5. ENFORCEMENT OF ENVIRONMENTAL LAWS

EPA enforcement can be avoided by always complying with environmental laws and seeking constantly to keep the environment clean. GPA is involved in the community and the environment of Guam in a way that preserves and protects the people and environment so that no EPA enforcement is necessary. It is important to GPA to keep the lines of communication open and active.

Region 9 of US EPA is the regional office in San Francisco which covers activities of the agency through the Pacific Islands Program office. Region 9 has been supportive and appreciative of the GPA efforts to import low sulfur diesel fuel to Guam. The Office also is taking a keen interest in SO2 non-attainment situation, which it would like to resolve.

Region 9 is a significant supporter of Green House Gas emission reductions, pollution prevention and sustainability initiatives. Expect support for any GPA initiatives in these areas.

6. RECOMMENDATIONS

GPA's Environmental Strategic Planning Team recommends the following initiatives to be able to provide safe, reliable, and responsive energy services in an environmentally sensitive and responsible manner:

Initiative 1: Compliance with current and upcoming Environmental Regulations should be included in planning for GPA's generation, transmission and distribution resources, as well as energy services. This initiative has commenced with the inclusion of Environmental Compliance in GPA's Integrated Resource Plan.

Initiative 2: Key Environmental Compliance Requirements shall be communicated regularly to internal partners (other GPA Divisions), and externally through meetings or discussions with stakeholders. This initiative has commenced through two internal Environmental Strategic Plan Presentations and conference calls with GPA's Environmental Consultant, and with a Stakeholder Meeting with representatives from the US Navy, Guam EPA and the Governor's Office in September 2011.

Initiative 3: GPA should establish a process that ensures each major activity (CIP or Major O&M) undergoes review for compliance with environmental requirements stated in this Strategic Plan (such as PSD Applicability Determination).

Initiative 4: In complying with the various regulatory requirements, GPA shall consider the installation of control devices, the use of a different fuel type, and others such as to request exemption from USEPA. GPA's consultant recommended the filing or requesting a consent decree to exempt GPA from various regulations. In a meeting with Guam EPA, they recommended the filing of a 325 Waiver for various sections of the Clean Air Act.

Initiative 5: GPA shall continue working on actions decreasing hazardous air emissions from the utility and the Guam community. Some of the actions recently completed were the transition from 0.5% Sulfur Diesel to Ultra Low (15 ppm or less) Sulfur Diesel for GPA's diesel-fired units, and the acquisition of 20 MW Renewable Energy Contract. GPA's leadership and facilitation of the effort to transition to ultra-low sulfur diesel decreased sulfur dioxide emissions in the Guam Transportation, Construction, Power Generation and other economic sectors. Furthermore, GPA has undertaken a Demand-Side Management Program with Large Customers and is working on programs for residential customers. GPA should provide additional resources (such as staffing and funding) to support these efforts under the Strategic Planning and Operations Research Division. These programs have created a virtual power plant of energy savings and hazardous air emission reductions.

APPENDIX A

Guam Power Authority Environmental Policy

Guam Power Authority
Environmental Policy

Guam Power Authority values highly a clean, healthy environment. GPA considers environmental issues as part of its core business planning and decision making. GPA shall provide safe, reliable, and responsive utility service in an environmentally sensitive and responsible manner.

Guam Power Authority's policy is to:

- Comply with relevant government environmental regulations, corporate policies and other applicable requirements.
- Implement standard environmental management system to prevent pollution and minimize environmental impacts and strive to continually improve the system.
- Implement Demand-Side Management Programs where cost effective to promote energy efficiency and conservation
- Develop quality management programs (QMP) to document, implement and maintain processes associated with improved environmental stewardship.
- Promote a workplace culture emphasizing proper employee training, personal responsibility and compliance with respect to environmental requirements, goals and program implementation.
- Ensure adequate resources are allocated for the implementation of this policy.

GPA shall hold all employees responsible and accountable for implementing this environmental policy.

____________________ General Manager

____________________ Date

Guam Power Authority
Environmental Commitment

1. We will integrate environmental factors throughout our decision-making process.

2. We accept accountability for our environmental performance and through our actions, will demonstrate high social integrity.

3. We recognize that every employee has a responsibility toward meeting our environmental commitment, and we will ensure that the necessary training and resources are available to employees.

4. We will openly communicate our environmental values, actions and performance, and will provide opportunities for feedback.

5. We will practice responsible environmental stewardship of all GPA-owned properties under our management.

6. We will ensure compliance with applicable environmental requirements at our operations and will monitor, assess, and continuously improve our environmental performance.

7. We will foster a corporate culture that protects the environment and promotes pollution prevention and long-term energy and natural resource efficiency

8. We will commit human and financial resources necessary to support and implement our environmental commitment and will continually review our performance for consistency with these principles.

APPENDIX B

Boiler MACT and RICE MACT Documents

TRC
Results you can rely on

MEMORANDUM: Cabras/Tanguisson MATS (MACT for Steam Electric Power Plants) Compliance Requirements

DATE: September 7, 2012

FROM: Gale F. Hoffnagle, CCM, QEP

TO: John Cruz, Jennifer Sablan, Sylvia Ipanag, Roger Pabunan, and Paz Tison

The MATS requires compliance with the emission limits in Table 1. GPA can choose whether to meet the total metals, individual metals or filterable particulate limit. The ICR stack sampling of Cabras Unit 1 yields the following calculated situation:

TABLE 1

MERCURY AND NON-MERCURY METALLIC HAP	lb/MMBTU	Convert to lb/Tbtu	Emission limit lb/Tbtu	Emissions/ Limit	% Control Required
Hg	8.33E-08	8.33E-02	4.00E-02	2.08	52.0%
Antimony	5.53E-05	5.53E+01	2.20E+00	25.14	96.0%
Arsenic	4.55E-06	4.55E+00	4.30E+00	1.06	5.5%
Beryllium	6.89E-08	6.89E-02	6.00E-01	0.11	
Cadmium	8.87E-07	8.87E-01	3.00E-01	2.96	66.2%
Chromium	3.84E-06	3.84E+00	3.10E+01	0.12	
Cobalt	2.15E-05	2.15E+01	1.10E+02	0.20	
Lead	3.71E-06	3.71E+00	4.90E+00	0.76	
Manganese	6.46E-06	6.46E+00	2.00E+01	0.32	
Nickel	7.55E-04	7.55E+02	4.70E+02	1.61	37.7%
Selenium	3.45E-06	3.45E+00	9.80E+00	0.35	
OR			lb/MMBTU		
Filterable Particulate	7.65E-02		3.00E-02	2.55	60.8%
OR					
Total HAP Metals	8.55E-04		6.00E-04	1.42	29.8%

A. Options for Control of Metals Emissions

Option 1: Retest Cabras Unit 1

The ICR tests for filterable particulates were performed at too low a temperature when compared to the final MATS testing requirements. The final testing requirements call for a temperature at the filter paper that would preclude the deposition of sulfates (from the SO_2 content of the exhaust). It is therefore expected that when re-tested, the filterable particulate would meet the MATS emission limit of 0.03 lbs/MMBTU. It is suggested that such a test be performed immediately to determine if no controls would be required to meet the MATS emission limits.

Option 2: Tanguisson

Tanguisson can avoid the MATS requirements completely (including the testing requirements) by limiting its capacity to less than 25 MW per unit. This would have to be memorialized in the Air Quality permit in order to be enforceable under the Clean Air Act.

Option 3: Reduced Metal in Oil

If metals were reduced in the purchased oil, it may be possible to meet the standard. Better refined residual fuel or distillate fuel could be used, even on an interim basis. This oil will, of course cost more.

Option 4: Control Equipment for MATS Compliance Only

We had previously calculated the expected cost of compliance with the MATS Standard using Electrostatic Precipitators (ESP). ESPs are preferable to baghouse filters because of the nature of oil smoke. The capital cost was $17.4 million per unit at Cabras and $7 million per unit at Tanguisson (35% Guam factor included). Annual operating costs were estimated at $442,200 per unit at Cabras and $177,500 per unit at Tanguisson.

Option 5: Control Equipment for Sulfur Dioxide and MATS Control

The proposed scrubbers for each of the four units to meet the SO_2 NAAQS would easily also meet the MATS requirements. The deadline for completion of the scrubbers would, however, need to be moved up to May 2015 from June 2017. There are nearly automatic one year extensions from the May 2015 compliance date and a second year of extension is possible based on electric reliability arguments. With both extensions the compliance dates would be similar (May vs. June of 2017). Wet scrubber systems were estimated at $79 million per unit at Cabras at dry scrubber systems were estimated at $129 million per unit.

Option 6: LNG

Natural gas is not subject to the MATS.

B. Control of Chlorinated Hydrocarbon Emissions

Control of Chlorine and Fluorine Emissions

Control of these emissions is attained by the use of fuel which is less than 1% water. Current water contents are well below 1%. Additionally the fuels were tested for chlorine and fluorine content and the results yield calculated emissions significantly below the emissions limits in the MATS.

C. Testing Requirements

There are two options: 1) Continuous Emissions Monitor (CEM) for Particulate Matter or 2) quarterly stack testing for metals. TRC currently recommends against the CEM because of the unreliability of the available monitors. Quarterly stack test costs are estimated at $200,000 per year for all four units. Testing is due in 2015.

D. Other Requirements

There are startup and shutdown requirements as well as tune-up requirements to be considered.

3. There may be some cost reduction if several units can be served by a single larger ESP. The savings may be on the order of 10% but would be offset by the costs of ducting to bring the emissions to a common ESP.
4. The annual operating and maintenance costs for oil fired ESPs are not addressed in the EEI data. The maintenance costs for a fabric filter ($3.7/kW) were considered to give an idea of the costs and $3/kW was added fro O&M of the DSI. A significant portion of the O & M costs will be for electricity needed to run the DSI ESP thus reducing the output of the units (this is called parasitic cost).
5. For Cabas Unit 1 the cost per unit of pollution, a common way to evaluate the cost effectiveness of a regulation is $803,000 per ton of metals emissions reduced. This calculation assumes 20 year depreciation and 6% cost of capital. The total metals emissions are 1.65 tons/year.
6. The GPA units do not qualify as a major source of HAP emissions (greater than 25 tons per year of all HAP emissions and /or greater than 10 tons per year for any single HAP). This proposed rule applies regardless of major source size.

The timing of the ability to comply with the MACT in 3 years, or even with an extension to 4 or 5 years, is problematic. EPA expects that US utilities will be able to meet these short deadlines because of the planning that has occurred for the CAIR rule over the last few years does not apply to GPA because it will have to start from scratch. The ability of engineers, suppliers and manufacturers to meet GPA requirements will also be strained because of continental demands and the distance to Guam.

SUMMARY

Compliance with the MACT by GPA will be extremely costly and the costs may be much higher than the $57 Million capital cost projected in TABLE 2. Only a very small emissions reduction (1.65 tons/year of metals) will be accomplished by this extraordinary expense of $803,000 dollar per ton of pollutant removed.

References

1. NESHAPS from Coal and Oil-Fired EGU's, EPA Proposed Rule, Federal Register, Vol. 76, No. 85, May 3,2011
2. "EPA Section 114 HAP Emissions Testing Program Test Report: Cabas Unit 1", Airkinetics, Inc. June 1 5, 21011.
3. "Cabas 1-4 Power Generation facility Air Pollution Control Permit Application", Guam power Authority submitted to Guam EPA, January 13, 2004.
4. "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet", Edison Electric Institute, January 2011.

MEMORANUM: MACT Requirements for Diesel Engines

DATE: May 22, 2012

FROM: Gale F. Hoffnagle, CCM, QEP

TO: John Cruz, Sylvia Ipanag, Paz Tison, and Jennifer Sablan

The MACT standard for Reciprocating Internal Combustion Engines (RICE) was promulgated on August 20, 2010 (40 CFR Part 63 Subpart ZZZZ). It requires that all diesel engines which are greater than 500 Horse Power (HP) either emit less than 23 ppm of Carbon Monoxide (CO is a surrogate for the unburned hydrocarbons (Hazardous Air Pollutants) that are emitted because of incomplete combustion. If the engine emits more than 23 ppm, then reducing emissions to 23 ppm or 70% control of the CO that is emitted is required.

Each and every diesel engine in the GPA fleet is greater than 500 HP. The rule applies whether the location is a major source of HAPs or an area (minor) source of HAPS. My current calculations using the ICR data indicate that each GPA location is a minor (area) source of HAPS.

The initial notification date was February 11, 2011 at which time GPA should have notified EPA that their diesel engines were subject to the rule.

The compliance date is May 3, 2013. GPA must conduct performance tests to demonstrate compliance within 180 days after the compliance date, which is December 16, 2013. There is the possibility of a one year extension (40 CFR Part 63.6i4) for compliance for the installation of controls.

Control Considerations

1. Ultra-Low Sulfur Fuel Diesels

The diesels which are fired on ultra-low sulfur diesel fuel would be expected by the rule to add an oxidation catalyst to the exhaust stream which oxidizes the CO to CO_2 (along with the HAP hydrocarbons). These are relatively standard installations and the capital costs are reasonably well known (about $27 per HP). The capitol costs are estimated at:

Tenjo 1 through 6:	6095 HP each	$170,000 each if separate
Dededo 1 through 4:	3600 HP each	$100,000 each if separate
Manenggon 1 and 2:	7400 HP each	$203,000 each if separate
Talofofo 1 and 2:	6095 HP each	$170,000 each if separate
	Total	**$2,166,000**

Multiple diesels could be serviced by a common control device, but there are operational considerations.

This is the capital cost and does include shipment to the site, installation, start-up and testing. Annual operating costs are about $5 per HP, or ~$140,000 for all these diesels.

GPA has indicated that the Dededo diesels may be retired. If so, these diesels should be removed from the air permit by May 3, 2013. This would reduce the estimated costs shown above by $400,000. An added benefit is that total emissions from Dededo would be reduced thereby facilitating the re-permitting of the Combustion Turbines.

2. Residual Fuel Oil Diesels

The diesels which are fired on RFO are a different matter because of the high sulfur content of the fuel. The catalyst will oxidize the SO_2 to SO_3 thereby creating sulfuric acid (combined with water in the exhaust or atmosphere). This oxidation could be up to 40% of the SO_2. One catalyst manufacturer has told us that 600 ppm SO_2 is the limit of his catalyst. Oxidation catalyst by itself is not a feasible alternative. The only approach is to reduce the sulfur content of the exhaust to 600 ppm and then apply the catalyst.

