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Golder Associates

December 22, 2011

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DIVISION OF AIR
RESOURCE MANAGEMENT

Mr. Alvaro Linero, PE Administrator
Air Permitting Section – Special Projects
Bureau of Air Regulation
Florida Department Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Re: AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS UPDATE FOR THE SHADY HILLS GENERATING STATION
Facility ID No: 1010373, FDEP Project No. 1010373-011-AC; PSD-FL-402A

1010373-012-AC

Dear Mr. Linero:

On behalf of Shady Hills Power Company, LLC, a subsidiary of GE Energy Financial Services, Golder Associates Inc. (Golder) is submitting the following air permit application and prevention of significant deterioration (PSD) analysis update for the Shady Hills Generating Station. This information supplements and replaces the corresponding analysis for CO emissions provided in the July 12, 2010 application, and supporting documents, submitted to the agency for the authorization of construction of two GE 7FA.05 combustion turbines and ancillary equipment.

The July 12, 2010 application proposed CO concentrations for the GE 7FA.05 combustion turbines at levels that were consistent with the previously issued permit for the project. At these levels, the proposed units would avoid PSD review for CO emissions. Upon further development of the project design and because there is no operational data for CO emissions from the new GE 7FA.05 model, the turbine vendor, GE Energy, is not offering emission guarantees for CO concentrations at the levels originally proposed, 6.0 ppmvd @15% O2 for natural gas firing and 13 ppmvd @15% O2 for fuel oil firing. Although operational data exists for CO emissions from GE7FA.03 and GE7FA.04 models that demonstrate these concentrations of CO are achievable and are the basis for prior BACT determinations, the Project will utilize GE 7FA.05 turbines for which no operational data exists. The design of the new 7FA.05 differs from the 7FA.03 and 7FA, and the MW output of the 7FA.05 is approximately 20% greater than the earlier models. The change in the 7FA.05 design yields uncertainty that the CO concentrations will be similar to the previous 7FA models, and vendor guarantees at those concentrations are not available. As such, Shady Hills Power Company, LLC is requesting CO concentration limits equivalent to the vendor emission guarantee rates of 9 ppmvd for natural gas firing and 20 ppmvd for fuel oil firing. These higher CO concentrations result in maximum annual emissions greater than the PSD applicability threshold of 100 tons per year. Because PSD review is triggered for CO emissions, a BACT analysis is provided herein to update Project No. 1010373-011-AC; PSD-FL-402A.

In addition, GE has updated the GE 7FA.05 combustion turbine expected performace specifications including an increase in the tubines heat input rates and output as follows:

Condition: Base load, 59 deg. F, Evap Cooler On.							
Natural Gas Firing				Fuel Oil Firing			
Heat Input (MMBtu/hr), LHV		Output (MW)		Heat Input (MMBtu/hr), LHV		Output (MW)	
Existing	**Updated**	Existing	**Updated**	Existing	**Updated**	Existing	**Updated**
1903.5	**1,923**	214.6	**217.9**	2106.9	**2,117**	221.2	**222.6**

The updated CO analyses provided herein are based on the updated CT performance noted above. The appropriate FDEP application forms and supporting emissions tables associated with the CO analysis are provided herein, including PE and RO representative signature forms. Additional information will be provided, as necessary, under separate cover to address other aspects of the July 12, 2010 application that may be impacted by the change in CT performance specifications.

If you have any questions, please contact me via telephone at (813) 287-1717 or Mr. Roy Belden at (203) 357-6820 or via electronic mail at roy.belden@ge.com.

Sincerely,

Scott Osbourn, P.E.
Associate and Senior Consultant

David Larocca
Senior Engineer

Attachment

Cc: Roy Belden, Shady Hills Power Company, LLC

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DIVISION OF AIR
RESOURCE MANAGEMENT

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS UPDATE FOR THE SHADY HILLS GENERATING STATION, FDEP Project No. 1010373-011-AC, PSD-FL-402A

REPORT

Submitted To: Shady Hills Power Company, LLC
c/o GE Energy Financial Services
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Stamford, CT 06927

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Distribution: 4 Copies—Florida Department of Environmental Protection
2 Copies— Shady Hills Power Company, LLC
1 Copy—Golder Associates Inc.

