PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

FINAL REPORT

Prepared For:

County of Kauai
Office of Economic Development
Kauai, Hawaii

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Prepared By:

SCS Energy
Long Beach, California

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TABLE OF CONTENTS

SECTION 1

EXECUTIVE SUMMARY

The purpose of the Pacific Missile Range Facility Combined Heat and Power Feasibility Study was to evaluate the feasibility of developing a combined heat and power (CHP) plant, at the Pacific Missile Range Facility (PMRF), utilizing landfill gas from the Kekaha Landfill. The Kekaha Landfill is owned by the County of Kauai.

SCS Energy (SCS) collected samples of landfill gas from the closed Phase I section of the Kekaha Landfill and analyzed data from a previous sampling effort of the open Phase II section of the Kekaha Landfill. SCS concluded that the landfill gas at Kekaha Landfill was suitable for use as a fuel for a CHP project. SCS prepared a 25-year projection of recoverable landfill gas, which indicated that the recoverable landfill gas could support 1.6 MW of electric power generation.

SCS prepared a conceptual design and cost estimate for a landfill gas collection system for the Kekaha Landfill, for a landfill gas compression and moisture removal facility at the Kekaha Landfill, and for a landfill gas transmission pipeline between the Kekaha Landfill and the existing PMRF power plant. The pipeline would be about 3.9 miles in length and would employ below-ground, 6-inch diameter, high density polyethylene (HDPE) pipe.

A review of PMRF's electric power consumption and production, thermal energy requirements (chilled water and hot water), fuel consumption (diesel oil and propane), and energy costs was undertaken. A review of PMRF's electric power production equipment, chilled water production equipment and hot water production equipment was also undertaken. The on-site electric power distribution system was evaluated. Technical alternatives for CHP were identified and discussed.

Six alternatives were configured based on SCS's findings from the above work. The alternatives were as follows:

> Alternative No. 1-A: Fuel the existing engines on diesel oil, with the addition of heat recovery, and retain the current program of intermittent operation;
>
> Alternative No.1-B: Fuel the existing engines on diesel oil, with the addition of heat recovery, and convert to full-time operation;
>
> Alternative No. 2-A: New landfill gas fired reciprocating engines at the existing PMRF power plant with heat recovery to produce chilled water with an absorption chiller, plus a microturbine with absorption chiller at Building 1262;
>
> Alternative No.2-B: New landfill gas fired reciprocating engines at the existing PMRF power plant with heat recovery to produce chilled water with an absorption chiller, without a microturbine at Building 1262;

Alternative No.3: New landfill gas fired reciprocating engines on PMRF grounds close to the landfill; and

Alternative No. 4: New landfill gas fired reciprocating engines at the landfill.

The above-identified six alternatives were compared on the basis of life cycle energy cost reduction, fossil fuel consumption reduction, and quantity of renewable power generated. Alternative No. 2-B was selected as the preferred alternative.

The principal components of Alternative No. 2-B are as follows:

- Installation of a landfill gas collection system at the Kekaha Landfill. The landfill gas collection system will consist of 39 landfill gas extraction wells, and related piping, as is more fully described in Section 5 of the Interim Report on Task 1;
- Installation of a landfill gas processing skid at the landfill. It will have a design capacity of 600 scfm and an operating pressure of 25 psig. It will chill the landfill gas to 45º F and reheat it to 65º F prior to introduction into the pipeline. A tentative location for the skid is shown on Figure No. 5-2 in Section 5 of the Interim Report on Task 1;
- A 3.9-mile, 6-inch diameter, landfill gas transmission pipeline from the landfill to the site of the existing PMRF power plant. The general alignment of the pipeline is shown on Figure No. 6-1 in Section 6 of the Interim Report on Task 1;
- A 1,640 kW landfill gas fired CHP plant, located adjacent to the existing PMRF power plant. The CHP plant will employ two 820 kW reciprocating engines, and engine appurtenant equipment, heat recovery equipment, and an absorption chiller. Table No. 2-1 in Section 2 of the Interim Report on Task 4 provides a summary of the major equipment that will be employed at the CHP plant. The CHP plant would interconnect into the PMRF power distribution system at the existing PMRF power plant;
- Chilled water delivery equipment and piping to supply chilled water to Buildings 130, 105 and 105ROCS. The existing cooling equipment would remain at these locations to provide supplemental and standby cooling; and
- A 12.47 kV electrical distribution line, about 13,800 feet in length, between the PMRF power plant and the Navy Housing area, to allow the Navy Housing area to receive power from the CHP plant. Implementation of this element of the project requires resolution of ownership issues for some of the power distribution lines in the Navy Housing area. These issues are discussed in Section 5 of the Interim Report on Task 4.

Additional information, descriptive of Alternative No. 2-B can be found in the Interim Report on Task 4.

The estimated cost of the proposed project is $8,231,700. Based on assumptions and analyses contained in the Interim Report on Task 4, and under all scenarios evaluated, the investment in the project would have an internal rate of return in excess of 25 percent.

The largest unknown factors affecting the financial performance of the project, at this point, are the price to be paid to the County for its landfill gas and the standby power charge that Kauai Island Utility Cooperative (KIUC) will charge. KIUC has recently filed for approval to increase their standby power charge. The following matrix summarizes the impact on internal rate of return of alternative assumptions on landfill gas purchase price and standby power charge, as computed in Section 3 of the Interim Report on Task 4. The low standby power charge is KIUC's current charge. The high charge is KIUC's proposed charge. The medium charge is, for reasons explained in Section 2 of the Interim Report on Task 3, what SCS feels to be a more reasonable expectation for the charge that will ultimately be approved.

Landfill Gas Purchase Price	**Standby Power Charge**		
	Low $5.00/kW	**Medium $10.45/kW**	**High $37.47/kW**
$1.00/mmBtu	33.1%	31.8%	25.6%
$2.00/mmBtu		30.2%	
$3.00/mmBtu		28.5%	
$4.00/mmBtu		26.8%	

The project will generate an average of almost 12 million kWh of renewable energy per year over its twenty-year life. It will reduce diesel oil consumption on Kauai by almost 800,000 gallons per year.

SECTION 2

SUMMARY OF CONTRACT DELIVERABLES BY TASK

SCS/County Contract Task 1 (County/DOE Contract Task 2)

Task 1 of the SCS/County contract is titled "Prepare a Gas Analysis and Recommendations for Gas Clean-up and Distribution." The contract calls for the following work:

a. The CONTRACTOR shall collect multiple samples of landfill gas (LFG) from the Kekaha Landfill Phase I (Phase I) passive LFG collection system of the Kekaha Landfill, using appropriate industry protocols, as required to ensure that the analyses specified herein are performed on representative LFG samples. The CONTRACTOR shall submit a sampling timeline/schedule for COUNTY approval before any work is performed so the Solid Waste Manager can coordinate ongoing landfill activities with the CONTRACTOR's work. The County intends for LFG generated at Phase I to be sampled from the passive LFG collection system currently in place. CONTRACTOR shall conduct laboratory analysis of the LFG using appropriate test protocols to determine the following:

    1. Percent of concentration of carbon dioxide, nitrogen, oxygen, and methane;
    2. Types and percent concentration for Sulfides;
    3. Types and percent concentrations for Siloxanes;
    4. Types and percent concentrations of NMOC's (non-methane organic compounds); and
    5. Types and percent concentrations of VOCs (volatile organic compounds;

    The County of Kauai Solid Waste Division recently completed work to sample and analyze LFG from the active Kekaha Landfill Phase II (Phase II) area. Laboratory test results from samples collected from Phase II will be provided to the CONTRACTOR. The COUNTY intends for the sampling techniques and methodologies used in the Phase I sampling via this contract to mirror the techniques, methodologies and testing standards from the Phase II samplings so the results can be compared and evaluated. All tests shall follow generally accepted industry testing standards and protocols.

b. The CONTRACTOR shall aggregate, compare and evaluate the results of the gas quality analyses tests with the previous testing conducted by the County of Kauai Solid Waste Division on Kekaha Landfill Phase II;

c. The CONTRACTOR shall obtain existing data and update the information to include the County of Kauai Solid Waste Division's plans for an additional 15 foot vertical expansion and also a lateral expansion to Kekaha Landfill Phase II. Findings from the tests conducted under this contract and the prior Phase II tests will be used by the CONTRACTOR to prepare findings on the potential of gas production and availability (quality and quantity), and the cost of collection, cleanup, and distribution to the PMRF CHP plant;

d. The CONTRACTOR shall prepare design recommendations and cost estimates for a distribution system from the Phase I and Phase II landfills' gas sources to the landfill property line and from the property line to PMRF end user. These recommendations shall also include any type of gas treatment needed and the recommended location of the treatment facility before the PMRF end user site;

e. The CONTRACTOR shall identify the fair market value of the landfill gas to the County;

f. The CONTRACTOR shall submit a draft report on Task 1 analyses, findings, cost estimates, fair market value and recommendations to the COUNTY for review and comment; and

g. The CONTRACTOR shall submit, for COUNTY approval, a final report on Task 1 analyses, findings, cost estimates, fair market value and recommendations.

SCS satisfied its obligations under Task 1 and issued its "Interim Report on Task 1" in March 2006. A complete copy of that report can be found in Appendix A.

<u>SCS/County Contract Task 2 (County/DOE Contract Task 3)</u>

Task 2 of the SCS/County contract is titled "Develop PMRF Facility Energy Baseline Evaluation and CHP Economic and Engineering Options." The contract calls for the following work:

a. The CONTRACTOR shall obtain and evaluate all existing PMRF energy data, electric and thermal load profiles, describe planned site modifications and expansions, inventory major equipment and replacement plans, obtain site layout drawings, develop a facility energy baseline, and provide an evaluation report for COUNTY review and approval;

b. The CONTRACTOR shall develop economic and engineering options for a comprehensive and cost effective CHP Project, with consideration given to thermal requirements of the site, use of waste heat in an optimum manner for heating and cooling, power quality and reliability issues, load management, current utility rates, and maximized environmental benefit. Sensitivity analyses shall be developed as appropriate. Determination of the following shall be included, but not limited to, the optimal configuration of the system (type and size) for the quality and amount of gas that will be delivered; and the potential for sale of excess power to the local utility;

c. The CONTRACTOR shall assess the specific economic and engineering feasibility of the following options:

1) Replacing the existing on-base power plant with a 24/7 CHP plant (type and size to be determined by the study) using petroleum-based fuel, propane, and/or methane gas options;

2) Retrofitting the existing on-base power plant for 24/7 use and to use methane gas from the County of Kauai Solid Waste Division's adjacent landfill, with consideration given to modifying the existing on-base power plant, based on availability of methane gas production and to exhaust heat recovery systems that could be added to the existing on-base power plant;

3) Constructing a back-up CHP plant of a type and size compatible with landfill gas production capability to run alternately with the existing on-base power plant;

4) The CONTRACTOR shall submit the preliminary analysis and summary to the COUNTY for review and comments;

5) Any other options determined by the Contractor to be viable, based on gathered data and analyses;

6) Accounting for any interconnection equipment/standards that the Kauai Island Utility Cooperative might require; and

7) Discussion shall also include the probable air emissions content from potential CHP technologies as it pertains to EPA and State Department of Health standards.

d. The CONTRACTOR shall provide a written report for multi-agency technical review and COUNTY approval, in accordance with Task 2, herein, describing these options to COUNTY.

SCS satisfied its obligations under Task 2 and issued its "Interim Report on Task 2: Energy Baseline Evaluation and CHP Economic and Engineering Options," dated September 2006. A copy of that report can be found in Appendix B.

SCS/County Contract Task 3 (County/DOE Contract Task 4)

Task 3 of the SCS/County contract is titled “Prepare Findings and Recommendations.” The contract calls for the following work:

a. The CONTRACTOR shall develop a site plan and present worth analysis for each option presented above based on industry engineering estimates. The analyses shall evaluate capital costs for each alternative along with installation, operation, maintenance and replacement costs over a 20-year life span, and present the results in present values. The analyses shall include predicted annual energy and cost savings in utility and operating costs reduction through the operation of each scenario;

b. The CONTRACTOR shall make a written and oral report on the preliminary draft findings to the COUNTY for COUNTY approval; and

c. The CONTRACTOR shall make a recommendation on the optimal system design to the Technical Review Committee and the COUNTY and shall move forward with the draft final report upon approval of the optimal system design by the COUNTY, with input from the Technical Review Committee.

SCS satisfied its obligations under Task 3 and issued its “Interim Report on Task 3: Findings and Recommendations on the Economic Evaluation of Alternatives,” dated November 2006. A copy of that report can be found in Appendix C.