It will be necessary to change fuels in order to meet this MACT at the RFO diesels. The costs are as follows:

1. Ultra-Low Sulfur Diesel – This conversion for the 4 RFO diesels would require additional fuel costs of $54/barrel, estimated at $73 million per year (a 33% increase). Then the estimated cost of the purchase and installation of the oxidation catalyst control devices would be $6,500,000. The estimated annual operating costs for the control device would be $1,170,000. Other capital costs may be needed to burn this fuel.

2. Low Sulfur RFO plus SO_2 Control – This option requires purchase of lower sulfur RFO (from current 2% and 1.19%) to about 0.3% or 0.5%. This change is estimated at $43/barrel or $58 million annually. The SO2 content of the exhaust would have to be further reduced using a dry scrubber and a bag house to meet the inlet requirements of the oxidation catalyst. These capital costs an operating costs are shown in the following table:

Plant	Unit	MW	Capital Cost	Annual Operating Cost
Cabras	3	39.3	$97,088,000	$2,095,000
	4	39.3	$97,088,000	$2,095,000
MEC	8	44.2	$109,094,000	$2,352,000
	9	44.2	$109,094,000	$2,352,000
TOTAL:			**$412,364,000**	**$8,894,000**

This alternative would also require storage of a fourth fuel with those added expenses.

3. Liquefied Natural Gas – The MACT for diesels does not apply to gas fired diesels.

Because the EPA preferred method of control is oxidation catalyst, it may be possible to claim the control is infeasible and be exempted from the rule because the cost of control is excessive for this location and fuel. It is important to note that Guam is exempted in the rule from being required to change fuels to meet the MACT standard. Continental diesels of this size will have to change to low sulfur fuels.

Extension Should Be Requested

For both the Ultra-Low Sulfur Diesels and the RFO Diesels, GPA should request an extension of the compliance date from May 2013 to May 2014. This would be based on the inability to come into compliance (build the control devices) by May 2013.

Request Exemption for RFO Engines

GPA should request an exemption from the MACT for the RFO engines based upon the following factors:

1. Compliance requires change in fuel for which Guam is already exempted.
2. GPA agrees to come into compliance for the ULSD engines, which are, in general, closer to the population.
3. Current emissions of CO from the 4 RFO units are on the order of 65 ppm which represents substantial combustion efficiency and means that compliance to 23 ppm represents a minimal reduction in emissions for a huge investment. The costs would be capital costs of $412 million and $9 million annually. This is at least $370,000/ton of CO removed which is beyond reasonable (most decisions on controls are made at the $5,000-$10,000/ton range).
4. EPA does not provide any guidance for compliance for the RFO engines.
5. Guam cannot afford the cost increases needed to meet the MACT.

6. GPA could propose switching to LNG at some later date if the above arguments are insufficient.

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Memorandum

To:	Gale Hoffnagle TRC
From:	Mark M. Hultman, P.E. TRC
Subject:	MACT Compliance for Slow Speed Diesels on Guam
Date:	April 12, 2012
CC:	Barry Stewart
Project No.:	182207

Executive Summary

In a previous memorandum dated December 5, 2011, (attached) wet and dry SO_2 control devices were costed for application to the Cabras Power plant Units 1 & 2 boilers on the Island of Guam in 2011 dollars. In that memo, the costs included the 35% cost escalation factor for Guam. As a follow-on to that analysis, compliance with the Maximum Achievable Control Technology (MACT) standard for Reciprocating Internal Combustion Engines (RICE) at area sources of Hazardous Air Pollutant (HAP) emissions has been completed for the slow-speed diesels Units 3 & 4 and the results are included herein.

	Engine 3 or 4	Control Eff
Lime Spray Dryer System	$97,087,000	85%
Fabric Filter Portion of the Above	$27,732,000	
Oxidation Catalyst	$ 1,934,000	>70% for CO

In a table that accompanies this report there is a detailed breakdown of the components of the costs to attain compliance with the MACT emission rate standard for RICE contained in 40 CFR Part 63, Subpart ZZZZ. In view of the large numbers of products of incomplete combustion emitted from these sources, EPA developed the MACT regulation to use a surrogate pollutant, carbon monoxide (CO) in place of each HAP. For the large RICE (Engines No. 3 and 4) at Cabras, the MACT standard is either compliance with an emission standard of 23 parts per million by volume dry (ppmvd) corrected to 15% O_2 in the exhaust or a 70% reduction in the inlet CO concentration (inlet to the oxidation catalyst).

Discussion

Large slow-speed diesels at Cabras are subject to the MACT standard for existing area sources with a maximum power output of greater than 500 brake horsepower (BHP). Each unit No. 3 and 4 is a 55,060 BHP Hanjung-MAN, B&W diesel engine burning residual fuel oil with a sulfur content of 2.2%. The engines are subject to the MACT standard for existing RICE and must reduce emissions of CO to 23 ppmvd @ 15% O_2, or by more than 70%. Stack test data performed in August 2011 show emissions from Unit #3 of 73.5 ppm and Unit #4 of 71.2 ppm.

In most cases a bed of catalytic material can be installed in the exhaust gas ducting of a compression reciprocating diesel engine to meet the MACT standard. The oxidation catalyst units typically start out with a control efficiency for CO of 90% or greater and then degrades over time to the minimum of 70% at which time the catalyst is changed. The CO control efficiency is a good surrogate parameter that will be indicative of the simultaneous destruction of the numerous HAP organics that exist in diesel exhaust. With continuous operation, the catalyst will last 2 to 3 years before it degrades and must be replaced. The MACT standard requires that inlet temperature to the catalyst bed and the bed pressure drop be recorded during operation of the unit.

A significant issue for the large diesels at Cabras is the fuel sulfur content. CO oxidation catalysts will degrade rapidly if the diesel engine fuel contains more than 500 ppm sulfur (0.05 weight percent). For this reason, compliance with the MACT standard must involve limitation of the sulfur in the fuel to the equivalent of this maximum limit or sulfur dioxide controls to reduce the equivalent exhaust sulfur to an acceptable level.

A conversion to ultra-low sulfur diesel fuel could be an option, however the cost of this option is likely out of the question. Nevertheless, a lower sulfur level No 6 fuel oil in the engine is necessary to prevent premature catalyst failure. The lowest available guaranteed sulfur content in No. 6 residual fuel oil is 0.3 weight percent, or 3000 ppmw.

In the interest of learning the maximum limit of sulfur content in diesel fuel, I searched for information on oxidation catalysts. I contacted a technical representative at BASF who provided the attached guidelines for sulfur in fuel in various parts of the world. They have one possible installation in Hawaii of an oxidation catalyst on a slow speed diesel with No. 6 fuel oil with a 0.3% sulfur content. BASF will not guarantee catalyst performance with this sulfur level and the application has not yet become operational. Large slow-speed diesels are common electrical generation units in non-continental areas of the world including Hawaii.

One way to approach MACT for the slow speed diesels is in conjunction with attaining compliance with the SO_2 NAAQS. A conversion to 0.3% S No. 6 oil with dry gas scrubbing and add-on particulate filtration to attain 85% SO_2 reduction could solve both the NAAQS attainment and the MACT oxidation catalyst issue together. The 85% reduction, presumed to be attainable with a lime spray dryer and baghouse will result in SO_2 emissions equivalent to a 500 ppmw sulfur in fuel equivalence which will be compatible with a CO oxidation catalyst for MACT compliance.

Available costing information for diesel oxidation catalysts is that the capital cost of a unit is a linear function of engine horsepower[1]. For costing of the Oxidation Catalyst module, the horsepower is the actual engine horsepower and not the adjusted engine horsepower used to size the dry scrubbing control equipment (see the December 5, 2011 memorandum for the cost rationale of the SO_2 control equipment costing). The oxidation catalyst is a static honeycomb-filled plug-flow reactor that contains the catalyst. The cost of a retrofit device is well represented by the following equation:

Oxidation Catalyst Cost = $27.4 x HP -$939

[1] ECR Incorporated, Nelson, Bradley, "Control Costs for Existing Stationary CI RICE", January 29, 2010.

One concern here is that even with the spray dryer absorber to reduce the SO_2 concentration into the oxidation catalyst, and the addition of a baghouse to control particulate matter, the catalyst inlet temperature must be maintained in the proper range. This could require reheating of the exhaust if the minimum catalyst operating temperature is not maintained. This penalty is not included in this analysis.

CABRAS ENGINE 3 OR 4
LIME SPRAY DRYING COSTING DEVELOPMENT
INCLUDING AN OXIDATION CATALYST

Variable	Designation	Units	Value	Equation/Input[1]
Unit Capacity (Gross)	A	(MW)	46.9	Input
Retrofit Factor	B		1	Difficulty of Retrofit
Gross heat rate	C	Btu/kWhr	9,545	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.314	Uncontrolled (0.3%S)
Type of Oil	E	No. 6		Input
Fuel Factor	F		1.05	Input
Heat Rate Factor	G		0.95	C / 10000
Heat input	H	MM Btu/hr	447.7	A X C x 1000
Lime Rate	K	(tons/hr)	0.10	See equation in report
Waste Rate	L	(tons/hr)	0.22	See equation in report
Fly Ash Waste Rate	P	(tons/hr)	1.28	See equation in report
Aux Power	M	(%)	1.30	See equation in report
Make Up Water	N	10^3 gph	2.60	See equation in report
Operating Labor Rate	T	($/hr)	81	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$11,728,374	See equation in report
FF Capital Cost	FF Cost	$438/kW	$27,731,970	See equation in report
Oxidation Catalyst[3]	$27.40/bhp-$939	($)	$1,933,794	
Reagent Preparation	BMF	($)	$5,004,445	See equation in report
ID Fan, Other Costs	BMB	($)	$16,975,649	See equation in report
Capital Cost	BM Sum	($)	$63,374,231	Base LSD Module
Engineering	A1	10%	$6,337,423	
Construction Labor	A2	10%	$6,337,423	
Contractor Fees	A3	10%	$6,337,423	
	CECC		$82,386,501	Capital, Eng, and Const
Owners Cost	B1	5%	$4,119,325	Various home office fees
AFUDC		10% of (CECC+B1)	$8,650,583	
Total Project Cost		2009$	$95,156,408	
		2011$	$97,087,627	
			2,029	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$227,448	2,080 hrs- one operator
Maintenance Material	FOMM		$855,552	1% of BM Capital Cost
Admin Labor Cost	FOMA		$17,090	
Auxiliary Power	VOMA		1.06	
Lime Cost	VOMR		$12.29	Lime cost in $/hr
Waste Disposal Cost	VOMW		$101.25	Waste Cost in $/hr
Annual Lime Requirements:		tons	839	
Waste Disposal Requirements:		tons	1,936	

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) All costs include 35% cost escalation for Guam

3) Based on the actual engine horsepower

BASF
The Chemical Company

DOC and DPX™

Sulfur tolerant diesel retrofit solutions

Product data

An important consideration in selecting a diesel emissions control retrofit product is the sulfur level of the diesel fuel. Sulfur tends to reduce the catalytic activity, so care must be taken when selecting a product.

This table gives guidelines for the use of BASF DOCs (Diesel Oxidation Catalysts) and DPX™ Diesel Particulate Filters. However each situation depends on a number of variables.

Variables to consider

- Specific model of engine to be retrofitted
- Year engine was manufactured
- Current emissions level of the engine (e.g. Euro II)
- Emissions reduction targeted (e.g. a certain opacity)

About BASF
As the world's leading chemical company, BASF's portfolio ranges from chemicals, plastics, performance products, agricultural products and fine chemicals to crude oil and natural gas. BASF's intelligent system solutions and high-value products help its customers to be more successful. BASF develops new technologies and uses them to open up additional market opportunities. It combines economic success with environmental protection and social responsibility, thus contributing to a better future.

Guidelines

Technology	Diesel fuel sulfur level [1]	Typical CO reduction [2]	Typical HC reduction [2]	Typical PM reduction [2]
BASF DOC	≤ 500 ppm	40-90%	50-80%	25-60%
BASF sulfur tolerant DOC	501 to ≤ 2000 ppm	40-80%	50-70%	25-50%
BASF DPX™	≤ 50 ppm	> 75%	> 75%	> 85%
BASF sulfur tolerant DPX	51 to ≤ 500 ppm	> 70%	> 70%	> 70%

[1] actual sulfur level that can be used depends upon the particular situation
[2] actual emission reductions will vary depending on emission test cycle and engine being tested

Sulfur levels in diesel fuel [3]

≤ 50 ppm	Australia; Hong Kong, China; Japan; Korea; European Union; United States
51-500 ppm	Beijing, China; India; Malaysia; Mexico; Philippines; Republic of Korea; Sao Paulo, Brazil; Singapore; Thailand
501-2000 ppm	Brazil; Cambodia; China; Vietnam
> 2000 ppm	Bangladesh; Indonesia; Pakistan; Sri Lanka

[3] Sulfur levels from industry and government sources. BASF is not responsible for accuracy of data as presented.

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Memorandum

To:	Gale Hoffnagle TRC
From:	Mark M. Hultman, P.E. TRC
Subject:	SO_2, Dry and Wet Scrubbing for Guam
Date:	December 5, 2011
CC:	Barry Stewart
Project No.:	182207

Executive Summary

Wet and dry SO_2 control devices have been costed for application to the Cabras Power plant on the Island of Guam in 2011 dollars. Both of the boilers and both of the engines use high sulfur residual oil as fuel. The results of the cost determinations are as follows in 2011 dollars:

	Boiler 1 or 2	Engine 3 or 4	Control Eff
Limestone Forced Oxidation Wet FGD	$79,150,000	$58,489,000	95+%
Lime Spray Dryer with	$129,370,000	$96,969,000	50-80%
Fabric Filter Portion of the Above	$39,025,000	$27,732,000	

In tables that accompany this report there is a detailed breakdown of the components of the costs in Tables 2 through 5. Chemical reagent requirements and waste production are listed at the bottom of each sheet. These are study level costs which are likely accurate within 30% of true cost values.

Discussion

There are a total of eight electric utility steam generating unit (EUSGUs) electric power plants on the island of Guam that burn high sulfur No. 6 residual oil (2% S)). In view of the likely need to control the sulfur dioxide (SO_2) emissions from these plants to comply with the new NAAQS, I have looked into lower sulfur fuel switching, dry scrubbing techniques, and wet flue gas desulfurization (FGD) systems to reduce SO_2 in order to attain compliance with the new standard. Dry injection techniques include the injection of dry sorbent like trona(sodium bicarbonate) or lime into the ducting with subsequent collection of the solids in a particulate control device, i.e., an ESP or a baghouse, and spray dryer absorbers also with subsequent particulate collection.

