CRMC Confidential

Assessment of the Additionality of the
Greater New Bedford Landfill Gas Utilization Project
Using the "Tool For The Demonstration And Assessment Of Additionality"
Issued by the Executive Board of the Clean Development Mechanism
Created Under the United Nations Framework Convention on Climate Change

Prepared by
CommonWealth Resource Management Corporation
For it's wholly-owned subsidiary
CommonWealth New Bedford Energy, LLC

1.0 BACKGROUND INFORMATION

The purpose of this document is to demonstrate the "additionality" of the Greater New Bedford Landfill Gas Utilization Project (the "Project") in accordance with the procedures set forth in the document entitled Methodological Tool: "Tool for the demonstration and assessment of additionality"(Version 05.2) (the "Additionality Tool") issued by the Executive Board of the Clean Development Mechanism ("CDM") established under the United Nations Framework Convention on Climate Change.

The Project is a landfill methane (*a.k.a*., "landfill gas" or "LFG") capture and utilization project located at a solid waste landfill (the "Landfill") in Dartmouth, Massachusetts. The Landfill is owned by the Greater New Bedford Regional Refuse Management District (the "District"). The owner of the Project is CommonWealth New Bedford Energy, LLC ("CNBE"), a wholly-owned subsidiary of CommonWealth Resource Management Corporation ("CRMC"), a Massachusetts corporation based in Boston, Massachusetts, U.S.A. CNBE also owns the exclusive rights to all of the LFG at the Landfill, and all of the environmental attributes associated with the collection, destruction and use of all of the LFG at the Landfill.

The Project consists of (a) an initial, minimal active LFG collection and flare system installed at the Landfill in June, 2000 for the purpose of controlling odors and LFG migration (the "District Initial System"), (b) an expanded active LFG collection system installed after January 1, 2002 in anticipation of using the LFG as a fuel for electric power generation, and (c) an electric power generating facility which commenced operation in November, 2005. The construction and operation of the expanded LFG collection system and the electric power generating facility constitute the Project Activity. A detailed description of the Project is contained in the following record documents, which collectively serve as the Project Design Document ("PDD") for the Project:

1. The Monitoring, Reporting and Verification Protocol For The Greater New Bedford LFG Utilization Project, Crapo Hill Landfill, Dartmouth Massachusetts, (MRV CNBE 2005 12) dated December 2005 (the "MRV"); and
2. The Supplement To The Monitoring, Reporting And Verification Protocol For The Greater New Bedford LFG Utilization Project Crapo Hill Landfill, Dartmouth Massachusetts, (MRV CNBE 2005 12), dated December 2007; and
3. A letter of December 24, 2008 from CRMC to Mr. Greg Kozak, Senior Environmental Engineer, First Environment, Inc. ("FE"), responding to certain Corrective Action Requests ("CARs") made to CRMC. by FE, in its role as a project validator.

The balance of this document sets forth the information called for in the Additionality Tool for the purpose of demonstrating project "additionality" under the CDM or other programs that make use of the CDM methodology for this purpose. Consistent with the options provided to project proponents using the Additionality Tool, this document follows the following pathway through the additionality demonstration process:

1. STEP 1. Identification of alternatives to the project activity consistent with mandatory laws and regulations.
2. STEP 3. Barrier Analysis
3. STEP 4. Common practice analysis.

2.0 ADDITIONALITY ASSESSMENT

Step 1: Identification of alternatives to the project activity consistent with current laws and regulations.

Sub-step 1a: Define alternatives to the project activity. This sub-step requires the project participant to identify realistic and credible alternatives available to the project participant or similar project developers that provide outputs or services comparable with the project activity. Consistent with this requirement, the activities listed below have been identified as realistic and credible alternatives to the Project Activity for the purposes of controlling odors and LFG migration at the Landfill. (The alternatives are identified using the numbering convention set forth in the Additionality Tool)

(1)(a): The Project Activity could have been undertaken without registering it as a project activity under the CDM or any other program using a CDM-based methodology.

(1)(b): Other realistic and credible alternatives to the Project Activity include:

1. The District could have installed and operated passive vents in new areas of waste to passively vent untreated methane to the atmosphere. As described in the PDD documents, landfill methane is not a regulated pollutant in the United States and is not subject to collection and control requirements as a pollutant. The District has not been required, pursuant to any environmental law, to collect, destroy or control the emission of methane, hazardous air pollutants or any other component of landfill gas. For the purpose solely of preventing migration, the District could have vented the methane to the atmosphere through a passive venting system. Passive venting of new areas of the landfill may have been a realistic and credible alternative, so long as the quantities and concentrations of gas emitted from those areas would not cause detectable odors offsite. This alternative is less obtrusive and disruptive to landfill operations in active areas than an active LFG collection system. Note that in connection with the Landfill expansion the District has taken steps to reduce the potential for generation of odors that might be detectable off-site. Specifically, the District discontinued accepting any unprocessed construction and demolition debris for disposal in the new areas of waste, which waste had

previously been taken in the Phase 1 area covered by the District Initial System. The biological degradation of construction demolition debris is the primary source of compounds that cause the odors in landfill gas. Therefore a primary source of odors has been eliminated from deposition in the Landfill expansion areas. Secondly, the District has purchased over 300 acres of land surrounding the landfill to act as a buffer from potential receptors of odors. The District continues to purchase land as it becomes available to expand its buffer zone. Through the purchase of the additional property over time, the District has continued to effectively expand its property lines further away from sources of potential odors, and has prevented further off-site property development that might conflict with or encroach upon Landfill operations. For these reasons, combined with the fact that it constitutes a common and effective industry practice across the U.S., passive venting of gas from the new areas of waste would have been, and could continue to be, a realistic and credible alternative to the Project Activity.

2. The District could have installed and operated (a) passive point flares to passively vent and destroy potentially odor-causing compounds in new areas of waste that provided evidence of potential odor problems, and (b) passive vents to relieve pressure from the landfill but in areas that would not cause detectable odors offsite. This alternative has the advantage of a relatively low cost vs. active gas collection, and is also less obtrusive and disruptive to landfill operations in active areas of waste deposition than an active LFG collection system. However, when compared to passive vents, passive point flares are more expensive to install and maintain. Point flares are also more disruptive to landfill operations than passive vents because of their propagation of high-temperature (1800 degrees F) , low-base (approximately eight feet above grade), unenclosed flames, that are difficult to approach and work around. Therefore, the District would likely install and operate passive vents over passive point flares.

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3. The District could have installed and operated a new but separate active gas collection system in new areas of waste for the purpose of treating or otherwise removing potentially odorous compounds from the collected landfill gas using several commercially available technologies in order to prevent detectable odors offsite, with no beneficial use of the LFG for electric power generation or otherwise. However, given that the District Initial System was already a cost expended by the District, funding a separate collection and control system would be less desirable than other plausible alternatives. In addition, installation and operation of an active gas collection system in active areas of landfill operations would have been more disruptive to landfill operations than alternatives 1(b)1 and 1(b)2 and therefore less desirable from a landfill operations standpoint. This potential disruption is more fully detailed in alternative 1(b)4.

4. The District could have installed and operated additional active gas collection wells in new areas of waste and connected those new wells to the District Initial System to relieve pressure from the landfill and destroy potential odor-causing compounds, with no beneficial use of the LFG for electric power generation or otherwise. However, the new areas of waste are in active areas of the landfill and operators attempt to limit other construction activities within active areas and limit potential obstacles in these areas such as gas wells. Limiting installation of active gas wells in active landfill areas reduces interference with landfill operations. Typically, landfill owners would install active gas wells in landfill areas that no longer are active. Also, damage to one active well results in shutting down the active system until a repair is made. Given the higher level of costs and potential disruption to landfill operations compared to alternatives 1(b)1 and 1(b)2, this scenario is less desirable operationally than those alternatives.

(1)(c). Continuation of the situation that pre-existed the Project Activity, namely operation of the initial minimal District System only, is not applicable as a realistic and credible alternative. As the new areas of waste are developed to their final grades, those areas are closed and capped. Good engineering practice is to install passive vents in the cap overlying those closed areas of the landfill to vent untreated methane to the atmosphere. This passive venting relieves gas pressure underneath the cap that could otherwise be disruptive to the cap and/or result in gas migration through undesirable pathways. This good engineering practice has been adopted into the Massachusetts State Solid Waste Regulations at 310 CMR 19.117. This regulation requires at a minimum, passive gas vents in all areas of the landfill that final cover has been applied to in order to prevent the buildup of explosive concentration of gas and prevent the lateral migration of gases beyond the boundaries of a landfill.

Sub-step 1b: Consistency with mandatory laws and regulations. This sub-step requires an assertion that the identified alternatives to the Project Activity would comply with applicable law and regulation.

As described in Section 2.6 of the MRV component of the PDD, the landfill does not fall under the Federal New Source Performance Standards (NSPS) regulation or any other local, state, or federal regulations requiring the active collection and destruction (or use) of the landfill gas. All of the applicable alternatives to the Project Activity described in Sub-step 1a., above, would satisfy any regulatory requirements relating to LFG odor control and migration at the Landfill, and none of the alternatives would have been in conflict with any applicable laws and regulations.

Step 3: Barrier Analysis.

This step requires that a determination be made that the Project Activity faced barriers that:

(a) Would have prevented the implementation of the Project Activity; and
(b) Would not have prevented one of the other alternatives to the Project Activity

Sub-step 3a: Identify barriers that would prevent the implementation of the Project Activity. The Additionality Tool indicates that the identified barriers may include investment barriers, technological barriers, or barriers due to prevailing practice, *among others*.

The Project Activity has faced a technological barrier to implementation in the form of stringent air emission limits for nitrogen oxides produced by the combustion of LFG in internal combustion ("i.c.") engines, which limits are significantly below (i) those normally required for LFG-fueled electric power generating projects in the U..S., and (ii) the limits guaranteed by vendors of the relevant available i.c. engine-generator systems. The barrier has had the effect of imposing significant technical performance risk and higher costs on the Project Activity when compared to projects of similar scale employing conventional i.c. engine technology available for LFG.

Specifically, the emission limitation for nitrogen oxide (NOx) imposed on the Project by permit is 0.6 grams per brake-horsepower hour (gm per BHphr). This limit is substantially more stringent than the most recently promulgated federal regulation for this class of engine utilizing landfill gas. Specifically, on January 18, 2008, the United States Environmental Protection Agency ("USEPA") promulgated the New Source Performance Standards (NSPS) and revised national emission standards for hazardous air pollutants (NESHAP) for Reciprocating Internal Combustion Engines, including those used to combust landfill gas. In accordance with these standards (at 40 CFR part 60, subpart JJJJ and 40 CFR part 63, subpart ZZZZ, respectively), lean burn engines with power output of greater than 500 and less than 1350 horsepower that are newly manufactured as of January 1, 2008 must comply with limits for NOx. Specifically, the limits for engines combusting LFG are 3.0 grams NOx per BHphr for engines manufactured after January 1, 2008, and 2.0 grams NOx per BHphr for engines manufactured after July 1, 2010[1].

Note that most states outside of Massachusetts use the standards promulgated by the USEPA as the basis for establishing emission limits in permits for new facilities. In particular, those states that are in compliance with national ambient air quality standards for ozone, do not have any reason to impose more stringent

[1] January 18, 2008, 73 Federal Register 3568, Table 1 To NSPS 40 CFR Part 60, Subpart JJJJ of - NOx, CO, and VOC Emission Standards For Stationary Spark Ignition Landfill/Digester Gas Engines.

emission requirements on NOx as a precursor pollutant to ozone. However, Massachusetts has been in non-attainment for ozone since the inception of the Clean Air Act and has taken a lead role in the United States in pushing the technology envelope to impose the most stringent limitations on combustion facilities that emit NOx.

To enable an engine to achieve such low emissions of NOx, the engine must combust the fuel in a very narrow operating window, which operating window is considered very lean (e.g. high excess combustion air) and bound by operating regimes that cause combustion within the cylinders to mis-fire and pre-detonate ("knocking"). Exhibit A depicts this narrow operating window required to achieve the low NOx emissions without misfiring or detonating the fuel mix both of which events adversely impact the continuous operation of the engine. The combustion is considered "lean" when high levels of excess air (70 percent to 80 percent above the theoretic air required for combustion) are introduced into the engine along with the fuel. Maintaining combustion in this very narrow operating range using landfill gas as a fuel is more difficult than for conventional fossil fuels because landfill gas continually changes in composition and quality. Therefore, the use of a sophisticated fuel management system is required to overcome this technical barrier. The fuel management system requires several measured parameters to be continuously monitored and adjusted to stay within the operating window.

To meet this technical challenge, the electric generating facility component of the Project has utilized a recently developed, and still-evolving advanced fuel management system to monitor and adjust the required parameters on each engine to stay within the narrow operating window, while producing the output that the engine is designed for. Developed by the Woodward Governor Company ("Woodward"), of Fort Collins, Colorado, the first commercial version of this system, the Woodward Tecjet EGS-01, was integrated into the Caterpillar 3516 engine gen-sets installed at the Project in late 2005. A subsequent version, the Woodward Tecjet EGS-02 system, was installed at the Project during February 2008. As of March, 2008 the current distributor of the Woodward equipment, Peaker Services Inc., has been using the CNBE installation as its reference installation to market the system to the LFG industry (see attached Exhibit B, the advertisement from Peaker with photos of CNBE facility).

Unfortunately, because of the complexity and sensitivity of the advanced fuel management system, it has proven to be highly susceptible to damage from the contaminants found in landfill gas. This damage results in more frequent and more costly equipment repairs, and more lost revenues due to engine downtime, than would be associated with use of a conventional fuel system that could be employed in a more lenient emissions regime, because the moving parts and measuring devices that fail in the advanced fuel system are not present in the conventional fuel systems (Exhibit C provides comparative system availability and cost data which is commercially sensitive and therefore confidential.)

Revenues from the sale of carbon credits have helped to alleviate the additional costs to CNBE of installing and maintaining the Woodward fuel management system. In addition, carbon revenues have enabled CNBE to commission independent development of a new fuel management system that is expected to perform more reliably than the Woodward system while providing the advanced fuel controls required to operate within the strict emissions limits that have been imposed on the Project. Exhibit D, attached, is a purchase order and scope of supply with Enginuity, Ltd, of Livingston, Texas for development and installation of the new system. The Acceptance Test criteria on page 4 of Exhibit D shows that the system is being developed to assure operation within the limited exhaust gas oxygen levels consistent with the stringent NOx limitations. (Exhibit D contains cost and performance information that is commercially sensitive and therefore confidential.) Use of the new system in this LFG engine application will represent a unique approach to addressing the identified technical barrier.

Sub-step 3b: Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed activity).

As between the Project Activity and the alternatives identified in Sub-step 3a, above, the identified technological barrier is only applicable to implementing the Project Activity. The alternatives would not be subject to the stringent NOx emissions requirement which creates the barrier, because the alternatives either do not involve combustion of LFG, or only limited combustion of LFG.

Step 4: Common practice analysis.

This step requires "an analysis of the extent to which the proposed project type (e.g., technology or practice) has already diffused in the relevant sector and region."

Sub-step 4a. Analyze other activities similar to the proposed project activity. In the present case, "other activities similar to the . . . project activity" refers specifically to active LFG collection combined with electric power production.

To identify common industry practice, CNBE has reviewed a database of information on 1,819 landfills, including 1,155 landfills not subject to federal regulation, which database was developed by the United States Environmental Protection Agency (USEPA) through its Climate Leaders program. The Climate Leaders database indicates that the overwhelming majority of landfills that are not required by law or regulation to collect and destroy methane have no system to do so. Specifically, 79 percent of the landfills in the United States, and 74 percent of the landfills in the Northeastern United States, that are not subject to the federal

New Source Performance Standards (NSPS) and/or the Existing Facility Guidelines (EG), do not collect or combust the landfill gas generated in the landfill. In other words, the most common practice at such landfills is unmitigated and uncontrolled release of methane to the atmosphere.

Note that the USEPA Climate Leaders database reflects the practice at only the 1,819 landfills that the USEPA Landfill Methane Outreach Program (LMOP) and the U.S. Department of Energy (USDOE) Energy Information Administration have identified as having the potential for collection of LFG to produce energy on a feasible basis. The USEPA has previously estimated that approximately 8,000 landfills were in existence in the United States in 1988. Putting these two results together, there were approximately 6,200 landfills not included in the Climate Leaders database that were not deemed to have the potential to produce energy on a feasible basis. Such landfills are much less likely to collect landfill gas than those for which energy recovery is deemed feasible. Thus, the fraction of all landfills not subject to federal regulation that do not control landfill gas is likely much higher than the 79 percent of the landfills in the United States, and the 74 percent of the landfills in the Northeastern United States, indicated by the Climate Leaders database.

Consistent with the above data, the methodology published by the USEPA for measuring landfill methane emissions reductions and for determining whether such reductions are “additional” for purposes of that agency’s Climate Leaders program contains a specific finding that active collection of LFG at unregulated landfill does not constitute “common practice” in the landfill sector.

Sub-step 4b. Discuss any similar options that are occurring. This step is only applicable if activities similar to the Project Activity are “widely observed and commonly carried out”.   Since activities similar to the Project Activity are ***not*** “widely observed and commonly carried out”, this sub-step is not applicable.

3.0 CONCLUSION

Based on the above analyses, which are consistent with the requirements for demonstrating and assessing additionality set forth in the Additionality Tool, the Project Activity is “additional”.

Exhibits:

Exhibit A: Operating Window for Low NOx Emissions
Exhibit B: Advertisement by Peaker depicting the Project Activity using the Woodward TecJet EGS-02 fuel management system.
Exhibit C: Cost comparison of Advanced Fuel System with Conventional Fuel System
Exhibit D: Purchase order and scope of supply with Enginuity Ltd.

