Teresa - Does all this make sense? Thanks Al

Nelson, Deborah

From: Nelson, Deborah
Sent: Tuesday, January 20, 2009 12:21 PM
To: Heron, Teresa
Cc: Linero, Alvaro
Subject: Okeechobee

2008

Teresa,

I wanted to clarify a couple of items regarding the Okeechobee project that I don't want to fall through the cracks with regards to the permit and what they modeled. If there is any confusion on these issues, we might want to discuss with WM.

With regards to the Interim Scenario (their operating flares prior to LOCat), see below:

Currently operating 2 flares
1 additonal flare is for emergency purposes only
Emergency flare was not modeled therefore, you might want to limit this flare as you would any other type of emergency source.
They no longer need the odor flare that they were originally proposing.
Therefore, we only need to permit 1 additional open flare.

Total flow 5,700 scfm
The 2 flares they have are rated at 3000 scfm each, however they modeled at 1700. You might want to limit them on this or they might go over on NAAQS before the LOCat can be installed. The new flare at 2300 scfm was modeled at 116.1 lb/hr and the existing enclosed flares are 51.5 lb/hr each.

Also, post LOCat, the flares they are proposing are rated at higher scfm's than what they are proposing, therefore the permit will need to address this in regards to their emission or flow limits.

E.U 003 1,700 scfm
E.U 004 1,700 scfm
E.U 005
E.U 006 2,300 scfm
$\boxed{5,700}$ scfm

Thanks,

Debbie

Debbie Nelson
Meteorologist
Special Projects Section
850-921-9537
deborah.nelson@dep.state.fl.us

Golder Associates Inc.

6026 NW 1st Place
Gainesville, FL 32607
Telephone (352) 336-5600
Fax (352) 336-6603

June 4

Hardcopy received June 9

Golder Associates

June 4, 2009

0938-7541

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

Attention: Mr. Syed Arif, P.E., Acting Program Administrator

**RE: REQUEST FOR ADDITIONAL INFORMATION
DEP FILE NO. 0930104-014-AC AND PSD-FL-382
BERMAN ROAD AND CLAY FARMS LANDFILLS
OKEECHOBEE LANDFILL, INC.
WASTE MANAGEMENT (WM), INC. OF FLORIDA**

Dear Mr. Arif:

Okeechobee Landfill, Inc. (OLI), a subsidiary of Waste Management, Inc. (WM) of Florida has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated May 6, 2009, regarding the construction permit application for the construction of additional flares and turbines along with the LO-CAT II desulfurization system at the Okeechobee Landfill. Each of FDEP's requests is answered below, in the same order as they appear in the RAI letter.

Comment 1. **On page 3 of your response you stated that *"siloxane removal systems... are unproven, and therefore, the SCR systems are not technically feasible for the OLI gas turbines"*. Since then, we have contacted the South Carolina Department of Health and Environmental Control where they have permitted a landfill, Lee County Landfill, which installed a siloxane gas removal treatment system. The gas-to-energy facility at this landfill, the Santee Cooper Electric Generation Facility, is currently in operation. It appears the applicant proposed the siloxane gas removal treatment system of the landfill gas for overall protection of their equipment and not necessarily for NOx reduction for their Solar Taurus 60 turbine and their 4 Jenbacher Engine engines. These units are not equipped with SCR. Also, the Enoree Landfill [listed in the EPA landfill methane outreach program (LMOP)], installed gas treatment to reduce siloxane content from parts per million to parts per billion based on initial laboratory testing according to the EPA website, it is expected that this gas cleaning technology could increase the life expectancy of the engines. Why is siloxane not of concern for WM at the Okeechobee landfill? What experience does WM have with this contaminant at the Pompano landfill and the gas-to-energy facility at this location?**

Response: Under current operation, siloxane is not a matter of concern to WM at the Okeechobee Landfill, or at its other landfills. Siloxane poses no problem to the operation of the three landfill gas (LFG)-fired turbines at the Central Sanitary Landfill & Recycling Center in Pompano Beach, Florida (Pompano Landfill). Small deposits of siloxane (in the form of silica and silicate) on the turbine blades at the Pompano Landfill have been noticed, but these are removed during the engine overhauls and cause no operational problem. There are no known installations of siloxane removal systems on LFG streams prior to combustion in a turbine. Siloxane removal systems do not remove all siloxane; therefore, the siloxane that passes through the removal system will still be deposited on turbine blades and inside post-combustion control devices. These deposits will foul the selective catalytic reduction (SCR) catalysts. Please note that WM is proposing a desulfurization gas treatment (LO-CAT II) system at the Okeechobee Landfill.

Comment 2. Submit Siloxane Contamination Information for the Okeechobee Landfill. List the concentration (ppmv or mg/m^3) of the following contaminants in the landfill gas: Tetramethylsilane; Tetramethyldisiloxane; Pentamethyldisiloxane; Hexamethyldisiloxane; Octamethyltrisiloxane; Hexamethylcyclotrisiloxane; Octamethylcyclotetrasiloxane; Decamethylcyclopentasiloxane and Dodecamethylcyclohexasiloxane.

Response: A gas analysis for siloxanes was conducted on the Okeechobee Landfill LFG in May 2008; the results are presented in Attachment A. As shown, only octamethyltrisiloxane was detected in the gas stream, at a concentration of 1,700 parts per billion, volumetric (ppbv).

Comment 3. Table 7 of the information submitted, lists the annualized cost for siloxane removal as $1,213,219 for all turbines. This value was also used for each individual turbine. Please adjust this value to reflect the cost for siloxane removal for each turbine alone.

Response: The annualized cost of $1,213,219 is for one siloxane removal system to treat the design LFG flow of 27,500 standard cubic feet per minute (scfm) for all 16 turbines. The same cost was used for each individual turbine with the conservative assumption that only one siloxane removal system will be installed to treat the total LFG flow instead of installing individual siloxane removal systems for individual turbines. The capital and annual costs for 16 siloxane removal systems will be many times higher than one siloxane removal system to serve all 16 turbines.

However, to satisfy the Department's request, a revised Table 7 is presented in Attachment B, which shows the annualized cost for individual siloxane removal systems. The annualized cost calculation tables are also attached. Please note that the equipment cost is based on the WM Pennsylvania project, where a siloxane removal system was considered for treating a gas flow of 8,000 scfm. The equipment cost of the Pennsylvania system was linearly scaled down to estimate the equipment cost to treat 1,500-scfm gas flow for the Centaur 40 turbine and 5,000-scfm gas flow for the Titan 130 turbine. This approach may result in costs that are lower than actual, as the cost of the siloxane removal system may not be linearly scalable. For example, based on Solar's information, the capital costs for the 1,500-, 3,000-, and 4,500-scfm siloxane removal systems are $335,000, $485,000, and $680,000, respectively.