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December 2011

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Golder Associates

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1.0 BACKGROUND

Shady Hills Power Company, LLC, a subsidiary of GE Energy Financial Services, owns and operates the Shady Hills Generating Station located at 14240 Merchant Energy Way, Shady Hills, Pasco County, Florida. This facility consists of three, dual-fuel, nominal 170 megawatt (MW) General Electric model PG7241FA (GE 7FA) simple cycle combustion turbine-electric generators, three 75-foot exhaust stacks, and one 2.8 million gallon fuel oil storage tank.

Air construction permit number PSD-FL-402, project number 1010373-007-AC, authorized the construction of two additional, nominal 170 MW simple cycle combustion turbine (CT) electric generators at the Shady Hills Generating Station (Shady Hills) through December 30, 2010. In addition to the two new CTs, PSD-FL-402 authorized the construction of a 2.5 MW emergency generator, a natural gas fuel heater, and a 2.8-million gallon distillate fuel oil storage tank. Construction of these units has not been initiated. Since the issuance of the air construction permit in 2009, a new generation of General Electric (GE) CTs has become available, the GE 7FA.05. A new air construction permit application was submitted on July 12, 2010 to update the application submitted to the Florida Department of Environmental Protection (DEP) in May 2008.

The July 12, 2010 application, consistent with the 2009 PSD permit, proposed CO limits of 6.0 ppmvd @15 O2 for natural gas firing and 13 ppmvd @15% O2 for fuel oil firing. At these concentrations, PSD review was avoided. Upon further development of the project design, Shady Hills Power Company was notified that the turbine vender, GE Energy, would not be able to guarantee the ability of the plant to consistently achieve CO concentrations at the levels proposed, 6.0 ppmvd @15% O2 for natural gas firing and 13 ppmvd @15% O2 for fuel oil firing, while operating under various conditions. Although existing operational data exists for GE7FA.03 and GE7FA.04 models that demonstrates low concentrations of CO (below 6 ppmvd on natural gas and below 13 ppmvd on fuel oil), and this data has been used as the basis for the Department's previous BACT determinations for GE 7FA.03 and GE7FA.04 models, the Project will utilize newer model GE 7FA.05 turbines for which no operational data exists. In addition, the turbine vendor, GE Energy, does not offer guarantees for the GE 7FA.05 turbine model to meet emission limits of 6 and 13 ppmvd on gas and oil, respectively. The design of the new 7FA.05 differs from the older 7FA.03 and 7FA.04 models in that the power generation has been increased by approximately 20% to over 200 MW at ISO conditions through a higher firing temperature and optimization. This yields uncertainty that the CO concentrations will be similar to the previous 7FA models. As such, Shady Hills Power Company, LLC is submitting an update to FDEP Project No. 1010373-011-AC, PSD-FL-402A, requesting CO emission limits equivalent to the vendor emission guarantees of 9 ppmvd for natural gas firing and 20 ppmvd for fuel oil firing. These higher concentrations result in an annual emissions increase greater than the PSD review thresholds, see Table 1, and as such the following CO BACT analysis is provided.

2.0 CONTROL TECHNOLOGY REVIEW

2.1 Applicability

The Prevention of Significant Deterioration (PSD) regulations require modifications at existing major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted in amounts that are greater than the PSD significant emission rates. This section presents the proposed Best Available Control Technology (BACT) for the pollutant carbon monoxide (CO) for the Shady Hills Generating Station (the Project). The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see Rule 62-210.200 F.A.C]. The analysis must, by definition, be specific to the Project (i.e., case by case).