EXHIBIT A
OPERATING WINDOW FOR
LOW NOx EMISSIONS

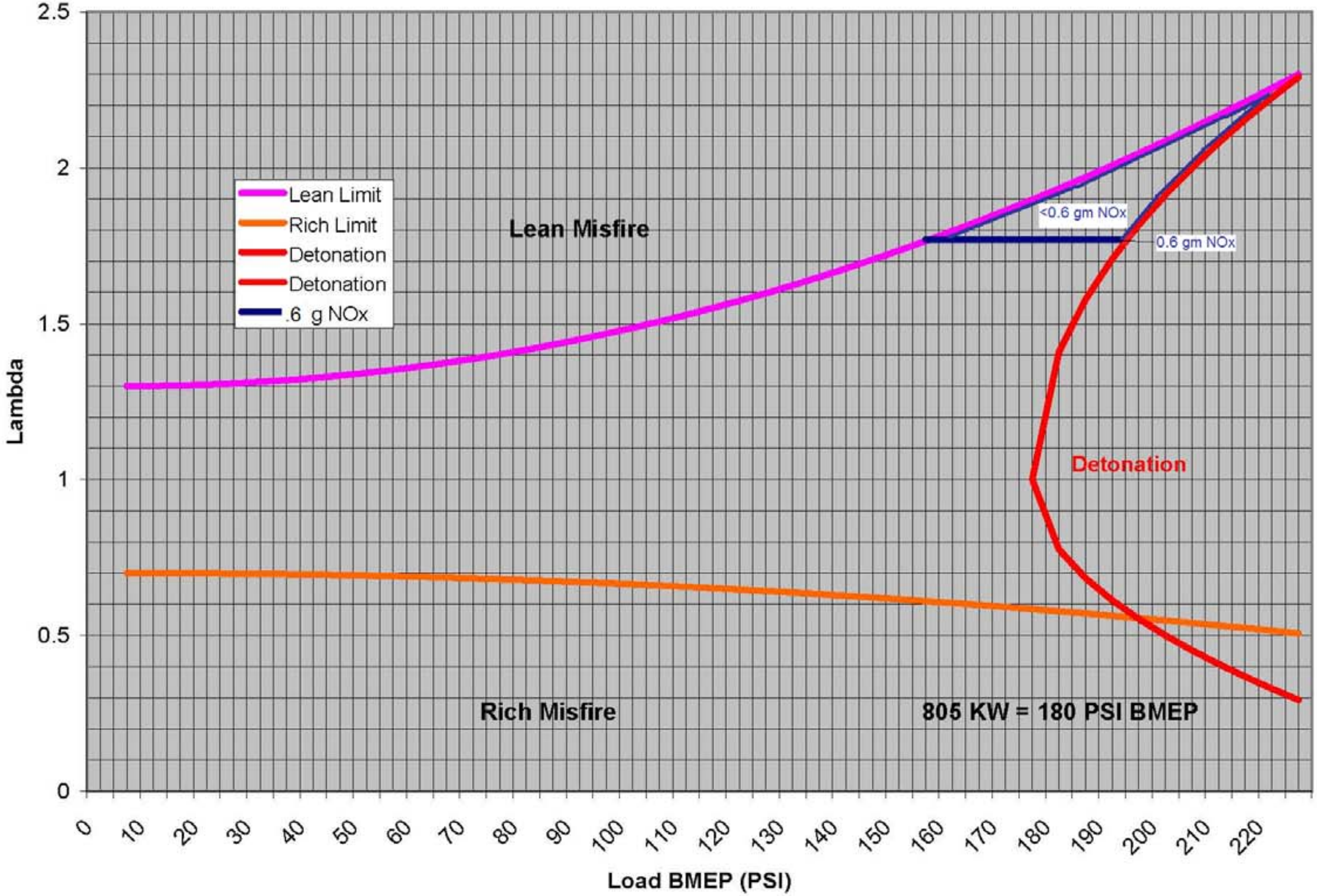


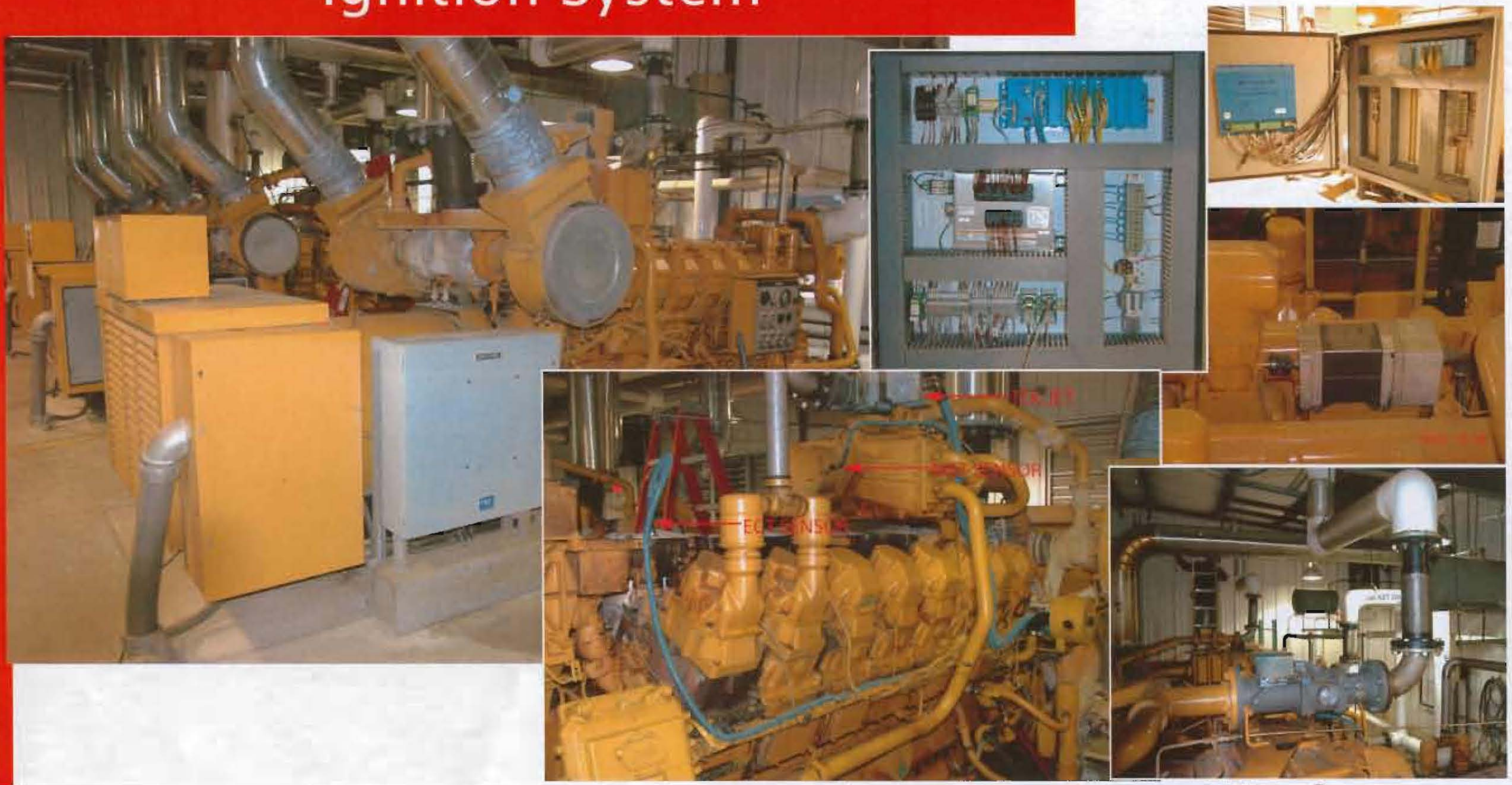
EXHIBIT B

- Optimum Speed, Air/Fuel Regulation at Varying BTU Content
- Reduced Emissions
- Startup & Shutdown Consistency
- Simplified Operation & Troubleshooting
- Increased Reliability
- Enhanced Remote and Local Monitoring and Troubleshooting

Landfill Gas Genset Solutions

EGS-02 Digital Speed/Air:Fuel Ratio Control, Electric Actuation, Ignition System

Quality Certification Bureau Inc.
ISO 9001:2000
Registered QMS



peaker services, inc.
engineered systems group

8080 Kensington Court, Brighton, MI 48116-8591
4060 N. DuPont Highway, Unit 10, New Castle, DE 19720
Business: 800-622-4224 Fax: 248-437-8280 www.peaker.com

EXHIBIT C							
COST COMPARISON OF ADVANCED FUEL SYSTEM WITH CONVENTIONAL FUEL SYSTEM							
	ADVANCED FUEL SYSTEM			CONVENTIONAL FUEL SYSTEM			
Fuel Management System	Woodward/Peaker Tecjet EGS-01	Required for Facility (4 engines)	Total	Conventional system	Required for Facility (4 engines)	Total	Incremental cost to overcome technical barrier
Initial Capital Cost							
Hardware							
Gas analyzer and calibration gases	$17,000	1	$17,000	$0	0	$0	
SCADA System	$20,000	1	$20,000	$0	0	$0	
Process control	$9,812	4	$39,248	$3,000	4	$12,000	
Pressure regulator	$8,370	4	$33,480	$2,000	4	$8,000	
Actuator valve	$3,500	4	$14,000	$5,000	4	$20,000	
Subtotal			$123,728			$40,000	
Installation, set-up, testing and startup							
Caterpillar engineer/technician	$14,400	4	$57,600	$7,200	4	$28,800	
RussElectric PLC engineer	$21,600	1	$21,600	$0	0	$0	
SCADA System	$30,000	1	$30,000	$0	0	$0	
Subtotal			$109,200			$28,800	
Total of Initial Capital Cost			$ 232,928			$ 68,800	
Additional Capital Cost							
Replacement of one Woodward Tecjet EGS-01 with EGS-02	$93,453	1	$ 93,453			$0	
Development of Enginuity Fuel Management System	$10,000	1	$ 10,000				
Replacement of 4 Woodward Systems with 4 Enginuity Systems	$24,000	4	$ 96,000			$0	
Total of Additional Capital Cost			$ 199,453			$0	
TOTAL CAPITAL COST			$ 432,381			$68,800	$363,581
Incremental Operating Costs to Date							
Annual parts replacement and repair			$ 34,939			$6,880	
Annual revenues lost due to fuel system downtime*			$ 23,562			$2,244	
TOTAL INCREMENTAL OPERATING COSTS TO DATE			$ 58,501			$9,124	$49,377
* Loss of engine's availability due to fuel system reliability			1.0%			0.1%	

CommonWealth

New Bedford Energy LLC

PURCHASE ORDER

Purchase Order #	CNBE–2009-02-24-09
Date issued	Tuesday, February 24, 2009
Reference quote	October 24, 2008 System Proposal for Development of Integrated Control Engine System for Caterpillar G3516 Engine (see attached and as modified under terms and conditions of this PO)
Authorized by	Thomas Yeransian, Principal, CRMC, Sole Member, CNBE

Vendor and Professional Service Provider:	Local distributor:
Ronald D. Richardson Enginuity Ltd. PO Box 420 Livingston, TX 77351 Tel. 936-566-4420 Fax. 936-566-5420 Cell. 936-329-2222 Email: enginuit@livingston.net Tax ID: 37-1332798	

Invoice to:	Service and equipment provided at:
CommonWealth New Bedford Energy LLC (CNBE) 229 Billings Street Sharon, MA 02067 Attn.: George H. Aronson Tel: (781) 784-9935 Fax: (781) 784-0468 Email: garonson@crmcx.com Tax ID: 41-2113538	CommonWealth New Bedford Energy LLC at site owned by the Greater New Bedford Regional Refuse Disposal District 300 Samuel Barnet Boulevard New Bedford, MA 02745 Attn.: Ray Bedard 508-985-0923 Or Tom Yeransian at Tel: (508) 339-3074 Fax: (508) 339-1326 Email tyeransian@crmcx.com

Description	*Quantity*	*Unit price*	*Total price*
Hardware and software development, purchase, installation, startup, and testing of fuel system on one CAT 3516 engine located at CNBE Facility, Dartmouth,MA. Travel expenses are not included in price.	1 Documented travel expenses TBD.	$20,000	$20,000
		Discount	-$2,500
		Tax/shipping	Exempt
		Balance due	$17,500

PURCHASE ORDER

Terms and Conditions

Site work date	To be determined
F.O.B./ship cost	Travel expenses are not included in price.
Sales tax	Exempt

Payment terms	*Percent of total*	*Amount*	*Terms*
Purchase Deposit	50%	$10,000.00	Payment within 5 days of execution of Purchase Order.
Upon acceptable performance demonstration of hardware and software on Engine	50% less discount applied	$10,000 - $2,500 =$7,500	Payable 10 days of completion of acceptance test and associated deliverables

Terms and Conditions

Development plan	Enginuity shall analyze the existing Woodward EGS 01 fuel system setup including control hardware, sensors and signal wires and any related RussElectric PLC commands on one engine. Enginuity shall prepare a plan that describes the control strategy and plan to install, test and operate the Enginuity Fuel System. Enginuity shall provide the plan to CNBE for review and approval. Upon CNBE approval of the plan, Enginuity shall purchase the required hardware and software, valves, sensors, wires and other items required to install the Enginuity Fuel System. Enginuity shall program and conduct off-site testing of the software as necessary to implement the plan.
Installation work	Enginuity shall install a fuel system on one engine including • Install a valve to work with Enginuity Fuel System as determined in development phase of work, which valve will replace the existing Woodward Tecjet on one engine; • Install monitoring and controls hardware and software of the Enginuity Fuel System, which system shall replace the existing Woodward EGS-01 fuel system on one engine; • Install new sensors to measure new required inputs to

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	Enginuity Fuel System. • Install connections from Enginuity Fuel System to engine, sensors and other new or existing contacts as necessary; • Confer with RussElectric in advance of the installation period regarding impact of fuel system on RussElectric PLC programming if any. Work with RussElectric to have RussElectric make any required changes. During the installation CNBE shall • Remove the existing Woodward Tecjet; • Provide access, and tools identified in advance by Enginuity, as necessary for Enginuity to perform its work; • Provide operations support for shut-down, start-up and testing of engine during installation process; and • Provide general support as necessary. Enginuity shall conduct the installation and testing of the Enginuity Fuel System to minimize downtime of the engine-generator set, and shall provide the ability to revert back to the original fuel system if required. The start date for installation shall be mutually agreed upon between Enginuity and CNBE. The estimated time to install Enginuity Fuel System and pass Acceptance Test is 8 days. If the engine-generator is down for more than 5 days during installation, or if the Enginuity fuel system fails to pass the Acceptance Test within 10 days from the agreed upon start date for installation, at CNBE's request Enginuity shall return the engine-generator to operation within one day by re-establishing the original fuel management system to its prior operational condition. If the Enginuity Fuel System fails to and pass the Acceptance Test, CNBE shall have no liability to pay the second payment to Enginuity.
Acceptance Test	Acceptable performance shall be demonstrated by the following Acceptance Test: • Maintain full load capability of the engine-generator continuously over 24 hours; • Maintain stable full load conditions over a range of

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	methane (45% to 55%) and oxygen (0% to 1.5% oxygen) concentrations in LFG; • Maintain stable full load conditions over a range of exhaust gas oxygen levels (e.g. 7% to 8.5% v/v wet oxygen); • Maintain stable operation at partial loads (25%, 50% and 75 % of full gross output); and • Maintain engine-generator stability throughout the idle, ramp up and ramp down operating modes.
Optional purchases:	Fully documented control software written in either C, C++, or Basic or combination for payment of $10,000. Engineering drawings and supplier information (all spare and replacement parts, associated manuals, and identification and contact information of suppliers of parts) for payment of $5,000. Enginuity shall maintain these documents in a current form to reflect the as-built and modified or amended form for delivery to CNBE upon request and payment. If Enginuity discontinues the product line or business for any reason, Enginuity shall make the documents available to CNBE at no cost. CNBE shall not use the information to compete against Enginuity.
Technical support	Enginuity shall provide CNBE with technical service and support in the form of remote assistance by phone and laptop, professional on-site service, and delivery and installation of spare parts and replacement parts. Enginuity shall provide such services at its standard commercial rate of $100 per hour plus travel expenses. Enginuity shall identity and provide a licensed third party qualified and trained to provide support on a 24 hour, 7 day per week basis. In event of a fuel system failure or malfunction, CNBE shall address the failure in the following steps: 1. Trouble shoot and remedy the failure or malfunction on-site with CNBE operators; 2. Contact Enginuity for technical service and support; and 3. Contact the licensed third party if Enginuity is unavailable for any reason. Enginuity acknowledges that the inability to operate an engine due

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	to the failure of the Enginuity Fuel System would cause substantial economic harm to CNBE, and therefore prompt technical service and support is required to remedy any failure of the Enginuity product.
Fuel system spare and replacement parts	Enginuity shall maintain required spare and replacement parts at the CNBE site as well as in its own inventory to provide prompt technical service and support to CNBE to remedy any technical problem with the fuel system. The spare parts at the CNBE site will be invoiced upon delivery to the site.
Training	Enginuity shall provide NEESCo and a representative from CNBE training on the system to be able to understand the basic algorithms, settings and adjustments necessary to operate the system, identify operational issues, and perform basic troubleshooting. This training shall be performed immediately subsequent to demonstration of performance of the fuel system.
Documentation to be delivered upon acceptance of system	Not later than 30 days after demonstrating acceptance of the Enginuity Fuel System, Enginuity shall provide CNBE with installation, as built diagrams and documentation; operating, maintenance and repair manuals, and a list of spare and replacement parts.
Warrantees	In the event that the development program does not demonstrate acceptable performance, Enginuity shall re-establish the original fuel management system to its prior operational condition promptly. The Enginuity system shall be free from defects in materials and workmanship for a period of 1 year from acceptance. Enginuity shall provide prompt assistance and technical support to remedy any such defects at its cost.
Sales tax	Exempt.

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PO reviewed and approved by:

Buyer:
Thomas Yeransian
CommonWealth New Bedford Energy LLC

Seller:
Ronald Richardson
Enginuity

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System Proposal for

Development of

Integrated Control Engine System for

Caterpillar® G3516 Engine

Enginuity *Ltd.*

24OCT2008

Enginuity Ltd. ™

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Livingston, TX 77351 936-566-5420 FAX

1. Introduction

This proposal is written with the intention of documenting the preliminary budget and resource estimates for developing a control system that includes hardware and software design and development for the G3516 gas engine.

2. Summary of Features

- Main chamber fuel control for starting, idle, and load control
- Combustion air flow control for power and emissions control
- Monitoring and protection
- Data logging
- Snapshot recorder
- Data transfer to a remote monitor or a PC
- Human Machine Interface [HMI] 20 X 4 LCD display with keypad
- PC based service tool
- Software flowchart documentation
- Troubleshooting manual
- Optional fully documented control code software and firmware

2.1 G3516 gas engine operation

a. The natural gas mass flow is required to determine the energy flow rate into the engine. This flow rate is required to determine the power of the engine or conversely the power can be measured to determine the fuel rate. Ideally, both power and fuel rate can be measured and used as an alarm or shutdown when the two do not agree.

b. Air mass flow will be determined by the speed density method with the use of manifold absolute pressure sensor(s), inlet manifold temperature sensor(s), and engine speed sensor(s).

c. The air fuel ratio, Lambda, and % oxygen in the exhaust will be determined from the fuel flow and air flow values. The NOx can be also calculated after engine emissions data is gathered to determine the emissions algorithms.

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d. Boost pressure will also be measured using absolute pressure sensor(s). The boost pressure will be controlled by the wastegate actuator.

e. Mass airflow is required to determine the air fuel ratio and the maximum allowable fuel energy flow rate into the engine. If the air flow rate is not sufficient the natural gas fuel energy contribution will be limited.

f. Magnetic pickup is required to determine engine speed. A dedicated sensor is preferred opposed to one that is shared with other control device(s). It is needed to along with the manifold air pressure and inlet air temperature sensors to determine airflow.

g. Manifold air pressure sensor is used to determine boost and display it. It is also used in conjunction with the speed pickup and inlet air temperature sensor to determine airflow.

h. Inlet air temperature sensor is used to determine the inlet air temperature, density, and display it.

i. A power or torque signal is required to determine the actual load on the engine and determine the proper amount of fuel and air required for proper engine operation. This can be a direct sensor measurement or calculation of the driven equipment load. Power, torque, and percent maximum available power will be determined and displayed. A KW transducer will be used for generator applications.

j. Natural gas solenoid valve will be controlled by ICE to shutoff the engine in a fault condition.

k. A 24VDC motor controlled fuel metering valve will receive signals from ICE to control engine speed and load. An H bridge motor controller will interface the ICE to the DC motor. A feedback position sensor will provide fuel valve position.

l. A manual fuel valve to allow fuel control for ease of starting and low idle fuel supply.

m. Speed demand signal is required to determine if the load is to be increased or decreased. This signal is customer provided and can be 0-5VDC analog, 4-20mA analog, or pulse width modulated digital signal.

n. Actuators and position sensors to control air flow are used. These include a butterfly valve to control air discharged from the turbocharger [choke] and a wastegate. The choke actuator can be either a Woodward EG3P actuator or ProAct. A poppet valve in the exhaust to bypass exhaust energy around the turbocharger turbine [wastegate] is controlled by a E/P transducer [30PSIG compressed air is to be provided by the customer].

o. A capacitive discharge high energy ignition system is to be used and is customer provided. The Caterpillar® Electronic Ignition System [EIS] is suitable.

p. HMI - An LCD display and keypad will be provided to alter engine operation and display current operational information.

q. Four panel LEDs will indication unit powered [green LED], alarm condition [yellow LED], shutdown condition [red LED], and speed signal present indicating the engine is running [blue LED].

2.2 G3516 gas engine operator station

The control can be started either locally or remotely. Emissions can be altered via the HMI. Other parameters and operational limits, shutdowns, and alarms can be programmed.

2.3 Monitoring and Protection

The control supports the following monitoring and protection features.

- Engine overspeed shutdown
- Overload alarm
- Over temperature alarm and shutdown
- Low oil pressure alarm and shutdown
- ***Other features need to be identified***

2.4 PC based service tool

A PC based service tool will be designed to provide following features.

