyst replacement		Catalyst only cost * CRFcat		225835	124338.1
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	99906.16	99906.16
		Total Direct Annual Cost (DAC)			368976.1	262404.3

Indirect Annual Cost (IAC)

Overhead			0.6 O&M costs	72536.2	72536.2
Administrative			0.02 TCC	34727.38	34727.38
Property Taxes			0.01 TCC	17363.69	17363.69
Insurance			0.01 TCC	17363.69	17363.69
Capital Recovery	for catalyst: CRFequip(TCC - 1.08(Cat only))			120367.2	120367.2
		Total Indirect Annual Cost (IAC)		262358.1	262358.1
	Total Annual Cost (TAC)			631334.2	524762.5

INPUTS AND CALCULATIONS

Model Turbine Number	9	
Turbine Exhaust Flow (lb/sec)	178	
Turbine Rating (MW)	27	
Turbine Rating (hp)	36207.54	
Heat Input, MMBtu/hr, including efficiency	263.2233	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	538310.4	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	376810.4	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

Cost Item		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	538310.4	538310.4
Instrumentation**	0.1 EC	53831.04	53831.04
Sales Tax	0.03 EC	16149.31	16149.31
Freight	0.05 EC	26915.52	26915.52
Total Purchased Equipment Cost, PEC	1.18 EC	635206.3	635206.3
Direct Installation Costs			
Foundations & supports	0.08 PEC	50816.5	50816.5
Handling & erection	0.14 PEC	88928.88	88928.88
Electrical	0.04 PEC	25408.25	25408.25
Piping	0.02 PEC	12704.13	12704.13
Insulation for ductwork	0.01 PEC	6352.063	6352.063
Painting	0.01 PEC	6352.063	6352.063
Direct Installation Cost	0.3 PEC	190561.9	190561.9
Site preparation	As required, SP	0	0
Buildings	As required, Bldg.	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg.	825768.2	825768.2
Indirect Costs (installation)			
Engineering	0.1 PEC	63520.63	63520.63
Construction and Field Expenses	0.05 PEC	31760.31	31760.31
Contractor Fees	0.1 PEC	63520.63	63520.63
Start-up	0.02 PEC	12704.13	12704.13
Performance test	0.01 PEC	6352.063	6352.063
Total Indirect Cost, IC	0.28 PEC	177857.8	177857.8
Contingencies	0.1 DC+IC	100362.6	100362.6
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	1103989	1103989

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop Assume 1" backpressure		1		5470	5470
Perf. Test	Performance Test Not speciated HAPs				5000	5000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		5860.375	2633.826
	Catalyst replacement		Catalyst only cost * CRFcat		143584.2	79053.24
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		18250	18250
	Supervisor	.15 *OL		0.15 OL	2737.5	2737.5
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	63520.63	63520.63
		Total Direct Annual Cost (DAC)			244422.7	176665.2

Indirect Annual Cost (IAC)

Overhead		0.6 O&M costs	50704.88	50704.88
Administrative		0.02 TCC	22079.77	22079.77
Property Taxes		0.01 TCC	11039.89	11039.89
Insurance		0.01 TCC	11039.89	11039.89
Capital Recovery	for catalyst: CRFequip(TCC - 1.08(Cat only))		76530.51	76530.51
	Total Indirect Annual Cost (IAC)		171394.9	171394.9
	Total Annual Cost (TAC)		415817.7	348060.1

INPUTS AND CALCULATIONS

Model Turbine Number	15	
Turbine Exhaust Flow (lb/sec)	83.6	
Turbine Rating (MW)	9	
Turbine Rating (hp)	12069.18	
Heat Input, MMBtu/hr, including efficiency	87.74111	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.109795	
Capital Recovery Factor, 3-yr Catalyst Life	0.381052	
Capital Recovery Factor, 6-yr Catalyst Life	0.209796	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	330364.5	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	231264.5	EPA formula based on Vendor Quotes
Ductwork	(No quantitative estimates available)	