2.2 Best Available Control Technology

2.2.1 Overview of Proposed BACT

In recent permitting actions, the Florida Department of Environmental Protection (FDEP) has established BACT for heavy-duty simple-cycle industrial gas turbines. The combustion turbines (CTs) proposed for the Project reflect the newest generation of turbines, GE 7FA.05, as compared to the previously authorized (Permit 1010373-007-AC) turbine units for the Shady Hills site, GE 7FA.03. The GE 7FA.05 provides increased output, 217.9 MW per CT for natural gas firing, 59 deg. F (222.6 MW fuel oil firing, 59 deg. F) with a heat input of 1,923 MMBtu/hr LHV natural gas (2,117 MMBtu/hr LHV fuel oil firing), as compared to the original application data of 181.6 MW per CT with a heat input of 1,704.4 MMBtu/hr for natural gas firing and 187.4 MW per CT with a heat input of 1,889 MMBtu/hr for fuel oil firing.

The FDEP has historically established simple cycle CT BACT emission rates based on the use of good combustion practices for minimizing CO emissions, as add-on CO controls have been determined to be cost prohibitive. Similarly, CO add-on controls for the Project have been determined to not be cost effective and BACT is based on good combustion practices.

The Project CTs will have two modes of operation for which a BACT analysis has been performed: natural gas firing and fuel oil firing. The results of the analysis have concluded that the following emission limits constitute BACT for the Project.

1. CTs - Natural Gas Fired:
   - CO emissions will be limited to 9 ppmvd during normal operation;
   - Good combustion practices will be utilized.

2. CTs - Fuel Oil Fired:
   - CO emissions will be limited to 20 ppmvd during normal operation;
   - Good combustion practices will be utilized; and
   - Hours of operation will be limited to an average of 1,000 hours combined operation per calendar year.

   - If only one CT is installed, then 750 hours fuel oil operation proposed if natural gas operation is limited to 1,640[=(3390 – 500) – (5 x 250)] hours per year equivalent to a natural gas reduction ratio of 5 : 1 (NG : FO). This is consistent with Shady Hills Power Company, LLC's Fuel Oil Alternative Request, submitted to the Department on May 24, 2011.

3. Emergency Generator:
   - Emission equivalent to 40 CFR Subpart IIII, Stationary Compression Ignition Internal Combustion Engines;
   - Good combustion practices will be utilized;
   - Hours of operation will be limited to 500 hours per year; and

4. Fuel Gas Heater
   - Natural gas firing only; and
   - Good combustion practices will be utilized.

The gas heater proposed for the Project will have potential emissions for each regulated pollutant of less than 5 TPY. As a result, the generator is classified as an insignificant activity under FDEP Rule 62-213.430(6)(b), F.A.C.

Table 1 summarizes the proposed BACT designs, practices and emission limitations, compliance methods for the Project.

2.2.2 Carbon Monoxide

2.2.2.1 Previous Determinations

A review of the most recent BACT determinations for large frame simple-cycle CT projects is provided in Table 3. Table 3 demonstrates that FDEP has historically established CT BACT emission rates based on the use of good combustion practices for minimizing CO emissions for simple cycle frame turbines. Although the Department has permitted GE7FA.03 and GE7FA.04 CT models with CO BACT levels as low as 4.1 ppmvd natural gas firing and 8 ppmvd for fuel oil firing based on operational data, the Project will utilize new GE model 7FA.05 turbines for which no operational data exists. The design of the new

7FA.05 differs from the 7FA.03 and 7FA.04 in that power generation has been increased by approximately 20% to over 200 MW at ISO conditions, through higher firing temperature and optimization. The new CT design yields uncertainty that the CO concentrations will be similar to the previous 7FA models. While other BACT determinations have established permit limits as low as 4.1 ppmvd, it has been through supporting operational data of their existing fleet of similar turbines. Because historical operating data is not available for the 7FA.05 units, vendor guarantees should be used to establish the BACT limits. be As such, Shady Hills Power Company, LLC is submitting an update to FDEP Project No. 1010373-011-AC, requesting CO BACT emission limits equivalent to the vendor emission guarantee provided in Section 2.2.1, and based on good combustion practices.