As shown in the revised Table 7, the cost effectiveness ($/ton) for the first phase of the project, which includes one Titan and four Centaur turbines, remains about the same. However, the cost effectiveness for all 16 turbines has increased from $4,018 to $4,259 per ton.

Comment 4. Explain the rationale why the Mercury 50 (4.6 MW) with a 25 ppm NOx emissions was not selected for this project instead of the Centaur 40 (3.5 MW) with a 42 ppm NOx emissions and the Titan (15 MW) with a 72 ppm NOx emissions. It is our understanding that the Ultra Lean Premix (ULP) combustion system on the Mercury 50 has been modified to support landfill gas combustion thus reducing NOx emissions.

Response: The Mercury 50 was not selected because it is not proven on LFG yet. WM operates the largest fleet of LFG-fired turbines in the country, all of which are Solar Turbines. WM has a long history with Solar Turbines and has been following the Mercury 50 product through its development. The Mercury 50 has not operated on LFG as of yet. Solar tested the unit with diluted pipeline natural gas in the factory. There have been Mercury 50's sold for LFG applications; however, none are currently in operation. Once starting operations, it will take a considerable amount of time to evaluate the turbine's performance and operating costs. Multiple turbine applications have failed using LFG as fuel; the Solar Saturn was one of them. WM wants to install a turbine that is proven to operate on LFG.

Comment 5. Submit a BACT analysis including $/ton of NOx removed using the Solar Mercury 50 turbine without SCR installation and with/without siloxane removal system.

Response: See response to Comment 4. The Solar Mercury 50 turbine was made commercially available in 2004; however, there are no known installations of a Mercury 50 turbine operating on LFG anywhere in the U.S. Since there are none operating, actual operating and maintenance cost data are unavailable. As a result, a cost analysis to estimate $/ton of nitrogen oxide ($NO_x$) removal using the Mercury 50 turbine is not practical.

Comment 6. Appendix C and Attachment A of your response gave information about the NOx and CO Controls Cost Analysis for the Centaur and Titan turbines. In reviewing the information, we noticed that the vendor's quote for NOx is missing and that the CO vendor's quote information lists fuel as natural gas and oil instead of landfill gas. Please submit updated quotes for this project specifically.

Response: The original vendor quote for the SCR NO_x control system used in the WM Pennsylvania project is not available. The Pennsylvania Department of Environmental Protection was contacted; they stated that they do not have the original vendor quote. However, the SCR cost basis of $955,000 used in the WM Pennsylvania project (for Solar Centaur 40 turbine) can be supported by the following references:

1. The U.S. Environmental Protection Agency's (EPA's) Alternative Control Techniques Document used a SCR capital cost of $622,000 in 1990 dollars (Table 6-10, Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines, EPA-453/R-93-007) for a Solar Centaur T4500 turbine, which is similar to the Centaur 40. Using the consumer price index (CPI-U) (consumer price index for all urban consumers, published by the Bureau of Labor Statistics available at inflationdata.com), this price is equivalent to more than $1 million in 2009 dollars. SCR cost for Centaur 40 turbine used in the Okeechobee BACT analysis is $955,000.
2. Based on internet research, in the PSD permit application dated February 2002 for PG&E Gas Transmission's Compressor Station 4 in Sandpoint, Idaho (see Attachment C for reference), an equipment cost of $1.3 million has been used for the SCR system on a Solar Titan gas turbine. This cost is equivalent to $1.55 million in 2009 dollars (assuming the equipment cost of $1.3 million is in 2002 dollars). The SCR cost for the Solar Titan turbine used in the Okeechobee Landfill BACT analysis is $1.4 million, which is a scaled-up cost based on the $955,000 used in the WM Pennsylvania project. The above references support the estimated cost of SCR for Okeechobee.

The carbon monoxide (CO) oxidation catalyst control system cost from BASF Catalysts LLC was obtained in September 2008 for a Solar Titan 130 turbine, which is fired with natural gas and oil. Please note that a CO oxidation catalyst system has never been used on a turbine fired with LFG and the cost for such a system is not readily available. The oxidation catalyst system is a post-combustion control technology and its effectiveness (and therefore, cost) depends primarily on the exhaust gas characteristics. It should also be noted that apart from siloxane compounds, the characteristics of the turbine exhaust gas from LFG combustion are similar to those of natural gas firing. The effect of siloxane compounds in the exhaust gas has been considered in the cost analysis in the form of more frequent catalyst replacements. The basic equipment cost should be the same as that for the system for a natural gas-fired turbine.

In support of the oxidation catalyst system costs used in the Okeechobee Landfill BACT analysis, an EPA memo on Oxidation Catalyst Costs for New Stationary Combustion Turbines, dated December 30, 1999, is included as Attachment D. Based on Table 1 of the memo (page 6, Engelhard costs), the oxidation catalyst system (catalyst + frame) cost for the Centaur 40 turbine is $155,000 (exhaust flow of OLI Centaur 40 turbine is 41.8 pounds per second) in mid-1998 dollars, which is about $205,000 in 2009 dollars. Also based on the linear relationship between catalyst cost and exhaust flow rates provided in page 6 of the memo, the oxidation catalyst system for the Titan 130 turbine is $274,000 in mid-1998 dollars, which is $361,000 in 2009 dollars. Note that the oxidation catalyst system costs used in the Okeechobee Landfill BACT analysis for the Centaur 40 and Titan 130 turbines are $289,000 and $308,000, respectively.

Comment 7. **In all the cost effectiveness calculations that were submitted with your response the project contingency was based on 15% of the Direct Capital Cost (DCC) plus the Indirect Capital Cost (ICC). Please explain the rationale for using a high percentage of 15% when the EPA Cost Manual uses 3% contingency figure. Additionally, explain the reasons for using contingency based on DCC+ICC and not on Purchased Equipment Cost (PEC) as indicated in the manual.**

Response: The project contingency figure of 15 percent is based on Table 2.5, Chapter 2, Section 4 (NO_x Control) of the EPA Cost Control Manual. As explained in Section 2.3.1 of Chapter 2, Section 1, project contingencies are designed to cover unforeseen costs that may arise from possible redesign and modification of equipment, escalation increases in cost of equipment, increases in field labor costs, delays encountered in start-ups, etc. As shown in Table 2.5, the project contingency is applied on the sum of DCC and ICC.