SCS/County Contract Task 4 (County/DOE Contract Task 5)

Task 4 of the SCS/County contract is titled “Final Economic and Strategic Feasibility Study.” The contract calls for the following work:

a. For the optimal system design scenario selected in Task 3c, the CONTRACTOR shall prepare an optimized configuration, economic feasibility, procurement and construction schedule, measurement and verification requirements, operation and maintenance considerations; identify barriers and make recommendations to mitigate these barriers;

b. The CONTRACTOR shall integrate all of the results obtained from Tasks 1 through 3, herein, into a CHP Site Plan to include schematic equipment layout on-site, identifying new and existing equipment, buildings and system tie-points, and identification of major equipment selections. Detailed equipment specifications shall not be prepared. Site plan shall include a discussion and a diagram of the biogas and CHP plant processes and distribution system design and operation.

Said CHP Site Plan shall be submitted for Technical Review Committee input and ultimate COUNTY approval;

c. The CONTRACTOR shall provide for Technical Review Committee input and COUNTY approval, a description and work plan for the future tasks required to implement the project, such as financing, preliminary and detailed engineering, equipment testing, equipment installation, project start-up and operation, and ongoing equipment monitoring; and

d. The CONTRACTOR shall submit for Technical Review Committee input and COUNTY approval, a draft final economic and strategic feasibility analysis to the COUNTY.

SCS satisfied its obligations under Task 4 and issued its "Interim Report on Task 4: Final Economic and Strategic Feasibility Study," dated January 2007. A copy of that report can be found in Appendix D.

SCS/County Contract Task 5 (County/DOE Contract Task 6)

SCS/County Task 5 is titled "Draft and Final Report." The contract requires that SCS complete the following work:

a. The CONTRACTOR shall submit for COUNTY review and approval a draft final report on the project. The draft report shall include, but not be limited to, an Executive Summary, an account of the CONTRACTOR's overall efforts in meeting the requirements of this Contract by Task as well as an evaluation of the efforts, and recommendations for follow-up and future activities. The gas analysis, energy baseline report, site plans, the economic and strategic feasibility analysis, and other analyses shall be included as appendices;

b. Following acceptance of the draft report by the COUNTY, the CONTRACTOR shall provide the COUNTY with two (2) unbound copy of the Final Report, twelve (12) bound copies of the final report; two (2) electronic disk copies of the final report with the text in MS Word for Windows 6.0; two (2) Excel versions of any spreadsheets (s) developed under the project; two (2) electronic version of design and, if appropriate, two (2) copies of instructions and manuals for any relevant software.

c. Contractor shall provide one (1) copy of the entire final report and all supporting documents in PDF format.

d. Contractor shall incorporate disclaimer language in the final report as dictated by the grant funding source(s).

SCS is satisfying its Task 5 obligations with this Final Report.

SECTION 3

RECOMMENDATIONS FOR FOLLOW-UP AND FUTURE ACTIVITIES

Parties Involved in Implementation

There are three parties who could have a role in this project -- PMRF, KIUC and the County. PMRF is the energy consumer. PMRF could take responsibility for design, construction and operation of the power plant, or PMRF could assume the role of an energy customer only. If PMRF elects to continue as an energy customer only, then KIUC or the County or a private investor could design, construct and operate the project.

KIUC, being in the energy supply business, is probably the most likely candidate for project ownership, if PMRF elects not to own the project. The least role KIUC would have in the project would be that of a traditional utility, under which KIUC would provide standby power and purchase excess power. As mentioned in prior sections of this report, it may be necessary for PMRF to buy or lease some segments of KIUC power distribution lines, now owned by PMRF, that are located within PMRF.

The County is the owner of the energy resource. The likely role of the County is energy supplier to PMRF or KIUC. The County could bear the cost of wellfield installation as part of their day-to-day landfill operation, or the wellfield could be installed and operated/maintained by the energy purchaser. The County's desire or ability to enter into a sole source landfill gas sale agreement should also be determined. HRS 103D-102(b)(3) might allow the County to proceed with a sole source negotiation. If the County cannot, or desires not to, negotiate with PMRF or KIUC on a sole source basis, then the County must solicit proposals from any interested party using an advertised Request for Proposals.

As a first step in project development, PMRF, KIUC and the County should meet to discuss their potential roles in the project and execute a Memorandum of Understanding (MOU) to govern their agreed-upon relationship.

Work Plan for Future Tasks

The following steps are necessary to implement the project. The presumption has been made in this discussion that PMRF will design, finance, own and operate the facilities associated with the project, or will engage an ESCO to implement the project on their behalf. If PMRF decides to employ an ESCO, then the additional step of selecting an ESCO needs to be added as the first step in the implementation plan. If another entity implements the project, the steps will be substantially the same. The steps are as follows:

- Negotiate a landfill gas sale agreement with the County;

- Negotiate with KIUC to obtain ownership of use of a few KIUC-owned power distribution line segments in the Navy Housing area;
- Design the landfill gas wellfield, the compressor skid, the landfill gas transmission line and the CHP power plant;
- File for and obtain a Hawaii Department of Health air permit for the engines;
- Prepare other environmental documentation;
- Obtain bids for construction;
- Construct the facilities;
- Perform startup and performance testing; and
- Commence commercial operation.

Negotiate a Landfill Gas Sale Agreement

The construction and operation/maintenance costs for the project assume that PMRF will install and operate the landfill gas collection system and compressor skid. The price paid to the County for the landfill gas must take into consideration the fact that PMRF, rather than the County, paid for these facilities. An alternative approach would be for the County to install and operate these facilities, and the price paid by PMRF to the County for the landfill gas would then be expected to be higher.

While compensation to the County could take several forms, the most common forms of compensation in the landfill gas to energy business are:

- The County would be paid on a $/mmBtu basis, using an agreed-upon $/mmBtu rate and actual mmBtu consumed (on a monthly basis); or
- The County would be paid on a percent of gross revenue basis (a percentage of the value of the power produced).

The second approach would be more difficult to employ, since the value of the power produced is based on net avoided cost, plus some power sale to KIUC, as compared to 100 percent power sale to KIUC, where the actual value of the power produced would be clearly known.

Negotiate with KIUC on Power Distribution Lines

As discussed in the Interim Report on Task 3, KIUC and PMRF have mixed ownership of the power distribution lines in the Navy Housing area. Most of the power distribution lines are owned by PMRF; however, the power distribution system is incomplete without KIUC's lines.

There are five possible resolutions to this issue:

- KIUC could give the lines to PMRF;
- KIUC could sell the lines to PMRF;
- KIUC could lease the lines to PMRF;
- PMRF could install its own power distribution lines in the "missing" segments; or
- Service to the Navy Housing area could be eliminated from the project.

While elimination of the Navy Housing area will adversely impact project revenues, the impact on the project's financial viability will not be that great since a $1.23 million investment in a new power transmission line between the PMRF power plant and the Navy Housing area would be eliminated, and the power not consumed in the Navy Housing area would be sold to KIUC, albeit at a lower value.

During the discussions with KIUC about their power distribution lines in the Navy Housing area, PMRF should inquire as to whether KIUC would be willing to wheel (transmit) power from the PMRF power plant to the Navy Housing area through KIUC's existing, off-site distribution lines, and at what price KIUC would be willing to provide that service. It may be more cost-effective to pay KIUC for wheeling than to construct a $1.23 million power transmission line on-site.

Design Landfill Gas to Energy Facilities

The design of the project will be relatively straightforward since:

- With the exception of about 200 feet of pipeline, the landfill gas transmission pipeline is located on property owned by PMRF. The remaining 200 feet is on property owned by the County. The acquisition of rights-of-ways is not an obstacle to be overcome on this project; and
- The CHP power plant will use proven equipment and technologies. There are more than 200 landfill gas fired reciprocating engine power plants in operation in the United States. There are almost 100 landfill gas compressor skids and pipelines in operation in the United States.

The package of design drawings would include: flow sheets; piping and instrumentation diagrams; single line diagrams; site plans; building plans; mechanical equipment plans; piping plans; conduit and cable schedules; electrical equipment plans; conduit routing plans; and control system architecture drawings. Complete equipment and installation specifications would accompany the design drawings.

Obtain Air Permits and Other Environmental Approvals

The principal permit to be obtained for this project is an air permit from the Hawaii Department of Health (HDH). The proposed power plant will be located in an attainment area. As long as the power plant employs Best Available Control Technology (BACT), as is currently proposed, issuance of an air permit should be straightforward. If the power plant is owned by an ESCO, the ESCO would obtain its own permit.

The landfill is not currently large enough to be subject to USEPA's New Source Standards for Municipal Solid Waste Landfills (NSPS). For this reason, installation of a landfill gas collection system is optional, and a backup flare is not being installed. If the landfill becomes subject to NSPS in the future, the County will probably be required by HDH to install a backup flare.

It is believed that the need for an overall environmental review of the project can be satisfied by obtaining a negative declaration or a mitigated negative declaration. An environmental assessment, a brief summary of the project's net environmental impacts, must be prepared to support obtaining such a declaration.

Obtain Bids for Construction

Construction bids would be obtained through a formal, advertised solicitation, if PMRF owns the project, or through a less formal bidding process, if an ESCO owns the project. In either case, construction of the power plant, landfill gas transmission pipeline and compression skid, and the power transmission line improvements could be awarded to a single contractor or multiple contractors.

Construct the Facilities

Construction of the facilities would be undertaken by a contractor or contractors under the inspection of PMRF or the ESCO. Construction of a project of this type and magnitude would take about 12 months.

Startup and Performance Testing

The contractor or contractors would be responsible for achieving full mechanical completion, commissioning and full functional testing of the individual components of the project. PMRF or the ESCO would jointly conduct the performance tests with the constructor or contractors.

Commercial Operation

If the facilities were owned by PMRF, PMRF would probably engage a contractor to operate the facilities. The contract could be a new contract or could be an amendment to the contract PMRF currently has for operation of the current power plant. It is anticipated that the existing PMRF power plant would remain available to provide standby power. If the operation of the new power plant was combined with the operation of the existing PMRF power plant, it will be possible to achieve some synergy, and perhaps labor cost savings, that were not considered in the costs estimated in this report.

If an ESCO is selected to implement the project, it may be desirable to have the same ESCO assume responsibility for operating the existing PMRF power plant.

APPENDIX A

INTERIM REPORT ON TASK 1

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 1

Prepared For:

County of Kauai
Office of Economic Development
Kauai, Hawaii

Prepared By:

SCS Energy
Long Beach, California

March 2006

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TABLE OF CONTENTS

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 1

TABLE OF CONTENTS (continued...)

Tables and Figures (continued...)

Appendices

SECTION 1

INTRODUCTION

The County of Kauai Office of Economic Development engaged SCS Energy (SCS) to conduct a combined heat and power feasibility study for the Pacific Missile Range Facility (PMRF). Task 1 of the work plan for this study calls for:

- Characterization of the quality of the landfill gas in the Phase I Landfill;
- Comparison of the Phase I Landfill's landfill gas characteristics to the Phase II Landfill's landfill gas characteristics, based on information already available for the Phase II Landfill;
- Projections of recoverable landfill gas from the Phase I and Phase II Landfills;
- Preparation of design and cost estimates for landfill gas collection, landfill gas processing and landfill gas conveyance piping (to PMRF); and
- Recommendations on the fair market price of the landfill gas.

SCS's agreement with the County requires that a report on SCS's Phase I work be completed, and that a Phase I report be issued, by March 31, 2006. It is the purpose of this report to satisfy that requirement.

A report on SCS's work under subsequent tasks, authorized by the agreement, is due on October 31, 2006.

SECTION 2

LANDFILL GAS SAMPLING OF PHASE I LANDFILL

The Phase I Landfill is closed. Installation of a geomembrane cover, and a network of landfill gas vents, was completed in February 1995. Twenty-five (25) vents were installed. The location of the vents, and details on the design of the vents, can be found on construction completion drawings in Appendix A. The construction completion drawings were prepared by Harding Lawson Associates (HLA).

The vents are connected to landfill gas collection piping located immediately below the geomembrane cover. The purpose of the vents and collection piping are to prevent the buildup of gas pressure below the geomembrane. The vents extend about ten feet above the surface of the landfill. Each vent was equipped with a gas monitoring port about four feet above the base of the vent. The gas monitoring port is equipped with a lab cock type valve.

It was agreed at the outset of this study that landfill gas samples would be drawn from the vents, and that the geomembrane cover would not be disturbed.

SCS executed a landfill gas sampling and analysis program on January 10 and 11, 2006. SCS selected ten (10) spatially dispersed vents for sampling. The vents selected for sampling were numbered 2, 6, 9, 11, 14, 16, 18, 20, 21 and 23 on the HLA construction completion drawings. A drawing locating these vents can be found in Appendix A.