2.2.2.2 Feasible Controls

The feasible control technologies, in order of highest to lowest control efficiency, for simple cycle CTs are as follows:

- Oxidation catalytic reduction (approximately 80% control efficiency); and
- Good Combustion Practice including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing) (unknown control efficiency.)

2.2.2.3 Technology Description

Emissions of CO are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The CTs proposed for the Project have designs to optimize combustion efficiency and minimize CO emissions, however as previously indicated, are new CTs with no existing in-service CO test data. Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with combustion controls alone.

The "Top Down" BACT analysis was performed for the following alternatives:

- Oxidation catalyst at approximately 80 percent removal, resulting in CO concentrations of approximately 2 ppmvd; and
- Combustion controls at 9 ppmvd when firing natural gas and 20 ppmvd when firing oil (normal operation).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with an efficiency of 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

2.2.2.4 Impact Analysis

Tables 4a, 4b, 5a, 5b, 6a, and 6b present the cost analysis for CO oxidation catalyst per CT. Three scenarios are presented, Tables 4a and 4b assume all gas firing and 3,390 hours per year of operation. Tables 5a and 5b present a total hour per year of operation of 3,390, of which 500 hours is with operation on oil firing. Tables 6a and 6b assume 750 hours of oil firing and 1,640 hours of natural gas firing, as described in Section 2.2.1. The following summarizes the CO oxidation catalyst cost effectiveness for the three scenarios:

- CO Oxidation Catalyst Cost Effectiveness
  - Scenario 1 (Table 4b) – 43.51 CO TPY Reduction x 2 CTs = 87.02 TPY CO reduction; $573,274 per year x 2 CTs = $1,146,548 / 87.02 = $13,177 per ton CO reduced;
  - Scenario 2 (Table 3b) – 53.32 CO TPY Reduction x 2 CTs = 106.64 TPY CO reduction; $574,046 per year x 2 CTs = $1,148,092 / 107 = $10,766 per ton CO reduced;
  - Scenario 3 (Table 5b) – 45.38 CO TPY Reduction x 1 CTs = 45.38 TPY CO reduction; $545,463 per year x 1 CTs = $545,463 / 45.38 = $12,021 per ton CO reduced

Economic - The capital and annualized cost of a CO oxidation catalyst are approximately $1,989,700 and $574,000 per unit, respectively, corresponding to the most cost effective scenario, Scenario 2. The resulting cost effectiveness is greater than $10,700 per ton of CO removed. The cost effectiveness is based on 3,390 hours per year on natural gas and 500 hours per year of operation on oil. No costs are associated with combustion techniques since they are inherent in the design. Detailed calculations are provided in Tables 4a, 4b, 5a, 5b, 6a, and 6b.

Environmental – As demonstrated in the original application submitted in support of issued air construction permit number PSD-FL-402, project number 1010373-007-AC the air quality impacts of combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy - An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,482,000 kWh/yr would result at 100 percent load, based on Scenario 2. This energy penalty is sufficient to supply the electrical needs of about 123 residential customers for a year.

To replace this lost energy, about 1.5×10^{10} Btu/yr or about 15 million ft^3/yr of natural gas would be required.

2.2.2.5 Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are insignificant environmental benefits and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission limits for CO are 9 ppmvd when firing natural gas and 20 ppmvd when firing distillate oil during normal operation. Catalytic oxidation is considered unreasonable for the following reasons:

- Catalytic oxidation will not produce measurable reduction in the air quality impacts;
- The economic impacts are significant (i.e., the capital cost is about $1.9 million per unit, with an annualized cost of approximately $570,000 per year per unit); and
- The CO oxidation catalyst cost effectiveness is greater than $10,000 per ton of CO reduced.
- No existing operational data exists for the new GE 7FA.05 turbines necessary to justify CO concentrations less than the vendor guarantee.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not produce a measurable reduction in the air quality impacts. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits, and even less so if actual emissions are less than the value that are guaranteed.