Historically, existing EUSGUs which utilize residual oil have not been required to control SO_2 and previous NAAQS for this pollutant were relatively easy to meet by utilizing tall stacks, in some cases combining a tall stack with a fuel sulfur content limit. This is no longer the case and with the new 1-hr SO_2 standard, many existing sources such as the GPA EUSGUs will need to control SO_2 by >90% when burning 2% S fuel and >50% when burning lower S (1.19%S) residual oil. Both wet and dry FGD systems have been optimized over the past two decades but application has been limited to coal fired boilers only.

While wet and dry FGD systems have only been applied to coal fired units, there is no reason that the same technology cannot apply to residual oil fired units as well. The theoretical amount of air required for combustion of a subbituminous coal or No. 6 residual oil are 756 and 758 pounds per million Btus respectively (Perry's, 5th ed., Table 9-19). Furthermore, to attain proper combustion, the same percentage of excess air, i.e. roughly 15 to 20% is utilized with either fuel (Perry's Figure 9-5). This indicates that nearly identical exhaust gas flow rates per MM (million) Btu of heat input will result from the combustion of either fuel. The major difference between the two is that coal contains approximately 20 times the particulate emissions of No. 6 residual oil due to ash in the coal.

Prior to 2010 the most comprehensive source of cost information for air pollution control equipment was the EPA Control Cost Manual from 2002. The manual provides information that can be utilized to develop cost estimates for VOC controls (thermal oxidizers), NO_x controls, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) controls, and particulate controls (electrotstatic precipitators (ESPs) and fabric filters (FFs)). Very little information on SO_2 controls was included.

In 2003 EPA published information on the capital and operating costs of SO_2 removal air pollution controls, but it was very broad and the information could only be used to develop broad ranges of costs (see EPA-452/F-03-034). For example, for a wet FGD scrubber system the information gives a capital cost of between $250 to $1,500 per KW for all boilers less than 400 MW in power output. While this was the only information available until recently, even the author, the US EPA, did not encourage use of these data for control costing analysis.

In light of the new interstate analyses being performed to assess issues like regional visibility under BART and interstate transport of NO_x under CAIR, major cost studies were performed under the supervision of EPA for the control of SO_2 and NO_x. The engineering firm Sargent & Lundy (S&L) published several papers that provided cost estimation tools for estimation of wet and dry scrubbing techniques for SO_2 and for SNCR and SCR NO_x controls. All data were developed in 2009 dollars and the cost techniques developed are from actual proprietary cost information. I believe these are the best data currently available.

SO_2 Control Efficiency to Comply with the NAAQS

Table 1 presents the results of modeling analyses for the north and south portions of Guam. The Cabras power plant is located in the southern part of the island and the two 66 MW boilers and two 40 MW diesels burn high sulfur residual No. 6 fuel oil (2% sulfur). Depending on wind direction, all units may switch to a lower sulfur (1.19% sulfur) residual fuel. Based upon the results of the modeling, and using the standard assumption that the ambient impacts are directly proportional to the fuel sulfur content, Table 1 shows the percentage reduction in fuel sulfur, or the percentage of SO_2 control that is required to attain compliance with the NAAQS. For 2% sulfur No. 6 oil greater than a 90% control of SO_2 in the north or south while a control efficiency of 50% or more is required if the 1.19% S fuel is burned. The type and design of control equipment at Cabras and/or Tanguisson strongly depends on the fuel sulfur content.

Limestone forced oxidation wet scrubbing (LSFO) can achieve in excess of 95% SO_2 control while dry techniques can attain 50 to 80% SO_2 control.

S&L Costing Approach

The estimation of the cost of wet FGD equipment by S&L was developed under finding from EPA. The empirical cost of the hardware was based on vendor data and actual installations. The details of the total cost for one Cabras 66 MW boiler and one 40 MW engine are presented in Tables 1 and 2. The costs for the absorber unit, the reagent preparation equipment, waste handling equipment, and other equipment are broken out separately. Installation costs for engineering, construction management, and owners costs are all determined as percentages of the total capital equipment cost as is standard in such costing analyses. All costs have been escalated by 35% to account for the remote location of the installations. Costs are expected to be study level costs, i.e., accurate to plus or minus 30%.

Larger utility boilers often require multiple absorber units per boiler, however, these units are small and one scrubber vessel per unit will suffice. It still would be advisable to have one spare absorber vessel associated with the two boilers and a spare for the two engines to allow continued operation with one scrubber vessel off line for scale removal.

Table 2 shows the results of application of the S&L cost analysis technique to Cabras 1 or 2 steam boilers. Sufficient detail is provided to show the breakdown of the hardware, construction, engineering, and other installation costs. Operation and maintenance costs are also included. Wet FGD is a labor intensive operation with 12 operators required for plants less than 500 MW.

Costing of Wet FGD Equipment for Cabras Power Station –Boilers 1 and 2

Wet scrubbing equipment for SO_2 control includes an absorber, reagent preparation equipment, injection pumps, recirculation tanks, waste removal equipment, and ducting, valving, and other support equipment. The concept is simple and the approach is to establish intimate contact with the SO_2 laden gas and the absorber liquid. Some scrubbers include packing material to provide a large surface area for gas/liquid contact and others use a venturi scrubber design that accelerates the gas through a nozzle for atomization and gas liquid contact. The technology is well developed.

The S&L costing study was based on coal fired boilers, but the costs will be only slightly different for No. 6 residual fuel oil fired units. Because S&L developed their empirical cost equations for the scrubber vessels portion of the systems for coal-fired units as proportional to the exhaust gas flow rates and used the megawatt output of the boiler as a surrogate for exhaust gas flow, using the MW output of a residual oil fired unit will be no different. Because the exhaust gas flow rate is essentially the same whether a MW is generated by bituminous/subbituminous coal or residual No. 6 fuel oil, the basic absorber costs will be the same.

Reagent costs and the resulting sludge from the absorber depend directly on the sulfur content of the fuel burned. The majority of new systems employ the LSFO FGD process. LSFO, or limestone forced oxidation, forces air into the absorption solution and converts the absorbed sulfite to sulfate (gypsum) which can be a saleable product with 99% conversion to the sulfate. Typically the absorber vessel will accumulate gypsum scale, but this can be controlled by the air injection process.

Costing of Wet FGD Equipment for Cabras Power Station –Engine Units 3 and 4

In addition to two steam electric boilers, there are two 55,000 brake horsepower (bhp) reciprocating internal combustion (compression ignition) engines (RICE) that also burn high sulfur No. 6 fuel oil. Each unit generates 40 MW at full load. The exhaust from each unit can be scrubbed for SO_2 control using the same basic absorption technology normally applied to boilers.

RICE operate with higher exhaust gas flows than equivalent heat input boilers. This is shown by the stack tests performed on the boilers and the engine sources which have 6% O_2 (boilers) and 14% O_2 (engines) in their exhaust gases. In view of the fact that the S&L empirical costing technique was based on boilers, a ratio of the exhaust gas flows was used to estimate the equivalent coal-fired boiler power output appropriate for application of Cabras Unit 3 or 4. Using a ratio of exhaust gas flows derived from stack tests on one boiler and one engine, it was determined that a scrubber sized for a 46.9 MW coal fired boiler could be used to scrub emissions from one 40 MW engine source. The amount of limestone consumed and the amount of gypsum formed is determined by the actual sulfur content of the fuel and the actual fuel firing rate of the engines.

Table 3 shows the results of application of the costing analysis technique to the emissions from the two RICE sources. You will note that the MW output of the plant at the top of the sheet is based on a 46.9 MW boiler to account for the greater exhaust gas flow rate for engines as compared to boilers.

Costing of Dry FGD Equipment for Cabras Power Station –Boilers 1 and 2

Dry scrubbing for the control of SO_2 injects a lime slurry into the exhaust gas with the solids reacting with the SO_2 to form salts which are then collected in either an electrostatic precipitator (ESP) or a fabric filter (FF). The slurry is injected in what is called a spray tower and the amount injected is such that the gas stream is not saturated but is significantly humidified. 50 to 80% SO_2 control is typically attained. Some recirculating dry scrubbing systems reinject the collected solids from the hopper of the FF, and removal efficiencies of 95% or more can be attained. The dry scrubber (lime spray drying) cost analysis is presented in Table 4.

Of special note, the dry scrubbing techniques include the cost of a pulse-jet fabric filter at a cost of $438/kW in 2008 dollars. For dry scrubbing, although more expensive, the filter cake on the fabric bags greatly enhances SO_2 removal efficiency.

Costing of Dry FGD Equipment for Cabras Power Station –Engine Units 3 and 4

The lime spray dryer costing approach by S&L is the same as for wet FGD systems and therefore the same assumption for the engine sources based on the higher exhaust gas flow rate was used.

Table 1

SO_2 Control Requirements Based on Modeling

Emissions, AERMINUTE Included, Downwash Included		Difference Between Run 12 and Run 14				
Northern SO_2 Impacts (Tanguisson Area)					**2% S**	**1.19% S**
Period	Concentration ($\mu g/m^3$)	Period	Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	SO_2 Control to Meet NAAQS No. 6 Oil	
1-HR	12463.4	1-HR	5946.50	196	97.0%	56.5%
3-HR	14666.76	3-HR	9219.16	1300	76.1%	35.6%
24-HR	3321.91	24-HR	554.50	365	86.8%	46.3%
Annual	344.21	Annual	208.35	80	41.1%	0.6%
Southern SO_2 Impacts (Cabras Area)					**2% S**	**1.19% S**
Period	Concentration ($\mu g/m^3$)	Period	Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	SO_2 Control to Meet NAAQS with 2% S No. 6 Oil	
1-HR	4577.35	1-HR	2505.35	196	90.5%	50.0%
3-HR	3658.49	3-HR	703.32	1300	56.0%	15.5%
24-HR	630.93	24-HR	-300.60	365	60.8%	20.3%
Annual	134.79	Annual	35.26	80	19.6%	none

TABLE 2 WET FGD SYSTEM FOR ONE 66 MW NO. 6 OIL FIRED BOILER AT CABRAS POWER PLANT

Variable	Designation	Units	Value	Equation/Input(1)
Unit Capacity (Gross)	A	(MW)	66	Input
Retrofit Factor	B		1	Difficulty of Retrofit
Gross heat rate	C	Btu/kWhr	9,545	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2.224	Uncontrolled
Type of Fuel	E	High S No. 6 Oil		Input
Fuel Factor	F	None	1	Input
Heat Rate Factor	G		0.95	C / 10000
Heat input	H	MM Btu/hr	630.0	A X C x 1000
Limestone Rate	K	(tons/hr)	1.23	See equation in report
Waste Rate	L	(tons/hr)	2.22	See equation in report
Aux Power	M	(%)	1.49	See equation in report
Make Up Water	N	10^3 gph	4.94	See equation in report
Limestone Cost	P	($/ton)	20.25	
Waste Disposal Cost	S	($/ton)	67.5	
Aux Power Cost	R	($/kWhr)	0.081	
Makeup Water Cost	S	$/$10^3$ gal	1.35	
Operating Labor Rate	T	($/hr)	81	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$14,530,400	Absorber Island
Reagent Preparation	BMF	($)	$6,455,859	Reagent Preparation
Waste Handling Cost	BMW	($)	$3,803,970	
ID Fan, Other Costs	BMB	($)	$26,875,650	Balance of Costs
Capital Cost	BM Sum	($)	$51,665,879	Base Wet FGD Module
Engineering, and Const	A1	10%	$5,166,588	
Construction Labor	A2	10%	$5,166,588	
Contractor Fees	A3	10%	$5,166,588	
	CECC		$67,165,642	Capital, Eng, and Const
Owners Cost	B1	5%	$3,358,282	Various home office fees
AFUDC	B2	10% of (CECC+B1)	$7,052,392	
Total Project Cost	TPC	2009$	$77,576,317	
		2011$	$79,150,744	
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$2,021,760	2,080 hrs- 12 operators
Maintenance Material	FOMM		$774,988	1% of BM Capital Cost
Admin Labor Cost	FOMA		$69,953	
Auxiliary Power	VOMP		$79.41	$/hr
Water Cost	VOMWW		$6.67	$/hr
Limestone Cost	VOMR		$116.60	Limestone cost in $/hr
Waste Disposal Cost	VOMW		$150.03	Waste Cost in $/hr

Annual Limestone Requirements:	tons	10,751
Waste Disposal Requirements:	tons	19,471

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) All costs increase by 35% for Guam

TABLE 3 WET FGD SYSTEM FOR ONE 39 MW NO. 6 OIL FIRED RICE AT CABRAS POWER PLANT

Variable	Designation	Units	Value	Equation/Input[1]
Unit Capacity (Gross)	A	(MW)	46.9	Input(2)
Retrofit Factor	B		1	Difficulty of Retrofit
Gross heat rate	C	Btu/kWhr	8,385	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2.224	Uncontrolled
Type of Fuel	E	High S No. 6 Oil		Input
Fuel Factor	F	None	1	Input
Heat Rate Factor	G		0.84	C / 10000
Heat input	H	MM Btu/hr	345.0	A X C x 1000
Limestone Rate	K	(tons/hr)	0.77	See equation in report
Waste Rate	L	(tons/hr)	1.39	See equation in report
Aux Power	M	(%)	1.30	See equation in report
Make Up Water	N	10^3 gph	3.08	See equation in report
Limestone Cost	P	($/ton)	20.25	
Waste Disposal Cost	S	($/ton)	67.5	
Aux Power Cost	R	($/kWhr)	0.081	
Makeup Water Cost	S	$/$10^3$ gal	1.35	
Operating Labor Rate	T	($/hr)	81	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$10,526,407	Absorber Island
Reagent Preparation	BMF	($)	$4,862,263	Reagent Preparation
Waste Handling Cost	BMW	($)	$2,809,833	
ID Fan, Other Costs	BMB	($)	$19,980,950	Balance of Costs
Capital Cost	BM Sum	($)	$38,179,453	Base Wet FGD Module
Engineering, and Const	A1	10%	$3,817,945	
Construction Labor	A2	10%	$3,817,945	
Contractor Fees	A3	10%	$3,817,945	
	CECC		$49,633,289	Capital, Eng, and Const
Owners Cost	B1	5%	$2,481,664	Various home office fees
AFUDC	B2	10% of (CECC+B1)	$5,211,495	
Total Project Cost	TPC	2009$	$57,326,449	
		2011$	$58,489,901	
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$2,021,760	2,080 hrs- 12 operators
Maintenance Material	FOMM		$572,692	1% of BM Capital Cost
Admin Labor Cost	FOMA		$67,525	
Auxiliary Power	VOMP		$49.57	$/hr
Water Cost	VOMWW		$4.16	$/hr
Limestone Cost	VOMR		$98.26	Limestone cost in $/hr
Waste Disposal Cost	VOMW		$126.44	Waste Cost in $/hr