On the morning of January 10, SCS covered the outlets of each of the vents, with plastic bags, and sealed the outlets with duct tape. In the afternoon, SCS commenced sampling and analysis.

A siloxane sample train was installed, and placed in operation, on Vent No. 14 and on Vent No. 21 at about 2:00 p.m. and 2:15 p.m., respectively. The methanol impinger sampling method was employed. Under this method, a sample pump continuously draws a fixed flow rate of gas through two, in-series, midget impingers for a duration of at least 180 minutes. The sample train operates unattended. SCS periodically confirmed that the trains were operating properly during their 180-minute sampling runs. The sampling train on Vent No. 14 operated for 210 minutes at a flow rate of 150 ml/min, processing a gas sample volume of 31.5 liters. The sampling train on Vent No. 21 operated for 194 minutes at 150 ml/min, processing 29.1 liters. At the conclusion of the sampling runs, the methanol vials were capped and secured in packaging provided by Air Toxics, Ltd., the analytical laboratory selected for analyzing the samples.

After activating the methanol impinger sampling trains, SCS proceeded to take gas composition readings of gas drawn from the sample ports at all ten of the vents. Vent Nos. 14 and 21 were read after the methanol impinger sample train was removed. Table No. 2-2 summarizes the landfill gas composition data obtained in the field. A Landtec GEM-2000 was used to determine methane (CH_4), carbon dioxide (CO_2) and oxygen (O_2) levels. The GEM is equipped with its own internal electric drive sampling pump. Gas was drawn through the GEM-2000 until a stable reading was obtained. Prior to engaging the sampling pump, the GEM-2000 was used to measure static pressure in the vent. A Drager tube apparatus was used to take a hydrogen sulfide (H_2S) reading after the GEM-2000 sample was taken. The Drager tube uses a hand pump, and it uses a colorimetric method to determine H_2S concentration.

Field instruments such as the GEM-2000 and the Drager tube apparatus are reasonably accurate; however, they are more susceptible to interference than laboratory analyses. The GEM-2000 sometimes shows high CH_4 readings, when small quantities of higher molecular weight hydrocarbons are present. In general, the maximum methane percentage found in landfill gas is in the vicinity of 60 percent. As seen on Table No. 2-2, several vents showed very high methane percentages -- specifically, Vent Nos. 2, 9, 14 and 18. The GEM-2000 incorporates separate analyzers for CH_4, CO_2 and O_2; however, the low CO_2 readings in these vents do not corroborate the high CH_4 readings, since the internal logic of the GEM-2000 suppresses the reported CO_2 reading to prevent the three gases from reporting over 100 percent in total. In reviewing Table No. 2-2, it will be noted that $CH_4 + CO_2 + O_2$ is less than 100 percent in most cases. This is to be expected. It is assumed in the landfill gas industry that the remaining fraction is nitrogen (N_2). The source of the N_2, like the O_2, is air.

At nine (9) of the ten (10) vents, samples of landfill gas were drawn into Tedlar bags using a sample pump. A one (1) liter, a three (3) liter or a five (5) liter bag was used, depending on the type and number of laboratory analyses desired. Table No. 2-1 is a matrix which identifies the vents selected for bag samples and identifies the laboratory tests that SCS intended to run.

The standard principal gas test reports out CH_4, CO_2, O_2, N_2 and twelve other compounds which are generally not present in landfill gas. The principal gas test is a cross-check of the GEM-2000 reading. Laboratory results are more accurate than the GEM-2000 readings. The laboratory reported that the bag from Vent No. 21 appeared to have developed a leak in transit. The laboratory results from Vent No. 21 will be considered invalid.

The sulfur test is a test for nineteen sulfur bearing compounds, in addition to H_2S. Normally, hydrogen sulfide is responsible for more than 85 percent of all sulfur present in landfill gas. The laboratory test for sulfur provides a cross-check on the Drager tube apparatus results, and is used to confirm that atypical sulfur compounds are not present.

Table No. 2-3 summarizes the laboratory results for the principal gases, sulfur and siloxane. The full laboratory reports can be found in Appendix B.

The following conclusions can be reached, based on the sampling and analysis work on the Phase I Landfill:

- The average methane content of the landfill gas in the Phase I Landfill was 58 percent, based on the laboratory results. A methane content of 58 percent is typical for raw landfill gas. Two of the vents had methane contents over 60 percent. While atypical, the readings are not a cause for concern. As suspected, the GEM 2000 reported out erroneously high readings for many of the vents;

- Hydrogen sulfide is virtually not present;
- Siloxane was below limits of detection;
- NMOCs and halogenated compounds are present in very low concentrations; and
- All of the vents were under slight positive pressure.

At least some landfill gas is present in the Phase I Landfill, and it is relatively free of any compounds that could be deleterious to boilers or electric power generation equipment.

TABLE NO. 2-1
KEKAHA LANDFILL PHASE I
SAMPLING/ANALYSIS MATRIX

Vent No.	Field Work			Laboratory Work			
	GEM	Drager	Bag Sample	Principal Gases	TO-15	Sulfur	Siloxanes
2	Y	Y	Y		X		
6	Y	Y	Y	X			
9	Y	Y	Y	X	X	X	
11	Y	Y	N				
14	Y	Y	Y	X	X		X
16	Y	Y	Y	X			
18	Y	Y	Y	X	X	X	
20	Y	Y	Y		X		
21	Y	Y	Y	X	X	X	X
23	Y	Y	Y	X			

TABLE NO. 2-2
KEKAHA LANDFILL PHASE I
SUMMARY OF FIELD COLLECTED DATA

Vent No.	Time	CH_4	CO_2	O_2	H_2S (ppmv)	Pressure (in. w.c.)	Comments
2	4:40 p.m.	94.2%	5.2%	0.5%	<2	+0.070	01/10/06. Methane value suspect
6	4:25 p.m.	65.8%	29.5%	0.7%	<2	+0.050	01/10/06
9	4:45 p.m.	96.6%	2.7%	0.6%	<2	+1.150	01/10/06. Methane value suspect
11	4:55 p.m.	65.2%	26.6%	0.7%	<2	+0.000	01/10/06
14	5:15 p.m.	81.8%	17.5%	0.6%	<2	+0.200	01/10/06. Methane value suspect
16	5:05 p.m.	54.9%	24.8%	1.8%	<2	+0.180	01/10/06
18	4:05 p.m.	97.5%	2.0%	0.5%	<2	+0.125	01/10/06. Methane value suspect
20	3:55 p.m.	70.8%	23.5%	0.9%	<2	+0.065	01/10/06
21	5:25 p.m.	68.7%	24.4%	0.4%	<2	+0.002	01/10/06
23	3:38 p.m.	51.5%	24.1%	0.7%	<2	+0.022	01/10/06
14	11:00 a.m.	86.5%	12.8%	0.7%	NA	+0.110	Repeat of 01/10/06 on 01/11/06.
21	10:45 a.m.	67.3%	67.3%	2.1%	NA	+0.085	Repeat of 01/10/06 on 01/11/06.

TABLE NO. 2-3
KEKAHA LANDFILL PHASE I
LABORATORY RESULTS FOR PRINCIPAL GASES, SULFUR AND SILOXANES

Vent No.	Principal Gases (%)				Sulfur (ppm)		Siloxanes
	CH_4	CO_2	O_2	N_2	H_2S	Other	
2	-	-	-	-	-	-	-
6	60%	27%	0.9%	14%	-	-	-
9	73%	24%	0.5%	4.9%	ND	0.07	-
11	-	-	-	-	-	-	-
14	48%	20%	6.5%	27%	-	-	ND
16	56%	24%	1.6%	20%	-	-	-
18	74%	20%	0.4%	7.1%	0.07	0.05	-
20	-	-	-	-	-	-	-
21	9%	3.8%	18%	68%	ND	0.03	ND
23	37%	17%	6.9%	40%	-	-	
Average	58%	22%	2.8%	18.8%			

Notes:

1) Sample bag for Vent No. 21 was damaged during shipping. Results are impacted by dilution by air and are invalid.
2) Average excludes Vent No. 21.

SECTION 3

LANDFILL GAS SAMPLING OF PHASE II LANDFILL

The Phase II Landfill is currently open. A landfill gas sampling program was undertaken at the Phase II Landfill by Earth Tech in January/February 2005, and the results were summarized in a report prepared by Earth Tech dated March 8, 2005.

On January 26, 2005, Earth Tech installed two direct push borings in the southeastern corner of the Phase II Landfill. The borings were installed to a depth of about 30 feet below the surface of the landfill. The borings were designated DP-1 and DP-2. The principal gases, based on laboratory analysis from gas samples drawn from the borings, were as follows:

Component	DP-1	DP-2
Methane	60%	39%
Carbon Dioxide	32%	28%
Nitrogen	7.4%	26%
Oxygen	2.0%	6.9%

Earth Tech opined that the DP-2 sample had been diluted by air. SCS agrees with that opinion.

Hydrogen sulfide in DP-1 and DP-2 was 7.8 ppmv and 0.3 ppmv, respectively. Siloxanes were at non-detect levels in DP-2. DP-1 was not tested for siloxane.

The landfill gas from both DP-1 and DP-2 were analyzed for trace quantities of volatile organic compounds (VOCs) using Modified EPA Method TO-14A. Modified EPA Method TO-14A uses a target compound list and analytical methods identical to EPA Method TO-15 (the method employed by SCS). Based on the chlorine and fluorine present in the compounds actually detected, the concentration of halogenated compounds is well below levels of concern to landfill gas to energy equipment.

SCS and Earth Tech used the same laboratory, Air Toxics, Ltd. of Folsom, California, for all of their analytical work.

The analytical work undertaken on the Phase II Landfill was very limited, and may not be representative of the entire refuse mass in the Phase II Landfill. The Phase II analytical shows:

- A methane percentage consistent with what would be expected for a landfill with active anaerobic decomposition of waste, with no evidence of aerobic decomposition;
- A landfill gas with very low H_2S levels;

- A landfill gas with low halogenated compound content; and
- A landfill gas with low siloxane content.

While SCS feels that a more comprehensive sampling program on the Phase II Landfill might produce higher H_2S, halogen and siloxane levels, it is unlikely that these parameters would prove to be greater than those for a typical active landfill.

Based on available information, for the Phase II Landfill, the landfill gas is relatively free from any compounds that could be deleterious to boilers or electric power generation equipment. The same conclusion was reached, in Section 2, about the landfill gas from the Phase I Landfill.

SECTION 4

LANDFILL GAS RECOVERY PROJECTION

Waste Filling History and Future Projection

The two most important factors affecting landfill gas generation are: 1) the tons of waste in place; and 2) the age of the waste. In order to run a landfill gas generation model, it is necessary to have, or to reconstruct, a waste disposal history and to make a future waste disposal projection.

The Kekaha Landfill consists of two phases. Phase I is a closed site. Phase II is currently open. The County estimates that a total of 601,000 tons of waste were disposed of in Phase I. The estimate is based on work undertaken when the Closure/Post-Closure Plan for Phase I was prepared. The estimate was based on a volumetric determination of the refuse mass, plus assumptions on in-place waste density. The number of tons disposed of in Phase I in any particular year is not known. Phase I operated from 1953 to October 8, 1993. A reconstruction of Phase I's waste disposal history was made by SCS and the result of that reconstruction is summarized on Table No. 4-1. Key assumptions and clarifications on Table No. 4-1 are as follows:

- The County accounts for waste disposal on an operating year basis, rather than on a calendar year basis. The operating year is July through June. Hence, the waste tonnage shown on Table No. 4-1 for 1994 is actually waste disposed of in July 1993 through October 1993;
- The annual waste tonnages for 1994 forward is actually known for Phase II. There was a surge in waste disposal after Hurricane Iniki (September 11, 1992). A pre-hurricane waste disposal rate of 50,000 tons per year seems reasonable, given the return to non-hurricane impacted waste disposal rates in subsequent years;
- Waste disposal rates were arbitrarily decreased (generally about ten percent per year) from 1992 backward until the 601,000 tons were exhausted. The waste was exhausted in 1970; and
- While the above is inconsistent with the statement that the landfill was open since 1953, it is doubtful that much pre-1970 waste would have contributed to the landfill volume calculated for the Closure/Post-Closure Plan.

The waste placement reconstruction on Table No. 4-1 is certainly not accurate, but is an acceptable estimate for purposes of modeling landfill gas generation at this site. The quantity of landfill gas generated by Phase I is significantly less than that from Phase II, and the quantity is declining each year. Any error in the Phase I landfill gas generation projection becomes increasingly less important each year.