2.3 Emergency Generator

The proposed BACT for the emergency generator is the utilization clean fuel (i.e., ultra low sulfur light oil) and good combustion techniques to minimize emissions. The emergency generator will meet the requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, published July 11, 2006 and effective on September 11, 2006.

2.4 Gas Heater

The proposed BACT for the natural gas fired, gas heater is the use of good combustion practices to limit emissions of CO. Emissions from the gas heater will be minimized to an expected CO emission rate of 0.080 lb/MMBtu. The gas heater proposed for the Project will have potential CO emissions of less than 5 TPY.

TABLE 1

SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE SHADY HILLS GENERATING STATION PROJECT

	Annual Emissions (tons/year)						
Pollutant	**2 CTs GE 7FA.05[a]**	**Emergency Generator**	**Natural Gas Heater**	**Fuel Oil Storage Tank**	**TOTAL**	**PSD Significant Emission Rate (tons/year)**	**PSD Review Required?**
CO	131.4	1.93	1.35	--	135	100	Yes

[a] Based on 2,890 hours of natural gas firing at 33 lb CO/hr per CT and 500 hours of fuel oil firing at 72 lb CO/hr per CT.

Source: Golder, 2011. Revision 12/22/11

Table 2: Proposed BACT Emission Limitations and Compliance Methods For The Project.

Emission Unit/Pollutant	Conditions	Heading	Compliance Method Proposed
CTs (EU 005 and EU 006):			
CO	9 and 20 ppmvd for gas and oil firing, respectively.	50 to 100 percent load	EPA Method 10 Initial Test. Good Combustion Practices.
Emergency Generator (EU 007):			
CO	2.6 g/hp-hr (40 CFR 60 Subpart IIII)	Normal Operation	500 hours per year operation, low sulfur distillate. Good Combustion Practices.
Gas Heater (EU 008):			
CO	84 lb/MMscf (AP-42)	Normal Operation	Natural Gas Combustion Only. Good Combustion Practices.

Note: CO = carbon monoxide

Table 3: Summary of CO BACT Limits for Recent Simple Cycle Combustion Turbines Projects in EPA Region IV.

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limits	Comments	Control Method	Avg. Time
JEA Greenland Energy Center	FL	Final Permit 3/5/2009	380	2	0	GE 7FA (176 MW NG, 190 MW ULSFO)	NG/FO	SC	3,500 NG; 500 FO	NG: 4.1 ppmvd; FO: 8 ppmvd	BACT Limit	Good Combustion Practices	24-hr
JEA Kennedy Generating Station	FL	Final permit 12/4/2008	172	1	0	GE 7FA (172 MW)	NG/FO	SC	172 MW Unit: 3,500 total; 500 FO	172 MW Unit: 9 ppmvd NG; 20 ppmvd FO	Not a BACT limit; PSD Avoidance.	Good Combustion Practices	3-hr
Oleander Power	FL	Final Permit 11/17/2006	190	1	0	GE 7FA	NG/FO	SC	3,390 NG; 500 FO	No CO limits	NA	NA	NA
Orlando Utilities - Curtis H Stanton Energy Center	FL	Final Permit 5/12/2008	300	1	1	GE 7FA	NG/FO	CC/SC [1]	8,760 NG; 1,000 FO	NG: 4.1 ppmvd (CTG normal) and 7.6 ppmvd CTG w/DB; FO: 8.0 ppmvd	BACT Limit	Good Combustion Practices	24-hr
Shady Hills Generating Station	FL	Final Permit 1/13/2000	510	3	0	GE 7FA (170 MW)	NG/FO	SC	3,390 NG/ 1,000 FO	NG: 12 ppmvd; FO: 20 ppmvd	Not a BACT limit, PSD Avoidance.	Good Combustion Practices	24-hr
FPL Manatee Power Plant	FL	Final Permit 12/12/2008	680	4	4	GE 7FA	NG	CC/SC [2]	1,000	7.4 (simple cycle) 12 ppmvd (SC/PA) 7.4 (CC-Normal Operation)	BACT Limit	Good Combustion Practices	24-hr