Comment 8. **On April 22, 2009, the Department received an e-mail from Mr. Dave Thorley of your organization stating that the landfill will require 4 additional 3,000 standard cubic feet per minute (scfm) open flares along with 1 existing flare. The new flares will be required in conjunction with 1 Titan and 6 Centaur turbines in the first 7 years of operation after the permit issuance. The original application stated that 1 additional flare with 1 existing flare will be sufficient for the landfill. Please explain the need for additional flares if turbines are also being installed at the facility.**

Response: WM revised and re-submitted the air construction permit application in October 2008 to include the additional flares. WM wants to install the additional flares to maintain 100-percent backup capability in the event all of the turbines are shut down, to ensure continued compliance with New Source Performance Standards (NSPS) Subpart WWW and other regulatory requirements. All turbines may be shut down if the electric grid is shut down due to natural calamities such as hurricanes, etc. Total design LFG flow of the Okeechobee Landfill is 32,400 scfm and all 11 flares will be needed to destruct the total flow. Please note that the email from Mr. David Thorley was in response to a verbal request by FDEP from an April 2009 conference call. The conference call was requested by FDEP to discuss the project, when a specific request was made by FDEP for the installation plans for the next 7 years.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David a Buff

David Buff, P.E., Q.E.P.
Principal Engineer

Salahuddin Mohammad
Senior Project Engineer

SKM/DB/tlc

Enclosures

cc: D. Thorley, WM
S. Nunes, OLI

R060409_541.docx

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff, P.E.** Registration Number: **19011**	
2. Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**	
3. Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**	
4. Professional Engineer E-mail Address: **DBuff@golder.com**	

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒; if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff ______ 6/4/09 ______

Signature Date

(seal)

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

ATTACHMENT A

RESULTS OF OKEECHOBEE LANDFILL SILOXANE ANALYSIS

MAY 2008

CHAIN OF CUSTODY RECORD

AIR TECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130
City of Industry, CA 91748
626-964-4032 • Fax: 626-964-5832

Project Name: Okeechobee Siloxanes
Project #: 012-0100
P.O. #: 0001-2008

FOR LABORATORY USE ONLY

Method of Transport: Walk-in ☐ Courier ☐ UPS ☐ FedEx ☒ ATL ☐

Sample Condition Upon Receipt:
1. CHILLED Y ☐ N ☒
2. HEADSPACE (VOA) Y ☐ N ☒
3. CONTAINER INTACT Y ☒ N ☐
4. SEALED Y ☐ N ☒
5. # OF SPLS MATCH COC Y ☐ N ☐
6. PRESERVED Y ☐ N ☒

Company:
Contact: Kris Carlson
Address: 400 West Windsor Street
City: Monroe State: NC Zip Code: 28112
TEL: (704) 506 7312
FAX: ( )

	Date	Time	Received by: (Signature and Printed Name)	Date	Time
Sampled/Relinquished by: (Signature and Printed Name) Jeff McNabb Jeff McNabb	5/2/08	1614			
Relinquished by: (Signature and Printed Name) FEDEX	5/6/08	1115	Joann DelaOssa Joann DelaOssa	5/6/08	1115
Relinquished by: (Signature and Printed Name)					

I hereby authorize ATL to perform the work indicated below:
Jeff McNabb 5/2/08
Project Mgr/Submitter (Print Name) Date
Jeff McNabb
Signature

Send Report To:
Attn: Kris Carlson
Co: Carlson Environmental
Address: 400 W Windsor St
City: Monroe State: NC Zip: 28112

Bill To:
Attn: Kris Carlson
Co: Carlson Environmental
Address: 400 W. Windsor St
City: Monroe State: NC Zip: 28112

Special Instructions/Comments:
Canister #3621 did not have any negative pressure when delivered. sample LFG#2

Unless otherwise requested, all samples will be disposed 14 days after reporting or at Lab's discretion.

Sample Archive/Disposal:
☐ Laboratory Standard
☐ Other
☐ Return To:

* $10.00 FEE PER HAZARDOUS SAMPLE DISPOSAL.

Circle or Add Analysis(es) Requested — CIRCLE APPROPRIATE MATRIX

DELIVERABLES: EDD ☐ LEVEL III ☐ LEVEL IV ☐

LAB USE ONLY Lab No.	Sample Description Sample I.D.	Date	Time	T03 Gas / BTEX / MTBE	T03 Hexane	T03 Carbon Chain	TO14A VOCs	TO15 VOCs Std or Low Level	15/16 Sulfur Comp Std/Low Level	15/16 H_2S Std or Low Level	Fixed Gas D1946 or 3C	25C/3C TNMOC	25.1 TGNMHC	D1945 Natural Gas	RSK 175 Dissolved Gas	Siloxanes	AIR • VAPOR	INDOOR AIR	LANDFILL GAS	WATER	SOLID • SOIL	OIL • SOLVENT • LIQUID	OTHER	TAT	Container(s) #	Container(s) Type	PRESERVATION	REMARKS
—	~~LFG #2~~ VOID *	5/2	1345													~~X~~ VOID			X						1	C	N	3621
A805005-01	LFG #1	5/2	1330													X			X						1	C	N	1344
	*Do not analyze per K. Carlson	5/6/08	1325																									

• TAT starts 8 a.m. following day if samples received after 5 p.m.

TAT: A= Overnight ≤ 24 hr B= Emergency Next workday C= Critical 2 Workdays D= Urgent 3 Workdays E= Routine 7 Workdays

Preservatives: H=Hcl N=None

Container Types: B=Tedlar Bag C=Canister V=VOA O= Other

DISTRIBUTION: White with report, Yellow to folder, Pink to submitter.