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
Instrumentation**	0.1 EC	$23,658	$23,658
Sales Tax	0.03 EC	$7,098	$7,098
Freight	0.05 EC	$11,829	$11,829
Total Purchased Equipment Cost, PEC	1.18 EC	$279,169	$279,169
Direct Installation Costs			
Foundations & supports	0.08 PEC	$22,334	$22,334
Handling & erection	0.14 PEC	$39,084	$39,084
Electrical	0.04 PEC	$11,167	$11,167
Piping	0.02 PEC	$5,583	$5,583
Insulation for ductwork	0.01 PEC	$2,792	$2,792
Painting	0.01 PEC	$2,792	$2,792
Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation	As required, SP	$0	$0
Buildings	As required, Bldg.	$0	$0
Total Direct Cost, DC	1.30 PEC + SP + Bldg.	$362,920	$362,920
Indirect Costs (installation)			
Engineering	0.1 PEC	$27,917	$27,917
Construction and Field Expenses	0.05 PEC	$13,958	$13,958
Contractor Fees	0.1 PEC	$27,917	$27,917
Start-up	0.02 PEC	$5,583	$5,583
Performance test	0.01 PEC	$2,792	$2,792
Total Indirect Cost, IC	0.28 PEC	$78,167	$78,167
Contingencies	0.1 DC+IC	$44,109	$44,109
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	$485,196	$485,196

Direct Annual Cost (DAC)

		3-Year Costs	6-Year Costs
Direct Costs			
Purchased Equipment Costs (PEC)			
Catalyst + auxiliary equipment* (EC)	1 EC	330364.5	330364.5
Instrumentation**	0.1 EC	33036.45	33036.45
Sales Tax	0.03 EC	9910.934	9910.934
Freight	0.05 EC	16518.22	16518.22
Total Purchased Equipment Cost, PEC	1.18 EC	389830.1	389830.1
Direct Installation Costs			
Foundations & supports	0.08 PEC	31186.41	31186.41
Handling & erection	0.14 PEC	54576.21	54576.21
Electrical	0.04 PEC	15593.2	15593.2
Piping	0.02 PEC	7796.602	7796.602
Insulation for ductwork	0.01 PEC	3898.301	3898.301
Painting	0.01 PEC	3898.301	3898.301
Direct Installation Cost	0.3 PEC	116949	116949
Site preparation	As required, SP	0	0
Buildings	As required, Bldg.	0	0
Total Direct Cost, DC	1.30 PEC + SP + Bldg.	506779.1	506779.1
Indirect Costs (installation)			
Engineering	0.1 PEC	38983.01	38983.01
Construction and Field Expenses	0.05 PEC	19491.5	19491.5
Contractor Fees	0.1 PEC	38983.01	38983.01
Start-up	0.02 PEC	7796.602	7796.602
Performance test	0.01 PEC	3898.301	3898.301
Total Indirect Cost, IC	0.28 PEC	109152.4	109152.4
Contingencies	0.1 DC+IC	61593.15	61593.15
Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	677524.7	677524.7

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop	Assume 1" backpressure	1			1820	1820
Perf. Test	Performance Test	Not speciated HAPs				5000	5000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime			3596.76	1616.49
	Catalyst replacement		Catalyst only cost * CRFcat			88123.72	48518.32
Operating Labor							
	Operator	2 hours per day	Per Engine ACT-NSCR			18250	18250
	Supervisor	.15 *OL		0.15	OL	2737.5	2737.5
Maintenance							
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1	PEC	38983.01	38983.01
		Total Direct Annual Cost (DAC)				158511	116925.3

Indirect Annual Cost (IAC)

Overhead			0.6	O&M costs	35982.31	35982.31
Administrative			0.02	TCC	13550.49	13550.49
Property Taxes			0.01	TCC	6775.247	6775.247
Insurance			0.01	TCC	6775.247	6775.247
Capital Recovery	for catalyst:	CRFequip(TCC - 1.08(Cat only))			46965.64	46965.64
		Total Indirect Annual Cost (IAC)			110048.9	110048.9
	Total Annual Cost (TAC)				268559.9	226974.3

INPUTS AND CALCULATIONS

Model Turbine Number	13	
Turbine Exhaust Flow (lb/sec)	41	
Turbine Rating (MW)	3.5	
Turbine Rating (hp)	4,694	
Heat Input, MMBtu/hr, including efficiency	34	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.1098	
Capital Recovery Factor, 3-yr Catalyst Life	0.3811	
Capital Recovery Factor, 6-yr Catalyst Life	0.2098	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

Catalyst Calculations:

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	$236,584	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$165,584	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (No quantitative estimates available)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

			3-Year Costs	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	$236,584	$236,584
	Instrumentation**	0.1 EC	$23,658	$23,658
	Sales Tax	0.03 EC	$7,098	$7,098
	Freight	0.05 EC	$11,829	$11,829
	Total Purchased Equipment Cost, PEC	1.18 EC	$279,169	$279,169
Direct Installation Costs				
	Foundations & supports	0.08 PEC	$22,334	$22,334
	Handling & erection	0.14 PEC	$39,084	$39,084
	Electrical	0.04 PEC	$11,167	$11,167
	Piping	0.02 PEC	$5,583	$5,583
	Insulation for ductwork	0.01 PEC	$2,792	$2,792
	Painting	0.01 PEC	$2,792	$2,792
	Direct Installation Cost	0.3 PEC	$83,751	$83,751
Site preparation		As required, SP	$0	$0
Buildings		As required, Bldg.	$0	$0
	Total Direct Cost, DC	1.30 PEC + SP + Bldg.	$362,920	$362,920
Indirect Costs (installation)				
	Engineering	0.1 PEC	$27,917	$27,917
	Construction and Field Expenses	0.05 PEC	$13,958	$13,958
	Contractor Fees	0.1 PEC	$27,917	$27,917
	Start-up	0.02 PEC	$5,583	$5,583
	Performance test	0.01 PEC	$2,792	$2,792
	Total Indirect Cost, IC	0.28 PEC	$78,167	$78,167
	Contingencies	0.1 DC+IC	$44,109	$44,109
	Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	$485,196	$485,196

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop Assume 1" backpressure		1.0		$710	$710
Perf. Test	Performance Test Not speciated HAPs				$5,000	$5,000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		$2,575	$1,157
	Catalyst replacement		Catalyst only cost * CRFcat		$63,096	$34,739
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		$18,250	$18,250
	Supervisor	.15 *OL		0.15 OL	$2,738	$2,738
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	$27,917	$27,917
		Total Direct Annual Cost (DAC)			$120,286	$90,511

Indirect Annual Cost (IAC)

Overhead			0.6 O&M costs	$29,343	$29,343
Administrative			0.02 TCC	$9,704	$9,704
Property Taxes			0.01 TCC	$4,852	$4,852
Insurance			0.01 TCC	$4,852	$4,852
Capital Recovery	for catalyst: CRFequip(TCC - 1.08(Cat only))			$33,637	$33,637
		Total Indirect Annual Cost (IAC)		$82,388	$82,388
	Total Annual Cost (TAC)			$202,673	$172,898

INPUTS AND CALCULATIONS

Model Turbine Number	17	
Turbine Exhaust Flow (lb/sec)	14.2	
Turbine Rating (MW)	1.13	
Turbine Rating (hp)	1,515	
Heat Input, MMBtu/hr, including efficiency	11	(Rating in MW / .29307 MW/MMBTU/hr)/ Efficiency
Hours of operation/yr	8000	
Life of equipment	15	
Life of catalyst	3 or 6 Years	
Interest rate (fraction)	0.07	
Capital Recovery Factor, Equipment, 15-yr Life	0.1098	
Capital Recovery Factor, 3-yr Catalyst Life	0.3811	
Capital Recovery Factor, 6-yr Catalyst Life	0.2098	
Destruction Efficiency - 3-yr & 6-yr Catalyst Life	80	for emission reduction calculation
Destruction Efficiency - 6-yr Catalyst Life w/Degradation	50	for emission reduction calculation
VAPCCI Escalator		
Fuel Type (CLEAN OR DIRTY)	CLEAN	
Turbine Assumed Efficiency (fraction)	0.35	for emission reduction calculation
Turbine Exhaust Temp (0F)	1000	

<u>Catalyst Calculations:</u>

Vendor Estimate - Based on 80 Percent Reduction of Formaldehyde

Catalyst, Frame & Housing	$177,564	Per Catalyst Vendors, assume housing is 30 percent of Total Catalyst Costs
Catalyst only	$124,264	EPA formula based on Vendor Quotes

Other catalyst - associated costs

Ductwork (No quantitative estimates available)

COSTS (Patterned after the OAQPS Cost Manual (1990) Thermal and Catalytic Incinerators Section)