- Easy trouble shooting procedures via the tool
- Configuring safety related set points
- Tuning engine performance
- Flashing application software
- Diagnostics display

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- ***Other features need to be identified***

3. Hardware Required

The hardware required for the control system will have the following features.

a) A Microprocessor control unit (MCU) with EEPROM, flash memory and RAM.
b) Analog to digital converter to convert analog sensor signals to digital signals that can be interpreted by MCU.
c) A 24 VDC to 12 VDC and 5 VDC converters to power sensors and the MCU.
d) An LCD touch screen display to display status of the control, faults etc.
e) An I/O board to acquire samples from sensors and drive outputs.
f) An enclosure for the electronics
g) 24 V supply with filtering
h) Over-voltage protection
i) RS-232, RS-422 [RS-485] serial port(s)
j) Solenoid driver for gas shutoff solenoid valve
k) H bridge circuit for motor control
l) Wiring harness(es) [please specify explosion proof requirements]

4. Specifications:

a) 24VDC supply at 5 amps with filtering
b) 16”X16”X10” Electrical enclosure
c) Fuel Wobbie Index range from 1200 to 480 BTU/SFC LHV
d) Fuel supply pressures range 2 to 5 PSIG.
e) Fuel flow 400 SCFM @ 5 PSIG and a specific gravity of 1.0 [this will provide approximately 1.0MW at 480 BTU WI.]
f) An enclosure for the electronics and terminations

5. Software Required

The software development effort includes the necessary control strategies for control of the G3516 gas engine; and will conform to the requirements documented in the project specification. Software development also includes fault logging, communications on the serial port, driving peripherals, reading and processing sensor inputs, annunciation of status and faults, ability to flash software into flash memory, etc. The ownership of the control software can be negotiated.

A PC based service tool that interfaces to the control through the serial port will be

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provided.

6. Pricing Summary

The hardware and software development cost will be $20,000 to invest resources on this project. This cost will be shared by Enginuity Ltd. and the customer. To begin work the customer will deposit $10,000. A discount of $2500 per unit will be returned to the customer for each unit ordered, to a maximum of four units. Customer ownership of the fully documented control software [written in either C, C++, or BASIC or combination] is an additional $10,000. Complete ownership of engineering drawings and supplier information is an additional $5000. [The contract will specifically prohibit using this information to compete against or reproduce the hardware or software. It will only be allowed if for any reason Enginuity Ltd. can not provide the technical support required to keep the engine(s) operational.] A third party [i.e. NEESCo] can be licensed to provide technical services to support this product in the event that Enginuity Ltd. is not able or willing to provide such support. The license would prohibit said third party from competing against Enginuity Ltd. without written permission.

Installation at the site is not included in the price, but can be contracted. All the expenses incurred during lab and field support such as travel expenses, travel time will be charged additionally.

To begin work a signed contract and the amount of $10,000 is required.

7. Deliverables

After the initial payment of $10,000, work will commence. The current control hardware will be analyzed on site and signals and suitability for use will be determined. The control strategy will be formalized and presented to the customer if desired. Upon acceptance of the strategy, hardware and software selection and development will commence. In 30 days one set of hardware for one engine will be available to test. Upon acceptable performance demonstration, an additional $18,000 - $2500 = $15,500, the balance of the payment is due. This estimate assumes that major components on the engine do not have to be changed or significantly modified. If major changes are required they will be discussed prior to further progress. Once the hardware and software are acceptable additional three (3) units can be purchased for $15,500 each. Additional units after the initial four will be $18,000 each.

December 23, 2008

Greg Kozak
Senior Environmental Engineer
First Environment, Inc.
1111 East Warrenville Road, Suite 200
Naperville, IL 60563

Dear Greg,

This letter responds to the December 17th request by First Environment for clarification and correction action in connection with the validation of the Greater New Bedford LFG Utilization Project (the Project), owned and operated by CommonWealth New Bedford Energy LLC (CNBE) in accordance with the Voluntary Carbon Standard ("VCS"). The Project includes the installation of an initial active LFG collection and flare system at the Crapo Hill Landfill in June 2000 (the District Initial System) and the subsequent expansion of the LFG collection system after January 1, 2002, and installation and operation of the Electric Generating Facility in November, 2005 (the Project Activity). This letter serves as a supplement to the information previously provided to First Environment in connection with previous validations of the Project in accordance with the program requirements of the Chicago Climate Exchange ("CCX"), the American Carbon Registry (formerly the GHG Registry of the Environmental Resources Trust), and Greenhouse Gas Services. The First Environment request is attached.

Request #1. Projects shall use one of the VCS program approved project methodologies or propose a new methodology. The use of ACM0001 was confirmed in the kickoff meeting. Please ensure this is included in the project documentation and that the applicability is provided.

Response: CNBE acknowledges the use of the Approved consolidated baseline methodology ACM0001/Version 09.1 titled " Consolidated baseline and monitoring methodology for landfill gas project activities" (the ACM0001 Methodology) promulgated by the United Nations Framework Convention on Climate Change (UNFCCC) under the Clean Development Mechanism (CDM). The ACM0001 Methodology lists and incorporates by reference several other operative documents, referred to as tools, that are required to be used as part of the ACM0001 methodology as applicable. The tools applicable to the Project Activity herein, include

- Tool for the demonstration and assessment of additionality

- Tool to determine project emissions from flaring gases containing methane
- Combined tool to identify the baseline scenario and demonstrate additionality.

The ACM0001 Methodology is applicable to landfill gas capture and project activities, where the baseline scenario is the partial or total atmospheric release of the gas and the project activities captured gas that is flared and/or used to produce energy. The Project Activity meets the applicability definition.

Request #2. ACM0001 (version 9.1) outlines a required procedure for selecting the most plausible baseline scenario. This procedure is not followed in the PDD provided and no justification for its exclusion was included. Please provide the justification or include the process.

Response to Request #2. The first component of establishing the baseline under ACM0001 Methodology is defining the project boundary that includes "the site of the project activity where the gas is captured and destroyed/used." The entire LFG collection system, flare and electric generating facility are included in the Project Boundary. The electric generating facility is specifically included within the Project Boundary because "the electricity for the project activity is from a captive generation source or electricity generated by the captured LFG." Within the Project Boundary is contained the District Initial System and the Project Activity.

The District Initial System was incorporated into the Landfill's state-approved operating plan at the initiative of the District to prevent odor complaints and sub-surface gas migration from those sections of the phase 1 landfill that were closed, being closed and in most cases being permanently capped. The timing of the installation of the District Initial System coincided with construction activities to close the large portions of Phase 1 landfill and minimized disruption to landfill operations within the Phase 1 landfill, both important considerations to the District. Approximately three quarters of the LFG collection system in place as of the date of this letter has been installed after January 1, 2002 (see attached Exhibit 1, Landfill and LFG Build-out). This expansion that is part of the Project Activity was performed primarily in new areas of waste that were and still remain active for landfill operations. Exhibit 1 details (a) the phased expansion of the landfill from 1998 through 2008 including the footprint area, waste accepted during each year and the cumulative waste by year (b) the installation and operation of the District Initial System in 2000 and the expansion of the LFG collection system subsequent to January 1, 2002 through 2008, and (c) the quantity of methane collected and controlled from the Project, the District Initial System and the Project Activity. Exhibit 1 lists all the wells that comprise the LFG collection system, the type of well, the length of perforated pipe, the portion of the landfill the well is installed, and the date that the well was connected and commenced operation.

The next component under the ACM0001 Methodology to select "the most plausible baseline scenario" requires CNBE, the project participant, to identify alternative scenarios using step 1 of the tool for the demonstration and assessment of additionality, which step 1 is titled Identification of alternatives to the project activity consistent with current laws and regulations. Step 1 requires the project participant to identify realistic and credible alternative scenarios to the Project Activity as a way of establishing a baseline against the Project Activity. Realistic and credible alternative scenarios to the Project Activity include the following:

1. The District could have installed and operated passive vents in new areas of waste to passively vent untreated methane to the atmosphere. Methane is not a regulated pollutant in the United States and is not subject to collection and control requirements as a pollutant and as described in the Monitoring, Reporting and Verification Protocol ("MRV") which together with all supplemental information subsequently provided to First Environment constitute the PDD. Note that the Greater New Bedford Regional Refuse Management District (the "District"), which is the owner of the subject site,_has not been required, pursuant to any environmental law, to collect, destroy or control the emission of methane, hazardous air pollutants or any other component of landfill gas. For the purpose solely of preventing migration, the District could have vented the methane to the atmosphere through a passive venting system. Passive venting of new areas of the landfill may have been a realistic and credible alternative, so long as the quantities and concentrations of gas emitted from those areas would not cause detectable odors offsite. This alternative is less obtrusive and disruptive to landfill operations in active areas than an active LFG collection system.

2. The District could have installed and operated (a) passive point flares to passively vent and destroy potentially odor-causing compounds in new areas of waste that provided evidence of potential odor problems, and (b) passive vents to relieve pressure from the landfill but in areas that would not cause detectable odors offsite. This alternative has the advantage of mitigating the potential landfill operational issues at a relatively low cost. This alternative also is less obtrusive and disruptive to landfill operations in active areas than an active LFG collection system.

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3. The District could have installed and operated a new but separate active gas collection system in new areas of waste for the purpose of treating or otherwise removing potentially odorous compounds from the collected landfill gas using several commercially available technologies in order to prevent detectable odors offsite. However, given that the District Initial System was already a cost expended by the District, funding a separate collection and control system would be less desirable than other plausible realistic and credible alternatives. In addition, installation and operation of an active gas collection system in active areas of landfill operations, which a separate system would have resulted, would have been more disruptive to landfill operations than alternatives # 1 and #2 and therefore less desirable from a landfill operations standpoint. This potential disruption is more fully detailed in alternative #4.

4. The District could have installed and operated additional active gas collection wells in new areas of waste and connected those new wells to the District Initial System to relieve pressure from the landfill and destroy potential odor-causing compounds. However, the new areas of waste are in active areas of the landfill and operators attempt to limit other construction activities within active areas and limit potential obstacles in these areas such as gas wells. Limiting installation of active gas wells in active landfill areas reduces interference with landfill operations. Typically, landfill owners would install active gas wells in landfill areas that no longer are active. Also, damage to one active well results in shutting down the active system until a repair is made. Given the higher level of costs and potential disruption to landfill operations compared to alternatives # 1 and #2, this scenario is less desirable operationally than those alternatives.

Of the plausible scenarios, the most desirable realistic and credible alternative to the Project Activity is scenario #1, so long as the gas generated from the new areas of the landfill did not cause detectable odors offsite, and scenario #2 if detectible odors are generated from new areas of waste as described above. Therefore, scenario #1 establishes the baseline emissions for methane from the Crapo Hill Landfill.

Based on the use of ACM0001 Methodology, the baseline emissions could be based upon the most desirable of the plausible baseline scenarios, that of uncontrolled methane emitted to the atmosphere from those areas of the landfill not covered by the District Initial System. Therefore, the most plausible baseline scenario results in baseline emissions that consider the quantity of methane collected and destroyed by the District Initial System during 2001. Specifically, the baseline emission calculation variable $MD_{BL,y}$, the amount of methane that would have been destroyed/combusted during the year in the absence of the project would equal the methane destroyed by the flare in Calendar Year 2001.

Request #3. In accordance with section 5.8 of the VCS, the project must demonstrate additionality using the VCS 2007 Project Test (Test 1), Performance Test (Test 2), or Technology Test (Test 3). The PDD includes information regarding regulatory additionality, but the selection of the test to be used and the remaining information is not provided. Please provide the needed information.

Response to Request #3.
The Project Activity is additional in accordance with Test 1, the Project Test. Specifically the Project Activity meets the requirements of the Project Test including Regulatory Surplus, Implementation Barriers, and Common Practice as described below.

Regulatory Surplus: The project is not mandated by any enforced law, statute or other regulatory framework as detailed in Section 2. 6 of the MRV.

Implementation Barrier: The Project faced technological barriers to implementation compared with barriers faced by alternative projects. The barriers involved significant technological risk when compared to other technologies typically used in alternative projects. The significant technological risks were necessary to implement the Project.

A first technological barrier included development and implementation of a new fuel management system that is uncommon to projects of this type because the Project Activity was subject to the most stringent air emission requirements for nitrogen oxides. The new fuel management system required substantial initial engineering and development to be integrated as part of the Project, and required substantial development during operations. The development of the system is still ongoing. The continued development of this fuel management system has required CNBE to invest substantial incremental financial resources that are funded in large part from the sale of carbon credits.

A second technological barrier included the aggressive expansion of the LFG collection system to insure adequate gas flows using innovative designs not employed at any other landfill. The innovative designs included installation of matrix-linked horizontal collectors at waste depths every 30-feet in active areas of the landfill. The horizontal collectors also incorporated unique well-head and moisture traps that separate and drain leachate and condensate from the landfill gas and direct the leachate and condensate directly to the leachate and condensate disposal system. This design innovation has been critical in overcoming potential gas supply constraints, as the Electric Generating Facility was aggressively sized to match a high recovery and collection rate of LFG generated from the landfill.

Common Practice: The Project is not common practice as detailed in the December 2007 Supplement to the MRV previously submitted to First Environment in connection with its validation of the Project under the Greenhouse Gas Services program requirements (page 3, 4 and Attachment C to the Supplement).

Request #4. Section III of ACM0001 (version 9.1) includes a list of data and parameters to be monitored by the project participant. Please ensure that the PDD includes a complete list of monitoring records and parameters as required by ACM0001 (version 9.1).

Response to Request #4. The data and parameters that are monitored for the Project have been provided in the PDD as well as previous submittals for verification statements under other protocols. These data and parameters meet the requirements of the ACM0001 Methodology. Note that indirect emissions portion of the baseline emissions, which are based upon electric power and thermal energy consumed by the project in the absence of the Project Activity, are negligible. Specifically, electric power used by compressors, blowers, and gathering system is provided by the electric power generated by the Project Activity, and therefore, no in-direct emissions are created by the electric power plants that would otherwise supply electric power to the site. Note that thermal energy used within the Project Boundary is provided by the thermal energy generated by the Project Activity, and therefore, no in-direct emissions are created by the thermal energy that would otherwise be supplied to the site. Further note that the flare has no auxiliary fuel to start or maintain the operation of the flare. A back-up diesel generator is available at the flare station to power the flare in case of an emergency. However the back-up diesel generator has not operated for several years and therefore the emissions associated with the generator are negligible.

Request #5. Indicate the key factors that will be used in the formulas to quantify the baseline emissions and emission reductions.

Response to Request #5. The key factors to determine baseline emissions and emission reductions include the following:

- Methane oxidation efficiently for electricity generation: 100%
- Methane oxidation efficiently for flare: 50%
- Global Warming Potential methane: 21
- $MD_{BL,y}$, the amount of methane that would have been destroyed/combusted during the year in the absence of the project: Equal to the methane destroyed by the flare in Calendar Year 2001, which methane declines each subsequent year by 12.5% (annual decline includes biological decay rate and loss of gas collection system effectiveness - see Exhibit 1).
- $EL_{LFG,y} = 0$ (Baseline Emissions calculation on page 6 of ACM001 Methodology).
- $ET_{LFG,y} = 0$ (Baseline Emissions calculation on page 6 of ACM001 Methodology).

The equations contained in ACM0001 Methodology will be used to calculate the baseline emissions and emissions reductions for each period that CNBE seeks verification. Specifically, the following equations will be used:

- To determine baseline emissions, Equation 1 contained the in ACM0001 Methodology;
- To determine emissions reductions for the Project Activity, Equation 8 contained the in ACM0001 Methodology;
- To determine emissions reductions for the electric generating facility, Equation 10 contained the in ACM0001 Methodology; and
- To determine emissions reductions for the flare, Equation 9 contained the in ACM0001 Methodology.

Please call me with any questions. Thank you.

Sincerely,

Thomas Yeransian
Principal

Copy: Christina M. Magerkurth, P.E.

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Landfill and LFG Collection System Build-out												
2	Crapo Hill Landfill, Dartmouth, Massachusetts												
3	4-Jun-08												
4													
5													Projected
6		**Units**	**1998**	**1999**	**[Note 4] 2000**	**2001**	**2002**	**2003**	**2004**	**[Note 5] 2005**	**2006**	**2007**	**2008**
7	**Landfill build-out and operating data**												
8	Stages of landfill receiving waste during this calendar year:												
9	Phase 1	N/A	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxx					
10	Phase 2, Cell 1	N/A					xxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxx
11	Phase 2, Cell 2							xxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxx
12	Phase 2, Cell 3												xxxxxxx
13	Phase 2, Cell 4												
14	Landfill footprint by end of calendar year	acres	18.6	18.6	18.6	28.3	28.3	28.3	28.3	28.3	28.3	28.3	35.4
15	Waste accepted during this calendar year	tons	114,827	108,846	116,192	113,454	113,675	108,155	110,053	113,338	110,398	101,342	115,000
16	Total waste in place by end of this calendar year	tons	434,780	543,626	659,818	773,272	886,947	995,102	1,105,155	1,218,493	1,328,891	1,430,233	1,545,233
17													
18	**LFGCS build out and operating data: [Note 1**												
19	Extraction points in place at start of year [Note 2]	each	0	0	0	16	22	28	31	39	44	45	70
20	Extraction points added during this year in Phase 1	each	0	0	16	6	6	3	4				
21	Extraction points added during this year in Phase 2, Cell 1	each							2	2	1	18	4
22	Extraction points added during this year in Phase 2, Cell 2	each							2	3		7	8
23	Extraction points added during this year in Phase 2, Cell 3	each											
24	Extraction points added during this year in Phase 2, Cell 4	each											
25	Extraction points removed/abandoned this yea	each	0	0	0	0	0	0	0	0	0	0	0
26	Net extraction points at end of year	each	0	0	16	22	28	31	39	44	45	70	82
27	Net extraction points at end of year, as percent of 2008 net total		0%	0%	20%	27%	34%	38%	48%	54%	55%	85%	100%
28	Percent of net extraction points at end of year that are post 1/1/2002		N/A	N/A	N/A	N/A	21%	29%	44%	50%	51%	69%	73%
39	The Project: Methane collected and controlled through flare and/or engines and flare during this year	metric tons	-	-	2,357	3,548	5,590	5,616	5,388	5,348	5,741	6,085	6,390
40	The District Initiative System: Methane collected and controlled from pre-1/1/2002 system	metric tons	-	-	2,357	3,548	3,104	2,716	2,377	2,080	1,820	1,592	1,393
41	The Project Activity: Methane collected and controlled from post-1/1/2002 system	metric tons	-	-	-	-	2,486	2,900	3,011	3,268	3,922	4,493	4,996
42	Percentage of methane collected and controlled from post-1/1/2002 system [Note 3]		0%	0%	0%	0%	44%	52%	56%	61%	68%	74%	78%
66													
67													
68	**Notes:**												
69	1."LFGCCS" means the landfill gas collection and combustion system												
70	2."Extraction points" means vertical wells, horizontal wells, and points in the leachate collection system from which LFG is actively collected												
71	3. Percentage based on proportion of methane collected and destroyed in post-year to that of the total year, accounting for an annual degradation rate of the methane in the pre-year system.												
72	including 10-percent decline due to reduced anaeorbic degradation and 2.5-percent decline due to reduced effectiveness of LFGCS.												
73	4. Year in which LFG collection system and flare was installed and commenced operation to destroy all LFG collected at the landfill.												
74	5. Year in which beneficial use Project commenced operation to destroy all LFG collected at the landfill.												
75													