LCS/LCSD Recovery and RPD Summary Report

QC Batch #: 080517MS2A1
Matrix: Air

EPA Method TO-14/TO-15

Lab No:	Method Blank		LCS		LCSD						
Date Analyzed:	05/17/08		05/17/08		05/17/08						
Data File ID:	17MAY009.D		17MAY006.D		17MAY007.D						
Analyst Initials:	VM		VM		VM						
Dilution Factor:	0.2		1.0		1.0			Limits			
ANALYTE	Result ppbv	Spike Amount	Result ppbv	% Rec	Result ppbv	% Rec	RPD	Low %Rec	High %Rec	Max. RPD	Pass/ Fail
1,1-Dichloroethene	0.0	10.0	9.8	98	10.1	101	2.6	70	130	30	Pass
Methylene Chloride	0.0	10.0	9.7	97	10.1	101	3.5	70	130	30	Pass
Trichloroethene	0.0	10.0	9.9	99	9.8	98	0.4	70	130	30	Pass
Toluene	0.0	10.0	9.3	93	9.4	94	0.6	70	130	30	Pass
1,1,2,2-Tetrachloroethane	0.0	10.0	7.9	79	8.0	80	2.1	70	130	30	Pass

RPD = Relative Percent Difference

Reviewed/Approved By: [signature] Date: 5-19-08

Mark Johnson
Operations Manager

The cover letter is an integral part of this analytical report

Client: Carlson Environmental
Attn: Kris Carlson

Client's Project: Okeechobee Siloxanes
Date Received: 05/06/08
Matrix: Air
Units: ppbv

EPA Method TO15 (Siloxanes)

Lab No:	A8050605-01				
Client Sample I.D.:	LFG#1				
Date Sampled:	05/02/08				
Date Analyzed:	05/17/08				
QC Batch No:	080517MS2A1				
Analyst Initials:	VM				
Dilution Factor:	87				

ANALYTE	PQL	Result	RL								
Hexamethyldisiloxane	10	ND	870								
Hexamethylcyclotrisiloxane	10	ND	870								
Octamethyltrisiloxane	10	ND	870								
Octamethylcyclotetrasiloxane	10	1,700	870								
Decamethyltetrasiloxane	10	ND	870								
Decamethylcyclopentasiloxane	50	ND	4,400								
Dodecamethylpentasiloxane	200	ND	17,000								

PQL = Practical Quantitation Limit
ND= Not Detected (below RL)
RL = PQL X Dilution Factor

Reviewed/Approved By: Mark Johnson

Mark Johnson
Operations Manager

Date 5-19-08

The cover letter is an integral part of this analytical report

AirTECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130 ♦ City of Industry, CA 91748 ♦ Ph: (626) 964-4032 ♦ Fx: (626) 964-5832

ATTACHMENT B

REVISED COST EFFECTIVENESS CALCULATIONS FOR NO_X AND CO CONTROL SCENARIOS

TABLE 1a
CAPITAL AND ANNUAL COSTS FOR SILOXANE REMOVAL SYSTEM FOR THE TITAN 130 TURBINE

Cost Items	Cost Factors	Siloxane Removal System Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Siloxane Removal System	Vendor Quote [(a)]	175,000
Auxiliary Equipment (control panel, etc.)	5% of equipment cost, estimated	8,750
(2) Freight	5% of equipment cost, CCM Chapter 2	8,750
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		192,500
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	15,400
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	26,950
(c) Electrical	16% of TEC, Solar Estimate	30,800
(d) Piping	16% of TEC, Solar Estimate	30,800
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	1,925
Total DCC:		298,375
INDIRECT CAPITAL COSTS (ICC): [(b)]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	9,625
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	19,250
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	9,625
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	5,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	1,925
(c) Spare Parts	Engineering Estimate	5,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	19,250
Total ICC:		69,675
PROJECT CONTINGENCY	15% of (DCC+ICC)	55,208
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	423,258
DIRECT OPERATING COSTS (DOC): [(b)]		
(1) Operating Labor		
Operator	1/2 hr/shift, $30/hr, 8760 hrs/yr	16,425
Supervisor	15% of operator cost	2,464
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	6,349
(3) Siloxane System Energy Requirement	6 in ΔP (estimated same as SCR), 48 MW/year, $60/MW	2,880
(3) Siloxane Removal Media Replacement	Vendor estimate, 35% of Equipment, Media Life 1/2 year	122,500
(4) Siloxane System Calibration	Solar Information - about $500K for 5 years	100,000
Total DOC:		250,618
INDIRECT OPERATING COSTS (IOC): [(b)]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	15,143
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	4,233
(3) Insurance	1% of total capital investment, CCM Chapter 2	4,233
(4) Administration	2% of total capital investment, CCM Chapter 2	8,465
Total IOC:	(1) + (2) + (3) + (4)	32,073
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	39,956
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	322,646

Notes:
[(a)] Cost estimates from similar systems considered for Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility Application for Plan Approval, No. 009-00007, September 2008. WM Pennsylvania cost = $280,000 (for 8,000 scfm). Scaled cost for Titan 130 (5,000 scfm) = $280,000 x 5,000/8,000 = $175,000.
[(b)] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 1b
CAPITAL AND ANNUAL COSTS FOR SILOXANE REMOVAL SYSTEM FOR THE CENTAUR 40 TURBINE

Cost Items	Cost Factors	Siloxane Removal System Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Siloxane Removal System	Vendor Quote [a]	52,500
Auxiliary Equipment (control panel, etc.)	5% of equipment cost, estimated	2,625
(2) Freight	5% of equipment cost, CCM Chapter 2	2,625
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		57,750
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	4,620
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	8,085
(c) Electrical	16% of TEC, Solar Estimate	9,240
(d) Piping	16% of TEC, Solar Estimate	9,240
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	578
Total DCC:		89,513
INDIRECT CAPITAL COSTS (ICC): [b]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	2,888
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	5,775
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	2,888
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	5,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	578
(c) Spare Parts	Engineering Estimate	5,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	5,775
Total ICC:		27,903
PROJECT CONTINGENCY	15% of (DCC+ICC)	17,612
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	135,027
DIRECT OPERATING COSTS (DOC): [b]		
(1) Operating Labor		
Operator	1/2 hr/shift, $30/hr, 8760 hrs/yr	16,425
Supervisor	15% of operator cost	2,464
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	2,025
(3) Siloxane System Energy Requirement	6 in ΔP (estimated same as SCR), 14 MW/year, $60/MW	840
(3) Siloxane Removal Media Replacement	Vendor estimate, 35% of Equipment, Media Life 1/2 year	36,750
(4) Siloxane System Calibration	Solar Information - about $250K for 5 years	50,000
Total DOC:		108,504
INDIRECT OPERATING COSTS (IOC): [b]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	12,548
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	1,350
(3) Insurance	1% of total capital investment, CCM Chapter 2	1,350
(4) Administration	2% of total capital investment, CCM Chapter 2	2,701
Total IOC:	(1) + (2) + (3) + (4)	17,950
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	12,747
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	139,200

Notes:
[a] Cost estimates from similar systems considered for Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility Application for Plan Approval, No. 009-00007, September 2008. WM Pennsylvania cost = $280,000 (for 8,000 scfm). Scaled cost for Centaur 40 (1,500 scfm) = $280,000 x 1,500/8,000 = $52,500.
[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 7 (Revision 6/4/09)
COST EFFECTIVENESS CALCULATION FOR NOx AND CO CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY

Cost Items	Comments/Reference	Value	NOx + CO Control Scenarios: 1 Titan 130	1 Centaur 40	1 Titan 130 + 4 Centaur 40	1 Titan 130 + 15 Centaur 40
Annualized Cost for Siloxane System Titan 130 ($/yr)	Table 1a	322,646	322,646	--	322,646	322,646
Annualized Cost for Siloxane System Centaur 40 ($/yr)	Table 1b	139,200	--	139,200	556,801	2,088,005
Annualized Cost of SCR System for Titan 130 ($/yr)	Table 2	1,165,516	1,165,516	--	1,165,516	1,165,516
Annualized Cost of SCR System for Centaur 40 ($/yr)	Table 3	777,761	--	777,761	3,111,044	11,666,415
Annualized Cost of CO Catalyst for Titan 130 ($/yr)	Table 4	402,702	402,702	--	402,702	402,702
Annualized Cost of CO Catalyst for Centaur 40 ($/yr)	Table 5	370,375	--	370,375	1,481,500	5,555,625
Total Annualized Cost (AC)($/yr):			1,890,864	1,287,336	7,040,209	21,200,909
Titan 130 Baseline NOx Emissions (TPY) :	72 ppm, Emission Guarantee	203.0	203.0	--	203.0	203.0
Centaur 40 Baseline NOx Emissions (TPY) :	42 ppm, Emission Guarantee	35.0	--	35.0	140.0	525.0
Titan 130 Baseline CO Emissions (TPY) :	100 ppm, Emission Guarantee	858.0	858.0	--	858.0	858.0
Centaur 40 Baseline CO Emissions (TPY) :	250 ppm, Emission Guarantee	263.0	--	263.0	1,052.0	3,945.0
Controlled NOx Emissions (TPY) :	90% Control		20.3	3.5	34.3	72.8
Controlled CO Emissions (TPY) :	90% Control		85.8	26.3	191.0	480.3
Reduction in NOx Emissions (TPY):	Baseline - Controlled		182.7	31.5	308.7	655.2
Reduction in CO Emissions (TPY):	Baseline - Controlled		772.2	236.7	1,719.0	4,322.7
Total Reduction in Emissions (TPY):			955	268	2,028	4,978
Cost Effectiveness (AC/Total Reduction)	$ per ton Removed		1,980	4,800	3,472	4,259

203 ppm
x .90
182.7 ppm

35 ppm
x0.90
31.5 ppm

ATTACHMENT C

PSD PERMIT APPLICATION FOR PG&E GAS TRANSMISSION COMPRESSOR STATION 4

PG&E National Energy Group
Gas Transmission Northwest

PSD PERMIT APPLICATION
PG&E GAS TRANSMISSION NORTHWEST
COMPRESSOR STATION 4 - UNIT A
SANDPOINT, IDAHO

REVISED IMPACTS MODELING FOR NO_X

FEBRUARY 2002

PREPARED FOR
PG&E GAS TRANSMISSION, NORTHWEST CORPORATION
1400 S.W. FIFTH AVENUE, SUITE 900
PORTLAND, OR 97201

BY
MEYER GROUP
2031 DORIS AVENUE
WALNUT CREEK, CA 94596

APPENDIX C

BACT ANALYSIS

Technological Considerations of SCR Controls in Pipeline Applications

At this time, the only natural gas compression facility which has been required to install SCR as BACT is the Southern California Gas Company (SoCalGas) compressor station at Wheeler Ridge in the southern San Joaquin Valley. The facility, which called for three 5,650 horsepower Solar Centaur Type H gas turbines, was permitted in 1991 by the San Joaquin Valley Unified APCD limiting NO_x to 5 ppmv at steady state conditions and 8 ppmv at non-steady state conditions. The turbines were placed in service in October 1993, utilizing Norton high temperature SCR systems. An initial source test satisfied the permit condition at steady state. As a result, the SJV APCD concluded that the technology was "achieved in practice" and posted the BACT determination on the California Air Pollution Control Officers Association (CAPCOA) BACT Clearinghouse database. (SJV APCD, 6/25/96)

The first variance petition for relief from the permitted NO_x limit was submitted in December 1993 while the manufacturer attempted to resolve SCR system failure problems. Seven additional petitions for variances were filed during the ensuing three years. In September 1996, SoCalGas filed an Application for Authority to Construct Emission Control Modifications requesting approval to remove the SCR systems and retrofit Solar's SoLoNOx™ lean pre-mix NO_x control system.

Following its analysis, in February 1997 the San Joaquin Valley Unified APCD issued its Notice of Preliminary Decision for the Proposed Issuance of an Authority to Construct. In January *1997, this determination was posted on the CARB BACT database with a statement that the high* temperature SCR system was deemed not technologically feasible. It was also posted on the USEPA RACT-BACT-LAER Clearinghouse database (as LAER) with a similar statement. None-the-less, the USEPA Region 9 intervened, over-ruling the APCD.

USEPA Region 9 required that SoCalGas replace the SCR system with one by a different vendor. The replacement system was supplied by Engelhard. The permit limits for NO_x were increased to 8 ppmv at steady state conditions and 12 ppmv at non-steady state conditions, while ammonia slip continues to be limited to 20 ppmv. This system operated successfully for about six months, at which time it began experiencing catalyst failure. With the catalyst deteriorating, it is necessary to increase the ammonia injection rate, with an increase in ammonia slip. While to date, the units have been in compliance with permit limits, they are now close to the limit for ammonia slip. It is expected that catalyst replacement will be necessary after about 18 to 24 months of operation, significantly less than the guaranteed three years. Due to the current high demand for the high temperature catalyst systems, it may not be possible to get all three systems replaced in time to avoid permit violations.

A spokesman for SoCalGas stated that while progress is being made, he believes that one or two more design cycles may be needed before they can be successful for pipeline applications. To achieve the original limit of 5 ppmv for NO_x, he believes catalyst replacement would be required about twice a year.