			3-Year Costs	6-Year Costs
Direct Costs				
Purchased Equipment Costs (PEC)				
	Catalyst + auxiliary equipment* (EC)	1 EC	$177,564	$177,564
	Instrumentation**	0.1 EC	$17,756	$17,756
	Sales Tax	0.03 EC	$5,327	$5,327
	Freight	0.05 EC	$8,878	$8,878
	Total Purchased Equipment Cost, PEC	1.18 EC	$209,525	$209,525
Direct Installation Costs				
	Foundations & supports	0.08 PEC	$16,762	$16,762
	Handling & erection	0.14 PEC	$29,334	$29,334
	Electrical	0.04 PEC	$8,381	$8,381
	Piping	0.02 PEC	$4,191	$4,191
	Insulation for ductwork	0.01 PEC	$2,095	$2,095
	Painting	0.01 PEC	$2,095	$2,095
	Direct Installation Cost	0.3 PEC	$62,858	$62,858
Site preparation		As required, SP	$0	$0
Buildings		As required, Bldg.	$0	$0
	Total Direct Cost, DC	1.30 PEC + SP + Bldg.	$272,383	$272,383
Indirect Costs (installation)				
	Engineering	0.1 PEC	$20,953	$20,953
	Construction and Field Expenses	0.05 PEC	$10,476	$10,476
	Contractor Fees	0.1 PEC	$20,953	$20,953
	Start-up	0.02 PEC	$4,191	$4,191
	Performance test	0.01 PEC	$2,095	$2,095
	Total Indirect Cost, IC	0.28 PEC	$58,667	$58,667
	Contingencies	0.1 DC+IC	$33,105	$33,105
	Total Capital Cost (TCC) = DC + IC + Contingencies	1.61 PEC + SP + Bldg.+0.1(DC+IC)	$364,154	$364,154

Direct Annual Cost (DAC)

Fuel Penalty	Fuel Penalty due to Pressure Drop -- Assume 1" backpressure				$230	$230
Perf. Test	Performance Test Not speciated HAPs				$5,000	$5,000
Cat. Costs	Freight to return catalyst for disposal		Freight=.05*Catalyst only cost*[i/[(1+i)^n-1], i=interest rate, n=catalyst lifetime		$1,933	$869
	Catalyst replacement		Catalyst only cost * CRFcat		$47,351	$26,070
Operating Labor						
	Operator	2 hours per day	Per Engine ACT-NSCR		$18,250	$18,250
	Supervisor	.15 *OL		0.15 OL	$2,738	$2,738
Maintenance						
	Labor & Materials	.10 PEC	Per Engine ACT-NSCR	0.1 PEC	$20,953	$20,953
		Total Direct Annual Cost (DAC)			$96,453	$74,109

Indirect Annual Cost (IAC)

Overhead			0.6 O&M costs	$25,164	$25,164
Administrative			0.02 TCC	$7,283	$7,283
Property Taxes			0.01 TCC	$3,642	$3,642
Insurance			0.01 TCC	$3,642	$3,642
Capital Recovery	for catalyst:	CRFequip(TCC - 1.08(Cat only))		$25,247	$25,247
		Total Indirect Annual Cost (IAC)		$64,977	$64,977
	Total Annual Cost (TAC)			$161,431	$139,086

Appendix F -- Description of SCONOx™ System

The SCONOx™ catalytic absorption system was described in a paper presented at the Power-Gen International '97 conference as follows:

> The SCONOx™ system uses a single catalyst for both CO & NOx control. It oxidizes CO to CO2 and NO to NO2, and the NO2 is then absorbed onto the surface of the catalyst. Just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be periodically regenerated. This is accomplished by passing a dilute hydrogen gas across the surface of the catalyst in the absence of oxygen. Nitrogen oxides are broken down into nitrogen and water, and this is exhausted up the stack instead of NOx.

Source: "The SCONOx™ Catalytic Absorption system for Natural Gas Fired Power Plants: The Path to Ultra-Low Emissions," Robert J. MacDonald, P.E., and Lawrence Debbage, presented to Power-Gen International '97, December 9-11, 1997.