EXHIBIT 2

1-Dec-08

GAS EXTRACTION WELL INFORMATION
CRAPO HILL LANDFILL

Vertical Wells			
Well ID	Landfill location	Screen Length, feet	Date Active: connections completed and operational
EW-1	Phase 1	19	June-00
EW-2	Phase 1	16	June-00
EW-3	Phase 1	14	June-00
EW-4	Phase 1	5	June-00
EW-5	Phase 1	5	June-00
EW-6	Phase 1	7	June-00
EW-7	Phase 1	19	June-00
EW-8	Phase 1	24	June-00
EW-9	Phase 1	21	June-00
EW-IO	Phase 1	22	June-00
EW-11	Phase 1	25	June-00
EW-12A	Phase 1	53	April-02
EW-12B	Phase 1	50	April-02
EW-13	Phase 1	52	April-02
EW-14	Phase 1	54	April-02
EW-18	Phase 1	59	April-02
EW-19	Phase 1	40	April-02
EW-15	Phase 1	62	September-04
EW-16	Phase 1	55	September-04
EW-17	Phase 1	49	September-04
N-EW-22	Phase 2, Cell 1	37	July-07
S-EW-24	Phase 2, Cell 1	33	June-07
N-EW-25	Phase 2, Cell 1	37	June-07
S-EW-27	Phase 2, Cell 1	35	June-07
N-EW-28	Phase 2, Cell 2	36	June-07
S-EW-30	Phase 2, Cell 2	40	June-07
N-EW-31	Phase 2, Cell 2	35	June-07
S-EW-34	Phase 2, Cell 2	33	June-07
EW-32	Phase 2, Cell 2	46	March-08
EW-33	Phase 2, Cell 2	40	March-08
EW-35	Phase 2, Cell 2	32	March-08
EW-36	Phase 2, Cell 1	26	March-08
TBD	Phase 2, Cell 1	50	September-08
TBD	Phase 2, Cell 2	50	September-08
TBD	Phase 2, Cell 2	50	Sep-08
TBD	Phase 2, Cell 2	50	Sep-08
Total		1,081	

Notes:
1. All wells have 8-inch diameter perforated HDPE screens
2. All wells have 6-inch diameter HDPE solid risers
3. All wells are equipped with telescoping slip joints between riser and screen.
4. All wells installed in 36" dia. boreholes

Horizontal Collectors			
Well ID	Landfill Location	Screen Length, feet	Date Active: connections completed and operational
HC-1	Phase 1	520	June-00
HC-2	Phase 1	570	June-00
HC-3	Phase 1	600	June-00
HC-4	Phase 1	705	June-00
HC-LT1	Phase 1	250	June-00
HC-4S, HC-5N, HC-6N	Phase 1	1,155	September-03
Perimeter trench	Phase 1	NA	September-04
HC 11	Phase 2, Cell 1	600	September-05
HC 12	Phase 2, Cell 1	600	September-05
HC 13	Phase 2, Cell 2	600	September-05
HC 14	Phase 2, Cell 2	600	September-05
HC 15	Phase 2, Cell 2	600	September-05
HC 16	South, Phase 2, Cell1	Shared with HC-11	Jun-07
HC 17	South, Phase 2, Cell1	Shared with HC-12	Jun-07
HC 18	South, Phase 2, Cell1	Shared with HC-13	Jun-07
HC 19	South, Phase 2, Cell 2	Shared with HC-14	Jun-07
HC 20	South, Phase 2, Cell 2	Shared with HC-15	Jun-07
HC 21	North, Phase 2, Cell 1	550	Jun-07
HC 22	North, Phase 2, Cell 1	500	Jun-07
HC 23	North, Phase 2, Cell 1	380	Jun-07
HC 24	North, Phase 2, Cell 1	380	Jun-07
HC 25	North, Phase 2, Cell 1	380	Jun-07
HC 26	North, Phase 2, Cell 1	350	Jun-07
HC 27	South, Phase 2, Cell 1	Shared with HC-21	Jun-07
HC 28	South, Phase 2, Cell 1	Shared with HC-22	Jun-07
HC 29	South, Phase 2, Cell 1	Shared with HC-23	Jun-07
HC 30	South, Phase 2, Cell 1	Shared with HC-24	Jun-07
HC 31	South, Phase 2, Cell 1	Shared with HC-25	Jun-07
HC 32	South, Phase 2, Cell 2	Shared with HC-26	Jun-07
TBD	Phase 2, Cell 1	300	Nov-08
TBD	Phase 2, Cell 1	300	Nov-08
TBD	Phase 2, Cell 2	300	Nov-08
TBD	Phase 2, Cell 2	300	Nov-08
Total		10,540	

Notes:
1. All horizontal collectors have 6-inch diameter perforated HDPE screens except HC-LT1, which has 12-inch diameter screen.

Connections to the leachate extraction system			
Well ID	Location side of Landfill	Approximate screen length, feet	Date Active
LC-1	Northwest, Phase 1	450	December-01
LC-2	Northwest, Phase 1	450	June-01
LC-3	Northeast, Phase 1	450	December-01
LC-4	East, Phase 1	450	June-01
LC-5	South, Phase 1	450	December-01
LC-6	South, Phase 1	450	June-01
LC-7	South, Phase 2, Cell 1	660	March-04
LC-8	South, Phase 2, Cell 1	660	March-04
LC-9	South, Phase 2, Cell 2	660	March-04
LC-10	South, Phase 2, Cell 2	660	March-04
LC-11	Phase 2, Cell 1 Sump	100	December-06
Total		5,440	

SUPPLEMENT
To The

MONITORING, REPORTING AND VERIFICATION PROTOCOL FOR THE GREATER NEW BEDFORD LFG UTILIZATION PROJECT CRAPO HILL LANDFILL, DARTMOUTH MASSACHUSETTS

(MRV CNBE 2005 12)

As initially prepared for
CommonWealth New Bedford Energy LLC, a wholly owned subsidiary of
CommonWealth Resource Management Corporation

By

Environmental Resources Trust, Inc.
Washington, DC

December, 2005

THIS SUPPLEMENT PREPARED FOR

GE AES Greenhouse Gas Services

By

CommonWealth Resource Management Corporation
Boston, Massachusetts

December, 2007

TABLE OF CONTENTS

1.0 INTRODUCTION

CommonWealth New Bedford Energy, LLC (CNBE) is the owner and operator of the Greater New Bedford LFG Utilization Project (the Project) located at the Crapo Hill Landfill in Dartmouth, Massachusetts. CNBE is a wholly-owned subsidiary of CommonWealth Resource Management Corporation (CRMC), of Boston, Massachusetts. In late 2005, CRMC, acting on behalf of CNBE, commissioned Environmental Resources Trust, Inc. (ERT) of Washington, DC, to prepare a Monitoring, Reporting and Verification Protocol (the MRV) to provide transparency and credibility in the quantification of the greenhouse gas emission reductions (a.k.a., "offsets" or "credits") associated with the collection, beneficial use and ultimate destruction of methane (CH_4), a principal constituent of landfill gas (LFG), at the Project.

In December, 2007, CRMC entered into a GHG Credit Purchase Agreement (the Agreement) with Greenhouse Gas Holdings, LLC, an affiliate of GE AES Greenhouse Gas Services (hereafter, GE-AES). The Agreement establishes specific requirements for an Initial Project Design Document, and for Verification Reports to be submitted to GE-AES with each delivery of Contract GHG Credits under the terms thereof.

This document in the Supplement as that term is defined in the Agreement. The purpose of the Supplement is to expand upon the information in the MRV, so that the MRV and this document taken together will (a) serve as a complete Initial Project Design Document, and (b) provide the basis for preparing Verification Reports on emissions reductions going forward, all in conformance with the GE-AES Standard of Practice and associated landfill gas project guidance documents and methodologies (collectively, the GE-AES Standard, or the Standard)[1].

By agreement between CRMC and GE-AES (as evidence by the letters at Attachments A and B) , the information contained in this Supplement corresponds to the specific elements called out in the column headed "Actions Proposed by CNBE to Satisfy Requirement" in the table entitled "CNBE Conformance with GE-AES Landfill Project Requirements (Revised November 15, 2007)" (the Conformance Table) at Attachment A. Accordingly, the balance of this Supplement provides information supplemental to the MRV called for by specified Item number in the Conformance Table.

2.0 ELEMENTS OF SUPPLEMENTAL INFORMATION

<u>Item #2 re: Common Industry Practice</u>. The GE-AES Standard requires that "Projects producing GHG credits marketing by GE AES Greenhouse Gas Services will not have been or be otherwise required by law, regulation, legal obligation, or common industry practice." The MRV addresses the legal and regulatory status of the Project, documenting that the Project is not required by federal or state law or regulation. Accordingly, this Supplement addresses solely whether the Project is required by "common industry practice."

[1] The documents comprising the GE-AES Standard are identified in Attachment J.

To identify common industry practice, CNBE has reviewed a database of information on 1,819 landfills, including 1,155 landfills not subject to federal regulation, which database was developed by the United States Environmental Protection Agency (USEPA) through its Climate Leaders program. The Climate Leaders database indicates that the overwhelming majority of landfills that are not required by law or regulation to collect and destroy methane have no system to do so[2] (See Attachment C). Specifically, 79 percent of the landfills in the United States, and 74 percent of the landfills in the Northeastern United States, that are not subject to the federal New Source Performance Standards (NSPS) and/or the Existing Facility Guidelines (EG), do not collect or combust the landfill gas generated in the landfill. In other words, the most common practice at such landfills is unmitigated and uncontrolled release of methane to the atmosphere.

Note that the USEPA Climate Leaders database reflects the practice at only the 1,819 landfills that the USEPA Landfill Methane Outreach Program (LMOP) and the U.S. Department of Energy (USDOE) Energy Information Administration have identified as having the potential for collection of LFG to produce energy on a feasible basis. The USEPA has previously estimated that approximately 8,000 landfills were in existence in the United States in 1988. Putting these two results together, there were approximately 6,200 landfills not included in the Climate Leaders database that were not deemed to have the potential to produce energy on a feasible basis. Such landfills are much less likely to collect landfill gas than those for which energy recovery is deemed feasible. Thus, the fraction of all landfills not subject to federal regulation that do not control landfill gas is likely much higher than the 79 percent of the landfills in the United States, and the 74 percent of the landfills in the Northeastern United States, indicated by the Climate Leaders database.

Item #10 re: Avoidance of Double Counting. The GE-AES Standard requires that "GHG credits marketed by GE-AES will not be subject to claims of double-sale or double counting", and further requires that the landfill gas owners certify that GHG credits offered under the GE-AES Standard from the collection and control of LFG are not used in other GHG markets. This Supplement describes the procedures that have been and will continue to be used to assure that all transactions involving CNBE emissions reductions are uniquely accounted for and made transparent.

CNBE has established a practice to prevent double-sale or double counting of GHG credits, and as owner of the landfill gas at the time it is used by the Project, will provide the required certification. CNBE will provide the documentation required for verification to an independent third-party verifier approved by GE AES to verify the quantity of GHG credits generated by the Project every six months. Once verified, the quantity of GHG

[2] United States Environmental Protection Agency, Climate Leaders, Draft Offset Protocol, Project Type: Landfill Methane Collection and Combustion, Appendix I. Development of the Performance Threshold – Dataset, Page 10 – 11, October 2006.

credits will be recorded in ERT's GHG Registry, in accordance with CNBE's standard practice and the Agreement. Upon registration, the GHG credits associated with the Project are assigned unique serial numbers. All transactions involving the sale, retirement or transfer of GHG credits from CNBE to another party are recorded in the GHG Registry. Each transaction record shows the transaction date, transaction description, and the vintage, quantity and unique serial numbers of the credits transacted. The quantities credited to the CNBE account on the ERT GHG Registry are traceable to the verification reports and each debit or transfer out of the registry is traceable to the transferee. The transactions are transparent, because the Registry is available for public access (see http://www.ecoregistry.org/account/details/cgnb.html). In addition, by contract, each transfer of GHG credits to GE AES by CNBE will be accompanied by a Title Transfer document and related certification.

Item #12 re: Flow Meter Accuracy. The GE AES Standard requires that initially "each flowmeter used to measure LFG flow rate shall meet a flowmeter accuracy of 2.0 percent of the upper range value" through an approved methodology or design. This Supplement describes the standards and methodologies used to assure the accuracy of the flowmeter initially as manufactured, and subsequently in the field.

The Project uses an orifice plate flow meter purchased directly from its manufacturer, Lambda Square Inc. The orifice plate flow meter is an Oripac® Model 5300 that determines flow based on pressure differentials measured across a 5-inch diameter bore pressure differential plate installed in the Project's 8-inch diameter LFG pipe. The design data for the instrument specifies an accuracy of ± 0.6 percent of full scale. The performance of the instrument in the field is assured by the manufacturer on the basis of bench scale testing in accordance with applicable design and methodologies prescribed by the International Standards Organization (ISO) and the American Society of Mechanical Engineers (ASME) (see Attachment E for vendor information that provides the basis for accuracy of the instrument).

On installation, CNBE performed an initial calibration of the instrument, under actual field conditions using the USEPA Protocols described under Item #13, below, that confirmed that the accuracy was within the ± 2.0-percent limit prescribed by the GE-AES Standard (see Attachment E, which provides calibration data sheets for November 9, 2005). As a back-up to the flowmeter measurements, actual quantities of LFG destroyed in the Project engine-generators can be accurately calculated based on (a) the known engine heat rate (the number of British Thermal Units (Btus) required to produce a kilowatt hour electric power, (b) the measured heat content of the LFG fuel, and the metered electric power output of the Project.

Item #13 re: Periodic Flow Calibration. The GE-AES Standard requires annual calibrations of flow meters using an approved methodology with a documented protocol. CNBE performs calibration of the orifice plate flow meter at least quarterly and often monthly. Section 4.2 of the MRV describes the instrumentation that CNBE uses to measure LFG flow and methane content, but does not describe the measurement and instrument calibration protocols. Accordingly, this Supplement describes those protocols.

CNBE follows the USEPA-promulgated test methods (USEPA Protocols) for determining flow rates of gas through pipes at 40 CFR 60 Appendix A, including (a) Method 1a - sample and velocity traverses for stationary sources with small stacks or ducts, and (b) Method 2c - determination of gas velocity and volumetric flow rate in small stacks or ducts (standard pitot tube) (see Attachment F). The USEPA Protocols were established by the USEPA to accurately determine the volumetric flow rates of gases through pipes at industrial facilities to determine compliance with permit limitations on process and exhaust gases.

Item #17 re: Periodic Methane Calibration. The GE-AES Standard requires that continuous methane monitoring be calibrated each day to prevent the variance of up to 20 percent that may occur in a week. As described in Section 4.2 of the MRV, each week or more frequently as necessary, CNBE calibrates methane concentration measured on an automated basis by a California Instruments NDIR Analyzer installed at the Project, and any hand-held instrument that may be used in addition to the NDIR Analyzer is calibrated prior to its use. CNBE has found that weekly calibrations are sufficient to provide accurate measurements because of the reliable performance of the instrument, and the stringent dependence of engine operations on the accuracy of the methane measurements. CNBE typically experiences a weekly variance of one percent or less and the nature of its operation limits the variance of methane to no more than six percent. This Supplement describes CNBE's experience with variance of methane measurements and its operations that limit the variation of methane measurements.

The methane reading provided by the California Instruments NDIR Analyzer is a continuous reading that is used as an input to the air to fuel ratio control fuel system for each of the Project's four engine-generators. A measurement that is either higher or lower than the actual value by more than four percent has an impact on the performance of the engines that is noticeable to the operator, and prompts the operator to recalibrate the instrument. A measurement that is higher than the actual value by more than six percent results in unstable engines that soon trip or shut-down (e.g. within approximately an one hour), which would require recalibration of the instrument. A measurement that is lower than the actual value by more than six percent might not shut-down the engines but represents a conservative under-measurement of methane quantities. Therefore, the operational limitation of running the CNBE engines result in the methane measurements never being higher than the actual value by six percent, and typically no less accurate than four percent without the operator recalibrating the instrument. Note that the variance of the instrument as measured during average weekly calibrations during the first six months of 2007 has been less than one percent of the actual value. The tolerances are so tight, because CNBE is required to operate the engines in a very lean mode to comply with the most stringent air emissions limitations in the United States for the formation of nitrogen oxides. The lean mode of operation is automatically adjusted by the fuel control system using methane as its key control input. This lean mode of operation does not permit much margin of error for the measurement of methane. The fuel system introduces more combustion air when a measurement of methane is higher than the actual value, which results in further leaning of the mixture of combustion air and fuel (e.g. higher air to fuel ratio). With little margin, the engines run unstable and then trip when the measured value of methane is six percent or higher than the actual value. Therefore, the operation of the CNBE Facility has a built-in worst-case confidence factor of 0.94, but typically runs within one percent of the actual methane value.

Another performance measure that is a further check and balance of methane content is the calculation of efficiency of the operating engine-generator sets, which is calculated daily and does not vary by more than approximately five percent during normal operations. CNBE will provide daily operations data, including engine run times and other performance data (e.g. engine-generator efficiency or heat rate) to the verifier along with the flow and methane data every six months. This will provide additional evidence that the methane is accurately measured over the timeframe.

Item # 19. re: Methane Quantity Data. The GE-AES Standard requires collection of at least one data point every fifteen minutes to determine hourly methane content of the LFG using an arithmetic average of the data points. CNBE exceeds this requirement by collecting data points each minute and accumulating the data points to calculate hourly and daily quantities of methane. CNBE reports the methane on a daily basis. Accordingly, this Supplement describes the CNBE procedure for determining methane quantities.

At the CNBE Facility the Supervisory Control and Data Acquisition (SCADA) system measures and records methane content and LFG volume once per minute, and then calculates methane quantities each minute. The results are then accumulated to provide hourly and daily totals in units of million British thermal units on a higher heating value basis [MMBtu (HHV)] and thousand standard cubic feet (KSCF) of LFG. An example of hourly data extracted from the SCADA system and corresponding daily reports is provided in Attachment D.

Items #20, 21, and 22 re: Combustion Efficiency. The GE-AES Methodology requires annual combustion efficiency tests, and continuous monitoring of methane in the exhaust gas or some other parameter that demonstrates combustion efficiency monitoring to verify a higher than 98% combustion efficiency. CNBE demonstrated a 99.2-percent combustion efficiency during testing of the Project in January 2006, and monitors a parameter in the exhaust gas from each engine each week to verify the combustion efficiency. This Supplement describes the conduct of combustion efficiency test and ongoing monitoring of a parameter that demonstrates combustion efficiency.

CNBE performed extensive testing at the Facility in January 2006, which testing was performed in accordance with USEPA reference methods and a testing protocol approved by the Massachusetts Department of Environmental Protection (MDEP) to demonstrate compliance with air pollutant emissions from each engine. This testing also demonstrates a combustion efficiency of at least 99.2 percent for each of the engines as shown in Attachment H. As shown in Attachment H, the combustion efficiency was calculated by comparing the equivalent quantity of carbon monoxide in the exhaust gas of each engine to the equivalent quantity of methane in LFG going into the engine. The presence of carbon monoxide in the exhaust gas provides a measure of incomplete combustion of the hydrocarbons, and therefore, provides a quantitative basis to calculate combustion efficiency of hydrocarbons that are combusted in each engine. Note that in addition to methane contained in LFG, quantities of non-methane hydrocarbons contained in LFG and lubricating oil are also combusted in the engines. These non-methane hydrocarbons are more difficult to combust than methane and therefore contribute significantly to the carbon monoxide found in the exhaust gas. For this reason, the calculation of 99.2 percent underestimates the combustion efficiency of methane in LFG, and therefore should be viewed as a conservatively low number for establishing destruction efficiency of methane.

On a weekly basis, CNBE measures oxygen content in the exhaust gas of each engine to demonstrate to the MDEP under the air permit for the facility that the air emissions of carbon monoxide and nitrogen oxides are in compliance with the air permit limits. This weekly monitoring provides assurance that combustion efficiency is maintained at the same level as the compliance testing. As shown in Attachment G, oxygen in the exhaust gas correlates directly to emissions of carbon monoxide and therefore combustion efficiency. CNBE maintains the oxygen content in the exhaust gas between 8 to 9-percent on a dry basis, which oxygen level corresponds to the lowest level of carbon monoxide shown in Attachment G. The range of oxygen content in the exhaust gas is maintained by the fuel management system. In this range, the CO levels are the same at approximately 2.2 grams of CO/BHPhr or 0.6 lb of CO per MMBtu, which is consistent with Attachment G and the compliance test results. A sample of weekly data that CNBE maintains as a required record for permitting is provided in Attachment I. CNBE believes that the measurement and recording of this parameter provides a reasonable basis for establishing a combustion efficiency of at least 99.2-percent.