The County supplied SCS with actual waste disposal tonnages at the Phase II Landfill through June 2005. Those tonnages are shown on Table No. 4-2. The currently permitted capacity of Phase II, including the recently improved vertical expansion to 85 feet MSL, is 1,467,260 tons. SCS escalated the 2005 waste disposal rate by 3.5 percent per year, resulting in a forecasted closure year of 2009. The County concurs that 2009 is the likely closure year.

After Phase II is filled, the County hopes to secure approval of at least one horizontal expansion. Table No. 4-3 continues to escalate the waste disposal rate at 3.5 percent per year, and presumes that the expansion area will be open for seven years through 2016. An expansion beyond 2016 is more speculative than the expansion in 2009. Expansions beyond 2016 will not be considered herein, but they are possible.

Table No. 4-4 aggregates Phases I and II and Table No. 4-5 aggregates Phases I, II and III.

Landfill Gas Collection System Coverage

Projecting landfill gas collection system coverage is an important aspect of landfill gas recovery modeling. For purposes of a landfill gas to energy (LFGE) project, the quantity of landfill gas generated is irrelevant. The quantity of landfill gas which is actually recovered is what is important. When a landfill is active, it is difficult to maximize landfill gas recovery due to conflicts with ongoing waste disposal. The following assumptions were made with respect to wellfield coverage:

- Phase I can immediately achieve 100 percent coverage when the landfill gas collection system is installed. The assumed installation year is 2007;
- Phase II can achieve 70 percent coverage in 2007 through the installation of landfill gas extraction wells on the bench road around the landfill, and perhaps a few top deck wells. Wellfield coverage will increase to 100 percent in 2010, after closure, through the installation of the remaining top deck wells; and
- Phase III will begin with 70 percent coverage shortly after it opens, and will reach 100 percent coverage after closure. A wellfield plan will not be laid out for Phase III since the physical configuration of Phase III is currently unknown. Horizontal collectors will probably be used in Phase III to temporarily allow landfill gas to be collected contemporaneously with waste filling. Vertical extraction wells would probably be installed after closure.

Table Nos. 4-1 through 4-5 reflect the above assumptions.

Landfill Gas Recovery Projection

SCS employs a first-order landfill gas recovery model which uses the same algorithm as USEPA's LandGEM Model. SCS's model differs from the USEPA model in two ways:

1) SCS projects recoverable landfill gas, rather than landfill gas generation. It predicts how much landfill gas can be recovered at a landfill if a comprehensive, well-operated landfill gas collection system was in place; and
2) SCS uses its own model coefficients (L_o and k), rather than using the USEPA default values. SCS's coefficients were derived, and continue to be refined, using a database of 170 operating landfill gas collection systems, which represent over 1,000 years of data.

For the Kekaha Landfill, SCS has selected a k of 0.038 and an L_o of 2,800 ft^3/ton. The coefficient k determines the rate of decline in landfill gas production. The coefficient L_o is the ultimate generation rate. It indicates the maximum long-term yield of recoverable landfill gas per ton of waste.

Table Nos. 4-1 through 4-5 and Figure No. 4-1 summarize SCS's projection of recoverable landfill gas for Kekaha Landfill. Initial landfill gas recovery is expected to be 400 scfm, gradually increasing to over 700 scfm at closure. A flow of 400 scfm at 50 percent methane is equivalent to 12.0 mmBtu/hr, and could support about 1,100 kW of electric power production capacity.

TABLE NO. 4-1
LFG RECOVERY PROJECTION -- PHASE I AREA
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	(mmcf/day)	(mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	(mmcf/day)	(mmBtu/yr)
1970	4,300	4,300	0	0.00	0	0%	0	0.00	0
1971	4,800	9,100	2	0.00	463	0%	0	0.00	0
1972	5,300	14,400	4	0.01	963	0%	0	0.00	0
1973	5,900	20,300	6	0.01	1,497	0%	0	0.00	0
1974	6,500	26,800	8	0.01	2,077	0%	0	0.00	0
1975	7,000	33,800	10	0.01	2,699	0%	0	0.00	0
1976	8,000	41,800	13	0.02	3,352	0%	0	0.00	0
1977	9,000	50,800	15	0.02	4,089	0%	0	0.00	0
1978	10,000	60,800	18	0.03	4,905	0%	0	0.00	0
1979	11,000	71,800	22	0.03	5,799	0%	0	0.00	0
1980	12,200	84,000	25	0.04	6,768	0%	0	0.00	0
1981	13,600	97,600	29	0.04	7,829	0%	0	0.00	0
1982	15,100	112,700	34	0.05	9,001	0%	0	0.00	0
1983	16,800	129,500	39	0.06	10,292	0%	0	0.00	0
1984	18,600	148,100	44	0.06	11,717	0%	0	0.00	0
1985	20,700	168,800	50	0.07	13,283	0%	0	0.00	0
1986	23,000	191,800	56	0.08	15,016	0%	0	0.00	0
1987	25,600	217,400	64	0.09	16,933	0%	0	0.00	0
1988	28,400	245,800	72	0.10	19,058	0%	0	0.00	0
1989	32,000	277,800	80	0.12	21,406	0%	0	0.00	0
1990	35,000	312,800	90	0.13	24,053	0%	0	0.00	0
1991	45,000	357,800	101	0.15	26,925	0%	0	0.00	0
1992	50,000	407,800	116	0.17	30,766	0%	0	0.00	0
1993	150,000	557,800	132	0.19	35,003	0%	0	0.00	0
1994	43,200	601,000	187	0.27	49,849	0%	0	0.00	0
1995	0	601,000	198	0.29	52,642	0%	0	0.00	0
1996	0	601,000	191	0.27	50,679	0%	0	0.00	0
1997	0	601,000	183	0.26	48,790	0%	0	0.00	0
1998	0	601,000	177	0.25	46,971	0%	0	0.00	0
1999	0	601,000	170	0.24	45,219	0%	0	0.00	0
2000	0	601,000	164	0.24	43,533	0%	0	0.00	0
2001	0	601,000	158	0.23	41,910	0%	0	0.00	0
2002	0	601,000	152	0.22	40,347	0%	0	0.00	0
2003	0	601,000	146	0.21	38,843	0%	0	0.00	0
2004	0	601,000	141	0.20	37,394	0%	0	0.00	0
2005	0	601,000	135	0.19	36,000	0%	0	0.00	0
2006	0	601,000	130	0.19	34,658	0%	0	0.00	0
2007	0	601,000	125	0.18	33,365	100%	125	0.18	33,365

TABLE NO. 4-1 (continued...)
LFG RECOVERY PROJECTION -- PHASE I AREA
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	LFG Recovery Potential (mmcf/day)	LFG Recovery Potential (mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	LFG Recovery from Planned System (mmcf/day)	LFG Recovery from Planned System (mmBtu/yr)
2008	0	601,000	121	0.17	32,121	100%	121	0.17	32,121
2009	0	601,000	116	0.17	30,924	100%	116	0.17	30,924
2010	0	601,000	112	0.16	29,771	100%	112	0.16	29,771
2011	0	601,000	108	0.16	28,661	100%	108	0.16	28,661
2012	0	601,000	104	0.15	27,592	100%	104	0.15	27,592
2013	0	601,000	100	0.14	26,563	100%	100	0.14	26,563
2014	0	601,000	96	0.14	25,573	100%	96	0.14	25,573
2015	0	601,000	93	0.13	24,619	100%	93	0.13	24,619
2016	0	601,000	89	0.13	23,701	100%	89	0.13	23,701
2017	0	601,000	86	0.12	22,817	100%	86	0.12	22,817
2018	0	601,000	83	0.12	21,967	100%	83	0.12	21,967
2019	0	601,000	80	0.11	21,147	100%	80	0.11	21,147
2020	0	601,000	77	0.11	20,359	100%	77	0.11	20,359
2021	0	601,000	74	0.11	19,600	100%	74	0.11	19,600
2022	0	601,000	71	0.10	18,869	100%	71	0.10	18,869
2023	0	601,000	68	0.10	18,165	100%	68	0.10	18,165
2024	0	601,000	66	0.09	17,488	100%	66	0.09	17,488
2025	0	601,000	63	0.09	16,836	100%	63	0.09	16,836
2026	0	601,000	61	0.09	16,208	100%	61	0.09	16,208
2027	0	601,000	59	0.08	15,604	100%	59	0.08	15,604
2028	0	601,000	56	0.08	15,022	100%	56	0.08	15,022
2029	0	601,000	54	0.08	14,462	100%	54	0.08	14,462
2030	0	601,000	52	0.08	13,923	100%	52	0.08	13,923

Methane Content of LFG Adjusted to:	50%	
Selected Decay Rate Constant (k):	0.0380	
Selected Ultimate Methane Recovery Rate (Lo):	2,800	cu ft/ton

TABLE NO. 4-2
LFG RECOVERY PROJECTION -- PHASE II AREA
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	LFG Recovery Potential (mmcf/day)	LFG Recovery Potential (mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	LFG Recovery from Planned System (mmcf/day)	LFG Recovery from Planned System (mmBtu/yr)
1994	85,600	85,600	0	0.00	0	0%	0	0.00	0
1995	125,700	211,300	35	0.05	9,217	0%	0	0.00	0
1996	216,700	428,000	84	0.12	22,408	0%	0	0.00	0
1997	93,300	521,300	169	0.24	44,906	0%	0	0.00	0
1998	64,300	585,600	200	0.29	53,278	0%	0	0.00	0
1999	67,600	653,200	219	0.32	58,215	0%	0	0.00	0
2000	72,800	726,000	238	0.34	63,324	0%	0	0.00	0
2001	77,200	803,200	259	0.37	68,801	0%	0	0.00	0
2002	74,700	877,900	280	0.40	74,549	0%	0	0.00	0
2003	81,100	959,000	300	0.43	79,812	0%	0	0.00	0
2004	86,500	1,045,500	322	0.46	85,569	0%	0	0.00	0
2005	89,200	1,134,700	345	0.50	91,692	0%	0	0.00	0
2006	92,320	1,227,020	368	0.53	97,878	0%	0	0.00	0
2007	95,550	1,322,570	392	0.56	104,169	70%	274	0.39	72,919
2008	98,890	1,421,460	416	0.60	110,574	70%	291	0.42	77,402
2009	45,800	1,467,260	440	0.63	117,099	70%	308	0.44	81,969
2010	0	1,467,260	442	0.64	117,664	100%	442	0.64	117,664
2011	0	1,467,260	426	0.61	113,277	100%	426	0.61	113,277
2012	0	1,467,260	410	0.59	109,053	100%	410	0.59	109,053
2013	0	1,467,260	395	0.57	104,987	100%	395	0.57	104,987
2014	0	1,467,260	380	0.55	101,072	100%	380	0.55	101,072
2015	0	1,467,260	366	0.53	97,303	100%	366	0.53	97,303
2016	0	1,467,260	352	0.51	93,675	100%	352	0.51	93,675
2017	0	1,467,260	339	0.49	90,182	100%	339	0.49	90,182
2018	0	1,467,260	326	0.47	86,820	100%	326	0.47	86,820
2019	0	1,467,260	314	0.45	83,583	100%	314	0.45	83,583
2020	0	1,467,260	303	0.44	80,466	100%	303	0.44	80,466
2021	0	1,467,260	291	0.42	77,466	100%	291	0.42	77,466
2022	0	1,467,260	280	0.40	74,577	100%	280	0.40	74,577
2023	0	1,467,260	270	0.39	71,796	100%	270	0.39	71,796
2024	0	1,467,260	260	0.37	69,119	100%	260	0.37	69,119
2025	0	1,467,260	250	0.36	66,542	100%	250	0.36	66,542
2026	0	1,467,260	241	0.35	64,061	100%	241	0.35	64,061
2027	0	1,467,260	232	0.33	61,672	100%	232	0.33	61,672
2028	0	1,467,260	223	0.32	59,373	100%	223	0.32	59,373
2029	0	1,467,260	215	0.31	57,159	100%	215	0.31	57,159
2030	0	1,467,260	207	0.30	55,028	100%	207	0.30	55,028

Methane Content of LFG Adjusted to:	50%	
Selected Decay Rate Constant (k):	0.0380	
Selected Ultimate Methane Recovery Rate (Lo):	2,800	cu ft/ton