Appendix G -- Cost-Effectiveness for Individual HAPs

Model 1 -- 85.4 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$85,213	$670,472	$70,432	$554,173	$112,692	$886,677
Toluene	$629,008	$3,366,524	$519,902	$2,782,575	$831,843	$4,452,120
Acetaldehyde	$1,365,847	$5,241,737	$1,128,930	$4,332,518	$1,806,289	$6,932,029
Xylenes	$3,983,720	$10,414,955	$3,292,714	$8,608,402	$5,268,342	$13,773,443
Ethylbenzene	$11,659,669	$11,659,669	$9,637,211	$9,637,211	$15,419,538	$15,419,538
Benzene	$12,226,251	$46,412,275	$10,105,515	$38,361,714	$16,168,825	$61,378,743
PAHs	$65,306,889	$214,370,595	$53,978,915	$177,186,393	$86,366,264	$283,498,228
Acrolein	$78,626,057	$87,075,852	$64,987,772	$71,971,886	$103,980,436	$115,155,018
Naphthalene	$144,424,903	$327,429,060	$119,373,310	$270,634,011	$190,997,296	$433,014,417
Total HAPs	$68,914	$454,166	$56,961	$375,388	$91,137	$600,620

Model 2 -- 170 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$61,887	$486,938	$51,100	$402,062	$81,760	$643,299
Toluene	$456,825	$2,444,978	$377,198	$2,018,804	$603,516	$3,230,087
Acetaldehyde	$991,963	$3,806,874	$819,058	$3,143,314	$1,310,492	$5,029,302
Xylenes	$2,893,224	$7,563,985	$2,388,918	$6,245,538	$3,822,269	$9,992,861
Ethylbenzene	$8,467,973	$8,467,973	$6,991,956	$6,991,956	$11,187,129	$11,187,129
Benzene	$8,879,461	$33,707,467	$7,331,718	$27,832,058	$11,730,750	$44,531,292
PAHs	$47,429,906	$155,689,197	$39,162,595	$128,551,656	$62,660,151	$205,682,649
Acrolein	$57,103,110	$63,239,874	$47,149,703	$52,216,793	$75,439,524	$83,546,868
Naphthalene	$104,890,305	$237,799,252	$86,607,309	$196,349,447	$138,571,694	$314,159,115
Total HAPs	$50,050	$329,844	$41,326	$272,350	$66,122	$435,760

Model 7 -- 39.6 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$100,204	$788,418	$83,289	$655,330	$133,262	$1,048,528
Toluene	$739,661	$3,958,748	$614,803	$3,290,496	$983,685	$5,264,793
Acetaldehyde	$1,606,121	$6,163,841	$1,335,001	$5,123,360	$2,136,002	$8,197,375
Xylenes	$4,684,519	$12,247,109	$3,893,753	$10,179,747	$6,230,005	$16,287,596
Ethylbenzene	$13,710,787	$13,710,787	$11,396,351	$11,396,351	$18,234,162	$18,234,162
Benzene	$14,377,040	$54,576,921	$11,950,138	$45,364,117	$19,120,221	$72,582,586
PAHs	$76,795,394	$252,081,741	$63,832,022	$209,529,327	$102,131,235	$335,246,924
Acrolein	$92,457,612	$102,393,858	$76,850,395	$85,109,363	$122,960,632	$136,174,980
Naphthalene	$169,831,505	$385,028,960	$141,163,263	$320,034,521	$225,861,221	$512,055,233
Total HAPs	$81,038	$534,061	$67,358	$443,910	$107,773	$710,255

Model 9 -- 27 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$96,796	$761,608	$81,023	$637,504	$129,637	$1,020,007
Toluene	$714,509	$3,824,133	$598,080	$3,200,990	$956,927	$5,121,583
Acetaldehyde	$1,551,505	$5,954,241	$1,298,687	$4,983,997	$2,077,900	$7,974,395
Xylenes	$4,525,223	$11,830,650	$3,787,838	$9,902,844	$6,060,540	$15,844,550
Ethylbenzene	$13,244,556	$13,244,556	$11,086,354	$11,086,354	$17,738,167	$17,738,167
Benzene	$13,888,154	$52,721,050	$11,625,077	$44,130,148	$18,600,124	$70,608,237
PAHs	$74,183,991	$243,509,783	$62,095,700	$203,829,832	$99,353,120	$326,127,732
Acrolein	$89,313,621	$98,911,988	$74,759,955	$82,794,267	$119,615,928	$132,470,827
Naphthalene	$164,056,440	$371,936,175	$137,323,422	$311,329,127	$219,717,475	$498,126,604
Total HAPs	$78,282	$515,901	$65,526	$431,835	$104,841	$690,935