Item #23 re: In-direct GHGs. The GE-AES Standard requires the calculation of in-direct emissions resulting from electric power used by compressors, blowers, and gathering system for LFG. All of the electric power used to power compressors, blowers and the gathering system is provided by the electric power generated by the Facility, and therefore, no in-direct GHG emissions are created by electric power plants that would otherwise supply electric power to the site.

3. ATTACHMENTS

A. CRMC letter to AES dated November 15, 2007 that includes table entitled "CNBE Conformance with GE-AES Landfill Project Requirements (Revised November 15, 2007)"
B. AES letter to CRMC dated November 21, 2007.
C. United States Environmental Protection Agency, Climate Leaders, Draft Offset Protocol, Project Type: Landfill Methane Collection and Combustion, Appendix I. Development of the Performance Threshold – Dataset, Page 10 – 11, October 2006.
D. Hourly data for LFG flow into the Engines and corresponding daily reports.
E. Supporting information for accuracy of flow meter including vendor information that provides the basis for accuracy of the Oripac Orifice and initial calibration of the flow meter in actual field conditions.
F. USEPA Gas Flow Measurement Protocols, 40 CFR 60 Appendix A Method 1a - sample and velocity traverses for stationary sources with small stacks or ducts, and Method 2c - determination of gas velocity and volumetric flow rate in small stacks or ducts (standard pitot tube).
G. Performance of CAT 3516 engine: Excess air versus CO and NOx
H. Compliance test results and combustion efficiency calculation
I. Records of oxygen measurements in each exhaust stack of engines.
J. List of Documents Comprising the GE-AES Standard

ATTACHMENT A

CRMC letter to AES dated November 15, 2007 that includes table entitled “CNBE Conformance with GE-AES Landfill Project Requirements (Revised November 15, 2007)”

CommonWealth
Resource Management Corporation

November 15, 2007

Karl R. Rábago
Vice President, Government & Regulatory Affairs
Alternative Energy Group
The AES Corporation
4300 Wilson Blvd., 8th Floor
Arlington, VA 22203

Re: Greater New Bedford LFG Utilization Project

Dear Karl:

Attached please find a table entitled "CNBE Conformance with GE-AES Landfill Project Requirements (Revised November 15, 2007)". This is a modified version of the table dated November 12, 2007 that served as the basis of the conference call on Tuesday, November 13, 2007 involving our company, you and other members of the GE-AES Greenhouse Gas Services, LLC team, and representatives of First Environment, Inc., an independent third party verification firm. The highlighted entries on the revised table were modified to reflect our understanding of the consensus reached during the conference call with respect to certain specific requirements for initial documentation of, and related methods of verification of the on-going greenhouse gas emission reduction claims associated with, the above-referenced landfill gas project (the "Project"), which is owned and operated by our wholly-owned subsidiary, CommonWealth New Bedford Energy, LLC ("CNBE").

Provisions of the recently-executed Term Sheet between CNBE and Greenhouse Gas Holding, LLC, require that as a condition precedent to entering into a final Emissions Reduction Purchase Agreement ("ERPA"), the two parties reach agreement on the protocol for verification and quantification of the emissions reduction ("VERs") under contract. Based on the November 13th conference call and our prior conversations, it is our intention to prepare a supplement (the "Supplement") to the Monitoring, Reporting and Verification Protocol (the "MRV") originally prepared for the Project by Environmental Resources Trust, Inc., dated December, 2005, and previously provided to you. The Supplement will modify, consistent with the table, specific sections of the MRV to provide additional project information and/or to describe the additional or modified methods of data collection, analysis and reporting that will be submitted for independent verification of emission reduction claims going forward. It is our understanding that the MRV as modified by the Supplement will satisfy the GE-AES requirements for an initial Project design document, and that verification reports based on the methods and procedures set forth in the MRV as modified by the Supplement will serve as an acceptable basis for verification going forward.

If upon review of the revised table you are in agreement with the above, please indicate your concurrence to us (and internally to Mark Wasilko and Annmarie Reynolds or others as appropriate) and we will proceed with the preparation of the Supplement.

Of course, if you have any question, please do not hesitate to call.

Sincerely,

Thomas Yeransian
Principal

Attachment

CNBE Conformance with GE-AES Landfill Project Requirements
(Revised November 15, 2007)

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
1	Project is not required by law or legal obligation	Standard of Practice; LFG Methodology	Yes	NSPS Calculations, ERT review of legal requirements summarized in MRV report.	
2	Project is not required by common industry practice	Standard of Practice, Voluntary & Additional Pg.3, H.1,	No	Need evidence demonstrating "not common industry practice"	CNBE will provide information from US EPA and other sources establishing what the most common technologies or practices for unregulated landfills are.
3	Credits would not be certified without the technical assistance and investment from credit funds	Standard of Practice, Voluntary & Additional Pg. 3., H.2,	Yes	Based on conference call on 11/13/07, the process of reaching an agreement with GE-AES for the sale of credits is evidence of meeting this requirement.	
4	Project started after January 1, 2000 (documentation required)	Standard of Practice; LFG Methodology	Yes	LFG collection system and flare became operational in 2000; LFG to energy project started in October 2005; project start documents verified	
5	Eligible emissions reductions are those after January 21, 2002	Standard of Practice; LFG Methodology	Yes	Project started in October 2005; project start documents verified	
6	Project manager must develop project documentation (Project Build and Project Operation Documents)	Standard of Practice, Project Management, Pg. 5, D.2	Yes	Project operation report (MRV report) developed for site includes monitoring and measurement requirements. Based on the 11-13-07 conference call, the Project Build document requirement would be for new projects and is not applicable to existing projects.	
7	Project must establish and maintain resources and procedures to monitor and control project	Standard of Practice; LFG Reporting Summary	Yes	Various - equipment and processes to be used included in MRV; see discussions below	
8	Project must report regularly on the performance and credit claims	Standard of Practice	Yes	Project issues spreadsheet with data and calculations every six months	

CNBE Conformance with GE-AES Landfill Project Requirements
(Revised November 15, 2007)

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
9	Clear demonstration of GHG credit ownership	LFG Methodology; LFG Reporting Summary	Yes	Lease agreement	
10	Project must certify that credits are not being used in another GHG market	LFG Methodology	No	No certification has been reviewed	CNBE will supplement the MRV to include a discussion of its process for registering all GHG credits generated by the site on the ERT registry where they are assigned a unique serial number. Credits sold are logged on this registry in a transparent, traceable manner. This along with the attestation every six months that CNBE has adhered to the MRV will serve as the certification.
11	LFG permit showing design capacity and NMOC calculations for site	LFG Methodology; LFG Reporting Summary	Yes	Reviewed during site visit; summarized in MRV report	
12	Flow meter must be initially calibrated and shown to be within 2% of the upper range limit through an approved methodology or design	LFG Methodology; LFG Monitoring Summary	No	Meter was initially calibrated. A copy of the protocol used for calibration was not provided, although a complete record of the calculations was reviewed.	CNBE will provide the vendor information that documents the flow meter accuracy of +/- 0.6%. CNBE will also include information in a supplement to the MRV on the relevant portions of the USEPA methods used to calibrate flow measurements in the field.
13	Annual calibration of flow meters using approved methodology with documented protocol	LFG Methodology; LFG Monitoring Summary	No	Flow meter calibrated quarterly using a pitot tube (Model 160-18, 5/16th inch Dwyer Instrument) connected to a manometer. No copy of the protocol used was provided for review, although a complete record the calculations was reviewed.	CNBE will include a statement that the USEPA methods described in the supplement to the MRV were followed on the quarterly calibration record and provide this to the verifier.

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
14	Continuous monitoring of the LFG flow	LFG Methodology; LFG Monitoring Summary	Yes	An orifice plate meter is used to monitor the flow and a Supervisory Control and Data Acquisition System (SCADA) stores the data electronically. A reading is taken every minute and hourly and daily totals are maintained by the system.	
15	Continuous monitoring of landfill gas temperature and pressure	LFG Methodology; LFG Monitoring Summary	Yes	System measures these parameters. The flow meter corrects for temperature and pressure so these data sets are not used again in the calculation of emissions reductions, rather the corrected totals are used.	
16	Continuous monitoring of methane content (data point every 15 minutes)	LFG Methodology; LFG Monitoring Summary	Yes	A California Analytical Instruments 602P Digital non-dispersive infrared analyzer (NDIR) is used to analyze the methane content. Results of the analysis are captured by the SCADA system. A reading is taken every minute and hourly and daily totals are maintained by the system. When the meter is being serviced by the manufacturer, operators use hand held instrument and engine heat rates to calculate methane content.	
17	Calibrate methane meter daily	LFG Methodology; LFG Monitoring Summary	No	The methane meter is calibrated every week. The electronic data collection system has pre-set alarms that notify operators if any reading is outside of the set levels. In addition, operators formally review the data each day to look for anomalies. Meter also sent to manufacturer for service regularly.	CNBE will provide operations data, including engine run times and other performance data, to the verifier along with the flow and methane data every six months. This will provide additional evidence that the methane meter worked properly over that timeframe. The verifier will discuss the evidence reviewed and any findings in the verification report.

CNBE Conformance with GE-AES Landfill Project Requirements
(Revised November 15, 2007)

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
18	Use an approved methodology for measuring methane content	LFG Methodology; LFG Monitoring Summary	Yes	IR ANALYSIS METHOD Non-Dispersive Infrared (NDIR)	
19	Methane flow rate calculation conducted for each hour of operation (equation in 8.2.1)	LFG Methodology	No	Although the data is available, the methane flow rate is currently tabulated daily.	The current system provides data every minute. This is rolled up to hourly and then daily totals by the SCADA system. CNBE will supplement the MRV to indicate this process. In addition, CNBE will provide the verifier with a sample of the raw data to enable them to verify that the roll-up occurs and that the daily totals provided are indeed a sum of the hourly totals. This will be discussed in the verification report.
20	Conduct and perform annual combustion efficiency tests per EPA methods	LFG Methodology; LFG Monitoring Summary	No	Efficiency of 99.9% or 98% used depending on the protocol methodology. No evidence of annual testing provided.	CNBE will evaluate whether existing alternate operations data can be used or if using the 98% efficiency rate from the simple method is preferred.
21	Conduct continuous combustion efficiency monitoring (methane content or other indicative parameter monitoring at outlet of combustion device)	LFG Methodology; LFG Monitoring Summary	No	No data provided for review.	See previous response regarding efficiency.
22	Compile hourly data for the combustion efficiency parameter and compare to test parameter to demonstrate efficiency is constant	LFG Methodology; LFG Monitoring Summary	No	No calculations provided for review.	See previous response regarding efficiency.
23	Define, document and monitor all SSRs including electricity use by collection equipment and any fuel use.	LFG Methodology; LFG Reporting Summary; LFG Monitoring Summary	No	Project did not document electricity use by equipment on site or justify its exclusion. Since the project generates electricity however, this data is maintained and is quantified as the difference between the gross electricity production and the net electricity provided to the grid.	CNBE will supplement the MRV to explain that the Project does not generate in-direct emissions from electric power used by on-site equipment because on-site equipment is powered by electricity generated on-site versus electricity generated by off-site sources.

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
24	Preserve original data sets for third party verification	LFG Methodology; LFG Recordkeeping Summary	Yes	Data has been reviewed for previous verifications; process in place to maintain records	
25	Retain records for the appropriate time periods as set forth in the methodology	LFG Methodology; LFG Recordkeeping Summary	Yes	Records have been reviewed and process is in place to maintain records (not all records listed in the protocol exist but these are addressed in the line items above)	
26	Executive Summary of project and signed statement certifying that the collection and control of the identified landfill gas stream is the result of voluntary action and not required by Federal, State, or Local requirements or consent order and that the project is in compliance with all applicable Federal, State, and Local ordinances.	LFG Reporting Summary	Yes	Per the 11-13-07 conference call, this requirement is satisfied by the project summary and other documents already provided to GE-AES.	
27	Detailed project description including: project title; purpose and objectives; type of GHG project; project location; conditions prior to project initiation; description of how project will achieve GHG reductions; equipment list; GHG emission reductions expected by project; identification of project risks; contact information; and project construction, initiation, and expected termination dates.	LFG Reporting Summary	Yes	Per the 11-13-07 conference call, this requirement is satisfied by the existing MRV report. The additional information requested applies to projects in development and not to this existing project.	
28	Project and baseline scenario information including: selected project scenario; selected baseline scenario; and rationale/justification for selected scenarios.	LFG Reporting Summary	Yes	MRV report addresses baseline and rationale; however it does not link to the specific numbered baseline and project scenarios listed in the LFG Methodology.	

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
29	Quantification of expected GHG emissions and GHG emission reductions based on LFG Quantification Spreadsheet provided by GGS. The project developer must provide the completed LFG Quantification Spreadsheet with the PDD.	LFG Reporting Summary	Yes	Per the 11-13-07 conference call, this requirement is satisfied by the existing MRV report and calculations spreadsheets. The additional information requested applies to projects in development and not to this existing project.	
30	Estimated annual GHG reductions for subsequent 5-year period or until expected project termination, based on LFG Quantification Spreadsheet provided by GGS.	LFG Reporting Summary	Yes	Per the 11-13-07 conference call, this requirement is satisfied by the existing MRV report and calculations spreadsheets. The additional information requested applies to projects in development and not to this existing project.	
31	The project developer will provide a semi-annual project status report that includes the following items: · Executive summary of status and signed statement certifying that the project is the result of voluntary action and is in compliance with all applicable ordinances. · Documentation of any changes or modifications to the project infrastructure or operation. · Summary of project eligibility status including: expected dates for compliance with applicable collection and control requirement of the Landfill NSPS or other regulations; current NMOC emission rate; and documentation of changes to any items demonstrating project eligibility that were provided in the initial PDD. · Results of all verification activities including verification report, identified corrective actions, and documentation of resolution of corrective actions.	LFG Reporting Summary	Yes	Per the 11-13-07 conference call, this requirement is satisfied by the project summary and other documents already provided to GE-AES as well as the typical semi annual report already generated by the site for this project. The additional information requested applies to projects in development and not to this existing project.	

	GE-AES Requirement	Source of Requirement	Verified Site Conformance	List of Relevant Evidence	Action Proposed by CNBE to Satisfy Requirement
	· Monthly and semi-annual summaries of GHG emissions and emission reductions generated by project based on the LFG Quantification Spreadsheet provided by GGS. The project developer must provide the completed spreadsheet. · Summary of all calibration activities and any associated corrective actions. · Estimated annual GHG credit generation for subsequent 5-year period, or until expected project termination date, based on Spreadsheet provided by GGS.				
32	Verification · Date of initial and annual third-party verification · Name and affiliation of third-party verifier · Initial and annual verification records and audit results	LFG Recordkeeping Summary	Yes	Verifications to date have occurred every six months and include this information.	

ATTACHMENT B

AES letter to CRMC dated November 21, 2007.

AES
the power of being global

The AES Corporation
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Arlington, VA 22203
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November 21, 2007

Thomas Yeransian
Principal
Commonwealth Resource Management Corporation
199 Corey Street
Boston, MA 02132

via Electronic Mail

RE: Greater New Bedford LFG Utilization Project

Dear Tom:

I write to acknowledge receipt of your letter of November 15, 2007, regarding the proposed Supplement to the Monitoring, Reporting and Verification Protocol (MRV) for the Project, and to accept the proposed Supplement in satisfaction of the requirements for an initial Project design document in conformance with the Standard of Practice and Landfill Gas Methodology developed and adopted by GE AES Greenhouse Gas Services, LLC.

In addition, I wish to confirm that verification reports that meet the requirements of the MRV and the Supplement will serve as an acceptable basis for verification of GHG credits on a going-forward basis.

Best regards,

Karl R. Rábago
Manager, GGS Standard of Practice

Cc Mark Wasilko
Annmarie Reynolds

ATTACHMENT C

United States Environmental Protection Agency, Climate Leaders, Draft Offset Protocol, Project Type: Landfill Methane Collection and Combustion, Appendix I. Development of the Performance Threshold – Dataset, Page 10 – 11, October 2006.

Appendix I. Development of the Performance Threshold - Dataset

The primary data source for the performance threshold is the database of almost 2,000 landfills in the United States developed and maintained by EPA's Landfill Methane Outreach Program (LMOP). This database was supplemented and crosschecked with data from the Energy Information Administration (EIA) and from selected flare vendors. In that gas collection and combustion at regulated landfills are not eligible as greenhouse gas offset projects (see previous discussion) detailed data on these landfills are not included here.

Of the 1,819 landfills in the U.S., 664 are NSPS/EG and approximately 1,155 landfills are non-NSPS/EG (not required to combust landfill gas). As shown in Table I.a, approximately 21% of the non-regulated landfills have gas recovery systems resulting in some type of combustion. Of the non-regulated landfills with combustion, 67% have flaring projects, 23% have electricity projects, and 10% have direct-use gas projects (see Table I.b).

Table I.a. Summary of Information on U.S. Landfills (NSPS/EG and Non-NSPS/EG).

	# Landfills	% Landfills	# With Gas Collection and Control	% With Gas Collection and Control
NSPS/EG	664	37	664	100
Non-NSPS/EG	1,155	63	240	21
Total	1,819	100	906	50

Table I.b. Summary of Information on Non-NSPS/EG Landfills.

Non-NSPS/EG landfills	Number of landfills	Percent of landfills
Flares	161	13.9
Electricity projects	55	4.8
Gas projects*	24	2.1
Subtotal	**240**	**21**
No gas recovery and combustion	915	79
Total	1,155	100

*Gas projects are those non-electricity projects labeled in LMOP as direct thermal, boiler, leachate evaporation, etc.

Spatial Area. The spatial area for this performance threshold includes all landfills in the United States. Table I.c shows the distribution of landfill projects by region.

Table I.c. Distribution of Landfills by Geographic Location.

Geographic region	Number of Landfills		Non-NSPS/EG Landfills with Gas Collection and Combustion			Percent with projects
	Total	Non-NSPS/EG	With flares	With LFGTE	Total	
Northeast	145	81	13	8	21	26
Mid-Atlantic	210	118	30	10	40	34
South	339	229	38	9	47	21
Mid-West	414	225	31	31	62	28
South Central	184	111	12	7	19	17
West Central	122	99	3	1	4	4
West	405	292	34	13	47	16

Northeast: CT, MA, ME, NH, NY, RI, VT
Mid-Atlantic: DE, MD, NJ, PA, VA, WV
South: AL, FL, GA, KY, MS, NC, SC, TN
Mid-West: IA, IL, IN, MI, MN, MO, OH, WI
South Central: AR, AZ, LA, NM, OK, TX
West Central: CO, KS, MT, ND, NE, SD, UT, WY
West: AK, CA, HI, ID, NV, OR, WA

Temporal range. The temporal range of the data set includes all landfills that are currently open or, landfills that closed within the last five years.

ATTACHMENT D

Hourly data for LFG flow into the Engines and corresponding daily reports.