Annual Limestone Requirements:	tons	6,711
Waste Disposal Requirements:	tons	12,155

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) All costs increase by 35% for Guam Power output based on an equivalent boiler

TABLE 4 CABRAS BOILER 1 OR 2
LIME SPRAY DRYING COSTING DEVELOPMENT

Variable	Designation	Units	Value	Equation/Input[1]
Unit Capacity (Gross)	A	(MW)	66	Input
Retrofit Factor	B		1	Difficulty of Retrofit
Gross heat rate	C	Btu/kWhr	9,545	Input
SO_2 Emiss Rate	D	lbs/MMBtu	1.34	Uncontrolled (1.19%S)
Type of Oil	E	No. 6		Input
Fuel Factor	F		1.05	Input
Heat Rate Factor	G		0.95	C / 10000
Heat input	H	MM Btu/hr	630.0	A X C x 1000
Lime Rate	K	(tons/hr)	0.60	See equation in report
Waste Rate	L	(tons/hr)	1.36	See equation in report
Fly Ash Waste Rate	P	(tons/hr)	1.80	See equation in report
Aux Power	M	(%)	1.31	See equation in report
Make Up Water	N	10^3 gph	3.70	See equation in report
Lime Cost	P	($/ton)	128.25	
Waste Disposal Cost	S	($/ton)	67.5	
Aux Power Cost	R	($/kWhr)	0.081	
Makeup Water Cost	S	$/$10^3$ gal	1.35	
Operating Labor Rate	T	($/hr)	81	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$15,197,538	See equation in report
FF Capital Cost	FF Cost	$438/kW	$39,025,800	See equation in report
Reagent Preparation	BMF	($)	$8,543,280	See equation in report
ID Fan, Other Costs	BMB	($)	$21,680,041	See equation in report
Capital Cost	BM Sum	($)	$84,446,659	Base LSD Module
Engineering	A1	10%	$8,444,666	
Construction Labor	A2	10%	$8,444,666	
Contractor Fees	A3	10%	$8,444,666	
	CECC		$109,780,657	Capital, Eng, and Const
Owners Cost	B1	5%	$5,489,033	Various home office fees
AFUDC		10% of (CECC+B1)	$11,526,969	
Total Project Cost		2009$	$126,796,658	
		2011$	$129,370,022	
			1,921	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$168,480	2,080 hrs- one operator
Maintenance Material	FOMM		$844,467	1% of BM Capital Cost
Admin Labor Cost	FOMA		$15,188	See equation in report
Auxiliary Power	VOMA		1.06	See equation in report
Lime Cost	VOMR		$77.51	Lime cost in $/hr
Waste Disposal Cost	VOMW		$213.42	Waste Cost in $/hr

Annual Lime Requirements:	tons	5,294
Waste Disposal Requirements:	tons	11,930

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) All costs include 35% cost escalation for Guam

TABLE 5 CABRAS ENGINE 3 OR 4

LIME SPRAY DRYING COSTING DEVELOPMENT

Variable	Designation	Units	Value	Equation/Input[1]
Unit Capacity (Gross)	A	(MW)	46.9	Input
Retrofit Factor	B		1	Difficulty of Retrofit
Gross heat rate	C	Btu/kWhr	9,545	Input
SO_2 Emiss Rate	D	lbs/MMBtu	1.34	Uncontrolled (1.19%S)
Type of Oil	E	No. 6		Input
Fuel Factor	F		1.05	Input
Heat Rate Factor	G		0.95	C / 10000
Heat input	H	MM Btu/hr	447.7	A X C x 1000
Lime Rate	K	(tons/hr)	0.43	See equation in report
Waste Rate	L	(tons/hr)	0.97	See equation in report
Fly Ash Waste Rate	P	(tons/hr)	1.28	See equation in report
Aux Power	M	(%)	1.31	See equation in report
Make Up Water	N	10^3 gph	2.63	See equation in report
Lime Cost	P	($/ton)	128.25	
Waste Disposal Cost	S	($/ton)	67.5	
Aux Power Cost	R	($/kWhr)	0.081	
Makeup Water Cost	S	$/$10^3$ gal	1.35	
Operating Labor Rate	T	($/hr)	81	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$11,899,797	See equation in report
FF Capital Cost	FF Cost	$438/kW	$27,731,970	See equation in report
Reagent Preparation	BMF	($)	$6,689,458	See equation in report
ID Fan, Other Costs	BMB	($)	$16,975,649	See equation in report
Capital Cost	BM Sum	($)	$63,296,874	Base LSD Module
Engineering	A1	10%	$6,329,687	
Construction Labor	A2	10%	$6,329,687	
Contractor Fees	A3	10%	$6,329,687	
	CECC		$82,285,936	Capital, Eng, and Const
Owners Cost	B1	5%	$4,114,297	Various home office fees
AFUDC		10% of (CECC+B1)	$8,640,023	
Total Project Cost		2009$	$95,040,256	
		2011$	$96,969,118	
			2,026	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$227,448	2,080 hrs- one operator
Maintenance Material	FOMM		$854,508	1% of BM Capital Cost
Admin Labor Cost	FOMA		$17,078	
Auxiliary Power	VOMA		1.063200191	
Lime Cost	VOMR		$55.08	Lime cost in $/hr
Waste Disposal Cost	VOMW		$151.66	Waste Cost in $/hr
Annual Lime Requirements:		tons	3,762	
Waste Disposal Requirements:		tons	8,478	

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010

Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) All costs include 35% cost escalation for Guam

IPM Model – Revisions to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

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SDA FGD Cost Development Methodology – Final

Establishment of Cost Basis

Cost data for the SDA FGD systems was more limited than that for the wet FGD systems. A similar trend with generating capacity is generally seen between the wet and SDA system. The same generating capacity relationship was used for the wet and SDA cost estimation.

A least squares curve fit of proprietary in-house cost data was defined as a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB; and
- Project Execution = Multiple lump sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for the small units would be accomplished by; treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering with natural gas, dry sorbent injection, and/or a reduction in operating hours. Capital costs of approximately $800/kW may be used for units below 50 MW under the premise that these will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu.

An alternate dry technology, circulating dry scrubber (CDS), can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

SDA FGD Cost Development Methodology – Final

Outputs

Total Project Costs (TPC)

First the base installed costs are calculated for each required module (BM_). The base installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The modules are:

BMR =	Base absorber island cost
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc.
BM =	BMR + BMF + BMB

The total base installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example capital cost estimation.

Table 1. Example Capital Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$ 20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$ 47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$ 102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =		341	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$ 6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**512**	Total project cost per kW

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SDA FGD installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW yr) basis.

- In general, 8 additional operators are required for a SDA FGD system. The FOMO was based on the number of additional operations staff required.

- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).

- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.

- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. The estimated reagent usage was based on a sulfur removal efficiency of 95% with a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F. The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet. The basis for the lime purity was 90% CaO with the balance being inert material.

- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.

- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Limestone cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1000 gallon; and
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR =	Variable O&M costs for lime reagent
VOMW =	Variable O&M costs for waste disposal
VOMP =	Variable O&M costs for additional auxiliary power
VOMM =	Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 2 contains an example O&M cost estimate, while Table 3 is a complete capital and O&M cost estimate worksheet.

Table 2. Example O&M Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$ 33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$ 20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$ 47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$ 102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =		341	Base module cost per kW
Total Project Cost			
A1 = 10% of BM		$ 10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$ 6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

APPENDIX C

Listing of Continuing Obligations

1. AIR Act
    a. Annual Emission Testing
    b. Continuous Emission Monitoring and Relative Accuracy Test Audits
    c. Annual Emission Inventory and Fees
    d. New Source Performance Standards reporting
    e. Intermittent Control Strategy, Cabras-Piti Area, Fuel Switching and Reporting Requirements
    f. Title V permit reporting requirements
2. Water Act
    a. Section 316(b) Phase I and Phase II requirements
    b. Effluent Discharge Monitoring
    c. Discharge Monitoring Reports
    d. Toxicity Testing
    e. Best Management Practice Plan
    f. Annual Chemical Usage Report
    g. Spill Prevention Control and Countermeasures Plan
    h. Oil Pollution Prevention Response Plan

3. Resource Conservation and Recovery Act

a. Solid/Hazardous Waste Management Plan
b. Used Oil Recycling Plan

4. Toxic Substance Control Act
    a. PCB Management Program
    b. Asbestos Operation and Management Plan

5. Environmental Planning and Community Right to Know
    a. Annual Toxic Release Inventory Report
    b. Oil Spill Emergency Response and Facility Response Plan

LIST OF CONTINUING OBLIGATIONS

Regulation	Requirement	DETAILS
Air Act	Annual Emission Testing	
		Emission Testing is performed once a year on most of our power plants (The exception being units that are offline pending repairs. Cabras Units 1 &2 are exempt from testing because they were built before the pertinent regulations were established.) Testing is being performed by 3rd party contractors.
		In the Fy2011 testing, limits have been complied with except Cabras Unit 4. It exceeded the PM limit of 93 lb/hr producing 104.6 lb/hr
		GPA has not yet been cited for non-compliance.
		Estimated annual cost $259,600.00 for activities related to annual emission testing.
	CEMS and Relative Accuracy Test Audits	
		GPA is required to operate and maintain a Continuous Emissions Monitoring System the Tenjo Generating Station and Cabras Units #3 and #4.
		The CEMS measures stack gas nitrogen oxide (NOx) concentrations and stack gas volumetric flow rates in accordance to 40 CFR Part 60. The CEMS operates and records data 24/7. A contractor visits the site 5 days a week to ensure that the system is working properly. The limit for NOx is 660ppm @ 15% o2 and 120 lbs/hr.
		GPA has not yet been cited for non-compliance.
		Estimated annual cost of $219,450.00 for activities related to CEMS and Relative Accuracy Test Audits.
	Intermittent Control Strategy, Fuel Switching and Reporting Requirements	The Intermittent Control Strategy is designed to allow the Cabras and MEC Power Plants to burn to burn economical fuels without violating USEPA clean air standards.
		When we are at Adverse Wind Conditions (blowing on-shore or are calm (<1m/s)), we must burn Low Sulfur Fuel Oil (max. sulfur of 1.19% by wt.). When winds are blowing off-shore , we can burn High Sulfur Fuel Oil (max. sulfur of 2.00% by wt.). After each quarter, we are reporting details of Adverse Winds, Low Sulfur Firing Events, Excursions (times when requirements are not met), and Sulfur Measurements.
		Consent Decree was given to GPA in 1997.
	Title V Permit Reporting	A comprehensive Air Permit which compiles all Clean Air Act requirements for a facility in one document.
		Reporting requirements are: Annual total tons per year emitted of each regulated air pollutant, including hazardous air pollutants; report in writing within thirty (30) days the modification, relocation, discontinuance of operation of dismantlement of any emission unit; results of all monitoring and recordkeeping required by the permit at least once every six (6) months; monthly summary reports indicating the quantity of fuel combusted in the subject year by the units; For CT's, the date and time of all instances when the water-to-fuel ratio falls below the minimum levels; for CT's and Cabras 3 and 4, all excess emissions for every calendar quarter; in the event of excess emission or malfunction, the permittee shall notify GEPA within twenty-four (24) hours by phone and submit written notice to GEPA within 2 weeks.
		GPA has not yet been cited for non-compliance.
	NAAQS	
		The National Ambient Air Quality Standards are standards established by USEPA to protect human health and public welfare. We are complying with the NAAQS except for SO2 .
		Piti/Cabras Areas still in nonattainment status. GPA is also required to comply with the new 1 hr SO2 & NO2 standards.
	Green House Gas Reporting	
		GHG Reporting is the reporting of the amount of greenhouse gases that are emitted by our power plants through the burning of fuel oil. This is a yearly report that applies to GPA facilities which emit more than 25 metric tons of CO2e. This Rule is under 40 CFR 98.
		GPA has been submitting an online report since the program started RY2010. Only the Cabras Power Plant is subject to this rule.
		GPA is required to report the annual amount CO2e for our facilities that are sublect to the rule. CO2e means "CO2 Equivalent" which is the sum of carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O), with each being multiplied by a Global Warming Potential Factor.

LIST OF CONTINUING OBLIGATIONS

Regulation	Requirement	DETAILS
Water Act	Sec. 316(b) Phase I and Phase II Requirements	A demonstration study to assess whether the location, design, construction, and capacity of cooling water intake structure (CWIS) reflect the best available for minimizing adverse environmental impact. The first part is the phase 1 (screening analysis) and the 2nd part is based on the findings of the phase 1.
	NPDES	NPDES stands for national pollutant discharge elimination system. The clean water act prohibits anybody from discharging pollutants through a point source into a water of the united states unless they have an NPDES permit. GPA is required to comply with the following condition. 1. Efficient Limitations and Monitoring Requirements. 2. Toxicity Testing. 3. General Conditons. 4. 316(b) studies 5. Best Management Practicies Plan (BMPs).
	Effluent Discharge Monitoring	GPA is required to monitor the following parameters: Flow, temperature (receiving water, influent, effluent), fluoride, pH, suspended solids, toxicity, and oil and grease. Monitoring frequency ranges from continuous (daily), weekly, monthly, and quarterly.
	Discharge Monitoring Reports	Discharge monitoring reports consist of effluent characteristics, discharge limitations and monitoring frequenc y. Temes and EWP fill out these reports with assistance from TEMES subcontractor Environmental Monitors. The reports are forwarded to planning and regulatory for review, then sent to USEPA. Reports are compiled every quarter.
	Toxicity Testing	Toxicity Testing is conducted by contractor quarterly. If toxicity is detected, then the contractor will perform accelerated testing. This means six additional tests, one approximately every 14 days, over a 12-week period.
	BMP Plan	The purpose of the plan is to ensure that pollutants are not making their way into storm water runoff from cabras power plant site. Planning and regulatory is conducting weekly inspections at Cabras Power Plant.
	Annual Chemical Usage Report	Inventory of chemicals are prepared by plant personel and checked by planning and regulatory. Report must be made annually and submitted to GEPA and USEPA.
	SPCC Plan	The purpose of the plan is to prevent, control and provide countermeasures to prohibit oil spills from contaminating the environment. All GPA facilites have SPCC plan including water and waste water facilities.
	Oil Pollution Prevention Response Plan Facility Response Plan	Facitlity response plan is a plan for responding to a worse case distance. The plan also includes responding to small and medium discharges as approprite.
Resource Conservation and Recovery Act	Solid/Hazardoues Waste Management Plan	GPA is conditionally exempt small quantity generator. GPA is exempt from requirements.
	Used Oil Recycling Plan	Used oil recycling is a GPA program for disposing of used oil on island by burning it in the boiler of cabras power plant. If cabras accepts used oil from other sources testing is required.
Toxic Substance Control Act	PCB Management Program	The purpose of the program is removing and disposal of PCB waste. All transformers that were manufactured before 1979 are tested for PCBS.
	Asbestos Operation and Management Plan	The program is focus on the preventation of visible emissions of asbestos fibers during demoliton and denovation operations.
Emergency Planning and Community Right to Know Act	Annual Toxic Relase Inventory Report	The purpose of the report is to increase the public's knowledge of, and access to information on both the presence and release and other waste management activites of chemicals. Planning and Regulatory is responsible for the reporting.
	TIER II	The purpose of the report is to provide information on hazardous chemicals on site to the SERC, LEPC, and local fire department. SERC (State Emergency Response Commission) is Guam EPA. LEPC (Local Emergency Planning Committee) is Guam Homeland Security/Office of Civil Defense.