HIGH TEMPERATURE SCR COST EFFECTIVENESS
REDUCE NOx 79% ON SOLAR TITAN GAS TURBINE

Component		Basis	Cost	Source
Capital Costs :				
Purchased Equipment Cost (PE):				
SCR System (design + media + exhaust duct work)			$1,092,068	Note 1
NH3 leak detections sys & sensors			$51,000	Note 1
Exhaust air dilution blowers (i.e., gas coolers to < 900 deg F)			$11,500	Note 1
Catalyst insulation (i.e., system protection for > 900 deg F exhaust temp)			$26,000	Note 1
CEM			$131,400	USEPA-CEMS
Freight @		5.0%	$61,173	OAQPA
Taxes on Materials @		5.0%	$68,657	Idaho
Total PE Cost			$1,441,798	
Installation Cost:				
Direct Cost @ 30% PE			$432,540	OAQPA, USDOE
Indirect Cost @ 31% PE			$446,956	OAQPA, USDOE
Taxes on Labor @		0.0%	$0	Idaho
Total Installation Cost:			$879,497	
Total Capital Cost			$2,321,296	
Annual Operating Costs:				
CEM Maintenance			$39,600	USEPA-CEMS
O&M Labor incl. Overheads and Supv. @ 3 hr./day,		$45.79 /hour	$50,140	USDOE, Note 2
Maintenance Materials @ 50% of O&M Labor			$25,070	USDOE
Annual Fuel Use		949967 MMBtu		MFR
Fuel Penalty (0.5% performance loss) @		$4.00 /MMBtu	$18,999	USDOE, Note 2
Injection Skid 7.5 KW Blower & 5 KW Pump @		$0.06 /KWH	$6,570	USDOE, Note 2
Ammonia (NH3 = NOx * 17/46 + 10 ppmv avg. slip)		8.0 lb/hr		USDOE, Note 2
	@	$550 /ton	$19,222	
Catalyst Replacement (3 year life)			$40,714	USDOE, Note 3
Catalyst Disposal, % of Catalyst Replacement Cost		3.75%	$1,221	USDOE
Administrative Costs @ 2% of Total Capital Cost		2.0%	$46,426	OAQPA, USDOE
Taxes, % of Total Capital Cost		0.9%	$20,195	Idaho
Insurance, % of Total Capital Cost		1.0%	$23,213	OAQPA, USDOE
Total Annual Operating Cost			$291,371	
Total Annualized Cost:				
Annualized Capital Cost - 15 year life @ 10%, CRF=		0.1315	$305,189	OAQPA, USDOE
Total Annual Operating Cost			$291,371	
Total Annualized Cost			$596,561	

NOx Emissions, Maximum Potential as Guaranteed:				Note 4
Uncontrolled NOx Emissions, tons/year			84.73	Appendix A
Controlled NOx Emissions, tons/year, @	79%	Effectiv	17.79	Note 5
NOx Emission Reduction, tons/year			66.94	
Total Annualized Cost			$596,561	Note 4
SCR Cost Effectiveness, $/ton			$8,912	Note 4
NOx Emissions, Expected Average Over Range:				Note 6
Uncontrolled NOx Emissions, tons/year			66.79	Appendix A
Controlled NOx Emissions, tons/year, @	79%	Effectiv	14.03	Note 5
NOx Emission Reduction, tons/year			52.76	
Total Annualized Cost			$592,491	Note 6
SCR Cost Effectiveness, $/ton			$11,229	Note 6
NOx Emissions, Expected Average Over Range, @ 90% Hours Operated:				Notes 6 & 7
Uncontrolled NOx Emissions, tons/year			60.11	Appendix A
Controlled NOx Emissions, tons/year, @	79%	Effectiv	12.62	Note 5
NOx Emission Reduction, tons/year			47.49	
Total Annualized Cost			$580,491	Notes 6 & 7
SCR Cost Effectiveness, $/ton			$12,224	Notes 6 & 7

References:

California Air Resources Board, Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines, May 18, 1992 (CARB)

Gas Turbine World 2000-2001 Catalog (GTW)

Manufacturer's data for the proposed installation (MFR)

Southern California Gas Company, personal communication with Jack Brunton, March 29, 2001 (SoCalGas)

U.S. Department of Energy, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines' November 5, 1999 (USDOE)

U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Cost Control Manual, Fifth Edition (OAQPS)

U.S. Environmental Protection Agency's Continuous Emission Monitoring System Cost Model Version 3.0 (USEPA-CEMS)

Notes:

General Note:
The overall structure of the cost estimate is based upon the cost analysis in USDOE.
The assumptions in USDOE were used unless better data were available.

1. USDOE cost data for high temperature SCR (Table A-6) incorporate cost quotes from Engelhard. However, actual costs tend to be significantly higher as the quoted systems are not complete. PG&E National Energy Group has "as constructed" data for the application of 3 high-temperature SCR

systems on simple-cycle gas turbines of 16.5MWe, nominal output for a guaranteed NOx outlet concentration of 9ppm. Based on that experience, actual cost data were employed after adjustment for turbine output. These higher costs are consistent with those reported in CARB.

2. Cost basis assumptions from USDOE, labor rates inclusive of overheads and energy costs from PG&E GTN

3. Catalyst life of 3 years is based upon manufacturer's guarantee and the experience of SoCalGas where actual life has been significantly less than 3 years. PG&E National Energy Group has secured vendor guarantees for SCR systems applied to electric generation ranging from 2200 hours of use and/or 37 months after the initial start-up date (even if not operated). Actual guarantees for dormant catalyst life are consistent with the 3 year life assumption for catalyst application on the pipeline system. Therefore, a 3-year replacement life represents the "best-case" cost scenario, where media life of 2200 hours of use (fired hours) would represent the "worst-case" cost scenario.
Actual life-cycle cost has yet to be obtained in practice.
Catalyst replacement cost is based on the formula and cost provided to PG&E NEG by Engelhard, 15 cu ft catalyst/MW @ $500/cu ft.

4. Maximum potential to emit, based upon highest emission rate as guaranteed by manufacturer in the normal lean pre-mix operating range and between 0 deg. And 100 deg. F.
Manufacturer's guarantee is 25 ppmv NOx between 94% and 100% gas generator speed (NGG) and 42 ppmv NOx between 90% and 94% NGG. (90% NGG is equivalent to approximately 35% to 50% available horsepower while 94% NGG is equivalent to approximately 60% to 75% available horsepower depending on ambient temperature. Worst case for NOx as guaranteed is at 42 ppmv and 94% NGG.
See emissions calculations in Appendix A.

5. Both USDOE and CARB assume uncontrolled emissions of 42 ppmv and a 79% removal efficiency to arrive at 9 ppmv as the controlled emission rate. A 79% removal efficiency has therefore been assumed.

6. Under normal operation, the unit will range between 100% and 90% NGG and the NOx emission concentration from 25 ppmv to 42 ppmv. Expected NOx emissions are the average of the manufacturer's guaranteed emissions over the 90% to 94% NGG range @ 42 ppmv and the 94% to 100% NGG range @ 25 ppmv. See emissions calculations in Appendix A.
Operating cost affected by emissions rate (ammonia use) has been reduced proportionately.