GREATER NEW BEDFORD LFG UTILIZATION FACILITY
HOURLY DATA FOR LFG FLOW INTO THE ENGINES

Date	Hour	LFG flow to Engines, KSCF	Cumulative LFG Flow to Engines, KSCF	LFG flow to Engines, MMBtu	Cumulative LFG Flow to Engines, MMBtu	LFG flow to Flare, KSCF	Cumulative LFG Flow to Flare, KSCF	LFG flow to Flare, MMBtu	Cumulative LFG Flow to Flare, MMBtu	Total LFG Flow, KSCF	Cumulative Total LFG Flow, KSCF	Total LFG flow, MMBtu	Cumulative Total LFG Flow, MMBtu
2/2/2006	1	63.755	63.755	35	35	0	0	0	0	63.755	63.755	35	35
2/2/2006	2	63.588	127.343	35	70	0	0	0	0	63.588	127.343	35	70
2/2/2006	3	63.818	191.161	35	105	0	0	0	0	63.818	191.161	35	105
2/2/2006	4	63.739	254.900	35	140	0	0	0	0	63.739	254.900	35	140
2/2/2006	5	63.991	318.891	35	175	0	0	0	0	63.991	318.891	35	175
2/2/2006	6	63.46	382.351	35	210	0	0	0	0	63.46	382.351	35	210
2/2/2006	7	63.561	445.912	35	245	0	0	0	0	63.561	445.912	35	245
2/2/2006	8	63.838	509.750	35	280	0	0	0	0	63.838	509.750	35	280
2/2/2006	9	63.727	573.477	35	315	0	0	0	0	63.727	573.477	35	315
2/2/2006	10	65.982	639.459	36	351	0	0	0	0	65.982	639.459	36	351
2/2/2006	11	68.207	707.666	37	388	0	0	0	0	68.207	707.666	37	388
2/2/2006	12	69.405	777.071	38	426	0	0	0	0	69.405	777.071	38	426
2/2/2006	13	67.983	845.054	37	463	0	0	0	0	67.983	845.054	37	463
2/2/2006	14	68.715	913.769	37	500	0	0	0	0	68.715	913.769	37	500
2/2/2006	15	68.727	982.496	37	537	0	0	0	0	68.727	982.496	37	537
2/2/2006	16	70.572	1,053.068	38	575	0	0	0	0	70.572	1,053.068	38	575
2/2/2006	17	71.91	1,124.978	39	614	0	0	0	0	71.91	1,124.978	39	614
2/2/2006	18	72.223	1,197.201	39	653	0	0	0	0	72.223	1,197.201	39	653
2/2/2006	19	72.814	1,270.015	39	692	0	0	0	0	72.814	1,270.015	39	692
2/2/2006	20	72.049	1,342.064	39	731	0	0	0	0	72.049	1,342.064	39	731
2/2/2006	21	72.063	1,414.127	39	770	0	0	0	0	72.063	1,414.127	39	770
2/2/2006	22	67.508	1,481.635	36	806	0	0	0	0	67.508	1,481.635	36	806
2/2/2006	23	65.414	1,547.049	35	841	0	0	0	0	65.414	1,547.049	35	841
2/2/2006	24	65.425	1,612.474	35	876	0	0	0	0	65.425	1,612.474	35	876
2/3/2006	1	65.225	65.225	35	35	0	0	0	0	65.225	65.225	35	35
2/3/2006	2	65.107	130.332	35	70	0	0	0	0	65.107	130.332	35	70
2/3/2006	3	65.04	195.372	35	105	0	0	0	0	65.04	195.372	35	105
2/3/2006	4	64.226	259.598	35	140	0	0	0	0	64.226	259.598	35	140
2/3/2006	5	63.918	323.516	35	175	0	0	0	0	63.918	323.516	35	175
2/3/2006	6	63.699	387.215	35	210	0	0	0	0	63.699	387.215	35	210
2/3/2006	7	63.577	450.792	35	245	0	0	0	0	63.577	450.792	35	245
2/3/2006	8	63.2	513.992	35	280	0	0	0	0	63.2	513.992	35	280
2/3/2006	9	64.468	578.460	35	315	0	0	0	0	64.468	578.460	35	315
2/3/2006	10	59.879	638.339	33	348	0	0	0	0	59.879	638.339	33	348
2/3/2006	11	65.811	704.150	36	384	0	0	0	0	65.811	704.150	36	384
2/3/2006	12	65.972	770.122	37	421	0	0	0	0	65.972	770.122	37	421
2/3/2006	13	65.733	835.855	37	458	0	0	0	0	65.733	835.855	37	458
2/3/2006	14	65.726	901.581	37	495	0	0	0	0	65.726	901.581	37	495
2/3/2006	15	66.36	967.941	37	532	0	0	0	0	66.36	967.941	37	532
2/3/2006	16	66.302	1,034.243	37	569	0	0	0	0	66.302	1,034.243	37	569
2/3/2006	17	66.928	1,101.171	37	606	0	0	0	0	66.928	1,101.171	37	606
2/3/2006	18	66.384	1,167.555	37	643	0	0	0	0	66.384	1,167.555	37	643
2/3/2006	19	65.074	1,232.629	36	679	0	0	0	0	65.074	1,232.629	36	679
2/3/2006	20	60.785	1,293.414	33	712	0	0	0	0	60.785	1,293.414	33	712
2/3/2006	21	61.327	1,354.741	34	746	0	0	0	0	61.327	1,354.741	34	746
2/3/2006	22	61.674	1,416.415	34	780	0	0	0	0	61.674	1,416.415	34	780
2/3/2006	23	62.427	1,478.842	34	814	0	0	0	0	62.427	1,478.842	34	814
2/3/2006	24	63.242	1,542.084	35	849	0	0	0	0	63.242	1,542.084	35	849
2/4/2006	1	64.14	64.140	35	35	0	0	0	0	64.14	64.140	35	35
2/4/2006	2	64.329	128.469	35	70	0	0	0	0	64.329	128.469	35	70
2/4/2006	3	64.625	193.094	36	106	0	0	0	0	64.625	193.094	36	106
2/4/2006	4	64.485	257.579	35	141	0	0	0	0	64.485	257.579	35	141
2/4/2006	5	64.219	321.798	35	176	0	0	0	0	64.219	321.798	35	176
2/4/2006	6	63.78	385.578	35	211	0	0	0	0	63.78	385.578	35	211
2/4/2006	7	63.689	449.267	35	246	0	0	0	0	63.689	449.267	35	246
2/4/2006	8	63.442	512.709	35	281	0	0	0	0	63.442	512.709	35	281
2/4/2006	9	62.225	574.934	34	315	0	0	0	0	62.225	574.934	34	315
2/4/2006	10	61.878	636.812	34	349	0	0	0	0	61.878	636.812	34	349
2/4/2006	11	61.326	698.138	34	383	0	0	0	0	61.326	698.138	34	383
2/4/2006	12	60.488	758.626	33	416	0	0	0	0	60.488	758.626	33	416
2/4/2006	13	60.409	819.035	33	449	0	0	0	0	60.409	819.035	33	449
2/4/2006	14	60.621	879.656	33	482	0	0	0	0	60.621	879.656	33	482
2/4/2006	15	60.347	940.003	33	515	0	0	0	0	60.347	940.003	33	515
2/4/2006	16	60.457	1,000.460	34	549	0	0	0	0	60.457	1,000.460	34	549
2/4/2006	17	61.002	1,061.462	34	583	0	0	0	0	61.002	1,061.462	34	583
2/4/2006	18	62.25	1,123.712	35	618	0	0	0	0	62.25	1,123.712	35	618
2/4/2006	19	62.418	1,186.130	35	653	0	0	0	0	62.418	1,186.130	35	653
2/4/2006	20	60.982	1,247.112	34	687	0	0	0	0	60.982	1,247.112	34	687
2/4/2006	21	60.779	1,307.891	34	721	0	0	0	0	60.779	1,307.891	34	721
2/4/2006	22	60.534	1,368.425	34	755	0	0	0	0	60.534	1,368.425	34	755
2/4/2006	23	60.436	1,428.861	34	789	0	0	0	0	60.436	1,428.861	34	789
2/4/2006	24	60.234	1,489.095	34	823	0	0	0	0	60.234	1,489.095	34	823

Notes:
KSCF means thousand standard cubic feet.
MMBtu means million British thermal units.

February 2006							
CNBE Daily Reports Summary Data							
	Wednesday	Thursday	Friday	Saturday	Sunday	Monday	Tuesday
	2/1/2006	2/2/2006	2/3/2006	2/4/2006	2/5/2006	2/6/2006	2/7/2006
Landfill Gas Flow to the Engines (KSCF)	1,547	1,612	1542	1,489	1,435	1,589	1,655
Landfill Gas Flow to the Engines (MMBTU HHV)	841	876	849	823	819	888	896
Landfill Gas Flow to the Flare (KSCF)	-	-	-	-	-	-	-
Landfill Gas Flow to the Flare (MMBTU HHV)	-	-	-	-	-	-	-
Landfill Gas Total Flow (KSCF)	1,547	1,612	1,542	1,489	1,435	1,589	1,655
Landfill Gas Total Flow (MMBTU HHV)	841	876	849	823	819	888	896
Average Methane Content (%)	54	54	55	55	56	55	53
Engine 1 Hours	24	24	24	24	24	24	24
Engine 2 Hours	24	24	24	24	24	24	24
Engine 3 Hours	24	24	24	24	24	24	24
Engine 4 Hours	24	24	23	24	24	24	24
Generator 1 Power Output (kWhr)	19,646	19,551	19,645	19,651	19,662	19,639	19,129
Generator 2 Power Output (kWhr)	19,115	18,519	16,399	14,346	14,379	16,930	18,407
Generator 3 Power Output (kWhr)	15,532	16,936	18,876	18,871	18,888	18,301	18,175
Generator 4 Power Output (kWhr)	17,214	17,705	17,255	16,541	16,529	18,113	17,950
Gross Power Output (kWhr)	71,984	73,156	72,598	69,799	69,830	73,371	74,064
Net Power Output (kWhr)	70,705	71,849	71,293	68,537	68,562	72,072	72,702
Power Sold as metered by NStar, (kWhr)	70,165	71,284	70,740	68,054	68,055	71,522	72,144
Calculated Performance Results							
Daily							
Power output (kW average when running)							
Generator 1	819	815	819	819	819	818	797
Generator 2	796	772	683	598	599	705	767
Generator 3	647	706	787	786	787	763	757
Generator 4	717	738	750	689	689	755	748
Power output (kW average over 24-hrs)							
Facility Gross	2,999	3,048	3,025	2,908	2,910	3,057	3,086
Facility Net	2,946	2,994	2,971	2,856	2,857	3,003	3,029
In-plant load	53	54	54	53	53	54	57
Daily availability factor							
Facility	100%	100%	99%	100%	100%	100%	100%
Engine 1	100%	100%	100%	100%	100%	100%	100%
Engine 2	100%	100%	100%	100%	100%	100%	100%
Engine 3	100%	100%	100%	100%	100%	100%	100%
Engine 4	100%	100%	96%	100%	100%	100%	100%
Daily capacity factor							
Facility	91%	92%	92%	88%	88%	93%	94%
Engine 1	99%	99%	99%	99%	99%	99%	97%
Engine 2	97%	94%	83%	72%	73%	86%	93%
Engine 3	78%	86%	95%	95%	95%	92%	92%
Engine 4	87%	89%	91%	84%	83%	91%	91%
Cumulative by engine							
Engine operating run hours in the month							
Max Cumulative Available, hours	24	48	72	96	120	144	168
Engine 1	24	48	72	96	120	144	168
Engine 2	24	48	72	96	120	144	168
Engine 3	24	48	72	96	120	144	168
Engine 4	24	48	71	95	119	143	167
Engine operating run hours total from 0 hours							
Engine 1	2,063	2,087	2,111	2,135	2,159	2,183	2,207
Engine 2	1,952	1,976	2,000	2,024	2,048	2,072	2,096
Engine 3	2,018	2,042	2,066	2,090	2,114	2,138	2,162
Engine 4	1,972	1,996	2,019	2,043	2,067	2,091	2,115
Cumulative availability, %							
Engine 1	100%	100%	100%	100%	100%	100%	100%
Engine 2	100%	100%	100%	100%	100%	100%	100%
Engine 3	100%	100%	100%	100%	100%	100%	100%
Engine 4	100%	100%	99%	99%	99%	99%	99%
Engine cumulative gross output, kWhr							
Max cumulative capacity one engine	825	1,650	2,475	3,300	4,125	4,950	5,775
Engine 1	819	1,633	2,452	3,271	4,090	4,908	5,705
Engine 2	796	1,568	2,251	2,849	3,448	4,154	4,921
Engine 3	647	1,353	2,139	2,926	3,713	4,475	5,232
Engine 4	717	1,455	2,205	2,894	3,583	4,338	5,086
Cumulative capacity factor, %							
Engine 1	99%	99%	99%	99%	99%	99%	99%
Engine 2	97%	95%	91%	86%	84%	84%	85%
Engine 3	78%	82%	86%	89%	90%	90%	91%
Engine 4	87%	88%	89%	88%	87%	88%	88%

	Wednesday	Thursday	Friday	Saturday	Sunday	Monday	Tuesday
	2/1/2006	2/2/2006	2/3/2006	2/4/2006	2/5/2006	2/6/2006	2/7/2006
Cumulative by Facility in month							
Max cumulative available engine run hours	96	192	288	384	480	576	672
Actual cumulative engine run hours	96	192	287	383	479	575	671
Cumulative Availability, %	100%	100%	100%	100%	100%	100%	100%
Max cumulative gross output, kWhr	79,200	158,400	237,600	316,800	396,000	475,200	554,400
Actual cumulative gross output, kWhr	71,984	145,140	217,738	287,537	357,367	430,738	504,802
Cumulative Capacity Factor	91%	92%	92%	91%	90%	91%	91%
Cumulative fuel input, MMBtu	841	1,717	2,566	3,389	4,208	5,096	5,992
Cumulative gross output, kWhr	71,984	145,140	217,738	287,537	357,367	430,738	504,802
Heat Rate							
Daily heat rate, Btu/kWe gross LHV	10,517	10,779	10,527	10,614	10,558	10,895	10,890
Daily heat rate, Btu/kWe gross HHV	11,683	11,974	11,695	11,791	11,728	12,103	12,098
Cumulative heat rate, Btu/kWe gross LHV	10,517	10,649	10,609	10,610	10,600	10,650	10,685
Cumulative heat rate, Btu/kWe gross HHV	11,683	11,830	11,785	11,786	11,775	11,831	11,870
Cumulative by Facility starting Calendar Year							
Max cumulative available engine run hours	3,072	3,168	3,264	3,360	3,456	3,552	3,648
Actual cumulative engine run hours	2,786	2,882	2,977	3,073	3,169	3,265	3,361
Cumulative Availability, %	91%	91%	91%	91%	92%	92%	92%
Max cumulative gross output, kWhr	2,534,400	2,613,600	2,692,800	2,772,000	2,851,200	2,930,400	3,009,600
Actual cumulative gross output, kWhr	2,156,118	2,229,274	2,301,872	2,371,671	2,441,501	2,514,872	2,588,936
Cumulative Capacity Factor	85%	85%	85%	86%	86%	86%	86%
Cumulative fuel input, MMBtu	25,542	26,418	27,267	28,090	28,909	29,797	30,693
Cumulative gross output, kWhr	2,156,118	2,229,274	2,301,872	2,371,671	2,441,501	2,514,872	2,588,936
Service							
Engine 1							
Engine 2							
Engine 3		MCAT Woodward programming					
Engine 4							
Oil - oil and filter change							
Service - plugs, air filter, valve inspection and adjustment							
NSTAR Power Reports							
Date	2/1/2006	2/2/2006	2/3/2006	2/4/2006	2/5/2006	2/6/2006	2/7/2006
Hour							
1	2,838	2,841	2,837	2,834	2,834	2,838	2,932
2	2,838	2,845	2,840	2,839	2,831	2,836	2,933
3	2,840	2,842	2,837	2,836	2,831	2,841	2,938
4	2,841	2,842	2,839	2,835	2,830	2,838	2,933
5	2,838	2,842	2,839	2,837	2,832	2,837	2,933
6	2,838	2,842	2,837	2,840	2,831	2,841	2,933
7	2,843	2,846	2,842	2,837	2,835	2,839	2,938
8	3,046	2,845	2,838	2,837	2,837	2,839	2,989
9	3,120	2,842	3,008	2,840	2,834	3,077	3,120
10	3,123	2,802	2,827	2,833	2,837	3,124	3,097
11	3,121	3,060	3,121	2,834	2,838	3,123	2,453
12	3,120	3,127	3,125	2,831	2,839	3,125	2,985
13	3,122	3,123	3,124	2,831	2,836	3,124	3,122
14	3,124	3,121	3,124	2,832	2,837	3,125	3,119
15	2,943	3,121	3,124	2,836	2,838	3,124	3,121
16	2,844	3,123	3,122	2,833	2,838	3,120	3,121
17	2,840	3,121	3,123	2,839	2,838	3,126	3,121
18	2,842	3,124	3,122	2,835	2,838	3,122	3,120
19	2,843	3,120	3,034	2,839	2,835	2,949	3,110
20	2,840	3,125	2,836	2,835	2,839	2,937	3,027
21	2,839	3,120	2,837	2,837	2,835	2,933	3,024
22	2,844	2,934	2,833	2,834	2,839	2,933	3,024
23	2,839	2,840	2,838	2,836	2,835	2,935	3,024
24	2,839	2,836	2,833	2,834	2,838	2,936	3,027
TOTAL	70,165	71,284	70,740	68,054	68,055	71,522	72,144
Cumulative Output Sold, kWhr	70,165	141,449	212,189	280,243	348,298	419,820	491,964
Transformer and line efficiency	99.2%	99.2%	99.2%	99.3%	99.3%	99.2%	99.2%
Hourly average	2,924	2,970	2,948	2,836	2,836	2,980	3,006

ATTACHMENT E

Supporting information for accuracy of flow meter including vendor information that provides the basis for accuracy of the Oripac Orifice and initial calibration of the flow meter in actual field conditions.

ORIPAC MODEL 5300

- About the Oripac Model 5300
- Part No. Reference System
- Dimension Sheet
- Specification Sheet
- Tech Support Sheet
- Installation Instructions

ABOUT THE ORIPAC MODEL 5300

The ORIPAC is a complete orifice plate flow metering package. It incorporates a stainless steel orifice plate with a unique holder or carrier ring containing metering taps and integral gaskets. Unlike a standard orifice plate, the ORIPAC is a true primary element including the various components for differential pressure measurement. It was designed for use wherever there is an application for a conventional flow orifice plate. It can also be used in place of other primary differential producers for efficiency and cost effectiveness. The ORIPAC was designed and developed by leading authorities in the differential flow measurement field. Installation is accomplished simply by slipping the unit between standard flanges (orifice flanges are not required). The ORIPAC is available in all line sizes and fluids, and meets or exceeds AMSE, AGA and ISO standards.

MODEL 5300

Material: All Stainless Steel

For Metering Water, Air, Steam
& Corrosive Fluids
High-Pressure Fluids
High-Temperature Fluids

The ORIPAC Model 5300 is used extensively for a wide variety of applications and a diverse industry base.

FEATURES

- Unitized construction
- Integral metering taps
- Full faced integral gasket
- Corner type metering taps
- Stainless steel welded parts
- Carrier ring material: stainless steel, exotic alloys or other materials (Model 5300)
- Proven through a wide range of applications for accuracy and energy efficiency
- Custom designs are available

BENEFITS

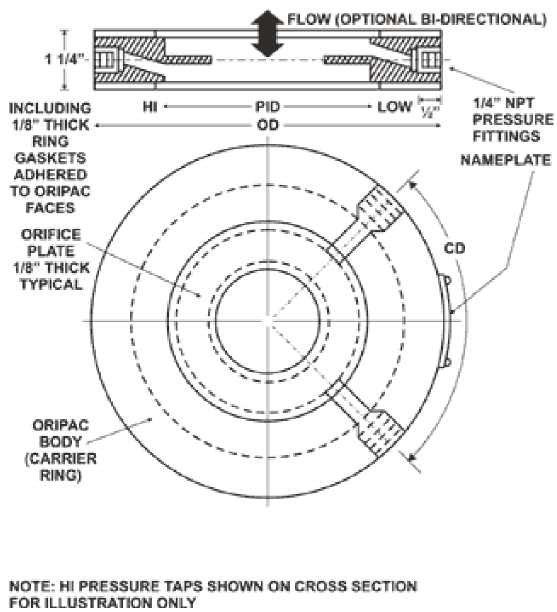
- Simplifies installation
- Used with standard flanges, eliminates costly orifice flanges or drilling and tapping pipe
- Precludes potential alignment difficulties
- Ensures superior accuracy
- Prevents plugging
- Use of superior high-tech materials prohibit corrosion
- Assures long term reliability and accuracy
- Specially engineered to specific applications

MODEL 5300 DIMENSION SHEET

Specifications:

- Weight: Varies with line size. See chart.
- Pressure: Limited only by pipe and flange rating restrictions
- Temperature: -600° F to +2000° F (dependant on material).
- Head Loss: Similar to standard orifice plates. See ref. sheet TM-100 or refer to tech support sheet.
- Fluids: Most liquids, gases and steam. High pressure / temperature, corrosive, etc.
- Line Sizes: 1/4" to 24" standard. Specials to 60".
- Installation: Standard flange, any rating (orifice flanges not required).
- Accuracy: 0.6% of full scale flow. (Refer to tech support sheet)
- Pipe Requirements: Refer to installation sheet or TM120 general requirements 10 Dia up and 5 Dia down.