APPENDIX D

Current Environmental Compliance Fees

GUAM POWER AUTHORITY
2011 Annual Emission Fees Summary

Facility		2011 Annual Fees
Cabras Power Plant	$	65,415.00
Dededo Power Plant	$	500.00
Macheche Combustion Turbine	$	500.00
Manenggon Diesel	$	500.00
Marbo Combustion Turbine	$	500.00
Talofofo Diesels	$	500.00
Tenjo Power Plant	$	1,110.00
Yigo Combustion Turbine	$	500.00
Water Systems Diesel (124 units)	$	12,400.00
TOTALS:	**$**	**81,925.00**

NOTE:

In accordance to Section 1104.24 of the Guam Air Pollution Control Standards and Regulations, Annual Emission Fees for all air pollution emission sources are required to be submitted within 60 days after the end of each calendar year.

GUAM POWER AUTHORITY
CABRAS POWER GENERATING FACILITY
2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Actual Annual Emissions[1]

Regulated Pollutant	Unit #1 Actual Annual Emission (Tons/Year)	Unit #2 Actual Annual Emission (Tons/Year)	Unit #3 Actual Annual Emission (Tons/Year)	Unit #4 Actual Annual Emission (Tons/Year)	TOTAL Actual Annual Emission (Tons/Year)
SO2	1,998.28	2,084.93	1,528.91	2,626.58	**8,238.70**
NOx	408.60	416.16	3,647.20	3,456.60	**7,928.56**
TOC	9.04	9.21	102.31	83.61	**204.17**
PM (total)	121.54	126.73	341.98	422.48	**1,012.72**
Total Tons/Year	**2,537.46**	**2,637.03**	**5,620.39**	**6,589.27**	**17,385**

Regulated HAP Pollutant	Unit #1 Actual Annual Emission (Tons/Year)	Unit #2 Actual Annual Emission (Tons/Year)	Unit #3 Actual Annual Emission (Tons/Year)	Unit #4 Actual Annual Emission (Tons/Year)	TOTAL Actual Annual Emission (Tons/Year)
Total HAPs	**5.26**	**5.35**	**4.93**	**4.79**	**21**

[1]See 2011 Annual Emission Calculation Worksheets

2011 Annual Fee Calculations

Cost for first 4,000 tons for Regulated Pollutant @ $6.00/Ton	$24,000.00
Cost for Regulated Pollutant > 4,000 @ $3.00/Ton	$40,155.00
Cost for HAPs @ $60/ton	$1,260.00
Total	**$65,415.00**

GUAM POWER AUTHORITY
CABRAS POWER PLANT
2011 ANNUAL EMISSION CALCULATION WORKSHEET

Boiler Units #1 & #2

2011 Annual Fuel Consumption[1]

	Annual High Sulfur Fuel Oil (HSFO) Consumption (Gallons)	Annual Low Sulfur Fuel Oil (LSFO) Consumption (Gallons)	Annual Total Fuel Consumption (Gallons)	Average Annual % Sulfur Content High Sulfur Fuel Oil (HSFO)	Average Annual % Sulfur Content Low Sulfur Fuel Oil (LSFO)
Boiler Unit #1	13,267,968	4,119,150	17,387,118	1.60	1.02
Boiler Unit #2	14,602,434	3,106,698	17,709,132	1.60	1.02
Total/Average	**27,870,402**	**7,225,848**	**35,096,250**	**1.60**	**1.02**

2011 Annual Emission Calculations

Non-Hazardous Pollutant	AP-42 Factors[2] Uncontrolled (lb/1000 gals)	Unit #1 Annual Emission[3] Uncontrolled (tons/year)	Unit #2 Annual Emission[3] Uncontrolled (tons/year)	TOTAL Annual Emission Uncontrolled (tons/year)
SO2	157*(S)	1,998.28	2,084.93	**4,083.22**
NOx	47	408.60	416.16	**824.76**
CO	5	43.47	44.27	**87.74**
TOC	1.04	9.04	9.21	**18.25**
PM (total)	8.3*(A)	121.54	126.73	**248.26**

S= %Sulfur by weight   A=1.12(S)+0.37

Organic HAPs	AP-42 Factors[2] Uncontrolled (lb/1000 gals)	Unit #1 Annual Emission[3] Uncontrolled (tons/year)	Unit #2 Annual Emission[3] Uncontrolled (tons/year)	TOTAL Annual Emission Uncontrolled (tons/year)
Benzene	2.14E-04	0.00	0.00	0.00
Ethylbenzene	6.36E-05	0.00	0.00	0.00
Formaldehyde	3.30E-02	0.29	0.29	0.58
Naphthalene	1.13E-03	0.01	0.01	0.02
1,1,1-Trichloroethane	2.36E-04	0.00	0.00	0.00
Toluene	6.20E-03	0.05	0.05	0.11
o-Xylene	1.09E-04	0.00	0.00	0.00
Acenaphthene	2.11E-05	0.00	0.00	0.00
Fluorene	4.47E-06	0.00	0.00	0.00
Indo(1,2,3-cd)pyrene	2.14E-06	0.00	0.00	0.00
Phenanthrene	1.05E-05	0.00	0.00	0.00
Pyrene	4.25E-06	0.00	0.00	0.00
OCDD	3.10E-09	0.00	0.00	0.00
Metal HAPs				
Antimony	5.25E-03	0.05	0.05	0.09
Arsenic	1.32E-03	0.01	0.01	0.02
Barium	2.57E-03	0.02	0.02	0.05
Beryllium	2.78E-05	0.00	0.00	0.00
Cadmium	3.98E-04	0.00	0.00	0.01
Chloride	3.47E-01	3.02	3.07	6.09
Chromium	8.45E-04	0.01	0.01	0.01
Chromium VI	2.48E-04	0.00	0.00	0.00
Cobalt	6.02E-03	0.05	0.05	0.11
Copper	1.76E-03	0.02	0.02	0.03
Fluoride	3.73E-02	0.32	0.33	0.65
Lead	1.51E-03	0.01	0.01	0.03
Manganese	3.00E-03	0.03	0.03	0.05
Mercury	1.13E-04	0.00	0.00	0.00
Molybdenum	7.87E-04	0.01	0.01	0.01
Nickel	8.45E-02	0.73	0.75	1.48
Phosphorous	9.46E-03	0.08	0.08	0.17
Selenium	6.83E-04	0.01	0.01	0.01
Vanadium	3.18E-02	0.28	0.28	0.56
Zinc	2.91E-02	0.25	0.26	0.51
TOTAL HAPS		**5.26**	**5.35**	**10.61**

NOTE(s):

[1] See attached "Cabras Power Plant 2011 Monthly Fuel and Operation Summary Report"

[2] AP-42 Factor Used is Chapter 1, Tables 1.3-1, 1.3-3, 1.3-4, 1.3-9, 1.3-11

[3] Annual Emision = AP-42 Factor (lb/1000 gals) * Annual Fuel Consumption (gals/year) * (1ton/2000 lbs)

GUAM POWER AUTHORITY
CABRAS POWER PLANT
2011 ANNUAL EMISSION CALCULATION WORKSHEET

Diesel Engine Units #3 & #4

2011 Annual Hours of Operation and Annual Fuel Consumption[1 & 2]

Annual	Total Annual Hours of Operation[1]	Annual High Sulfur Fuel Oil (HSFO) Consumption[2] (Gallons)	Annual Low Sulfur Fuel Oil (LSFO) Consumption[2] (Gallons)	Average Annual Sulfur Content High Sulfur Fuel Oil (HSFO)[2]	Average Annual Sulfur Content Low Sulfur Fuel Oil (LSFO)[2]
Diesel Engine Unit #3	8,152	13,005,484	2,061,374	1.60	1.02
Diesel Engine Unit #4	8,078	12,639,964	1,989,220	1.60	1.02
Total/Average	**16,230**	**25,645,448**	**4,050,594**	**1.60**	**1.02**

2011 Annual Emission Calculations

Non-Hazardous Pollutant	Unit #3 Emissions Results[3] lbs/hr	Unit #3 Annual Emission[4] Controlled (tons/year)	Unit #4 Emissions Results[3] lbs/hr	Unit #4 Annual Emission[4] Controlled (tons/year)	TOTAL Annual Emission Controlled (tons/year)
SO_2	**375.10**	1,528.91	**650.30**	2,626.58	**4,155.49**
NOx as NO_2	**894.80**	3,647.20	**855.80**	3,456.60	**7,103.80**
CO	**56.50**	230.29	**54.50**	220.13	**450.42**
TOC	**25.10**	102.31	**20.70**	83.61	**185.92**
PM_{10}	**83.90**	341.98	**104.60**	422.48	**764.46**

Speciated Organic HAPs	AP-42 Factors[5] Uncontrolled (lb/1MM Btu)	Unit #3 Annual Emission[6] Uncontrolled (tons/year)	Unit #4 Annual Emission[6] Uncontrolled (tons/year)	TOTAL Annual Emission Uncontrolled (tons/year)
Benzene	7.76E-04	0.88	0.85	1.73
Formaldehyde	7.89E-05	0.09	0.09	0.18
Toluene	2.81E-04	0.32	0.31	0.63
o-Xylene	1.93E-04	0.22	0.21	0.43
Acetaldehyde	2.52E-05	0.03	0.03	0.06
Acrolein	7.88E-06	0.01	0.01	0.02
Propylene	2.79E-03	3.15	3.06	6.21

Polyaromatic Hydrocarbons (PAHs)	AP-42 Factors[5] Uncontrolled (lb/1MM Btu)	Unit #3 Annual Emission[6] Uncontrolled (tons/year)	Unit #4 Annual Emission[6] Uncontrolled (tons/year)	TOTAL Annual Emission Uncontrolled (tons/year)
Naphthalene	1.30E-04	0.15	0.14	0.29
Acenaphthene	4.68E-06	0.01	0.01	0.01
Acenaphthylene	9.23E-06	0.01	0.01	0.02
Anthracene	1.23E-06	0.00	0.00	0.00
Benz(a)anthracene	6.22E-07	0.00	0.00	0.00
Beno(b)fluoranthene	1.11E-06	0.00	0.00	0.00
Beno(k)fluoranthene	2.18E-07	0.00	0.00	0.00
Benzo(g,h,I)perylene	5.56E-07	0.00	0.00	0.00
Benzo (a) pyrene	2.57E-07	0.00	0.00	0.00
Chrysene	1.53E-06	0.00	0.00	0.00
Dibenzo(a,h)anthracene	3.46E-07	0.00	0.00	0.00
Fluoranthene	4.03E-06	0.00	0.00	0.01
Fluorene	1.28E-05	0.01	0.01	0.03
Indo(1,2,3-cd)pyrene	4.14E-07	0.00	0.00	0.00
Phenanthrene	4.08E-05	0.05	0.04	0.09
Pyrene	3.71E-06	0.00	0.00	0.01
TOTAL HAPS		**4.93**	**4.79**	**9.72**

NOTE(s)

[1] See attached "Cabras Power Plant 2011 Monthly Fuel and Operation Summary Report"

[2] See attached Plant Monthly Summary Report or Jan. - Dec. 2011

[3] Based on Tests performed by ETI August 23, 2011

[4] Annual Emission = Emissions Results (lbs/hr) * Total Annual Hours of Operation (Hours/Year) / 2000 (lbs/ton)

[5] AP-42 Factor Used is Chapter 3, Tables 3.4-3, 3.4-4

[6] Annual Emision = AP-42 Factor (lb/MMbtu) * Total (High Sulfur + Low Sulfur) Annual Fuel Consumption (gals/year) * (150MMBtu/1000gals) * (1ton/2000 lbs)

CABRAS POWER PLANT
2011 MONTHLY FUEL AND OPERATION SUMMARY REPORT

Month/Year	Cabras Unit #1				Cabras Unit #2			
	Fuel Used (Gallons)		Sulfur Content of #2 Fuel Oil (based on analysis)		Fuel Used (Gallons)		Sulfur Content of #2 Fuel Oil (based on analysis)	
	HSFO	LSFO	HSFO	LSFO	HSFO	LSFO	HSFO	LSFO
Jan-11	811,608	288,204	1.60	1.10	1,743,924	168,378	1.60	1.10
Feb-11	722,946	195,468	1.41	1.10	1,135,092	424,998	1.41	1.10
Mar-11	525,210	3,276	0.81	0.97	2,399,124	37,758	0.81	0.97
Apr-11	578,592	74,634	1.32	0.97	1,831,536	252,336	1.32	0.97
May-11	1,776,978	85,344	1.32	0.97	2,071,104	88,536	1.32	0.97
Jun-11	2,146,200	186,102	1.94	0.97	327,978	66,528	1.94	0.97
Jul-11	643,944	551,754	1.94	0.97	1,050,672	403,368	1.94	0.97
Aug-11	697,200	835,968	1.87	1.05	1,035,426	723,660	1.87	1.05
Sep-11	753,396	706,524	1.76	1.00	519,876	263,004	1.76	1.00
Oct-11	1,202,292	340,368	1.87	1.02	473,508	35,784	1.87	1.02
Nov-11	1,470,042	660,786	1.81	1.06	467,502	586,614	1.81	1.06
Dec-11	1,939,560	190,722	1.57	1.06	1,546,692	55,734	1.57	1.06
TOTAL	13,267,968	4,119,150			14,602,434	3,106,698		
AVERAGE			1.60	1.02			1.60	1.02