TABLE NO. 4-3
LFG RECOVERY PROJECTION -- PHASE III AREA
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential			LFG System Coverage (%)	LFG Recovery from Planned System		
			(scfm)	(mmcf/day)	(mmBtu/yr)		(scfm)	(mmcf/day)	(mmBtu/yr)
2009	56,550	56,550	0	0.00	0	0%	0	0.00	0
2010	105,930	162,480	23	0.03	6,089	70%	16	0.02	4,262
2011	109,640	272,120	65	0.09	17,268	70%	45	0.07	12,088
2012	113,480	385,600	107	0.15	28,430	70%	75	0.11	19,901
2013	117,450	503,050	149	0.21	39,589	70%	104	0.15	27,712
2014	121,560	624,610	191	0.27	50,760	70%	134	0.19	35,532
2015	125,810	750,420	233	0.34	61,956	70%	163	0.23	43,369
2016	130,210	880,630	275	0.40	73,193	70%	193	0.28	51,235
2017	0	880,630	318	0.46	84,484	100%	318	0.46	84,484
2018	0	880,630	306	0.44	81,334	100%	306	0.44	81,334
2019	0	880,630	294	0.42	78,301	100%	294	0.42	78,301
2020	0	880,630	283	0.41	75,382	100%	283	0.41	75,382
2021	0	880,630	273	0.39	72,571	100%	273	0.39	72,571
2022	0	880,630	263	0.38	69,865	100%	263	0.38	69,865
2023	0	880,630	253	0.36	67,260	100%	253	0.36	67,260
2024	0	880,630	243	0.35	64,752	100%	243	0.35	64,752
2025	0	880,630	234	0.34	62,338	100%	234	0.34	62,338
2026	0	880,630	226	0.32	60,013	100%	226	0.32	60,013
2027	0	880,630	217	0.31	57,776	100%	217	0.31	57,776
2028	0	880,630	209	0.30	55,621	100%	209	0.30	55,621
2029	0	880,630	201	0.29	53,547	100%	201	0.29	53,547
2030	0	880,630	194	0.28	51,551	100%	194	0.28	51,551

Methane Content of LFG Adjusted to:	50%	
Selected Decay Rate Constant (k):	0.0380	
Selected Ultimate Methane Recovery Rate (Lo):	2,800	cu ft/ton

TABLE NO. 4-4
LFG RECOVERY PROJECTION -- PHASES I AND II COMBINED
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	LFG Recovery Potential (mmcf/day)	LFG Recovery Potential (mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	LFG Recovery from Planned System (mmcf/day)	LFG Recovery from Planned System (mmBtu/yr)
1970	4,300	4,300	0	0.00	0	0%	0	0.00	0
1971	4,800	9,100	2	0.00	463	0%	0	0.00	0
1972	5,300	14,400	4	0.01	963	0%	0	0.00	0
1973	5,900	20,300	6	0.01	1,497	0%	0	0.00	0
1974	6,500	26,800	8	0.01	2,077	0%	0	0.00	0
1975	7,000	33,800	10	0.01	2,699	0%	0	0.00	0
1976	8,000	41,800	13	0.02	3,352	0%	0	0.00	0
1977	9,000	50,800	15	0.02	4,089	0%	0	0.00	0
1978	10,000	60,800	18	0.03	4,905	0%	0	0.00	0
1979	11,000	71,800	22	0.03	5,799	0%	0	0.00	0
1980	12,200	84,000	25	0.04	6,768	0%	0	0.00	0
1981	13,600	97,600	29	0.04	7,829	0%	0	0.00	0
1982	15,100	112,700	34	0.05	9,001	0%	0	0.00	0
1983	16,800	129,500	39	0.06	10,292	0%	0	0.00	0
1984	18,600	148,100	44	0.06	11,717	0%	0	0.00	0
1985	20,700	168,800	50	0.07	13,283	0%	0	0.00	0
1986	23,000	191,800	56	0.08	15,016	0%	0	0.00	0
1987	25,600	217,400	64	0.09	16,933	0%	0	0.00	0
1988	28,400	245,800	72	0.10	19,058	0%	0	0.00	0
1989	32,000	277,800	80	0.12	21,406	0%	0	0.00	0
1990	35,000	312,800	90	0.13	24,053	0%	0	0.00	0
1991	45,000	357,800	101	0.15	26,925	0%	0	0.00	0
1992	50,000	407,800	116	0.17	30,766	0%	0	0.00	0
1993	150,000	557,800	132	0.19	35,003	0%	0	0.00	0
1994	128,800	686,600	187	0.27	49,849	0%	0	0.00	0
1995	125,700	812,300	233	0.33	61,859	0%	0	0.00	0
1996	216,700	1,029,000	275	0.40	73,088	0%	0	0.00	0
1997	93,300	1,122,300	352	0.51	93,696	0%	0	0.00	0
1998	64,300	1,186,600	377	0.54	100,249	0%	0	0.00	0
1999	67,600	1,254,200	389	0.56	103,434	0%	0	0.00	0
2000	72,800	1,327,000	402	0.58	106,857	0%	0	0.00	0
2001	77,200	1,404,200	416	0.60	110,711	0%	0	0.00	0
2002	74,700	1,478,900	432	0.62	114,896	0%	0	0.00	0
2003	81,100	1,560,000	446	0.64	118,655	0%	0	0.00	0
2004	86,500	1,646,500	462	0.67	122,963	0%	0	0.00	0
2005	89,200	1,735,700	480	0.69	127,692	0%	0	0.00	0
2006	92,320	1,828,020	498	0.72	132,536	0%	0	0.00	0
2007	95,550	1,923,570	517	0.74	137,535	77%	400	0.58	106,284
2008	98,890	2,022,460	537	0.77	142,695	77%	412	0.59	109,523
2009	45,800	2,068,260	557	0.80	148,022	76%	424	0.61	112,893

TABLE NO. 4-4 (continued...)
LFG RECOVERY PROJECTION -- PHASES I AND II COMBINED
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential			LFG System Coverage (%)	LFG Recovery from Planned System		
			(scfm)	(mmcf/day)	(mmBtu/yr)		(scfm)	(mmcf/day)	(mmBtu/yr)
2010	0	2,068,260	554	0.80	147,435	100%	554	0.80	147,435
2011	0	2,068,260	534	0.77	141,937	100%	534	0.77	141,937
2012	0	2,068,260	514	0.74	136,645	100%	514	0.74	136,645
2013	0	2,068,260	495	0.71	131,550	100%	495	0.71	131,550
2014	0	2,068,260	476	0.69	126,645	100%	476	0.69	126,645
2015	0	2,068,260	458	0.66	121,923	100%	458	0.66	121,923
2016	0	2,068,260	441	0.64	117,376	100%	441	0.64	117,376
2017	0	2,068,260	425	0.61	113,000	100%	425	0.61	113,000
2018	0	2,068,260	409	0.59	108,786	100%	409	0.59	108,786
2019	0	2,068,260	394	0.57	104,730	100%	394	0.57	104,730
2020	0	2,068,260	379	0.55	100,825	100%	379	0.55	100,825
2021	0	2,068,260	365	0.53	97,065	100%	365	0.53	97,065
2022	0	2,068,260	351	0.51	93,446	100%	351	0.51	93,446
2023	0	2,068,260	338	0.49	89,962	100%	338	0.49	89,962
2024	0	2,068,260	326	0.47	86,607	100%	326	0.47	86,607
2025	0	2,068,260	314	0.45	83,378	100%	314	0.45	83,378
2026	0	2,068,260	302	0.43	80,269	100%	302	0.43	80,269
2027	0	2,068,260	291	0.42	77,276	100%	291	0.42	77,276
2028	0	2,068,260	280	0.40	74,395	100%	280	0.40	74,395
2029	0	2,068,260	269	0.39	71,621	100%	269	0.39	71,621
2030	0	2,068,260	259	0.37	68,950	100%	259	0.37	68,950

Methane Content of LFG Adjusted to:	50%	
Selected Decay Rate Constant (k):	0.0380	
Selected Ultimate Methane Recovery Rate (Lo):	2,800	cu ft/ton

TABLE NO. 4-5
LFG RECOVERY PROJECTION -- PHASES I - III COMBINED
KEKAHA LANDFILL, KAUAI, HAWAII

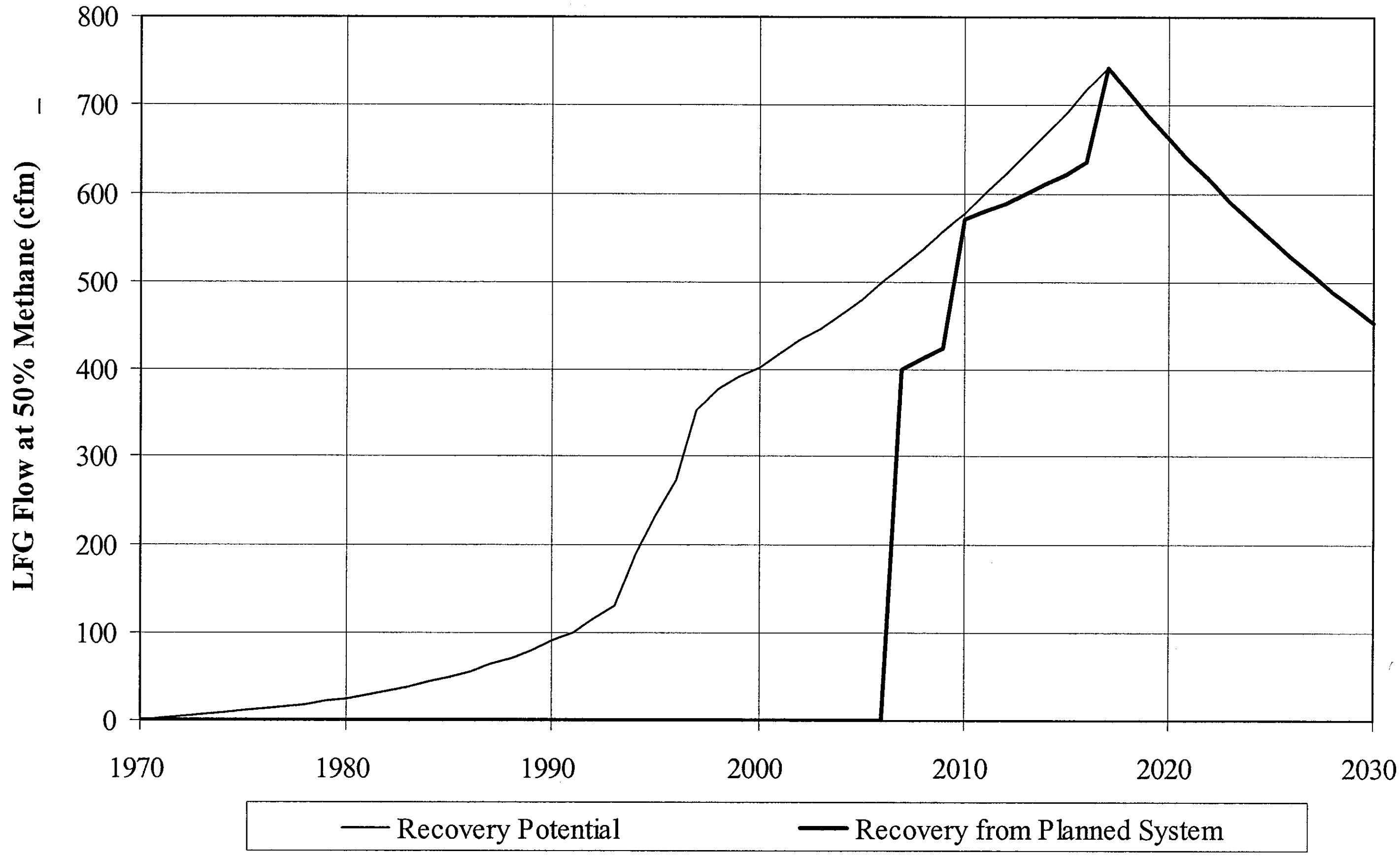
Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	LFG Recovery Potential (mmcf/day)	LFG Recovery Potential (mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	LFG Recovery from Planned System (mmcf/day)	LFG Recovery from Planned System (mmBtu/yr)
1970	4,300	4,300	0	0.00	0	0%	0	0.00	0
1971	4,800	9,100	2	0.00	463	0%	0	0.00	0
1972	5,300	14,400	4	0.01	963	0%	0	0.00	0
1973	5,900	20,300	6	0.01	1,497	0%	0	0.00	0
1974	6,500	26,800	8	0.01	2,077	0%	0	0.00	0
1975	7,000	33,800	10	0.01	2,699	0%	0	0.00	0
1976	8,000	41,800	13	0.02	3,352	0%	0	0.00	0
1977	9,000	50,800	15	0.02	4,089	0%	0	0.00	0
1978	10,000	60,800	18	0.03	4,905	0%	0	0.00	0
1979	11,000	71,800	22	0.03	5,799	0%	0	0.00	0
1980	12,200	84,000	25	0.04	6,768	0%	0	0.00	0
1981	13,600	97,600	29	0.04	7,829	0%	0	0.00	0
1982	15,100	112,700	34	0.05	9,001	0%	0	0.00	0
1983	16,800	129,500	39	0.06	10,292	0%	0	0.00	0
1984	18,600	148,100	44	0.06	11,717	0%	0	0.00	0
1985	20,700	168,800	50	0.07	13,283	0%	0	0.00	0
1986	23,000	191,800	56	0.08	15,016	0%	0	0.00	0
1987	25,600	217,400	64	0.09	16,933	0%	0	0.00	0
1988	28,400	245,800	72	0.10	19,058	0%	0	0.00	0
1989	32,000	277,800	80	0.12	21,406	0%	0	0.00	0
1990	35,000	312,800	90	0.13	24,053	0%	0	0.00	0
1991	45,000	357,800	101	0.15	26,925	0%	0	0.00	0
1992	50,000	407,800	116	0.17	30,766	0%	0	0.00	0
1993	150,000	557,800	132	0.19	35,003	0%	0	0.00	0
1994	128,800	686,600	187	0.27	49,849	0%	0	0.00	0
1995	125,700	812,300	233	0.33	61,859	0%	0	0.00	0
1996	216,700	1,029,000	275	0.40	73,088	0%	0	0.00	0
1997	93,300	1,122,300	352	0.51	93,696	0%	0	0.00	0
1998	64,300	1,186,600	377	0.54	100,249	0%	0	0.00	0
1999	67,600	1,254,200	389	0.56	103,434	0%	0	0.00	0
2000	72,800	1,327,000	402	0.58	106,857	0%	0	0.00	0
2001	77,200	1,404,200	416	0.60	110,711	0%	0	0.00	0
2002	74,700	1,478,900	432	0.62	114,896	0%	0	0.00	0
2003	81,100	1,560,000	446	0.64	118,655	0%	0	0.00	0
2004	86,500	1,646,500	462	0.67	122,963	0%	0	0.00	0
2005	89,200	1,735,700	480	0.69	127,692	0%	0	0.00	0
2006	92,320	1,828,020	498	0.72	132,536	0%	0	0.00	0
2007	95,550	1,923,570	517	0.74	137,535	77%	400	0.58	106,284
2008	98,890	2,022,460	537	0.77	142,695	77%	412	0.59	109,523
2009	102,350	2,124,810	557	0.80	148,022	76%	424	0.61	112,893