DIMENSIONAL DRAWING click to enlarge



MODEL 5300

Stainless Steel
Construction For Steam,
Gas and Liquids.

DIMENSIONS IN INCHES

Thickness = 1.25"
On All Line Sizes

Line Size (D)	Oripac Outside Diameter (OD)	Pipe Inside Diameter (PID)	Tap Location (CD)	Weight (Pounds)
0.25"	1.890"	0.364"	4.500	1
0.50"	1.890"	0.622"	4.500	2
0.75"	2.250"	0.824"	4.500	2
1.00"	2.625"	1.049"	4.500	3
1.25"	3.000"	1.380"	4.500	3
1.50"	3.375"	1.610"	4.500	3
2.00"	4.125"	2.067"	4.500	4
2.50"	4.875"	2.469"	4.500	4
3.00"	5.375"	3.068"	4.500	5
4.00"	6.875"	4.026"	4.500	6
5.00"	7.750"	5.047"	4.500	7
6.00"	8.750"	6.065"	4.500	9
8.00"	11.000"	7.891"	4.500	10
10.0"	13.374"	10.020"	4.500	14
12.0"	16.125"	12.000"	4.500	16
14.0"	17.750"	14.000"	4.500	20
16.0"	20.250"	16.000"	4.500	22
18.0"	21.625"	18.000"	4.500	36
20.0"	23.875"	20.000"	4.500	47
24.0"	28.250"	24.000"	4.500	58

Dimensions based on 150# flange rating and standard schedule pipe

MODEL 5300 TECH SUPPORT SHEET

The importance of proper pressure tap connections for orifice plate installations is often minimized or overlooked in the field. Faulty connections nullify the precision of the machining in the manufacture of the orifice plate and calibration accuracy of the secondary instrument. An orifice plate, properly installed, will provide satisfactory, low-cost service over a wide capacity range.

ADVANTAGES:
Lambda Square, Inc. has developed the ORIPAC to combine accuracy of measurement with certainty of correct installation. Made by specialist's in the manufacture of metering equipment, the ORIPAC provides the following advantages over orifices installed with main line taps.

1. Easy Installation is accomplished through elimination of drilling and taping pressure pipe connections. ORIPAC features factory made pressure taps so that drilling and tapping of the pipe line is unnecessary and the possibility of faulty installation of taps is avoided.

2. Errors resulting from incorrect pressure tap locations are avoided. Incorrect tap locations will cause inaccurate meter readings as the differential pressure measured will not correspond to the flow for which the secondary instrument has been calibrated. The downstream tap location is particularly critical in this respect. An Installation made with the ORIPAC which has the tap locations accurately placed in manufacture and secondary instrument calibrated accordingly, is not subject to such errors.

3. Factory-made pressure connections in the ORIPAC do away with the possibility of protruding nipples in the pipeline. Nipples protruding beyond the inner surface of the pipe create flow conditions unlike those on which the secondary instrument calibration is based. The amount of disturbance depends upon the degree of nipples protrusion, being more critical for downstream connections.

4. Tapping and drilling are unnecessary when the ORIPAC is used. Therefore, the possibility of burrs on the inner pipe surface is eliminated. Such burrs cause flow disturbances and consequent metering inaccuracies similar to those resulting from protruding nipples.

5. Location of pressure pipe connections in the ORIPAC overcomes metering errors caused by pipe friction between connections as made in other type orifice installations

6. Exact centering of orifice plates aided by the concentric finish on the rim of the ORIPAC adds to overall accuracy of the installation.

7. Metering pipe taps frequently plug due to corrosion. The

MODEL 5300 ACCURACY

The ORIPAC utilizes the corner tap proportions as defined in ISO 5167. While this code may not be referred to as International Standard until accepted by the ISO Council, the ASME Fluid Meters Research Committee has suggested that the dimensionless coefficient equation developed by the International Standards Organization (ISO) and presented in ISO 5167 is significantly better for the broad spectrum of flow measurement applications throughout process industries.

The coefficient values used in the ORIPAC bore calculations represent the same confidence level assigned to the flange and radius taps widely accepted in fluid flow measurement.

The accuracy assigned to the coefficient values is ± 0.6% full scale flow for d/D (Beta) values 0.2 to 0.6 and ± ß% for Beta values 0.6 to 0.75 (i.e. ß of 0.7 would have an uncertainty value of ± 0.7% full scale flow).

Accuracy of the differential signal produced by the ORIPAC equals or exceeds that of a properly manufactured and installed flange or radius tap orifice meter.

The elimination of errors caused by poor installation practices as well as the fact that all critical ORIPAC components are manufactured in corrosion resistant materials gives the ORIPAC an installed and sustained accuracy beyond that of the normal flange or radius tap orifice plate installation.

ORIPAC CAPACITY REFERENCE

MODEL 5300 SPECIFICATION SHEET

Suggested Specifications:

GENERAL:
This specification describes a differential pressure type of metering primary for the main line metering of liquid, gas or steam in a _____" pipe. The orifice plate flow meter "Oripac Model 5300" wafer type unit shall include high & low metering taps utilizing a "corner tap" configuration. Orifice primary shall meet or exceed ASME requirements for corner style metering taps with regards to accuracy, tolerances & calculations. A flow vs differential pressure curve shall be provided for each set of flow conditions.

MOUNTING:
The orifice metering primary shall be suitable for installation between standard ANSI 125 /150# or 250/300# flanges (any material) mounted on standard pipe (any material). The unit shall be "self centering" within the bolt circle of the flanges. No alignment of the orifice shall be necessary. Drilling and or tapping of the main or flanges will not be allowed or required. The overall laying length shall be 1.25" including pre-attached ring type 1/8" thick Buna "N" Gaskets. Other gasket materials available upon request.

CAPACITY:
Normal flow rate of insert ____SCFM or ____ PPH or ____GPM at a differential pressure to be determined by Lambda Square Inc. at pressures & temperatures provided by engineer and calculated by Lambda Square Inc.

MATERIALS OF CONSTRUCTION:
The Oripac Model 5300 primary element shall be monolithic (single piece) constructed entirely of 300 series ss. Metering connections shall be 1/8" or 1/4" NPT female taps. Hose barb connections or extension nipples may be threaded to high & low pressure connections if desired.

ACCURACY:
The orifice primary shall be precision calculated, bored and bench calibrated to ASME & ISO specifications yielding a predictable accuracy of +/- 0.6 % of full scale flow. Calculations shall be performed by Lambda Square Inc. to determine exact differential & headloss at full scale & normal flow conditions. Calculation formulas shall be based on ASME guidelines. The orifice primary shall be tested under similar conditions for at least 15 years and shall be equal in all respects to ORIPAC Model 5300 as manufactured by Lambda Square Inc. of Babylon, NY.

METER PERFORMANCE:
Calculations for pressure loss may be performed in conjunction with the Oripac flow calculations by Lambda Square Inc. The overall pressure loss and differential pressure shall be determined at maximum & normal flow conditions. The permanent headloss shall be within the requirements of the application, and determined by the engineer in conjunction with Lambda Square Inc.

Lambda Square Inc.
71 Deer Park Ave., Babylon, NY 11702
www.lambdasquare.com
(800) 587-5423 / (631) 587-1000
FAX (631) 587-1011
info@lambdasquare.com

ORIPAC® ACCURACY

ORIPAC utilizes the corner tap proportions as defined in ISO 5167. While this code may not be referred to as International Standard until accepted by the ISO Council, the ASME Fluid Meters Research Committee has suggested that the dimensionless coefficient equation developed by the International Standards Organization (ISO) and presented in ISO 5167 is significantly better for the broad spectrum of flow measurement applications throughout process industries.

The coefficient values used in the ORIPAC bore calculations represent the same confidence level assigned to the flange and radius taps widely accepted in fluid flow measurement.

The accuracy assigned to the coefficient values is ±0.6% for $\frac{d}{D}$ (Beta) values 0.2 to 0.6 and $\pm\beta\%$ for Beta values 0.6 to 0.75 (i.e. a β of 0.7 would have an uncertainty value of ±0.7%).

Accuracy of the differential signal produced by the ORIPAC equals that of a properly manufactured and installed flange or radius tap orifice meter.

The elimination of errors caused by poor installation practices plus the fact that all critical ORIPAC dimensions are manufactured in corrosion resistant materials gives the ORIPAC an installed and sustained accuracy beyond that of the normal flange or radius tap orifice plate installation.

Orifice Plate Accuracy Table

Source: ASME Flow Measurement Engineering Handbook
Second Edition Author: Richard W. Miller

Table 9.54 ***(Continued)***

Primary device	Nominal pipe diameter D, in (mm)	Beta ratio β	Pipe Reynolds-number R_D range	Coefficient accuracy, %
Venturi nozzle	3–20 (75–500)	0.3–0.75	2×10^5 to 2×10^6	$\pm 1.2 \pm 1.5\beta^4$
Orifice				
Corner, flange, D and $D/2$	2–36 (50–900)¶	0.2–0.6	10^4 to 10^7	± 0.6
		0.6–0.75	10^4 to 10^7	$\pm \beta$
		0.2–0.75	2×10^3 to 10^4	$\pm 0.6 \pm \beta$
$2\frac{1}{2}D$ and $8D$ (Pipetaps)	2–36 (50–900)	0.2–0.5	10^4 to 10^7	± 0.8
		0.51–0.7		± 1.6
Quadrant-edged	1–30 (25–750)	0.24–0.6	$R_{D,\min} < R_D < 10^5\beta$	± 2
Flanged and corner			$R_{D,\min} = 1000\beta + 9.4(\beta - 0.24)^8$	
Conical entrance	>1 (25)	0.1–0.316	$250\beta \le R_D \le 5000\beta$ for $C = 0.730$	± 2
Corner			$5000\beta \le R_D \le 2 \times 10^5\beta$ for $C = 0.734$	± 2

Landfill Gas Flow Measurements	
Crapo Hill Landfill, New Bedford/Dartmouth, Massac	
Measurements by	TY
Date	9-Nov-05
Time	**2:50**
Drive Speed (1 to 10)	
Flow valve	
Pipe inside diameter, inches	10.42
Orifice measurement, cfm	
Ambient Temperature, F	50
Barometric Pressure, In Hg	30.22
Blower Inlet Temperature, F	74
Outlet Temperature, F	109
Blower Inlet Pressure (SP), In H20	-40
Blower Outlet Pressure, PSIG	**3.00**
Blower Outlet Pressure, In H20	83.04
Measurement	
Manometer	
Pitot Tube	
Velocity Pressure (dP)	
Point	
1	0.15
2	0.18
3	0.2
4	0.2
5	0.2
6	0.2
7	0.2
8	0.19
9	0.2
Average	0.191
Gas Composition	
Compound	
CH4	56.0%
CO2	43.0%
O2	0.0%
N2	1.0%
Total	100.0%

Landfill Gas Flow Calculation

Crapo Hill Landfill, New Bedford/Dartmouth, Massachusetts

Note: Calculation of volumetric flow of LFG through a pipe using a pitot tube and manometer.

MEASURING INSTRUMENT:		Pitot Tube:	161
		Manometer:	Dwyer Mark I
DATE OF MEASUREMENT:			9-Nov-05
TIME OF MEASUREMENT:			**2:50**
PARAMETERS		UNITS	VALUES
Pipe dimensions			
	Inside Diameter	inches	**10.420**
	Area of cross section	square feet	0.5922
Flow Calculation			
Kp	pitot tube constant	ft/sec[(lb/lb-mole)(in. Hg)/(R)(in H20)]^1/2	85.49
Cp	Pitot tube coefficient	dimensionless	1.00
dP	Average velocity pressure of stack gas	in H20	**0.191**
Blower Inlet			
Ts	Stack temperature	Degrees Fahrenheit	**74**
		Degrees Rankine	534
Pg	Stack static pressure	inch H20	-40
		inch Hg	(2.94)
Ps	Absolute stack gas pressure	inch Hg	27.28
Blower Outlet			
Ts	Stack temperature	Degrees Fahrenheit	**109**
		Degrees Rankine	569
Pg	Stack static pressure	inch H20	83.0
		inch Hg	6.11
		psig	3.00
Pbar	Barometric pressure	inch Hg	**30.22**
Ps	Absolute stack gas pressure	inch Hg	36.33
Ms	Molecular weight of stack gas, wet	lb/lb-mole	27.50
Vs	Average stack gas velocity	feet per second	31.5
Qact	Volumetric Flow	actual cubic feet per minute	1,120
Qstd	**Volumetric Flow at actual methane content**	**standard cubic feet per minute ***	**1,010**
Qstd	Volumetric Flow at 50% methane	standard cubic feet per minute **	1,131
Ht HHV	Heat input	MMBtu per hour HHV	34.34
Ht LHV	Heat input	MMBtu per hour LHV	30.92
	Methane Content	%, vol/vol	56.00%
Orifice Reading: Facility Continuous Measurement Device			1.015
dP	Delta pressure across orifice plate	inches H20	7.50
Qact	Volumetric Flow	acfm	910
Qstd	**Volumetric Flow at actual methane content**	**standard cubic feet per minute ***	**1,025**
Qstd	Volumetric Flow at 50% methane	standard cubic feet per minute **	1,148
Ht HHV	Heat input	MMBtu per hour HHV	34.85
Ht LHV	Heat input	MMBtu per hour LHV	31.37
Difernece between ptot tube and orifice reading:			1%

* Standard conditions are corrected to 68 degrees F and 29.92 in Hg at actual methane content.

** Standard conditions corrected to 50 % methane content.

Input values are in blue or bold.

Calculated output values are in black or not bold.

Calculation Formulas:

Vs = Kp*Cp*(sqrt dP) * sqrt (Ts/(Ps*Ms))

Qact = Vs * A * 60

Qstd = Qact * Tstd/ Ts * Ps/Pstd

Flow, ACFM = 96.3221*SQRT(dP)*SQRT((460+Temperature)/(2.703*(Pressure +14.7)))

Conversions and constants

13.596 in H2O/in Hg

1 PSI = 2.036 in HG

1 PSI = 27.68 in WG

Tstd = 528 degrees R

Pstd = 29.92 in Hg

Methane heat content = 1,012 BTU per scf HHV

Methane heat content = 911 BTU per scf LHV

ATTACHMENT F

USEPA Gas Flow Measurement Protocols,
40 CFR 60 Appendix A Method 1a - sample and velocity traverses for stationary sources with small stacks or ducts, and Method 2c - determination of gas velocity and volumetric flow rate in small stacks or ducts (standard pitot tube).

METHOD 1A - SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES WITH SMALL STACKS OR DUCTS

NOTE: This method does not include all of the specifications (*e.g.*, equipment and supplies) and procedures (*e.g.*, sampling) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test method: Method 1.

1.0 Scope and Application.

1.1 Measured Parameters. The purpose of the method is to provide guidance for the selection of sampling ports and traverse points at which sampling for air pollutants will be performed pursuant to regulations set forth in this part.

1.2 Applicability. The applicability and principle of this method are identical to Method 1, except its applicability is limited to stacks or ducts. This method is applicable to flowing gas streams in ducts, stacks, and flues of less than about O.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) in cross-sectional area, but equal to or greater than about O.10 meter (4 in.) in diameter, or 0.0081 m^2 (12.57 $in.^2$) in cross-sectional area. This method cannot be used when the flow is cyclonic or swirling.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method.

2.1 The method is designed to aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source. A measurement site or a pair of measurement sites where the effluent stream is flowing in a known direction is (are) selected. The cross-section of the stack is divided into a number of equal areas. Traverse points are then located within each of these equal areas.

2.2 In these small diameter stacks or ducts, the conventional Method 5 stack assembly (consisting of a Type S pitot tube attached to a sampling probe, equipped with a nozzle and thermocouple) blocks a significant portion of the cross-section of the duct and causes inaccurate measurements. Therefore, for particulate matter (PM) sampling in small stacks or ducts, the gas velocity is measured using a standard pitot tube downstream of the actual emission sampling site. The straight run of duct between the PM sampling and velocity measurement sites allows the flow profile, temporarily disturbed by the presence of the sampling probe, to redevelop and stabilize.

3.0 Definitions. [Reserved]

4.0 Interferences. [Reserved]

5.0 Safety.

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

6.0 Equipment and Supplies. [Reserved]

7.0 Reagents and Standards. [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport. [Reserved]

9.0 Quality Control. [Reserved]

10.0 Calibration and Standardization. [Reserved]

11.0 Procedure.

11.1 Selection of Measurement Site.

11.1.1 Particulate Measurements - Steady or Unsteady Flow. Select a particulate measurement site located preferably at least eight equivalent stack or duct diameters downstream and 10 equivalent diameters upstream from any flow disturbances such as bends, expansions, or contractions in the stack, or from a visible flame. Next, locate the velocity measurement site eight equivalent diameters downstream of the particulate measurement site (see Figure 1A-1). If such locations are not available, select an alternative particulate measurement location at least two equivalent stack or duct diameters downstream and two and one-half diameters upstream from any flow disturbance. Then, locate the velocity measurement site two equivalent diameters downstream from the particulate measurement site. (See Section 12.2 of Method 1 for calculating equivalent diameters for a rectangular cross-section.)

11.1.2 PM Sampling (Steady Flow) or Velocity (Steady or Unsteady Flow) Measurements. For PM sampling when the volumetric flow rate in a duct is constant with respect to time, Section 11.1.1 of Method 1 may be followed, with the PM sampling and velocity measurement performed at one location. To demonstrate that the flow rate is constant (within 10 percent) when PM measurements are made, perform complete velocity traverses before and after the PM sampling run, and calculate the deviation of the flow rate derived after the PM sampling run from the one derived before the PM sampling run. The PM sampling run is acceptable if the deviation does not exceed 10 percent.

11.2 Determining the Number of Traverse Points.

11.2.1 Particulate Measurements (Steady or Unsteady Flow). Use Figure 1-1 of Method 1 to determine the number of traverse points to use at both the velocity measurement and PM sampling locations. Before referring to the figure, however, determine the distances between both the velocity measurement and PM sampling sites to the nearest upstream and downstream disturbances. Then divide each distance by the stack diameter or equivalent diameter to express the distances in terms of the number of duct diameters. Then, determine the number of traverse points from Figure 1-1 of Method 1 corresponding to each of these four distances. Choose the highest of the four numbers of traverse points (or a greater number) so that, for circular ducts the number is a multiple of four; and for rectangular ducts, the number is one of those shown in Table 1-1 of Method 1. When the optimum duct diameter location criteria can be satisfied, the minimum number of traverse points required is eight for circular ducts and nine for rectangular ducts.

11.2.2 PM Sampling (Steady Flow) or only Velocity (Non-Particulate) Measurements. Use Figure 1-2 of Method 1 to determine number of traverse points, following the same procedure used for PM sampling as described in Section 11.2.1 of Method 1. When the optimum duct diameter location criteria can be satisfied, the minimum number of traverse points required is eight for circular ducts and nine for rectangular ducts.

11.3 Cross-sectional Layout, Location of Traverse Points, and Verification of the Absence of Cyclonic Flow. Same as Method 1, Sections 11.3 and 11.4, respectively.