Month/Year	Cabras Unit #3					Cabras Unit #4				
	Fuel Used (Gallons)		Sulfur Content of #2 Fuel Oil (based on analysis)		Hours of Operation	Fuel Used (Gallons)		Sulfur Content of #2 Fuel Oil (based on analysis)		Hours of Operation
	HSFO	LSFO	HSFO	LSFO		HSFO	LSFO	HSFO	LSFO	
Jan-11	1,119,138	64,980	1.60	1.10	720.77	1,139,695	64,554	1.60	1.10	740.00
Feb-11	906,012	212,416	1.41	1.10	654.15	881,435	226,852	1.41	1.10	652.85
Mar-11	1,154,931	13,169	0.81	0.97	648.38	1,129,116	20,585	0.81	0.97	648.60
Apr-11	1,110,788	137,934	1.32	0.97	714.48	1,103,895	135,800	1.32	0.97	714.33
May-11	1,207,531	16,973	1.32	0.97	716.20	1,226,645	16,800	1.32	0.97	734.80
Jun-11	1,259,130	47,605	1.94	0.97	704.02	1,257,149	48,286	1.94	0.97	708.80
Jul-11	983,561	375,709	1.94	0.97	738.77	811,668	329,646	1.94	0.97	622.20
Aug-11	882,958	282,033	1.87	1.05	603.50	854,017	262,279	1.87	1.05	602.18
Sep-11	862,677	561,349	1.76	1.00	701.87	851,250	519,406	1.76	1.00	691.78
Oct-11	1,182,301	291,020	1.87	1.02	733.13	1,056,207	283,931	1.87	1.02	685.17
Nov-11	959,659	58,186	1.81	1.06	524.70	1,240,334	81,081	1.81	1.06	686.12
Dec-11	1,376,798	-	1.57	1.06	692.02	1,088,553	-	1.57	1.06	591.23
TOTAL	13,005,484	2,061,374			8,151.99	12,639,964	1,989,220			8,078.06
AVERAGE			1.60	1.02				1.60	1.02	

GUAM POWER AUTHORITY
DEDEDO POWER GENERATING FACILITY
2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	CT #1 Annual Emission (Tons/Year)	CT #2 Annual Emission (Tons/Year)	Diesels #1 - #4 Annual Emission (Tons/Year)	TOTAL Annual Emission (Tons/Year)
SO_2	0.15	0.00	0.03	0.18
NO_x	0.07	0.00	1.06	1.13
VOC	0.00	0.00	0.03	0.03
PM (total)	0.02	0.00	0.03	0.05
Total Tons/Year	**0.24**	**0.00**	**1.15**	**1.39**

Regulated HAP Pollutant	CT #1 Annual Emission (Tons/Year)	CT #2 Annual Emission (Tons/Year)	Diesels #1 - #4 Annual Emission (Tons/Year)	TOTAL Annual Emission (Tons/Year)
Total HAPs	**0.00**	**0.00**	**0.00**	**0.00**

2011 Annual Fee Calculations[2]

Cost for Regulated Pollutant @ $6.00/Ton	$12.00
Cost for HAPs @ $60/ton	$0.00
Total	**$12.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
DEDEDO POWER GENERATING FACILITY
2011 ANNUAL EMISSION CALCULATION WORKSHEET

Combustion Turbines Unit #1 & #2

2011 Annual Fuel Consumption[1]

Annual	Above 80% Load (Hours)	Below 80% Load (Hours)	Total Annual Hours of Opertion	Annual Fuel Consumption (Gallons)	Average Annua Sulfur Content
Unit #1	0.00	2.33	2.33	3,753	0.0920
Unit #2	0.00	0.00	0.00	0	0.0920
Total / Average			**2.33**	**3,753**	**0.0920**

2011 Annual Emission Calculations

Non-Hazardous Pollutant	AP-42 Factors[2] Controlled (lb/MMBTU)	Unit #1 Emission Results lb/hr[6]	Unit #1 Annual Emission Controlled (tons/year)[7]	Unit #2 Annual Emission Controlled (tons/year)[3]	TOTAL Annual Emissio Controlled (tons/year)
SO2[4]	1.01	126.04	0.15	0.00	**0.15**
NOx[5]	0.24	61.62	0.07	0.00	**0.07**
CO[5]	0.076	9.80	0.01	0.00	**0.01**
VOC	0.00041	0.59	0.00	0.00	**0.00**
PM (total)	0.012	15.80	0.02	0.00	**0.02**

Hazardous Air Pollutants	AP-42 Factors[2] Uncontrolled (lb/MMBTU)	Unit #1 Annual Emission[3] Uncontrolled (tons/year)	Unit #2 Annual Emission[3] Uncontrolled (tons/year)	TOTAL Annual Emission Uncontrolled (tons/year)
1,3 Butadiene	1.60E-05	0.000	0.000	0.000
Benzene	5.50E-05	0.000	0.000	0.000
Formaldehyde	2.80E-04	0.000	0.000	0.000
Naphthalene	3.50E-05	0.000	0.000	0.000
PAH	4.00E-05	0.000	0.000	0.000
Arsenic	1.10E-05	0.000	0.000	0.000
Beryllium	3.10E-07	0.000	0.000	0.000
Cadmium	4.80E-06	0.000	0.000	0.000
Chromium	1.10E-05	0.000	0.000	0.000
Lead	1.40E-05	0.000	0.000	0.000
Manganese	7.90E-04	0.000	0.000	0.000
Mercury	1.20E-06	0.000	0.000	0.000
Nickel	4.60E-06	0.000	0.000	0.000
Selenium	2.50E-05	0.000	0.000	0.000
TOTAL HAPs:		0.000	0.000	**0.000**

NOTE(s)

[1] See 2011 Monthly Fuel Report Summary

[2] AP-42 Factor Used is Chapter 3, Tables 3.1-1, 3.1-2a, 3.1-4, 3.1-5

[3] Annual Emislon = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.0920

[5] Water Injection used for NOx and CO emission controls.

[6] CT Unit #1 Tested by ETI on Sept. 15, 2006

[7] Annual Emissions = Test Result x Annual Hours of Operation

GUAM POWER AUTHORITY
DEDEDO POWER GENERATING FACILITY
2011 ANNUAL EMISSION CALCULATION WORKSHEET

Dededo Diesel Engines Units #1 - #4

2011 Annual Fuel Consumption

Annual	Annual Fuel Consumption (Gallons)	Average Annual Sulfur Content (% by weight)
January 2011 - December 2011	4,752	0.0920

2011 Annual Emission Calculations

Regulated Pollutant	Annual Fuel Consumption (Gallons)	AP-42 Factors[2]	Annual Emission[3]
		Uncontrolled (lb/MMBTU)	Uncontrolled (tons/year)
SO2[4]	4,752	1.01	**0.03**
NOx	4,752	3.20	**1.06**
CO	4,752	0.85	**0.28**
VOC	4,752	0.09	**0.03**
PM (total)	4,752	0.10	**0.03**

Hazardous Air Pollutants[5]	Annual Fuel Consumption (gals/year)	AP-42 Factors[2]	Annual Emission[3]
		Uncontrolled (lb/MMBTU)	Uncontrolled (Tons/Year)
Benzene	4,752	7.76E-04	**0.00**
Toluene	4,752	2.81E-04	**0.00**
Xylenes	4,752	1.93E-04	**0.00**
Formaldehyde	4,752	7.89E-05	**0.00**
Acetaldehyde	4,752	2.52E-05	**0.00**
Acrolein	4,752	7.88E-06	**0.00**
Napthalene	4,752	1.30E-04	**0.00**
TOTAL HAPs:			**0.00**

NOTE(s)

[1]See attached Plant Monthly Summary Report for Jan. - Dec. 2011

[2] AP-42 Factor Used is Chapter 3, Tables 3.4-1, 3.4-3, 3.4-4

[3] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.0920

[5] Hazardous Air Pollutant listed in the Clean Air Act.

GUAM POWER AUTHORITY
DEDEDO POWER GENERATING FACILITY
2011 MONTHLY FUEL REPORT SUMMARY

Month/Year	Dededo CT1				Dededo CT2				Dededo Diesel Units #1 - #4	
	Total On-line Hrs.		Fuel Used (Gallons)	Sulfur Content of #2 Fuel Oil (based on analysis)	Total On-line Hrs.		Fuel Used (Gallons)	Sulfur Content of #2 Fuel Oil (based on analysis)	Fuel Used (Gallons)	Sulfur Content of #2 Fuel Oil (based on analysis)
	Above 80% Load	Below 80% Load			Above 80% Load	Below 80% Load				
Jan-11	0.00	0.00	1,624	0.0920	0.00	0.00	0	0.0920	0	0.0920
Feb-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Mar-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Apr-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
May-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	672	0.0920
Jun-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Jul-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	3,232	0.0920
Aug-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Sep-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Oct-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	848	0.0920
Nov-11	0.00	2.33	2,129	0.0920	0.00	0.00	0	0.0920	0	0.0920
Dec-11	0.00	0.00	0	0.0920	0.00	0.00	0	0.0920	0	0.0920
Totals	**0.00**	**2.33**	**3,753**		**0.00**	**0.00**	**0**		**4,752**	
Average				**0.0920**				0.0920		0.0920

GUAM POWER AUTHORITY

23-MW DEDEDO C.T. UNIT NO. 1 SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011				
MONTH	TOTAL ON LINE HOURS		SULFUR CONTENT of # 2 Fuel Oil (based on analysis)	EMISSION TEST RESULTS (lbs/hr)
	Above 80% Load	Below 80% Load		
JANUARY	0.00	0.00	0.092	(see note 2 below)
FEBRUARY	0.00	0.00	0.092	(see note 2 below)
MARCH	0.00	0.00	0.092	(see note 2 below)
APRIL	0.00	0.00	0.092	(see note 2 below)
MAY	0.00	0.00	0.092	(see note 2 below)
JUNE	0.00	0.00	0.092	(see note 2 below)
JULY	0.00	0.00	0.092	(see note 2 below)
AUGUST	0.00	0.00	0.092	(see note 2 below)
SEPTEMBER	0.00	0.00	0.092	(see note 2 below)
OCTOBER	0.00	0.00	0.092	(see note 2 below)
NOVEMBER	0.00	2.33	0.092	(see note 2 below)
DECEMBER	0.00	0.00	0.092	(see note 2 below)
TOTAL	**0.00**	**2.33**		
AVERAGE			**0.092**	

NOTES:

1. The following are conditions based on GEPA permit no. F0-003, dated May 11, 2009

   a. Total Hours of Operation per calendar year shall not exceed 7760 hours above 80% load and 1000 at 50% load

   b. Maximum Sulfur content of No. 2 fuel oil shall not exceed 0.6 percent by weight.

   c. The water to fuel ratio shall not go below 0.63 @ 50% load and 0.59 @ 100% load

2. Dededo CT Unit no. 1 is currently not operational and therefore was not tested during this year's emission test program

3. Emission testing last was conducted on September 15, 2006 @ 50% and 100% load, test results are as follow:

	50% load		100% load	
Parameter	**Emission Result**	**Emission limit**	**Emission Result**	**Emission limit**
CO(lbs/hr)	61.97	86.00	9.80	21.00
NOx(lbs/hr)	18.65	49.00	61.62	83.00
THC(lbs/hr)	3.74	14.00	0.59	4.00
SO2(lbs/hr)	-	-	126.04	218.00
OPACITY(%)	-		0.00	10.00
PM(lbs/hr)	-	-	15.80	19.80

GUAM POWER AUTHORITY

23-MW DEDEDO C.T. UNIT NO. 2 SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH NOVEMBER 2011				
MONTH	TOTAL ON LINE HOURS		SULFUR of # 2 Fuel Oil (based on analysis)	EMISSION TEST RESULTS (lbs/hr)
	Above 80% Load	Below 80% Load		
JANUARY	0.00	0.00	0.092	(see note 2 below)
FEBRUARY	0.00	0.00	0.092	(see note 2 below)
MARCH	0.00	0.00	0.092	(see note 2 below)
APRIL	0.00	0.00	0.092	(see note 2 below)
MAY	0.00	0.00	0.092	(see note 2 below)
JUNE	0.00	0.00	0.092	(see note 2 below)
JULY	0.00	0.00	0.092	(see note 2 below)
AUGUST	0.00	0.00	0.092	(see note 2 below)
SEPTEMBER	0.00	0.00	0.092	(see note 2 below)
OCTOBER	0.00	0.00	0.092	(see note 2 below)
NOVEMBER	0.00	0.00	0.092	(see note 2 below)
DECEMBER	0.00	0.00	0.092	(see note 2 below)
TOTAL	**0.00**	**0.00**		
AVERAGE			**0.092**	

NOTES:

1. The following are conditions based on GEPA permit no. F0-003, dated May 11, 2009

   a. Total Hours of Operation per calendar year shall not exceed 7760 hours above 80% load and 1000 at 50% load

   b. Maximum Sulfur content of No. 2 fuel oil shall not exceed 0.6 percent by weight.

   c. The water to fuel ratio shall not go below 0.63 @ 50% load and 0.59 @ 100% load

2. Dededo CT Unit no. 2 is currently not operational and therefore was not tested during this year's emission test program

3. Emission testing was conducted @ 100% load on September 28-29, 1996.

Parameter	Emission Result	Emission Limit
Nox(lbs/hr)	74.10	83.00
SO2(lbs/hr)	89.20	218.00
PM10(lbs/hr)	14.10	20.00

EPA monthly summary report

GUAM POWER AUTHORITY

DEDEDO DIESEL PLANT MONTHLY SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011

MONTH	FUEL USED (GALLONS)	SULFUR CONTENT of # 2 Fuel Oil (based on analysis)
JANUARY	0	0.092
FEBRUARY	0	0.092
MARCH	0	0.092
APRIL	0	0.092
MAY	672	0.092
JUNE	0	0.092
JULY	3,232	0.092
AUGUST	0	0.092
SEPTEMBER	0	0.092
OCTOBER	848	0.092
NOVEMBER	0	0.092
DECEMBER	0	0.092
TOTAL	**4,752**	
AVERAGE		**0.092**

NOTES:

1. Maximum Sulfur content of No.2 fuel oil shall not exceed 0.6 percent by weight (Based on GEPA permit no. FO-003, dated May 1
2. Emission test was conducted on July 27-29, 2011
3. Dededo Dieseil Unit no. 4 is currently not operational and therefore was not tested during this year's emission test program
4. Sulfur content has been revised in this report due to an error in coversion in previous report.