Notes:

[1] The CTG/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply)

[2] Simple Cycle Operation: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.
(1) Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.
(2) After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per unit during any consecutive 12 months.

PA = power augmentation

Table 4a: Direct and Indirect Capital Costs Oxidation Catalyst, GE Frame 7FA in Simple Cycle 3,390 hr/yr Gas Fired Only.

Cost Component	***Costs***	***Basis of Cost Component***
Direct Capital Costs		
CO Associated Equipment	$896,243	Based on Vendor Quote and Construction Cost Index
Auxiliary Equipment (ducts, catalyst housing)		Assumed included
Instrumentation	$89,624	10% of SCR Associated Equipment
Freight	$44,812	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,030,680	
Direct Installation Costs		
Foundation and supports	$82,454	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$144,295	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$41,227	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$20,614	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$51,534	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$360,738	
Total Capital Costs	$1,391,417	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$69,571	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$27,828	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$13,914	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,597	
Contingencies	$208,713	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$1,989,727	Sum of TCC and TInCC

Table 4b: Annualized Cost for CO Catalyst GE Frame 7FA in Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$16,425	8 hours/week at $15/hr
Supervision	$2,464	15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$29,846	1.5% of TDICC, OAQPS Seciton 4
Catalyst Replacement	$56,904	7 year catalyst life, 50% catalyst replaced
Inventory Cost	$35,093	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,037	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$147,769	
Energy Costs		
Heat Rate Penalty	$98,203	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$98,203	
Indirect Annual Costs		
Overhead	$29,241	60% of Operating/Supervision Labor
Property Taxes	$19,897	1% of Total Capital Costs
Insurance	$19,897	1% of Total Capital Costs
Administration	$39,795	2% of Total Capital Costs
Annualized Total Direct Capital	$218,472	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$327,302	
Total Annualized Costs	$573,274	Sum of TDAC, TEC and TIAC
	43.51	Net CO Emission Reduciton
Cost Effectiveness	$13,177.2	per ton of CO Removed

Table 5a: Direct and Indirect Capital Costs Oxidation Catalyst, GE Frame 7FA in Simple Cycle 3,390 Hr/yr Total, 500 Hr/yr Oil Fired.

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$896,243	Based on Vendor Quote and Construction Cost Index
Auxiliary Equipment (ducts, catalyst housing)		Assumed included
Instrumentation	$89,624	10% of Oxidation Catalyst Associated Equipment
Freight	$44,812	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	$1,030,680	
Direct Installation Costs		
Foundation and supports	$82,454	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$144,295	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$41,227	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$20,614	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$51,534	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$360,738	
Total Capital Costs	$1,391,417	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$69,571	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$27,828	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$13,914	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,597	
Contingencies	$208,713	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$1,989,727	Sum of TCC and TInCC

Table 5b: Annualized Cost for CO Catalyst GE Frame 7FA in Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	$16,425	1/2 hr/shift, $30/hr, 8760 yr
Supervision	$2,464	15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$29,846	1.5% of TDICC, OAQPS Seciton 4
Catalyst Replacement	$56,904	7 year catalyst life, 50% catalyst replaced
Inventory Cost	$35,093	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,037	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$147,769	
<u>Energy Costs</u>		
Heat Rate Penalty	$98,975	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$98,975	
<u>Indirect Annual Costs</u>		
Overhead	$29,241	60% of Operating/Supervision Labor
Property Taxes	$19,897	1% of Total Capital Costs
Insurance	$19,897	1% of Total Capital Costs
Administration	$39,795	2% of Total Capital Costs
Annualized Total Direct Capital	$218,472	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$327,302	
Total Annualized Costs	$574,046	Sum of TDAC, TEC and TIAC
	53.32	Net CO Emission Reduciton
Cost Effectiveness	$10,766	per ton of CO Removed

Table 6a: Direct and Indirect Capital Costs Oxidation Catalyst, GE Frame 7FA in Simple Cycle 1,640 Hr/yr Natural Gas, 750 Hr/yr Oil Fired.