12.0 Data Analysis and Calculations. [Reserved]

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References.

Same as Method 1, Section 16.0, References 1 through 6, with the addition of the following:

1. Vollaro, Robert F. Recommended Procedure for Sample Traverses in Ducts Smaller Than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, North Carolina. January 1977.

17.0 Tables, Diagrams, Flowcharts, and Validation Data.

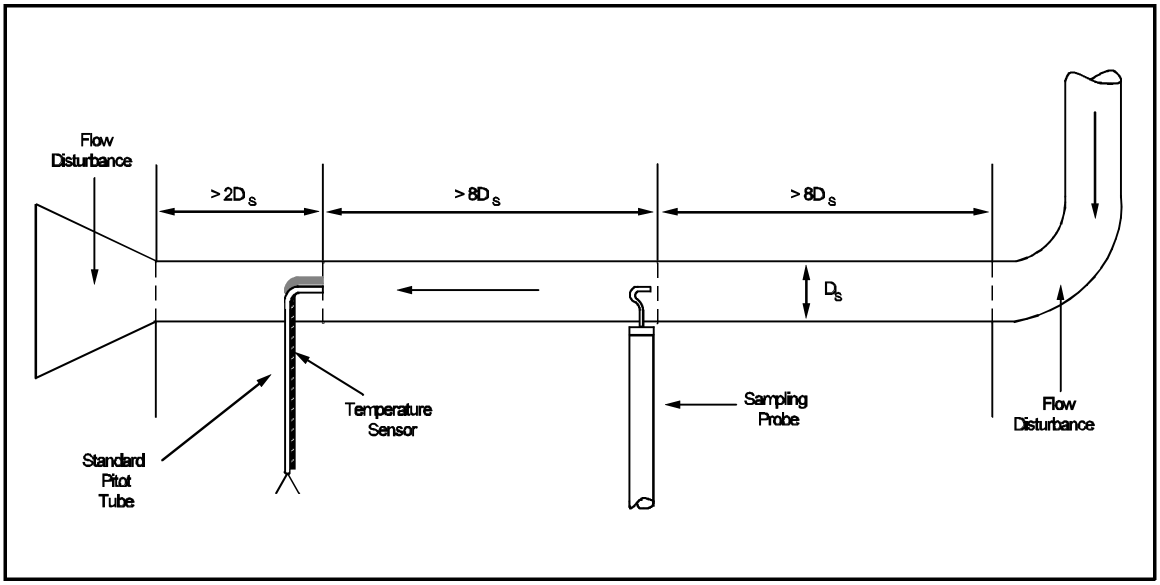


Figure 1A-1. Recommended sampling arrangement for small ducts

METHOD 2C - DETERMINATION OF GAS VELOCITY AND VOLUMETRIC FLOW RATE IN SMALL STACKS OR DUCTS (STANDARD PITOT TUBE)

NOTE: This method does not include all of the specifications (*e.g.*, equipment and supplies) and procedures (*e.g.*, sampling) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should also have a thorough knowledge of at least the following additional test methods: Method 1, Method 2.

1.0 Scope and Application.

1.1 This method is applicable for the determination of average velocity and volumetric flow rate of gas streams in small stacks or ducts. Limits on the applicability of this method are identical to those set forth in Method 2, Section 1.0, except that this method is limited to stationary source stacks or ducts less than about O.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) in cross-sectional area, but equal to or greater than about O.10 meter (4 in.) in diameter, or 0.0081 m^2 (12.57 $in.^2$) in cross-sectional area.

1.2 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method.

2.1 The average gas velocity in a stack or duct is determined from the gas density and from measurement of velocity heads with a standard pitot tube.

3.0 Definitions. [Reserved]

4.0 Interferences. [Reserved]

5.0 Safety.

5.1 This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

6.0 Equipment and Supplies.

Same as Method 2, Section 6.0, with the exception of the following:

6.1 Standard Pitot Tube (instead of Type S). A standard pitot tube which meets the specifications of Section 6.7 of Method 2. Use a coefficient of O.99 unless it is calibrated against another standard pitot tube with a NIST-traceable coefficient (see Section 10.2 of Method 2).

6.2 Alternative Pitot Tube. A modified hemispherical-nosed pitot tube (see Figure 2C-1), which features a shortened stem and enlarged impact and static pressure holes. Use a coefficient of 0.99 unless it is calibrated as mentioned in Section 6.1 above. This pitot tube is useful in particulate liquid droplet-laden gas streams when a "back purge" is ineffective.

7.0 Reagents and Standards. [Reserved]

8.0 Sample Collection and Analysis.

8.1 Follow the general procedures in Section 8.0 of Method 2, except conduct the measurements at the traverse points specified in Method 1A. The static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, adequate proof that the openings of the pitot tube have not plugged during the traverse period must be furnished; this can be done by taking the velocity head ()p) heading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another)p reading. If the)p readings made before and after the air purge are the same (within ±5 percent) the traverse is acceptable. Otherwise, reject the run. Note that if the)p at the final traverse point is unsuitably low, another point may be selected. If "back purging" at regular intervals is part of the procedure, then take comparative)p readings, as above, for the last two back purges at which suitably high)p readings are observed.

9.0 Quality Control.

Section	Quality Control Measure	Effect
10.0	Sampling equipment calibration	Ensure accurate measurement of stack gas velocity head

10.0 Calibration and Standardization.

Same as Method 2, Sections 10.2 through 10.4.

11.0 Analytical Procedure.

Sample collection and analysis are concurrent for this method (see Section 8.0).

12.0 Calculations and Data Analysis.

Same as Method 2, Section 12.0.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References.

Same as Method 2, Section 16.0.

17.0 Tables, Diagrams, Flowcharts, and Validation Data.

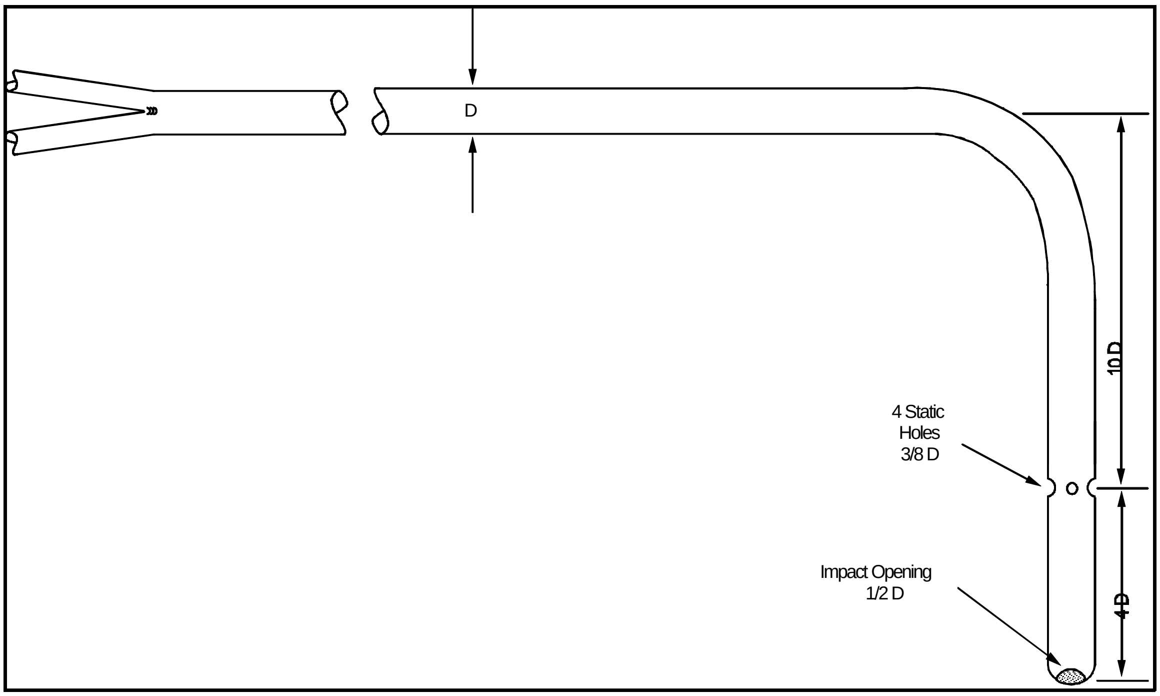
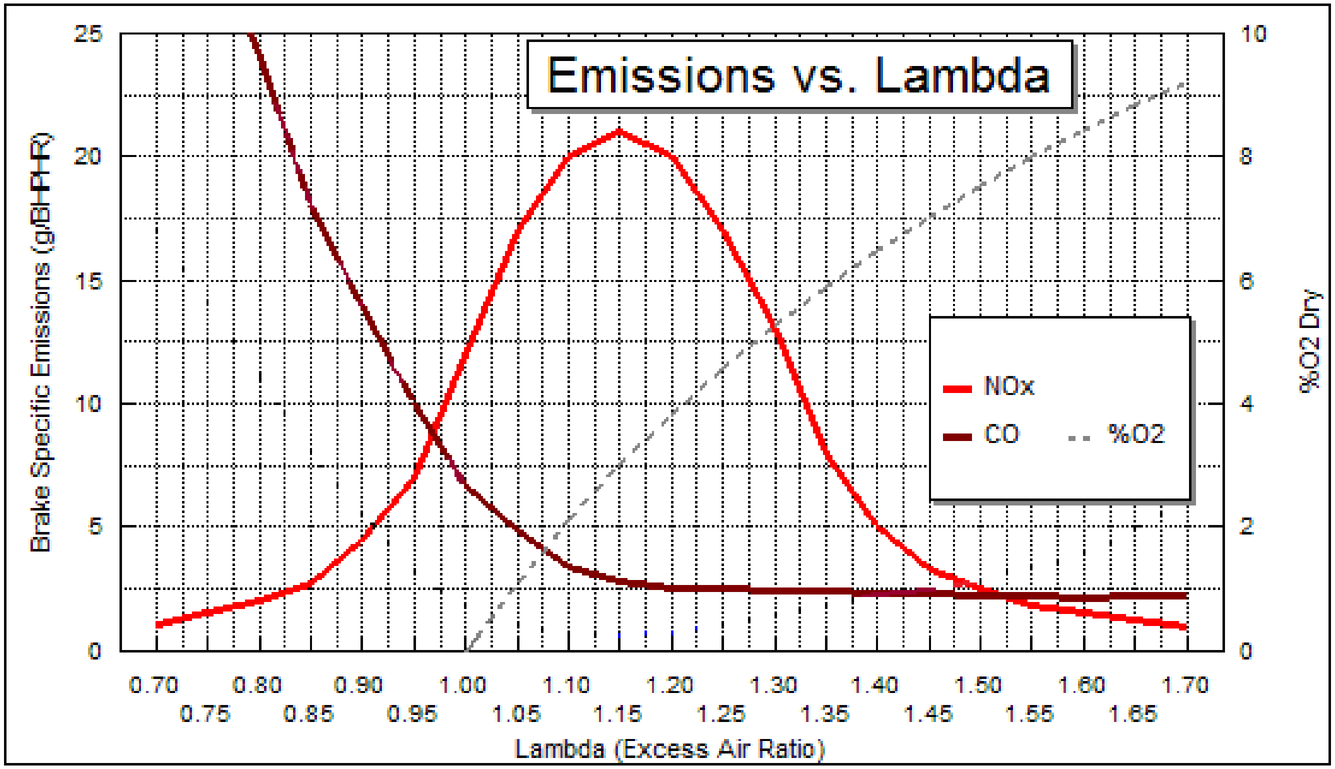


Figure 2C-1. Modified Hemispherical-Nosed Pitot Tube.

ATTACHMENT G

Performance of CAT 3516 engine: Excess air versus CO and NOx



Emissions vs. Lambda
Brake Specific Emissions (g/BHP-HR)
%O2 Dry
Lambda (Excess Air Ratio)
NOx
CO
%O2
25
20
15
10
5
0
10
8
6
4
2
0
0.70
0.75
0.80
0.85
0.90
0.95
1.00
1.05
1.10
1.15
1.20
1.25
1.30
1.35
1.40
1.45
1.50
1.55
1.60
1.65
1.70

ATTACHMENT H

Compliance test results and combustion efficiency calculation

GREATER NEW BEDFORD LFG UTILIZATION FACILITY			
Compliance Test Results and Combustion Efficiency Calculation			
	Carbon monoxide air emissions		Combustion efficiency,
Engine	lb CO per	lb-mole CO per	1-(CO lb-mole/MMBtu per
Number	MMBtu of heat input	MMBtu of heat input	per CH4 lb-mole/MMBtu)
1	0.601	0.0215	99.2%
2	0.595	0.0213	99.2%
3	0.589	0.0210	99.2%
4	0.594	0.0212	99.2%
Constants:			
Methane heat value		Btu HHV/lb	23,875
		MMBtu HHV/lb	0.0239
		lb/MMBtu HHV	41.88
		lb-mole/MMBtu	2.62
Molecular weight			
	CO	lb/lb-mole	28
	CH4	lb/lb-mole	16

ATTACHMENT I

Records of oxygen measurements in each exhaust stack of engines.

GREATER NEW BEDFORD LFG UTILIZATION PROJECT
CommonWealth New Bedford Energy LLC
Operator: NEESCo

Bacharach Oxor II Inputs are in % volume wet

Moisture content, 12%

		Oxygen content in exhaust gas, % v/v wet					Oxygen content in exhaust gas, % v/v dry				
	Engine #	1	2	3	4		1	2	3	4	Comments
Week ending	Sample Date										
7-Jan-07	3-Jan-07	8.2	8.0	7.9	8.0		9.3	9.1	9.0	9.1	
14-Jan-07	10-Jan-07	8.2	7.9	7.8	8.0		9.3	9.0	8.9	9.1	
21-Jan-07	17-Jan-07	8.2	7.9	7.8	8.0		9.3	9.0	8.9	9.1	
28-Jan-07	26-Jan-07	8.2	7.9	7.9	8.0		9.3	9.0	9.0	9.1	
4-Feb-07	2-Feb-07	8.2	7.9	7.9	8.0		9.3	9.0	9.0	9.1	
11-Feb-07	8-Feb-07	8.1	7.9	7.9	8.2		9.2	9.0	9.0	9.3	
18-Feb-07	15-Feb-07	8.2	7.9	7.8	8.0		9.3	9.0	8.9	9.1	
25-Feb-07	22-Feb-07	8.2	8.0	7.8	8.0		9.3	9.1	8.9	9.1	
4-Mar-07	27-Feb-07	8.2	7.9	7.8	8.0		9.3	9.0	8.9	9.1	
11-Mar-07	8-Mar-07	8.2	8.0	7.8	8.0		9.3	9.1	8.9	9.1	
18-Mar-07	15-Mar-07	8.1	7.9	7.7	8.0		9.2	9.0	8.8	9.1	
25-Mar-07	22-Mar-07	8.2	7.9	7.8	8.0		9.3	9.0	8.9	9.1	
1-Apr-07	30-Mar-07	8.2	8.0	7.8	8.2		9.3	9.1	8.9	9.3	
8-Apr-07	5-Apr-07	8.1	8.0	7.8	8.2		9.2	9.1	8.9	9.3	
15-Apr-07	12-Apr-07	8.2	8.0	7.7	8.2		9.3	9.1	8.8	9.3	
22-Apr-07	19-Apr-07	8.2	8.0	7.8	8.2		9.3	9.1	8.9	9.3	
29-Apr-07	26-Apr-07	8.2	7.9	7.8	8.2		9.3	9.0	8.9	9.3	
6-May-07	3-May-07	8.2	8.0	7.8	8.1		9.3	9.1	8.9	9.2	
13-May-07	10-May-07	8.2	8.0	7.9	8.1		9.3	9.1	9.0	9.2	
20-May-07	17-May-07	8.2	7.9	7.8	8.3		9.3	9.0	8.9	9.4	
27-May-07	24-May-07	8.2	8.0	7.8	8.3		9.3	9.1	8.9	9.4	
3-Jun-07	31-May-07	8.2	8.0	7.8	8.3		9.3	9.1	8.9	9.4	
10-Jun-07	6-Jun-07	8.2	8.0	7.9	8.3		9.3	9.1	9.0	9.4	
17-Jun-07	16-Jun-06	8.2	8.0	7.9	8.4		9.3	9.1	9.0	9.5	
24-Jun-07	22-Jun-06	8.2	7.9	8.0	8.3		9.3	9.0	9.1	9.4	
1-Jul-07	28-Jun-06	8.2	7.9	8.0	8.4		9.3	9.0	9.1	9.5	
8-Jul-07	2-Jul-07	8.2	7.9	8.0	8.4		9.3	9.0	9.1	9.5	
15-Jul-07	11-Jul-07	8.2	8.0	7.9	8.4		9.3	9.1	9.0	9.5	
22-Jul-07	16-Jul-07	8.2	8.0	7.9	8.4		9.3	9.1	9.0	9.5	
29-Jul-07	24-Jul-07	8.3	8.0	7.9	8.5		9.4	9.1	9.0	9.7	
5-Aug-07	30-Jul-07	8.2	8.0	7.9	8.5		9.3	9.1	9.0	9.7	
12-Aug-07	7-Aug-07	8.2	7.9	8.0	8.4		9.3	9.0	9.1	9.5	
19-Aug-07	14-Aug-07	8.2	7.9	8.0	8.4		9.3	9.0	9.1	9.5	
26-Aug-07	21-Aug-07	8.3	8.0	7.9	8.4		9.4	9.1	9.0	9.5	
2-Sep-07	27-Aug-07	8.2	8.0	7.9	8.5		9.3	9.1	9.0	9.7	
9-Sep-07	5-Sep-07	8.3	8.0	8.0	8.4		9.4	9.1	9.1	9.5	
16-Sep-07	10-Sep-07	8.3	8.0	8.0	8.5		9.4	9.1	9.1	9.7	
23-Sep-07	17-Sep-07	8.2	8.0	8.0	8.5		9.3	9.1	9.1	9.7	
30-Sep-07	24-Sep-07	8.3	8.0	8.0	8.5		9.4	9.1	9.1	9.7	
7-Oct-07	1-Oct-07	8.3	7.9	8.0	8.4		9.4	9.0	9.1	9.5	
14-Oct-07	8-Oct-07	8.3	8.0	8.0	8.5		9.4	9.1	9.1	9.7	
21-Oct-07	15-Oct-07	8.3	8.0	8.0	8.4		9.4	9.1	9.1	9.5	
28-Oct-07	22-Oct-07	8.3	8.0	8.0	8.4		9.4	9.1	9.1	9.5	
4-Nov-07	30-Oct-07	8.3	8.0	8.0	8.5		9.4	9.1	9.1	9.7	
11-Nov-07	5-Nov-07	8.2	8.0	8.0	8.4		9.3	9.1	9.1	9.5	
18-Nov-07	13-Nov-07	8.3	8.1	8.0	8.5		9.4	9.2	9.1	9.7	
25-Nov-07	20-Nov-07	8.3	8.0	8.0			9.4	9.1	9.1	-	
2-Dec-07	27-Nov-07	8.3	8.0	8.0	8.5		9.4	9.1	9.1	9.7	
9-Dec-07	3-Dec-07	8.3	8.0	8.0	8.4		9.4	9.1	9.1	9.5	
16-Dec-07											
23-Dec-07											
30-Dec-07											

ATTACHMENT J

List of Documents Comprising the GE-AES Standard

1. GE-AES Greenhouse Gas Services, Standard Practice for the Production, Management and Marketing of Greenhouse Gas Credits, Version 1.0 - July 25, 2007;
2. GE-AES Methodology for Landfill Gas Methane Capture and Destruction Projects, Version 1.0 - July 25, 2007 (the GE-AES Methodology);
3. Summary of Reporting Requirements for Landfill Gas Projects, Version 1.0 – October 24, 2007;
4. Summary of Record-keeping Requirements for Landfill Gas Projects, Version 1.0 – October 24, 2007; and
5. Summary of Monitoring Requirements for Landfill Gas Projects, Version 1.0 – October 24, 2007