7. The above calculations assume that the unit is operating 100% of the time.
During year 2000, operating records indicate that system wide, the average unit operated 72% of the time.
For purposes of this analysis, it is assumed that the unit will operate on average 90% of the time.
Emissions and all variable operating expenses have been reduced in proportion to operating hours.

Catalyst Replacement Cost:	
Rating, MW	13.5
Cu. Ft. catalyst/MW	15
Catalyst cost/cu. Ft.	$500
Total cost of replacement catalyst	$101,250
Life, years	3
Capital Recovery Factor (CRF) @ 10% Interest	0.4021
Amortized Cost of replacement catalyst	$40,714
Disposal cost/cu. Ft.	$15
Total cost of catalyst disposal	$3,038
Amortized Cost of catalyst disposal	$1,221

ATTACHMENT D

1999 EPA MEMO ON OXIDATION CATALYST COSTS FOR NEW STATIONARY COMBUSTION TURBINES

December 30, 1999

MEMORANDUM

FROM: Sims Roy
Emission Standards Division
Combustion Group

TO: Docket A-95-51

SUBJECT: Oxidation Catalyst Costs for New Stationary Combustion Turbines

The purpose of this memorandum is to summarize information on the cost of oxidation catalyst control for new stationary combustion turbines. Catalyst vendors provided information to EPA on the costs of acquiring, installing, and operating oxidation catalysts for HAP reduction for various turbines; these costs were applied to seven model turbines ranging in size from 1.13 megawatts (MW) to 170 MW. The total capital and annual costs were then estimated using methodologies from the OAQPS Control Cost Manual. A detailed description of the cost methodologies is given in Attachment A.

The total capital and annual costs for each model turbine are presented in the table below. The annual costs were estimated for both the guaranteed life of the catalyst (3 years) and the "typical" life of the catalyst (6 years).

Model Turbine	**Total Capital Cost ($)**[a]	**Total Annual Cost ($)**	
		3-Year Costs	**6-Year Costs**
GE PG 7121EA, 85.4 MW	3,272,268	1,157,833	956,998
GE PG 7231FA, 170 MW	4,753,816	1,673,902	1,382,131
GE PG 6561B, 39.6 MW	1,736,369	631,334	524,762
GE LM25000, 27 MW	1,103,989	415,818	348,060
Solar Centaur 40, 3.5 MW	677,525	268,560	226,974
Solar Mars T12000, 9 MW	485,196	202,673	172,898

Model Turbine	Total Capital Cost ($)[a]	Total Annual Cost ($)	
		3-Year Costs	6-Year Costs
Solar Saturn T1500, 1.13 MW	364,154	161,431	139,086

[a]Costs reflect mid-1998 figures.

Attachment A

MEMORANDUM

DATE: May 14, 1999

SUBJECT: Stationary Combustion Turbines Control Options Cost Information Summary

The purpose of this memorandum is to summarize the cost information that has been received for control options to date. This information will be used with model turbines developed for the Stationary Combustion Turbines source category as part of estimating the national impacts of viable regulatory options.

Background

In support of MACT determinations for new and existing combustion turbines, a set of model turbines has been developed that can be used to evaluate the national impact of control options being considered. The following approach will be used to determine national impacts:

1) Develop model turbines
2) Estimate control costs for each control option for each model turbine
3) Estimate emission reduction for each control option for each model turbine
4) Relate model turbines to turbines in the EPA Inventory Database for Stationary Combustion Turbines
5) Extrapolate from the inventory database population to the national population
6) Determine regulatory options
7) Estimate economic impacts for each regulatory option

Cost information has been received that will be used to estimate the control costs for each option being considered on a model turbine basis. This memorandum reflects the cost information that has been received to date. Any additional cost data received from vendors will be incorporated, as necessary, at a later time.

Cost Information

The methodology in the OAQPS Control Cost Manual will be used to determine the annual cost of control technologies. The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. Direct cost inputs are required for certain key elements, such as the capital costs of the control device. Other costs, such as installation, are then estimated based on percentages of the direct cost inputs.

In the OAQPS methodology, five cost categories are used to describe the annual cost of a control device. These are as follows:

1) Purchased Equipment Costs (PEC), which include the capital cost of the control device and auxiliary equipment, instrumentation, sales tax, and freight;
2) Direct Costs for Installation (DCI), which are the construction-related costs associated with installing the catalyst;
3) Indirect Costs for Installation (ICI), which include expenses related to engineering and start-up;
4) Direct Annual Costs (DAC), which include annual increases in operating and maintenance costs due to the addition of the control device; and
5) Indirect Annual Costs (IAC), which are the annualized cost of the control device system and the costs due to tax, overhead, insurance, and administrative burdens.

The cost that will be used in model turbine analyses is the total annual cost, which is the sum of the Direct Annual Costs (DAC) and the Indirect Annual Costs (IAC). The following information reflects the capital and operating costs that have thus far been obtained from vendors on the control technologies under consideration. Cost estimates are in 1998 dollars unless otherwise indicated.

Catalytic Systems

- **CO Oxidation Catalyst Systems**

Several vendors were contacted for capital and operating-related costs for CO oxidation catalysts. The following general information was requested:

1) What is the cost range of the catalyst material?
2) Would this number change in considering three flow ranges, i.e., small, medium, and large, starting with a minimum flow of 100 Mlbs/hour and ending with ~3000 Mlbs/hour?
3) What operating temperature ranges with respect to high CO removal/oxidation are recommended?
4) What happens during start-up and low load operation? What would be the result of a prolonged operation with gas turbine exhaust temperatures of ~500°F?
5) What are recommended space requirements and would flow straightening equipment be necessary?
6) What is the cost of reactor housing, required steel support, foundation needs and ductwork?

Cost information for CO oxidation catalysts was received from Engelhard, a catalyst vendor, and Nooter/Eriksen, a heat recovery steam generator (HRSG) vendor. Generalized estimates were also received for costs associated with increased pressure drops and retrofit applications. The information received is summarized below.

Engelhard

Engelhard CO catalysts are manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. The individual modules are installed within the support frame. The modules typically weigh approximately 50 lb. each. The number of modules required increases with gas flow. Substrate depth and corrugation patterns can vary depending on project requirements. Typically, performance is warranted for 2 to 3 years with an expected life of 5 to 7 years. Typical guarantees are based on a ±15% gas velocity profile distribution. The catalyst is not a hazardous material and in most cases can be recycled to reclaim the precious metals. Engelhard can also provide catalysts on a ceramic substrate.

Engelhard provided costs for a simple cycle turbine installation (catalyst at turbine discharge temperature) for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec. These 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). The costs provided include the cost of an internal support frame and catalyst modules only. These costs are shown in Table 1.