Model 13 -- 3.5 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$363,955	$2,863,658	$310,486	$2,442,953	$496,777	$3,908,725
Toluene	$2,686,563	$14,378,788	$2,291,876	$12,266,378	$3,667,001	$19,626,205
Acetaldehyde	$5,833,680	$22,388,026	$4,976,645	$19,098,966	$7,962,632	$30,558,345
Xylenes	$17,014,900	$44,483,398	$14,515,214	$37,948,271	$23,224,342	$60,717,234
Ethylbenzene	$49,799,706	$49,799,706	$42,483,553	$42,483,553	$67,973,684	$67,973,684
Benzene	$52,219,641	$198,231,840	$44,547,971	$169,109,287	$71,276,753	$270,574,860
PAHs	$278,932,781	$915,599,980	$237,954,325	$781,087,739	$380,726,920	$1,249,740,383
Acrolein	$335,820,387	$371,910,374	$286,484,483	$317,272,433	$458,375,173	$507,635,893
Naphthalene	$616,854,367	$1,398,484,901	$526,231,317	$1,193,031,273	$841,970,107	$1,908,850,037
Total HAPs	$294,341	$1,939,794	$251,099	$1,654,815	$401,758	$2,647,705

Model 15 -- 9 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$187,550	$1,475,677	$158,509	$1,247,173	$253,614	$1,995,477
Toluene	$1,384,418	$7,409,561	$1,170,045	$6,262,213	$1,872,072	$10,019,541
Acetaldehyde	$3,006,165	$11,536,816	$2,540,669	$9,750,376	$4,065,071	$15,600,602
Xylenes	$8,767,980	$22,922,824	$7,410,286	$19,373,296	$11,856,457	$30,997,274
Ethylbenzene	$25,662,381	$25,662,381	$21,688,641	$21,688,641	$34,701,826	$34,701,826
Benzene	$26,909,402	$102,151,226	$22,742,565	$86,333,426	$36,388,104	$138,133,482
PAHs	$143,737,381	$471,819,563	$121,480,094	$398,759,771	$194,368,151	$638,015,633
Acrolein	$173,052,241	$191,649,841	$146,255,640	$161,973,459	$234,009,023	$259,157,534
Naphthalene	$317,872,394	$720,655,908	$268,650,843	$609,064,582	$429,841,348	$974,503,331
Total HAPs	$151,677	$999,599	$128,191	$844,814	$205,105	$1,351,702

Model 17 -- 1.13 MW Turbine

Pollutant	80% Reduction & 3-Yr Catalyst Life		80% Reduction & 6-Yr Catalyst Life		50% Reduction & 6-Yr Catalyst Life	
	Highest EF	Average EF	Highest EF	Average EF	Highest EF	Average EF
Formaldehyde	$897,899	$7,064,815	$773,614	$6,086,919	$1,237,782	$9,739,070
Toluene	$6,627,912	$35,473,330	$5,710,491	$30,563,190	$9,136,785	$48,901,104
Acetaldehyde	$14,392,037	$55,232,597	$12,399,923	$47,587,423	$19,839,877	$76,139,877
Xylenes	$41,976,774	$109,743,200	$36,166,442	$94,552,789	$57,866,307	$151,284,462
Ethylbenzene	$122,858,851	$122,858,851	$105,853,000	$105,853,000	$169,364,800	$169,364,800
Benzene	$128,828,974	$489,049,793	$110,996,752	$421,356,601	$177,594,803	$674,170,562
PAHs	$688,143,835	$2,258,839,853	$592,892,485	$1,946,176,230	$948,627,977	$3,113,881,969
Acrolein	$828,488,959	$917,525,113	$713,811,348	$790,523,314	$1,142,098,156	$1,264,837,302
Naphthalene	$1,521,816,578	$3,450,145,803	$1,311,170,089	$2,972,584,242	$2,097,872,142	$4,756,134,788
Total HAPs	$726,157	$4,785,587	$625,644	$4,123,176	$1,001,030	$6,597,082