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$896,243	Based on Vendor Quote and Construction Cost Index
Auxiliary Equipment (ducts, catalyst housing)		Assumed included
Instrumentation	$89,624	10% of Oxidation Catalyst Associated Equipment
Freight	$44,812	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	$1,030,680	
Direct Installation Costs		
Foundation and supports	$82,454	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$144,295	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$41,227	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$20,614	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,307	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$51,534	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$360,738	
Total Capital Costs	$1,391,417	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$69,571	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$139,142	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$27,828	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$13,914	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,597	
Contingencies	$208,713	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$1,989,727	Sum of TCC and TInCC

Table 6b: Annualized Cost for CO Catalyst GE Frame 7FA in Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	$16,425	1/2 hr/shift, $30/hr, 8760 yr
Supervision	$2,464	15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$29,846	1.5% of TDICC, OAQPS Seciton 4
Catalyst Replacement	$56,904	7 year catalyst life, 50% catalyst replaced
Inventory Cost	$35,093	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,037	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$147,769	
<u>Energy Costs</u>		
Heat Rate Penalty	$70,392	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$70,392	
<u>Indirect Annual Costs</u>		
Overhead	$29,241	60% of Operating/Supervision Labor
Property Taxes	$19,897	1% of Total Capital Costs
Insurance	$19,897	1% of Total Capital Costs
Administration	$39,795	2% of Total Capital Costs
Annualized Total Direct Capital	$218,472	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$327,302	
Total Annualized Costs	$545,463	Sum of TDAC, TEC and TIAC
	45.38	Net CO Emission Reduciton
Cost Effectiveness	$12,021	per ton of CO Removed

REPLACEMENT FDEP APPLICATION FORMS

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

[X] Air construction permit.

[ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

[ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

The project will consist of two General Electric Frame 7FA.05 CTs (GE 7FA.05) and associated facilities. Natural gas will be used as the primary fuel, and fuel oil will be used as a backup fuel.

The purpose of this application is to request CO emission limits equivalent to the vendor emission guarantees of 9 ppmvd for natural gas firing and 20 ppmvd for fuel oil firing. This application supplements and replaces the corresponding analysis provided in the July 12, 2010 application, and supporting documents.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Roy S. Belden, Vice President**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Shady Hills Power Company, LLC** Street Address: **120 Long Ridge Road** City: **Stamford** State: **CT** Zip Code: **06927**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(203) 357-6820** ext. Fax: **(203) 961-5116**
4.	Owner/Authorized Representative E-mail Address: **roy.belden@GE.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Roy S. Belden — 12/21/11 Signature — Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **5100 West Lemon Street, Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. Fax: **(813) 287-1716**
4. Professional Engineer E-mail Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

Signature ______________________ Date 12/21/11

(seal)

SCOTT OSBOURN
LICENSE
NO. 57557
STATE OF FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization #00001670

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
005	222.6 MW simple-cycle combustion turbine		
006	222.6 MW simple-cycle combustion turbine		

Application Processing Fee

Check one: ☐ Attached - Amount: $______________ ☒ Not Applicable

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Two simple-cycle combustion turbines.[a]

3. Emissions Unit Identification Number: **005 and 006**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:

8. Federal Program Applicability: (Check all that apply)

   [X] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
   Manufacturer: **GE** Model Number: **7FA.05**