Table 1. CO Oxidation Catalyst Costs Provided by Engelhard

Turbine Exhaust Flow (lb/sec)	Turbine Exhaust Temperature (F)	Required Inside Liner Cross Section (sq. ft.)	Estimated Cost Catalyst + Frame[a]
28.4	1050	67	$140,000
41.0	819	90	$155,000
318.0	990	716	$600,000
658.0	998	1522	$1,100,000
812.0	975	1881	$1,450,000
984.0	1116	2388	$1,550,000

[a]Costs reflect mid-1998 figures.

Regression analysis on the cost data in Table 1 suggest 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). Therefore, in estimating catalyst costs for the model turbines, the capital cost of a CO catalyst and frame for a given exhaust flow rate can be calculated using this relationship.

Information was also provided by Engelhard in response to the questions posed concerning operating issues associated with operating CO oxidation catalysts. A graph showing that lower performance/conversion accompanies lower temperatures was supplied. Typically, the catalysts Engelhard provides for gas turbine installations are supplied to a Heat Recovery Steam Generator (HRSG) supplier. The CO catalyst is generally installed within a HRSG. Supplemental firing usually is performed to increase steam production and thus gas temperatures at the catalyst and conversion requirements can be impacted by supplemental firing. Engelhard typically meets given HRSG cross section and maximum specified pressure drop allowed.

Engelhard indicated that reasonable retrofit estimates could not be provided due to many site-specific requirements. Their scope includes an internal support frame and catalyst modules which are installed inside the HRSG housing and as such, issues including flow straightening, housing, foundations, etc., are handled by other vendors.

<u>Nooter/Eriksen</u>

Nooter/Eriksen has become virtually sole sourced to Engelhard's Camet catalyst for their oxidation catalysts and provided an estimate of $650,000 for a 60% CO oxidation catalyst (no support frame or casing) in a GE Frame 7F installation (3,500,000 lb/hr with a catalyst temperature of approximately 900°F). They indicated that the price variation is approximately linear with mass flow and would approximately double to achieve 90% conversion. They were unable to comment on HAP destruction. The CO catalyst is occasionally required to also oxidize volatile organic compounds (VOCs), in which cases the catalyst is generally effective with unsaturated VOCs only and the catalyst must be located in a higher temperature window.

For high CO oxidation (90%), a temperature range of approximately 700°F to 760°F is preferred. If VOC oxidation is also required, the temperature window generally increases to 950°F to 1,100°F. It was indicated that prolonged operation at 500°F will not generally harm an oxidation catalyst unless the combustion turbine is operating with a high soot concentration in the exhaust, although there is little oxidation activity at 500°F.

Concerning retrofit issues, it was indicated that new ductwork to redirect flow outside of the original flow path would probably have the effect of obsoleting the greater portion of the HRSG. Most catalyst system guarantees are based on even flow distribution (typically ±15% RMS of the mean) entering the catalyst. If flow distribution devices were not originally included with the HRSG, this could increase the overall HRSG pressure loss by 0.5" to 1.0" W.C.

Generalized Pressure Drop Costs

Installation of a catalyst system will increase the pressure drop experienced by the turbine exhaust flow. The additional pressure drop results in a decrease in turbine power output. If the turbine is not operating at full load, additional fuel can be burned to make up for the lost power (fuel penalty). The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a percentage heat rate increase per inch of pressure drop due to the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. An equation for the fuel penalty was provided by the Gas Research Institute, which is based on an anticipated heat rate increase of 0.105% per inch pressure drop, $2/MMBtu for natural gas, and a 9,000 Btu/hp-hr baseline.

If the unit is operating at full load, the loss in power cannot be regained by burning additional fuel and will result in a loss in electricity sales. The costs associated with the power loss depend on site-specific factors, such as value of lost product or capital and annual costs for equipment required to make up for the power loss. Information on the loss in annual sales at different selling prices for electrical power was provided to EPA by Dow Chemical Company. For a GE Frame 7 turbine, the annual cost (lost sales) per inch of water pressure drop may be estimated using the following relationship: Annual Cost ($/inch) = 1,160*Power Value ($/Mwh) + 100.

Generalized Retrofit Costs

Estimates for retrofit costs were provided to EPA by Dow Chemical Company. 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. Estimates were provided for retrofit costs for adding a catalyst system to an ABB Type 11 turbine (gas flow rate = 580 lb/sec). The retrofit costs totaled about $800,000, which included $100,000 for ductwork. The cost of down time must also be estimated. It is difficult to extrapolate from the costs provided for this unit since the complexity and cost associated with retrofit installations varies so much by site.

- **Other Catalytic Systems**

Cost information in the form of comparisons to SCR systems for NOX control were received for SCONOx and XONON. More detailed cost information is needed from each vendor before an accurate assessment can be made concerning the cost of using these systems in conjunction with the model turbines. The information provided on these two systems is summarized below.

SCONOx™

Cost information for SCONOx was submitted by Goal Line Environmental Technologies LLC. The information consisted of a cost comparison model between SCONOx and SCR (selective catalytic reduction). The comparison is difficult to use for HAPs since it was based on NOX control and therefore takes into account cost issues concerning ammonia use in the SCR system. The lifetime cost (10 years) for the reduction of NOX from 20 ppm to 2.5 ppm for a typical 270 MW plant was estimated as $12,970,970 for the SCONOx system and $17,882,560 for an SCR system. This analysis would need to be significantly adapted to be used constructively in model turbine cost analyses.

XONON

A cost comparison of the XONON system was provided by Catalytica Combustion Systems. The comparison consisted of estimates for DLN (dry low NOX), DLN + SCR (selective catalytic reduction), and XONON for controlling NOX from two different turbine models. As with the SCONOx information, the use of ammonia is a cost consideration that needs to be excluded when considering the cost of the XONON system.

Lean pre-mix (LPM) Combustors

Cost information for lean pre-mix combustors was taken from the "Alternative Control Techniques Document -- NOX Emissions from Stationary Gas Turbines" (ACT). The incremental capital costs for LPM units relative to diffusion flame units are provided for eight turbines in the ACT. A regression formula was developed where the incremental capital cost is a function of turbine rating (MW). This relationship is as follows:

$$\text{Incremental capital cost (1990\$)} = 21454.3 * \text{MW} + 408431;\ r^2 = 0.981$$

It is not expected that the maintenance requirements for an LPM unit will be different than for a standard design; therefore, the incremental capital cost is the only cost to be considered in calculating annual costs. According to the ACT, retrofit costs are 40 to 60 percent greater than new installation costs.

meeting august 20

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