TABLE NO. 4-5 (continued…)
LFG RECOVERY PROJECTION -- PHASES I - III COMBINED
KEKAHA LANDFILL, KAUAI, HAWAII

Year	Disposal Rate (tons/yr)	Refuse In-Place (tons)	LFG Recovery Potential (scfm)	LFG Recovery Potential (mmcf/day)	LFG Recovery Potential (mmBtu/yr)	LFG System Coverage (%)	LFG Recovery from Planned System (scfm)	LFG Recovery from Planned System (mmcf/day)	LFG Recovery from Planned System (mmBtu/yr)
2010	105,930	2,230,740	577	0.83	153,524	99%	570	0.82	151,697
2011	109,640	2,340,380	599	0.86	159,206	97%	579	0.83	154,025
2012	113,480	2,453,860	621	0.89	165,075	95%	589	0.85	156,546
2013	117,450	2,571,310	643	0.93	171,139	93%	599	0.86	159,262
2014	121,560	2,692,870	667	0.96	177,404	91%	610	0.88	162,176
2015	125,810	2,818,680	691	1.00	183,879	90%	622	0.89	165,292
2016	130,210	2,948,890	717	1.03	190,569	88%	634	0.91	168,611
2017	0	2,948,890	743	1.07	197,484	100%	743	1.07	197,484
2018	0	2,948,890	715	1.03	190,120	100%	715	1.03	190,120
2019	0	2,948,890	688	0.99	183,031	100%	688	0.99	183,031
2020	0	2,948,890	663	0.95	176,207	100%	663	0.95	176,207
2021	0	2,948,890	638	0.92	169,636	100%	638	0.92	169,636
2022	0	2,948,890	614	0.88	163,311	100%	614	0.88	163,311
2023	0	2,948,890	591	0.85	157,222	100%	591	0.85	157,222
2024	0	2,948,890	569	0.82	151,359	100%	569	0.82	151,359
2025	0	2,948,890	548	0.79	145,716	100%	548	0.79	145,716
2026	0	2,948,890	527	0.76	140,282	100%	527	0.76	140,282
2027	0	2,948,890	508	0.73	135,052	100%	508	0.73	135,052
2028	0	2,948,890	489	0.70	130,016	100%	489	0.70	130,016
2029	0	2,948,890	471	0.68	125,168	100%	471	0.68	125,168
2030	0	2,948,890	453	0.65	120,501	100%	453	0.65	120,501

Methane Content of LFG Adjusted to:	50%	
Selected Decay Rate Constant (k):	0.0380	
Selected Ultimate Methane Recovery Rate (Lo):	2,800	cu ft/ton

FIGURE NO. 4-1
LFG RECOVERY PROJECTION
KEKAHA LANDFILL, KAUAI, HAWAII



SECTION 5

LANDFILL GAS COLLECTION SYSTEM

Figure No. 5-1 presents a preliminary wellfield plan for Phase I. Nine vertical extraction wells would be installed. The average depth of the wells would be 30 feet deep. The well casings would be equipped with a geomembrane apron which would be welded to the existing geomembrane cover to preserve the existing watertight and airtight cover. The existing vents would remain, but would be capped. It is expected that the vacuum generated by the landfill gas extraction wells will have a large area of influence and prevent positive pressures from building up under the cover. If a positive pressure remains at any vent, that vent can be connected to the nearest landfill gas collection pipe via a small diameter pipe.

The landfill gas collection piping would be located on the surface of the landfill and could be HDPE or PVC pipe. The diameter of the pipe would be four inches in diameter throughout Phase I. A 4-inch diameter tie line to Phase II would also be installed.

Figure No. 5-2 presents a preliminary wellfield plan for Phase II. Thirty vertical extraction wells would be installed. The bench road wells would average 35 feet deep. The top deck wells would average 60 feet deep.

The landfill gas collection piping would be HDPE or PVC pipe. The bench road piping would vary from eight inches to six inches in diameter. The lateral lines would be four inches in size.

A budget cost estimate for the landfill gas collection system can be found on Table No. 5-1. The budget cost estimate of $449,100 includes engineering, permitting, materials and installation for a distribution system from the Phase I and Phase II landfill's gas sources to the landfill property line.

TABLE NO. 5-1
BUDGET COST ESTIMATE FOR
PHASE I AND PHASE II
LANDFILL GAS COLLECTION SYSTEM

Component	Quantity	Unit Price	Extended Price
Wellheads	39	$600	$23,400
Well Aprons	9	$400	$3,600
Extraction Wells	2,310 feet	$90	$207,900
4-inch LFG Pipe	5,700 feet	$8	$45,600
6-inch LFG Pipe	1,900 feet	$10	$19,000
8-inch LFG Pipe	1,700 feet	$12	$20,400
Condensate Sumps	3	$12,000	$36,000
2-inch Condensate Pipe	2,800 feet	$3	$8,400
2-inch Air Pipe	2,800 feet	$3	$8,400
6-inch Transmission Line	200 feet	$32	$6,400
		Subtotal	**$379,100**
		Engineering	$30,000
		Contingency	$40,000
		Grand Total	**$449,100**