Test results are as follow:

Parameter	Emission Unit	Emission Result (lb/hr)	Emission Limit (lb/hr)
PM	Unit 1	3.39	
	Unit 2	4.65	
	Unit 3	1.41	
	Total	9.45	32.00
SO2	Unit 1	10.64	
	Unit 2	10.76	
	Unit 3	10.65	
	Total	32.05	57.60
NOx	Unit 1	31.60	
	Unit 2	34.00	
	Unit 3	52.50	
	Total	118.10	320.00

GUAM POWER AUTHORITY
MACHECHE COMBUSTION TURBINE POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Annual Emission (Tons/Year)
SO2	6.21
NOx	3.32
VOC	0.09
PM (total)	0.78
Total Tons/Year	**10.40**

Regulated HAP Pollutant	Annual Emission (Tons/Year)
Total HAPs	**0.02**

2011 Annual Fee Calculations[2]

Cost for Regulated Pollutant @ $6.00/Ton	$66.00
Cost for HAPs @ $60/ton	$0.00
Total	**$66.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (j) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
MACHECHE COMBUSTION TURBINE POWER GENERATING FACILITY

2011 ANNUAL EMISSION CALCULATION WORKSHEET

2011 Annual Fuel Consumption [1]

Annual	Annual Fuel Consumption (Gallons)	Annual Hours of Opertion	Average Annual Sulfur Content
January 2011 - December 2011	195,726	153	0.06160

2011 Annual Emission Calculations

Non-Hazardous Pollutant	Emmision Test Results [2]	Annual Emission[3]
	lb/hr	(tons/year)
SO2	81.10	6.21
NOx	43.30	3.32
CO	11.70	0.90
VOC	1.12	0.09
PM (total)	10.20	0.78

Hazardous Air Pollutants	AP-42 Factors [4]	Annual Emission[5]
	(lb/MMBTU)	(tons/year)
1,3 Butadiene	1.60E-05	0.00
Benzene	5.50E-05	0.00
Formaldehyde	2.80E-04	0.00
Naphthalene	3.50E-05	0.00
PAH	4.00E-05	0.00

Metallic Hazardous Air Pollutants	AP-42 Factors [4]	Annual Emission[5]
	(lb/MMBTU)	(tons/year)
Arsenic	1.10E-05	0.00
Beryllium	3.10E-07	0.00
Cadmium	4.80E-06	0.00
Chromium	1.10E-05	0.00
Lead	1.40E-05	0.00
Manganese	7.90E-04	0.01
Mercury	1.20E-06	0.00
Nickel	4.60E-06	0.00
Selenium	2.50E-05	0.00
TOTAL HAPs:		0.02

NOTE(s)

[1] See 2011 Monthly Fuel and Operation Summary Report

2 Emission testing was conducted @ 50% and 100% on August 3-4, 2011

[3] Annual Emision = Operating Hours (hr/yr) * Emission Rate (lb/hr) * (1ton/2000 lbs)

[4] AP-42 Factor Used is Chapter 3, Tables 3.1-1, 3.1-2a, 3.1-4, 3.1-5

[5] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[6] Water Injection used for NOx and CO emission controls.

GUAM POWER AUTHORITY
MACHECHE COMBUSTION TURBINE POWER GENERATING FACILITY

2011 MONTHLY FUEL AND OPERATION SUMMARY REPORT

Month/Year	Fuel Used (Gallons)	Hours of Operation	Sulfur Content of #2 Fuel Oil (based on analysis)
Jan-11	4,362	3.30	0.09200
Feb-11	4,160	3.25	0.09200
Mar-11	25,105	5.77	0.09200
Apr-11	10,853	7.83	0.09200
May-11	12,327	8.62	0.09200
Jun-11	19,784	15.05	0.09200
Jul-11	6,935	7.27	0.09200
Aug-11	45,889	39.30	0.09200
Sep-11	43,775	43.30	0.00081
Oct-11	12,682	11.87	0.00081
Nov-11	9,854	7.65	0.00070
Dec-11	0	0.00	0.00082
	195,726	153.21	0.06160
	Total	**Total**	**Average**

GUAM POWER AUTHORITY

22-MW MACHECHE C.T. UNIT SUMMARY REPORT

PERIOD COVERED:JANUARY THROUGH DECEMBER 2011			
MONTH	FUEL USED (GALLONS)	SULFUR of # 2 Fuel Oil (based on analysis)	EMISSION TEST RESULTS (lbs/hr)
JANUARY	4,362	0.09	(see note 2 below)
FEBRUARY	4,160	0.09	(see note 2 below)
MARCH	25,105	0.0920	(see note 2 below)
APRIL	10,853	0.0920	(see note 2 below)
MAY	12,327	0.0920	(see note 2 below)
JUNE	19,784	0.0920	(see note 2 below)
JULY	6,935	0.0920	(see note 2 below)
AUGUST	45,889	0.0920	(see note 2 below)
SEPTEMBER	43,775	0.00081	(see note 2 below)
OCTOBER	12,682	0.00081	(see note 2 below)
NOVEMBER	9,854	0.00070	(see note 2 below)
DECEMBER	0	0.00082	(see note 2 below)
TOTAL	**195,726**		
AVERAGE		**0.06160**	

NOTES:

1. The following are conditions based on GEPA permit no. FO-004, dated May 11, 2009:

   a. Total Yearly Consumption shall not exceed 7,140,000 gallons this shall be calculated on a 12-month rolling average basis.
   b. Maximum Sulfur content of No. 2 fuel oil shall not exceed 0.5 percent by weight.
   c. The water to fuel ratio shall not go below 0.73 @30% load
   d. The water to fuel ratio shall not go below 0.82 @100% load

2. Emission testing was conducted @ 50% and 100% on August 3-4, 2011

3.Sulfur content has been revised in this report due to an error in coversion in previous report.

Test results are as follow:

	50% load		100% load
Paramter	**Emission Result**	**Emission Limit**	**Emission Result**
PM(lbs/hr)			10.20
SO2(lbs/hr)			81.10
NOx(lbs/hr)			43.30
CO(lbs/hr)			11.70
THC(lbs/hr)	1.12	4.00	

GUAM POWER AUTHORITY
MANENGGON DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	0.26
NOx	30.55
VOC	1.45
PM (total)	1.61
Total Tons/Year	**33.87**

Regulated HAP Pollutant	TOTAL Actual Annual Emission (Tons/Year)
Total HAPs	**0.024**

2011 Annual Fee Calculations [2]

Cost for Regulated Pollutant @ $6.00 /Ton	$204.00
Cost for HAPs @ $60 /Ton	$0.00
Total 2011 Annual Fee Due:	**$204.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
MANENGGON DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSION CALCULATION WORKSHEET

2011 Annual Fuel Consumption

Annual	Annual Fuel Consumption (Gallons)	Average Annual Sulfur Content
January 2011 - December 2011[1]	231,350	0.01603

2011 Annual Emission Calculations

Regulated Pollutant	Annual Fuel Consumption (Gallons)	AP-42 Factors Controlled (lb/MMBTU)[2]	Annual Emission Controlled (tons/year)[3]
SO_2[6]	231,350	1.01	**0.26**
NOx[4]	231,350	1.90	**30.55**
CO	231,350	0.85	**13.67**
VOC	231,350	0.09	**1.45**
PM (total)	231,350	0.10	**1.61**

Hazardous Air Pollutants[5]	Annual Fuel Consumption (gals/year)	AP-42 Factors Uncontrolled (lb/MMBTU)[2]	Annual Emission Uncontrolled (Tons/Year)[3]
Benzene	231,350	7.76E-04	**0.012**
Toluene	231,350	2.81E-04	**0.005**
Xylenes	231,350	1.93E-04	**0.003**
Formaldehyde	231,350	7.89E-05	**0.001**
Acetaldehyde	231,350	2.52E-05	**0.000**
Acrolein	231,350	7.88E-06	**0.000**
Napthalene	231,350	1.30E-04	**0.002**
TOTAL HAPs:			**0.024**

NOTE(s)

[1] See attached Plant Monthly Summary Report for Jan. - Dec. 2011

[2] AP-42 Factor Used is Chapter 3, Tables 3.4-1, 3.4-3, 3.4-4

[3] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] Controlled NOx is by ignition timing retard

[5] Hazardous Air Pollutant listed in the Clean Air Act.

[6] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.01603

GUAM POWER AUTHORITY

MANENGGON DIESEL UNITS MONTHLY SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011

MONTH	FUEL USED (GALLONS)	SULFUR CONTENT of # 2 Fuel Oil (based on analysis)
JANUARY	1,674	0.09
FEBRUARY	13,881	0.09
MARCH	75,862	0.00072
APRIL	25,343	0.00107
MAY	1,201	0.00107
JUNE	13,816	0.00079
JULY	344	0.00079
AUGUST	6,198	0.00079
SEPTEMBER	29,346	0.00079
OCTOBER	16,765	0.00081
NOVEMBER	33,895	0.00070
DECEMBER	13,025	0.00079
TOTAL	**231,350**	
AVERAGE		**0.01603**

NOTES:

1. The following are conditions based on GEPA permit no. FO-005, dated May 11, 2009:

   a. Total Yearly Fuel Consumption shall be not exceed 1,305,543 gallons and calculated on a 12-month rolling average basis.
   b. Maximum Sulfur content of No.2 fuel oil shall not exceed 0.6 percent by weight.

2. Emission test was conducted at 100% load on August 16 to 17, 2011

3.Sulfur content has been revised in this report due to an error in coversion in previous report.

Ttest results are as follow:

Parameter	Emission Results Unit No. 1 (lb/hr)	Emission Results Unit No. 2 (lb/hr)	Emission Limit (lb/hr)
PM	1.48	1.24	4.95
SO2	0.87	1.63	29.80
NOx	67.50	100.70	127.85
CO	7.70	7.65	17.10
THC	1.90	2.05	6.10

GUAM POWER AUTHORITY
MARBO COMBUSTION TURBINE POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	0.00
NOx	0.00
VOC	0.00
PM (total)	0.00
Total Tons/Year	**0.00**

Regulated HAP Pollutant	Actual Annual Emission (Tons/Year)
Total HAPs	**0.00**

2011 Annual Fee Calculations[2]

Cost for Regulated Pollutant @ $6.00/Ton	$0.00
Cost for HAPs @ $60/ton	$0.00
Total	**$0.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
MARBO COMBUSTION TURBINE POWER GENERATING FACILITY

2011 Annual Fuel Consumption

Annual		Annual Fuel Consumption (Gallons)	Average Annual Sulfur Content
January 2011 - December 2011		0	0.0920

2011 Annual Emissions

Non-Hazardous Pollutant	Annual Fuel Consumption (gals/year)	AP-42 Factors[2] Water-Steam Injection (lb/MMBTU)	Annual Emission[3] Water-Steam Injection (tons/year)
SO2[5]	0	1.01	0.00
NOx[4]	0	0.24	0.00
CO[4]	0	0.076	0.00
VOC	0	0.00041	0.00
PM (total)	0	0.012	0.00
CO2	0	157	0.00
Hazardous Air Pollutants	**Annual Fuel Consumption (gals/year)**	**AP-42 Factors[2] Uncontrolled (lb/MMBTU)**	**Annual Emission[3] Uncontrolled (tons/year)**
1,3 Butadiene	0	1.60E-05	0.00
Benzene	0	5.50E-05	0.00
Formaldehyde	0	2.80E-04	0.00
Naphthalene	0	3.50E-05	0.00
PAH	0	4.00E-05	0.00
Metallic Hazardous Air Pollutants	**Annual Fuel Consumption (gals/year)**	**AP-42 Factors[2] Water-Steam Injection (lb/MMBTU)**	**Annual Emission[3] Water-Steam Injection (tons/year)**
Arsenic	0	1.10E-05	0.00
Beryllium	0	3.10E-07	0.00
Cadmium	0	4.80E-06	0.00
Chromium	0	1.10E-05	0.00
Lead	0	1.40E-05	0.00
Manganese	0	7.90E-04	0.00
Mercury	0	1.20E-06	0.00
Nickel	0	4.60E-06	0.00
Selenium	0	2.50E-05	0.00
TOTAL HAPs:			**0.00**

NOTE(s)

[1] See attached Plant Monthly Summary Report for Jan. - Dec. 2011

[2] AP-42 Factor Used is Chapter 3, Tables 3.1-1, 3.1-2a, 3.1-4, 3.1-5

[3] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] Water Injection used for NOx and CO emission controls.

[5] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.0920

GUAM POWER AUTHORITY

15.2-MW MARBO C.T. UNIT SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011			
MONTH	**FUEL USED (GALLONS)**	**SULFUR CONTENT of # 2 Fuel Oil (based on analysis)**	**EMISSION TEST RESULTS (lbs/hr)**
JANUARY	0	0.092	(see note 4 below)
FEBRUARY	0	0.092	(see note 4 below)
MARCH	0	0.092	(see note 4 below)
APRIL	0	0.092	(see note 4 below)
MAY	0	0.092	(see note 4 below)
JUNE	0	0.092	(see note 4 below)
JULY	0	0.092	(see note 4 below)
AUGUST	0	0.092	(see note 4 below)
SEPTEMBER	0	0.092	(see note 4 below)
OCTOBER	0	0.092	(see note 4 below)
NOVEMBER	0	0.092	(see note 4 below)
DECEMBER	0	0.092	(see note 4 below)
TOTAL	**0**		
AVERAGE		**0.092**	

NOTES:

1. The following are conditions based on GEPA permit no. FO-004, dated May 11, 2009:

   a. Total Yearly Consumption shall not exceed 4,760,000 gallons
      this shall be calculated on a 12-month rolling average basis.
   b. Maximum Sulfur content of No. 2 fuel oil shall not exceed 0.75 percent by weight.
   c. The water to fuel ratio shall not go below 0.41 whenever CT is in operation.
   d. Water injection is not required for loads below 7 MW.