10. Generator Nameplate Rating: **222.6 MW/CT[b]**

11. Emissions Unit Comment:

[a] **Two simple-cycle General Electric Model 7FA.05 (GE 7FA.05) combustion turbines.**
[b] **Parameter of distillate oil at 59°F and 100% base load.**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **2,117** million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **5,000** hours/year
6. Operating Capacity/Schedule Comment: **Parameter of distillate oil at 59F and 100% base load.** **Maximum heat input rates: Natural gas firing – 1,923 MMBtu/hr** **Distillate fuel oil firing – 2,117 MMBtu/hr** **Maximum heat input rates are based on lower heating value (LHV) of each fuel at ambient conditions of 59 degrees F, 60 percent RH 100 percent load, and 14.7.**		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **005 and 006**	2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **75 feet**	7. Exit Diameter: **18 feet**
8. Exit Temperature: **1,100°F[a]**	9. Actual Volumetric Flow Rate: **2,776,485 acfm[a]**	10. Water Vapor: **12.1 %**

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): **347.0** North (km): **3,139.0**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **28/22/00** Longitude (DD/MM/SS) **82/30/00**
15. Emission Point Comment: [a] **Parameter of distillate oil at 59°F and 100% base load.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Natural-Gas Firing**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet of natural gas burned**	
4. Maximum Hourly Rate: **2.06**	5. Maximum Annual Rate: **6,983.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933**
10. Segment Comment: **Based on natural gas lower heating value (LHV) of 933 MMBtu/MMcf** **Maximum hourly rate = 1,923 MMBtu/hr / 933 MMBtu/MMcf = 2.06 MMcf/hr** **Maximum annual rate = 2.06 MMcf/hr x 3,390 hr/yr = 6,983.4 MMcf/yr**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil Firing**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **16.04**	5. Maximum Annual Rate: **12,028**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment: **Based on distillate fuel oil LHV of 132 MMBtu/1,000 gal** **Maximum hourly rate = 2,117 MMBtu/hr / 132 MMBtu/1,000 gal = 16,037.8 gal/hr** **Maximum annual rate = 16,037.8 gal/hr x 750 hr/yr = 12,028,350 gal/yr**		

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **73.2** lb/hour **75.08** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **9 ppmvd for natural gas** **20 ppmvd for distillate fuel oil firing** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Annual emissions based on 3,390 hrs/yr of natural gas firing:
Annual emissions: 33.5 lb/hr x 3,390 hrs/yr x ton/2,000 lb = 56.78 TPY

Annual emissions based on 3,390 of natural gas firing and 500 hrs/yr of distillate oil firing:
Annual emissions: (33.5 lb/hr x 3,390 hrs/yr + 73.2 lb/hr x 500 hrs/yr) x ton/2,000 lb = 75.08 TPY

Annual emissions based on 1,640 of natural gas firing and 750 hrs/yr of distillate oil firing:
Annual emissions: (33.5 lb/hr x 1,640 hrs/yr + 73.2 lb/hr x 750 hrs/yr) x ton/2,000 lb = 54.92 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Hourly emissions concentrations based on distillate oil firing. Annual emissions based on most conservative scenario.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **33.5** lb/hour **56.8** tons/year
5. Method of Compliance: **Annual testing using EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hrs/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **73.2** lb/hour **27.5** tons/year
5. Method of Compliance: **Annual testing using EPA Method 10. (Testing required only when fuel oil firing exceeds 400 hours per year.)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate fuel oil firing for 750 hrs/yr.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

At Golder Associates we strive to be the most respected global group of companies specializing in ground engineering and environmental services. Employee owned since our formation in 1960, we have created a unique culture with pride in ownership, resulting in long-term organizational stability. Golder professionals take the time to build an understanding of client needs and of the specific environments in which they operate. We continue to expand our technical capabilities and have experienced steady growth with employees now operating from offices located throughout Africa, Asia, Australasia, Europe, North America and South America.

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