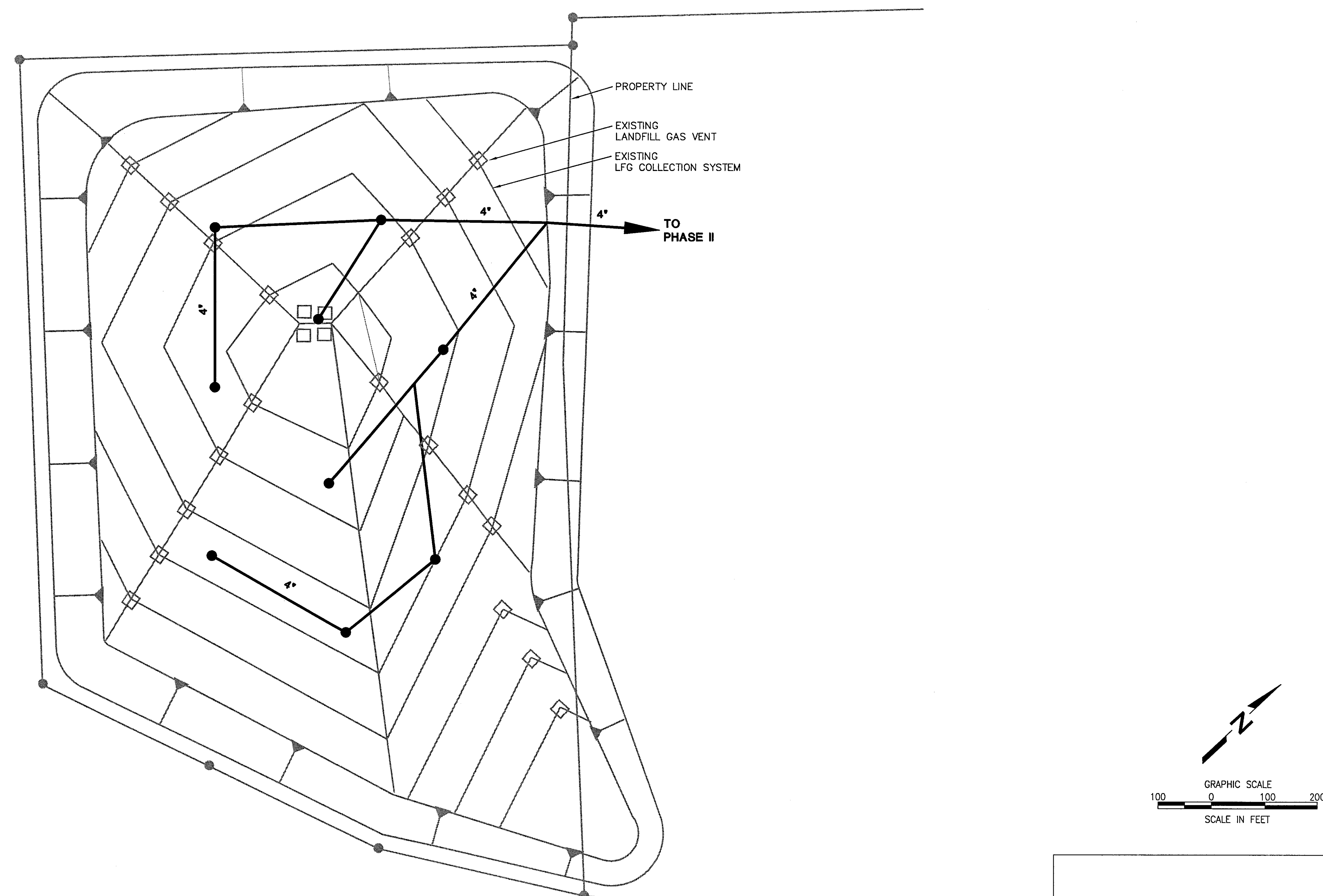


FIGURE 5-1

KEHAHA LANDFILL PHASE I
PROPOSED LANDFILL GAS COLLECTION SYSTEM

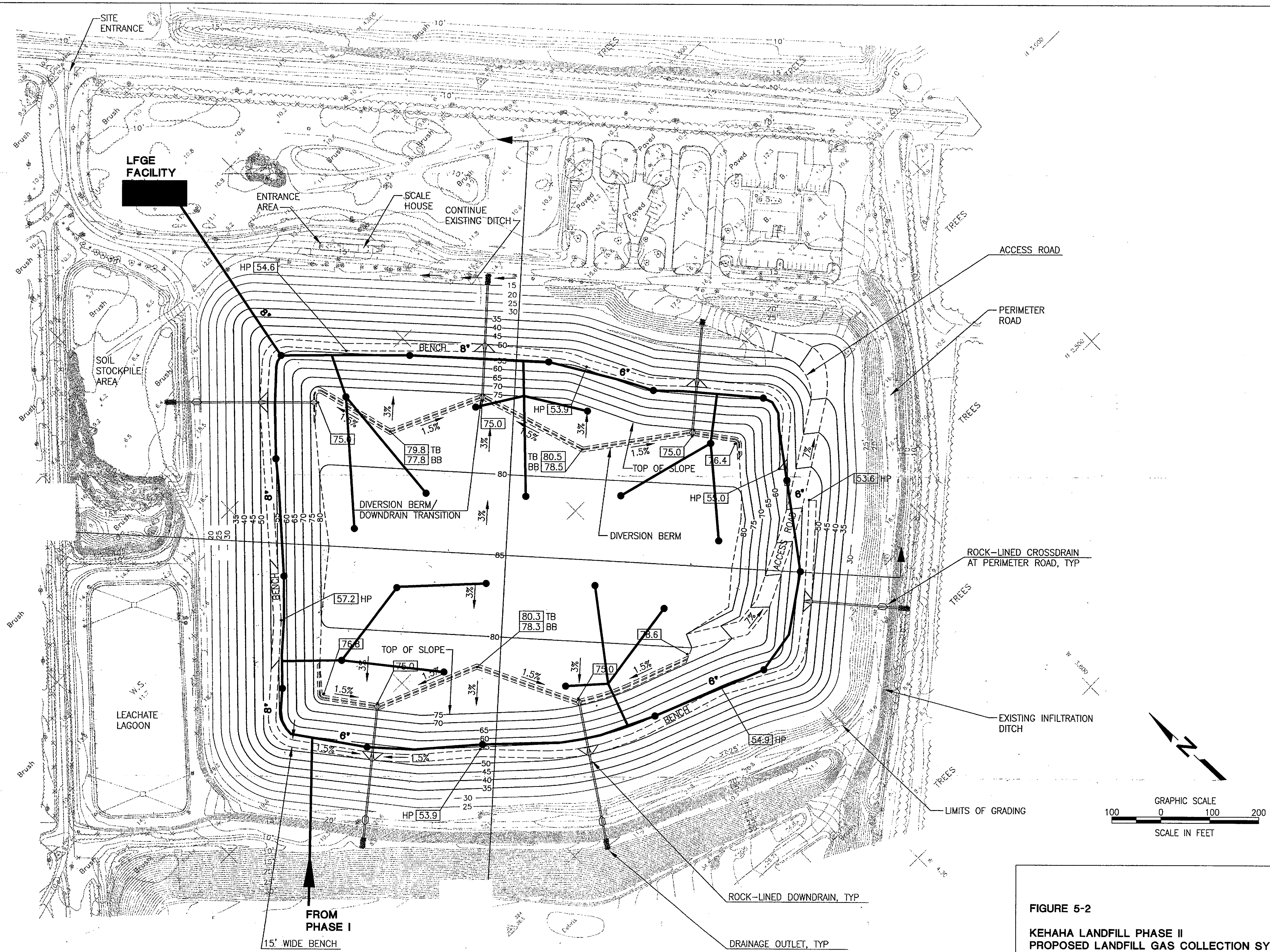


FIGURE 5-2

KEHAHA LANDFILL PHASE II
PROPOSED LANDFILL GAS COLLECTION SYSTEM

SECTION 6

LANDFILL GAS PROCESSING AND CONVEYANCE

As determined in Section 4, landfill gas recovery will vary from as low as 400 scfm to as high as 740 scfm. A maximum sustained recovery rate of 600 scfm (on a ten-year average basis) is expected. The distance to the power plant at PMRF is about 20,400 feet (3.9 miles). A 6-inch diameter, below-grade, HDPE pipe, operating at 80 psig at the landfill, would be employed to handle up to 600 scfm. The budget cost estimate for the landfill gas transmission line from the Kekaha Landfill property line to the existing PMRF power plant is $714,000. The budget cost for the landfill gas transmission line includes engineering, permitting, materials and installation. With respect to permitting, it has been assumed that National Environmental Policy Act (NEPA) requirements would be addressed by a NEPA category exclusion.

Landfill gas processing would be limited to compression, chilling to 45° F and reheating. A 600 scfm landfill gas processing skid would cost about $495,000 installed. The skid could be located in front of Phase II as shown on Figure No. 5-2, or at any other location which would not conflict with future horizontal expansions. Table No. 6-1 provides a budget cost estimate for the landfill gas processing skid.

For a reciprocating engine or boiler end use (at the end of pipeline) project, it will not be necessary to provide additional landfill gas treatment. In the case of reciprocating engines, it is a common practice to add relatively inexpensive coalescing-type filters just prior to the engines to provide added insurance of engine protection.

TABLE NO. 6-1
BUDGET COST ESTIMATE FOR
LANDFILL GAS PROCESSING SKID

Equipment	
Compressor	$110,000
Reheat Heat Exchanger	$15,000
Chilled Water Heat Exchanger	$15,000
Chiller	$30,000
Methane Analyzer	$20,000
Coalescing Filter	$5,000
Computer and PLC	$30,000
Power Distribution Panel	$15,000
On-Skid Installation	
Piping/Valves	$35,000
Electrical	$30,000
Other Fabrication Work	$35,000
Off-Skid Installation	
Foundation	$15,000
Fence	$10,000
Grading/Crushed Stone	$15,000
Rigging	$5,000
Electric Power Supply	$30,000
Piping Interconnection	$5,000
Engineering	$30,000
Contingency	$45,000
Total	**$495,000**

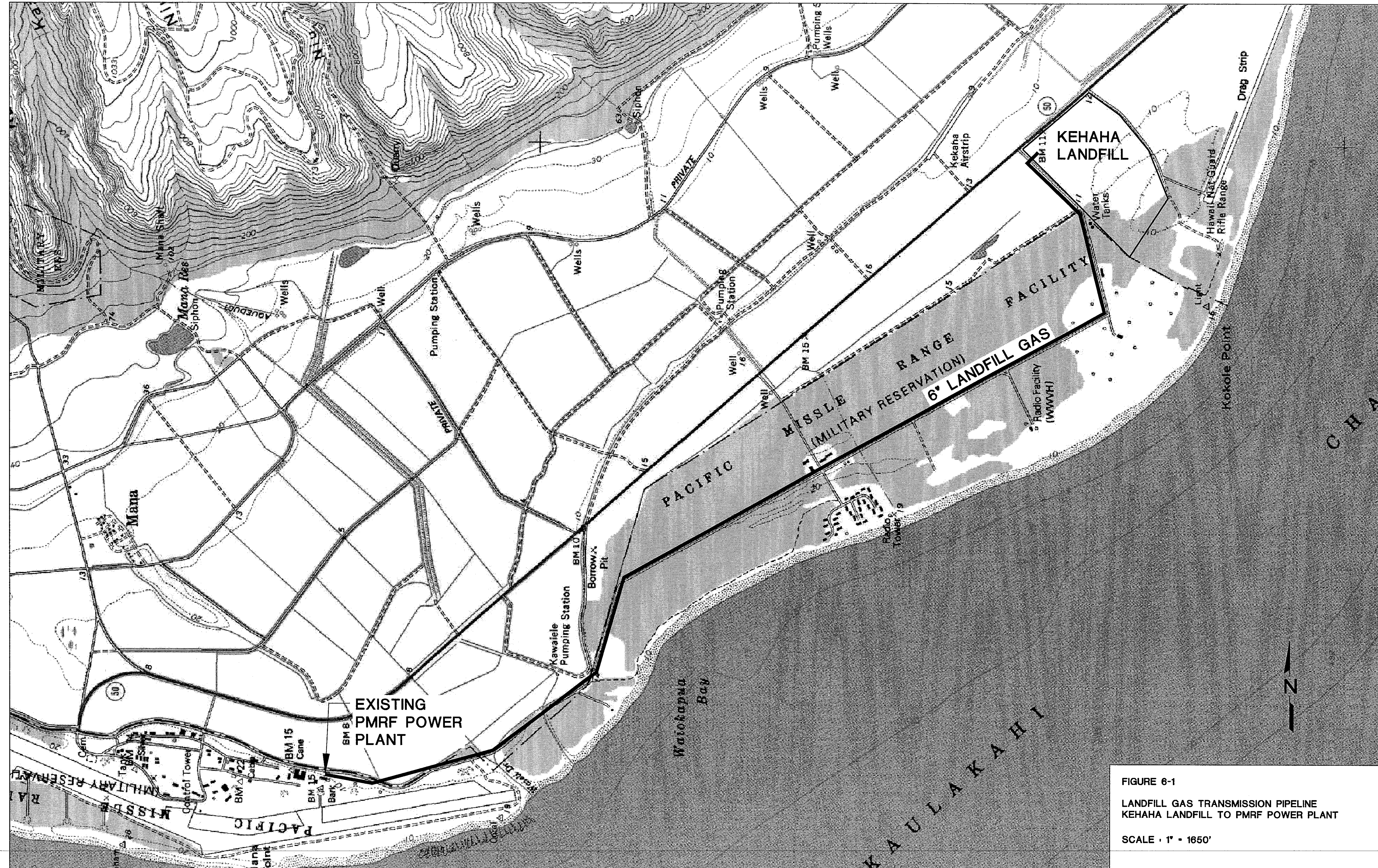


FIGURE 6-1

LANDFILL GAS TRANSMISSION PIPELINE
KEHAHA LANDFILL TO PMRF POWER PLANT

SCALE : 1" = 1650'

SECTION 7

LANDFILL GAS VALUE

The price paid to a landfill owner for landfill gas varies on a project-by-project basis. The price is negotiated case-by-case, and the price is directly related to what the LFGE project can afford to pay. The principal variables include:

- The value of the product sold to an end consumer ($/mmBtu for a gas sale or $/kWh for an electric power sale);
- The project-specific cost of the facilities necessary to convert landfill gas to a useable product;
- The quantity of landfill gas available; and
- Who covers the cost of wellfield installation and operation/maintenance.

At the present time, LFGE projects are virtually always installed at landfills that already have landfill gas collection systems in place. If the LFGE project is not developed by the landfill owner himself, and a project developer is used, project developers typically buy the landfill gas after collection at a flare station. In 2004, SCS conducted a survey of operating LFGE projects in California and determined that the average price being paid for landfill gas by developers was $0.60/mmBtu with a range from $0.25/mmBtu to $1.25/mmBtu.

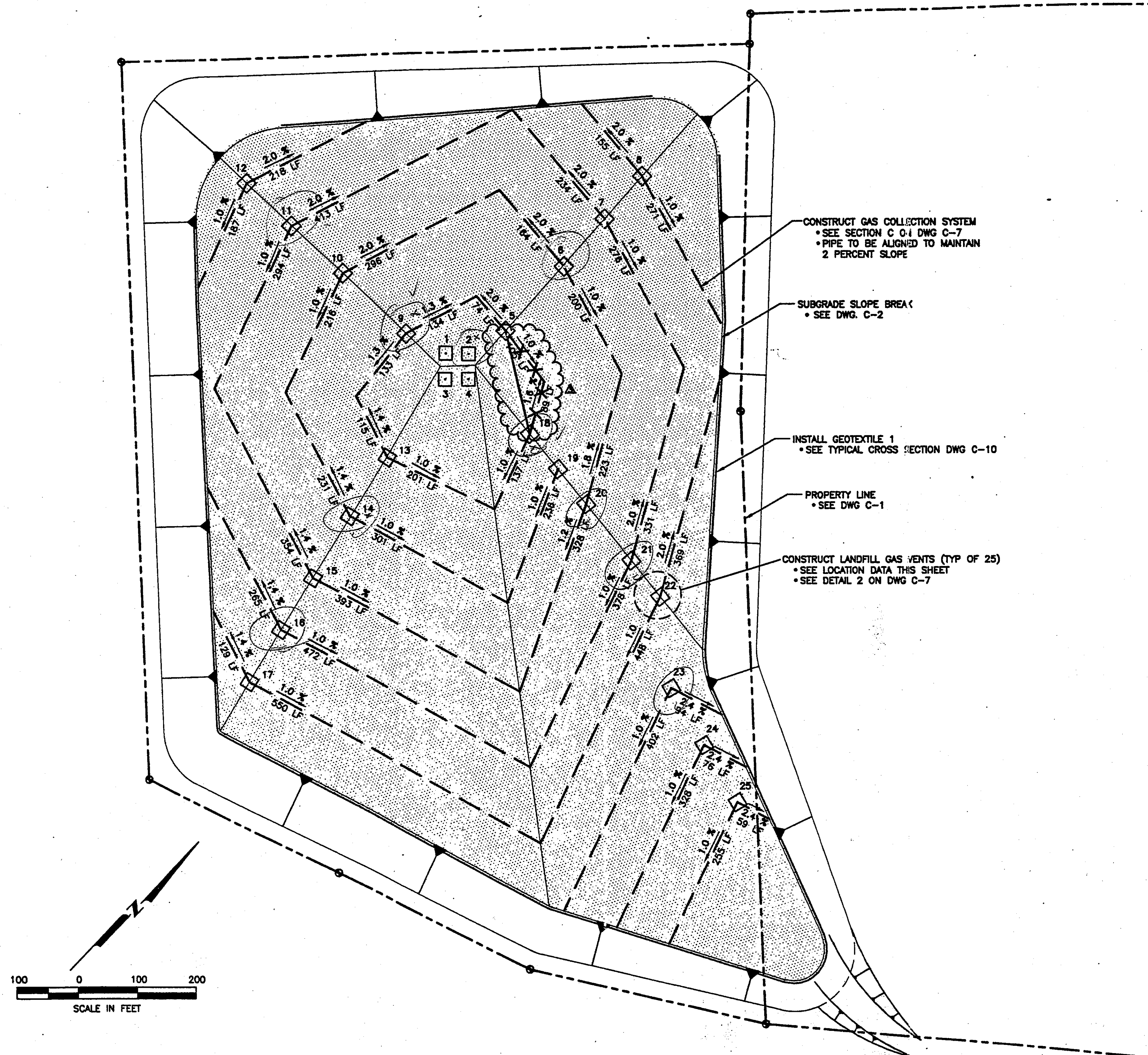
At Kekaha Landfill, if the developer is expected to install and operate/maintain the wellfield, it is SCS's opinion that it is likely that no more than the lower end of the above range ($0.25/mmBtu) could be charged for the landfill gas. Typically, the agreed-upon price would increase at a fixed percentage each year, or would be indexed to a benchmark energy cost (e.g., price of oil).