2. Guam Power Authority officially took over the plant from the US Navy PWC on Oct. 16, 1995.

3. Marbo CT Unit is currently not operational and therefore was not tested during this year's emission test program

4. Emission testing was conducted at 100% load on December 12, 1996

Test results are as follow:

Parameter	**Emission Result**	**Emission Limit**
PM(lb/hr)	6.6	9.3
SO2(lb/hr)	64.80	188.00
CO(lb/hr)	22.10	28.60
NOx(lb/hr)	36.50	98.20
THC(lb/hr)		10.30

GUAM POWER AUTHORITY
TALOFOFO DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	0.13
NOx	29.89
VOC	1.42
PM (total)	1.57
Total Tons/Year	**33.01**

Regulated HAP Pollutant	TOTAL Actual Annual Emission (Tons/Year)
Total HAPs	**0.02**

2011 Annual Fee Calculations[2]

Cost for Regulated Pollutant @ $6.00 /Ton	$204.00
Cost for HAPs @ $60 /Ton	$0.00
Total 2011 Annual Fee Due:	**$204.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
TALOFOFO DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSIONS CALCULATION WORKSHEET

2011 Annual Fuel Consumption

Annual	Annual Fuel Consumption (Gallons)	Average Annual Sulfur Content
January 2011 - December 2011[1]	226,322	0.00835

2011 Annual Emission Calculations

Regulated Pollutant	Annual Fuel Consumption (Gallons)	AP-42 Factors Uncontrolled (lb/MMBTU)[2]	Annual Emission Controlled (tons/year)[3]
SO2[6]	226,322	1.01	**0.13**
NOx[4]	226,322	1.90	**29.89**
CO	226,322	0.85	**13.37**
VOC	226,322	0.09	**1.42**
PM (total)	226,322	0.10	**1.57**

Hazardous Air Pollutants[5]	Annual Fuel Consumption (gals/year)	AP-42 Factors Uncontrolled (lb/MMBTU)[2]	Annual Emission Uncontrolled (Tons/Year)[3]
Benzene	226,322	7.76E-04	**0.012**
Toluene	226,322	2.81E-04	**0.004**
Xylenes	226,322	1.93E-04	**0.003**
Formaldehyde	226,322	7.89E-05	**0.001**
Acetaldehyde	226,322	2.52E-05	**0.000**
Acrolein	226,322	7.88E-06	**0.000**
Napthalene	226,322	1.30E-04	**0.002**
TOTAL HAPs:			**0.023**

NOTE(s)

[1] See attached Plant Monthly Summary Report for Jan. - Dec. 2011

[2] AP-42 Factor Used is Chapter 3, Tables 3.4-1, 3.4-3, 3.4-4

[3] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] Controlled NOx is by ignition timing retard

[5] Hazardous Air Pollutant listed in the Clean Air Act.

[6] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.00835

GUAM POWER AUTHORITY

TALOFOFO DIESEL UNITS MONTHLY SUMMARY REPORT
(Consist of 2 units with nominal rating of 4.88MW each)

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011

MONTH	FUEL USED (GALLONS)	SULFUR CONTENT of # 2 Fuel Oil (based on analysis)
JANUARY	1,438	0.0920
FEBRUARY	13,555	0.0012
MARCH	71,105	0.00072
APRIL	26,897	0.00060
MAY	2,001	0.00060
JUNE	0	0.00079
JULY	11,194	0.00064
AUGUST	0	0.00064
SEPTEMBER	41,968	0.00070
OCTOBER	21,526	0.00081
NOVEMBER	30,864	0.00070
DECEMBER	5,774	0.00079
TOTAL	**226,322**	
AVERAGE		**0.00835**

NOTES:

1. The following are conditions based on GEPA permit no. FO-007, dated May 11, 2009:

   a. Total Yearly Fuel Consumption shall not exceed 1,480,851 gallons and calculated on a 12-month rolling average basis.
   b. Maximum Sulfur content of No.2 fuel oil shall not exceed 0.6 percent by weight.

2. Emission tests were conducted at 100% load on July 19-20, 2011

3.Sulfur content has been revised in this report due to an error in coversion in previous report.

Test results are as follow:

Parameter	Emission Result Unit no. 1 (lb/hr)	Emission Result Unit no. 2 (lb/hr)	Emmission Limit (lb/hr)
PM	2.42	2.43	9.27
SO2	0.496	0.33	27
NOx	77.6	78.80	107.70
CO	16.2	16.00	23.94
THC	2.28	1.29	5.24

GUAM POWER AUTHORITY
TENJO DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	1.34
NOx	157.02
VOC	7.44
PM (total)	8.26
Total Tons/Year	**174.06**

Regulated HAP Pollutant	TOTAL Actual Annual Emission (Tons/Year)[2]
Total HAPs	**0.12**

2011 Annual Fee Calculations[2]

Cost for Regulated Pollutant @ $6.00 /Ton	$1,050.00
Cost for HAPs @ $60 /Ton	$60.00
Total 2011 Annual Fee Due:	**$1,110.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
TENJO DIESEL POWER GENERATING FACILITY

2011 ANNUAL EMISSION CALCULATION WORKSHEET

2011 Annual Fuel Consumption

Annual	Annual Fuel Consumption (Gallons)	Average Annual Sulfur Content
January 2011 - December 2011[1]	1,189,069	0.01603

2011 Annual Emission Calculations

Regulated Pollutant	Annual Fuel Consumption (Gallons)	AP-42 Factors[2] Controlled (lb/MMBTU)	Annual Emission[3] Controlled (tons/year)
SO2[6]	1,189,069	1.01	**1.34**
NOx[4]	1,189,069	1.90	**157.02**
CO	1,189,069	0.85	**70.24**
VOC	1,189,069	0.09	**7.44**
PM (total)	1,189,069	0.10	**8.26**
TOTAL:			**244.30**

Hazardous Air Pollutants[5]	Annual Fuel Consumption (gals/year)	AP-42 Factors[2] Uncontrolled (lb/MMBTU)	Annual Emission[3] Uncontrolled (Tons/Year)
Benzene	1,189,069	7.76E-04	0.06
Toluene	1,189,069	2.81E-04	0.02
Xylenes	1,189,069	1.93E-04	0.02
Formaldehyde	1,189,069	7.89E-05	0.01
Acetaldehyde	1,189,069	2.52E-05	0.00
Acrolein	1,189,069	7.88E-06	0.00
Napthalene	1,189,069	1.30E-04	0.01
TOTAL HAPs:			**0.12**

NOTE(s)

[1] See attached Plant Monthly Summary Report for Jan. - Dec. 2011

[2] AP-42 Factor Used is Chapter 3, Tables 3.4-1, 3.4-3, 3.4-4

[3] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

[4] Controlled NOx is by ignition timing retard

[5] Hazardous Air Pollutant listed in the Clean Air Act.

[6] SO2 factor is multiplied by sulfur content. Thus, 1.01 (AP-42 of SO2) is multiplied by 0.01603

GUAM POWER AUTHORITY

TENJO VISTA DIESEL UNITS MONTHLY SUMMARY REPORT
(Consist of 6 units with nominal rating of 4.88MW each)

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011

MONTH	FUEL USED (GALLONS)	SULFUR CONTENT of # 2 Fuel Oil (based on analysis)
JANUARY	7,134	0.09200
FEBRUARY	25,719	0.09200
MARCH	202,222	0.00078
APRIL	57,258	0.00107
MAY	14,011	0.00107
JUNE	88,155	0.00079
JULY	65,029	0.00075
AUGUST	145,892	0.00073
SEPTEMBER	198,557	0.00081
OCTOBER	94,330	0.00081
NOVEMBER	190,218	0.00070
DECEMBER	100,534	0.00082
TOTAL	**1,189,059**	
AVERAGE		**0.01603**

NOTES:

1. The following are conditions based on GEPA permit no. FO-008, dated May 11, 2009:

   a. GPA shall not operate any of the diesel engine below 50% of the rated load except during periods of startup, shutdown, testing or maintenance.
   b. Maximum Sulfur content of No.2 fuel oil shall not exceed 0.3% by weight.

2. Emission test was conducted at 100% load on July 11 to 15 / August 19, 2011

3.Sulfur content has been revised in this report due to an error in coversion in previous report.

Test results are as follow:

	PM (lb/hr)	SO2 (lb/hr)	Nox (lb/hr)	CO (lb/hr)	THC (lb/hr)
Unit no. 1	2.28	0.386	56.7	15.80	1.30
Unit no. 2	2.42	0.18	66.50	13.40	1.50
Unit no. 3	1.65	0.07	68.20	11.50	1.78
Unit no. 4	1.91	0.30	73.50	18.10	1.39
Unit no. 5	1.07	0.02	77.80	9.23	1.99
Unit no. 6	2.61	0.15	85.20	21.70	1.18
Emission Limit	**6.50**	**13.50**	**120.00**	**24.00**	**5.00**

GUAM POWER AUTHORITY
YIGO COMBUSTION TURBINE POWER GENERATING FACILITY

2011 ANNUAL EMISSION FEE CALCULATION WORKSHEET

2011 Annual Emissions[1]

Regulated Pollutant	Actual Annual Emission (Tons/Year)
SO2	0.05
NOx	1.75
VOC	0.01
PM (total)	0.18
Total Tons/Year	**1.99**

Regulated HAP Pollutant	Actual Annual Emission (Tons/Year)
Total HAPs	**0.012**

2011 Annual Fee Calculations

Cost for Regulated Pollutant @ $6.00/Ton	$12.00
Cost for HAPs @ $60/ton	$0.00
Total	**$12.00**

2011 Annual Minimum Fee is	**$500.00**

note(s)

[1] See 2011 Annual Emission Calculation Worksheets

[2] Guam Air Pollution Control Standards and Regulations 1104.24 (i) states "...Emissions of any pollutant calculated at less than 0.1 ton shall not be subjct to fees."

GUAM POWER AUTHORITY
YIGO COMBUSTION TURBINE POWER GENERATING FACILITY

2011 ANNUAL EMISSION CALCULATION WORKSHEET

2011 Annual Fuel Consumption [1]

Annual	Annual Fuel Consumption (Gallons)	Annual Hours of Opertion	Average Annual Sulfur Content
January 2011 - December 2011	131,048	95	0.00082

2011 Annual Emission Calculations

Non-Hazardous Pollutant	Emmision Test Results [2]	Annual Emission[3]
	lb/hr	(tons/year)
SO2	1.11	0.05
NOx	36.90	1.75
CO	16.40	0.78
VOC	0.16	0.01
PM (total)	3.79	0.18

Hazardous Air Pollutants	AP-42 Factors [4]	Annual Emission[5]
	(lb/MMBTU)	(tons/year)
1,3 Butadiene	1.60E-05	0.00
Benzene	5.50E-05	0.00
Formaldehyde	2.80E-04	0.00
Naphthalene	3.50E-05	0.00
PAH	4.00E-05	0.00

Metallic Hazardous Air Pollutants	AP-42 Factors [4]	Annual Emission[5]
	(lb/MMBTU)	(tons/year)
Arsenic	1.10E-05	0.00
Beryllium	3.10E-07	0.00
Cadmium	4.80E-06	0.00
Chromium	1.10E-05	0.00
Lead	1.40E-05	0.00
Manganese	7.90E-04	0.01
Mercury	1.20E-06	0.00
Nickel	4.60E-06	0.00
Selenium	2.50E-05	0.00
TOTAL HAPs:		0.012

NOTE(s)

[1] See attached Plant Monthly Summary Report for Jan. - Dec. 2011

2. Emission testing was conducted at 50% and 100% load on August 10 to 11, 2011

[3] Annual Emision = Operating Hours (hr/yr) * Emission Rate (lb/hr) * (1ton/2000 lbs)

[4] AP-42 Factor Used is Chapter 3, Tables 3.1-1, 3.1-2a, 3.1-4, 3.1-5

[5] Annual Emision = AP-42 Factor (lb/MMbtu) * Annual Fuel Consumption (gals/year) * (139 MMBtu/1000gals) * (1ton/2000 lbs)

GUAM POWER AUTHORITY
YIGO COMBUSTION TURBINE POWER GENERATING FACILITY

2010 MONTHLY FUEL AND OPERATION SUMMARY REPORT

Month/Year	Fuel Used (Gallons)	Total Hours On-line	Sulfur Content of #2 Fuel Oil (based on analysis)
Jan-11	10,809	8.98	0.00140
Feb-11	1,964	1.28	0.00120
Mar-11	9,678	8.17	0.00087
Apr-11	3,289	2.37	0.00087
May-11	9,942	6.72	0.00065
Jun-11	7,879	7.72	0.00065
Jul-11	1,216	1.37	0.00065
Aug-11	13,533	11.30	0.00073
Sep-11	12,440	10.12	0.00072
Oct-11	1,284	2.43	0.00072
Nov-11	59,014	34.53	0.00070
Dec-11	0	0.00	0.00070
	131,048	94.99	0.00082
	Total	Total	Average

GUAM POWER AUTHORITY

22-MW YIGO C.T. UNIT SUMMARY REPORT

PERIOD COVERED: JANUARY THROUGH DECEMBER 2011			
MONTH	FUEL USED (GALLONS)	SULFUR CONTENT of #2 Fuel Oil (based on analysis)	EMISSION TEST RESULTS (lbs/hr)
JANUARY	10809	0.00140	(see note 2 below)
FEBRUARY	1964	0.00120	(see note 2 below)
MARCH	9678	0.00087	(see note 2 below)
APRIL	3289	0.00087	(see note 2 below)
MAY	9942	0.00065	(see note 2 below)
JUNE	7879	0.00065	(see note 2 below)
JULY	1216	0.00065	(see note 2 below)
AUGUST	13533	0.00073	(see note 2 below)
SEPTEMBER	12440	0.00072	(see note 2 below)
OCTOBER	1,284	0.00072	(see note 2 below)
NOVEMBER	59,014	0.00070	(see note 2 below)
DECEMBER	0	0.00070	(see note 2 below)
TOTAL	**131,048**		
AVERAGE		**0.00082**	

NOTES:

1. The following are conditions based on GEPA permit no. FO-009, dated May 11, 2009:

   a. Total Yearly Consumption shall not exceed 7,140,000 gallons and this shall be calculated on a 12-month rolling average basis.
   b. Maximum Sulfur content of No. 2 fuel oil shall not exceed 0.5 percent by weight.
   c. The water to fuel ratio shall not go below 0.77 @ 50% load
   d. The water to fuel ratio shall not go below 0.91 @ 100% load

2. Emission testing was conducted at 50% and 100% load on August 10 to 11, 2011

3.Sulfur content has been revised in this report due to an error in coversion in previous report.

Test results are as follow:

	50% load		100% load	
Paramter	**Emission Result**	**Emission limit**	**Emission Result**	**Emission limit**
PM(lb/hr)			3.79	20.00
SO2(lb/hr)			1.11	125.00
NOx(lb/hr)			36.90	55.80
NOx @ 15%O2 (ppm)	49.3	59		
CO(lb/hr)	16.40	21.80		
UHC(lb/hr)	0.16	4.00		