The above development scenario presumes that the County assumes none of the costs associated with the wellfield, landfill gas processing skid or transmission pipeline construction and operation/maintenance. The benefit to the County is a "free" landfill gas collection system, plus $0.25/mmBtu for all landfill gas productively used. In an alternative scenario, the County could self-develop the project, assuming all costs, and sell the processed landfill gas to PMRF, delivered to the PMRF power plant. In this scenario, the County would receive a much higher price for the landfill gas. Under such a scenario, the County could probably charge between 65 percent and 90 percent of PMRF's avoided cost of fuel. The higher percentage would apply if PMRF incurred little or no cost to convert to landfill gas firing. The higher the PMRF conversion cost, the lower the percentage that would be paid by PMRF to the County.

As an illustration, if it is assumed that PMRF is paying $1.50 per gallon for oil, that the energy content of the oil is 140,000 Btu/gal, and that the discount is 70 percent, the County could charge $7.50/mmBtu. The forthcoming report on the other tasks under SCS's scope of work will discuss the advantages and disadvantages to the County in taking alternative approaches to development of the project.

APPENDIX A

PHASE I LANDFILL CONSTRUCTION COMPLETION DRAWINGS AND SAMPLING LOCATIONS



GAS VENT LOCATIONS

VENT NO.	NORTHING	EASTING
1	55715.9	414115.7
2	55742.3	414143.9
3	55684.8	414145.3
4	55712.7	414173.2
5	55813.1	414161.1
6	55955.4	414155.6
7	56057.3	414148.8
8	56150.8	414144.3
9	55691.3	414045.8
10	55686.3	413900.8
11	55681.7	413787.1
12	55678.9	413686.2
13	55524.0	414167.7
14	55411.8	414192.1
15	55296.8	414222.3
16	55199.5	414245.5
17	55102.4	414269.1
18	55721.3	414309.8
19	55713.2	414383.8
20	55705.1	414457.9
21	55692.1	414577.2
22	55683.8	414653.7
23	55590.4	414772.6
24	55563.5	414876.9
25	55536.7	414980.8

NOTES AND LEGEND:

1. See Landfill Gas Collection System Details and Sections, DWG C-7.
2. See Typical Cross Section on DWG C-10.

Geotextile 1

RECORD DRAWINGS

These drawings have been revised to show significant changes which occurred during construction. Revisions are based on contractor red-lined drawings and other record information. These drawings are not intended to present all "As-Built" information, except where noted on individual drawings.

William C. Gurley — 1-31-96

Prepared By — Date

NO.	DATE	REVISIONS	BY	CHK
3	1/96	RECORD DRAWINGS	WTH	
2	6/94	ADJUSTED DESIGN BASED ON ACTUAL TOPOGRAPHIC SURVEY	WTH	
1	4/94	ISSUED FOR CONSTRUCTION	WTH	

DRAWN: JRL/JCL	PROJECT NO: 22924.703
ENGINEER:	SCALE: AS SHOWN
CHECKED:	APPROVED:
DATE:	DATE:

Harding Lawson Associates
Engineering and Environmental Services
235 Pearlridge Center, Phase 1, 98-1005 Moanalua Road
Aiea, Hawaii 96701
(808) 486-6009 Phone
(808) 486-7184 Fax

PHASE I CLOSURE

KEKAHA SANITARY LANDFILL
COUNTY OF KAUAI
KEKAHA, HAWAII

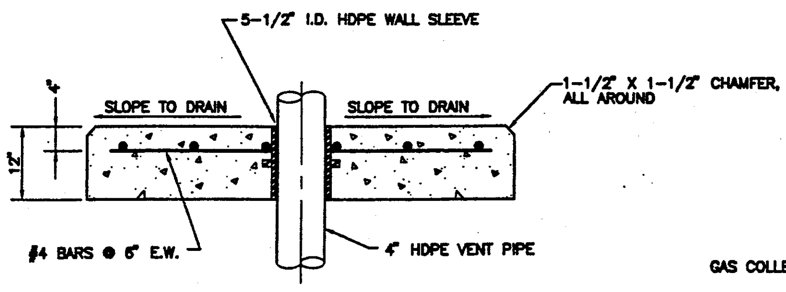
LANDFILL GAS SYSTEM & GEOTEXTILE 1 PLAN

DRAWING: C-3

SHEET: 5 OF 12

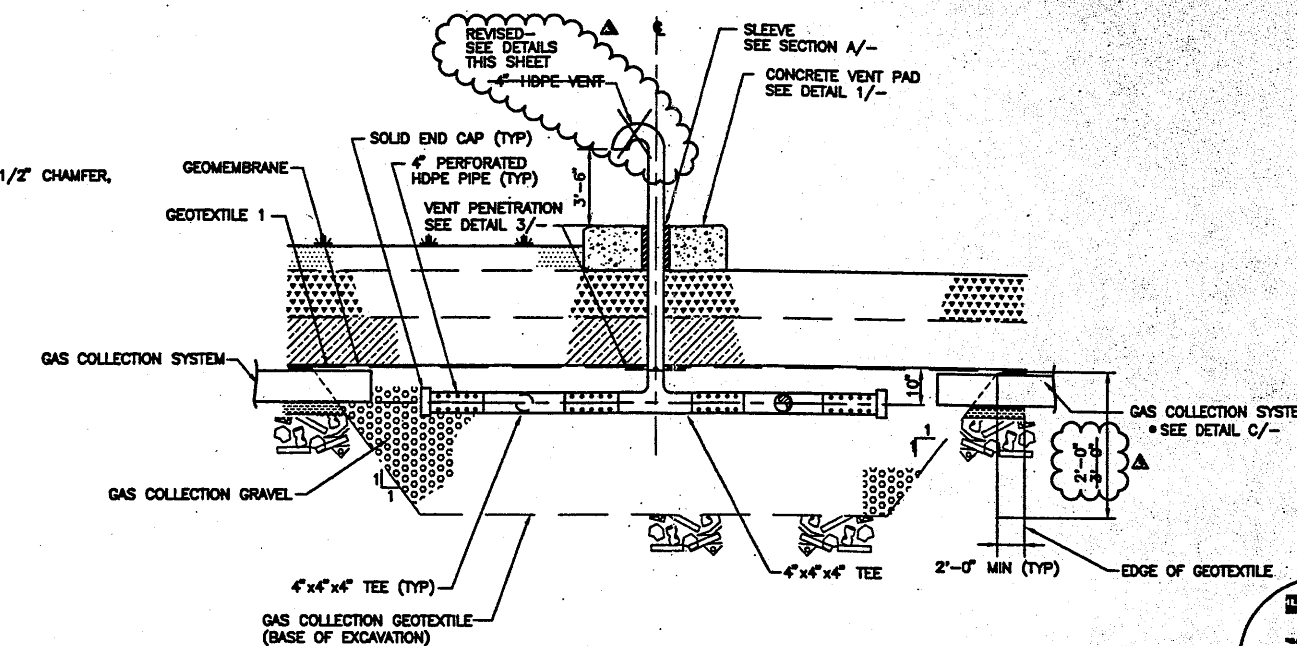
REVISION NUMBER: 3

DATE: JANUARY 31, 1996



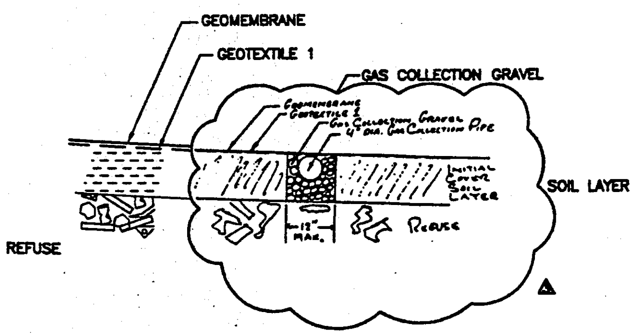
CONCRETE VENT PAD

SECTION (A) NOT TO SCALE



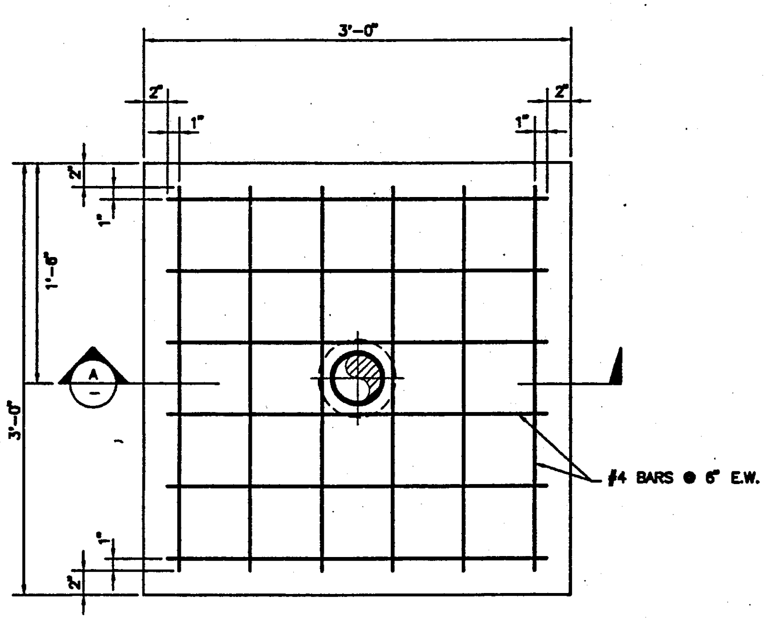
LANDFILL GAS VENT

SECTION (B) NOT TO SCALE



GAS COLLECTION SYSTEM

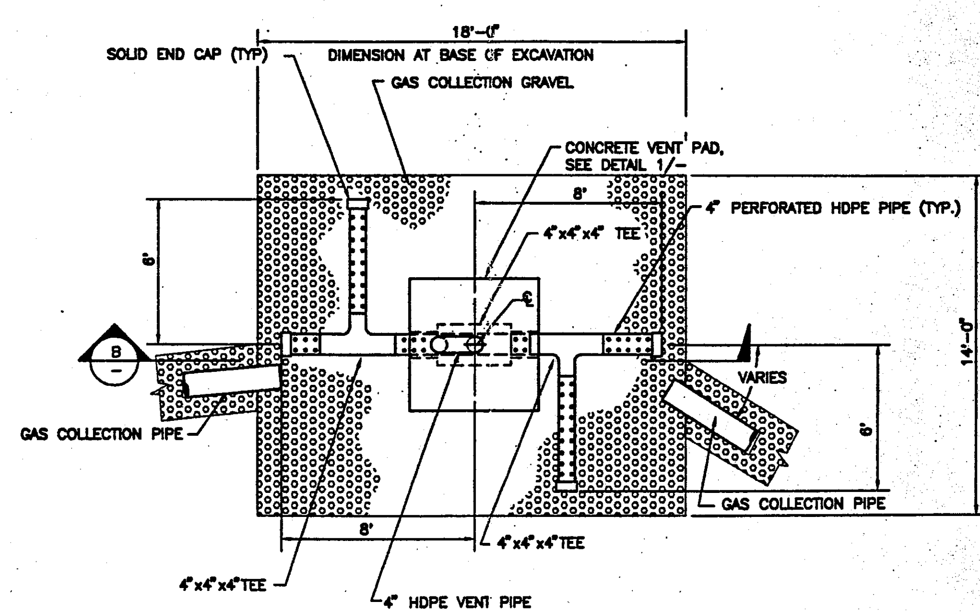
SECTION (C) NOT TO SCALE C-3



CONCRETE VENT PAD

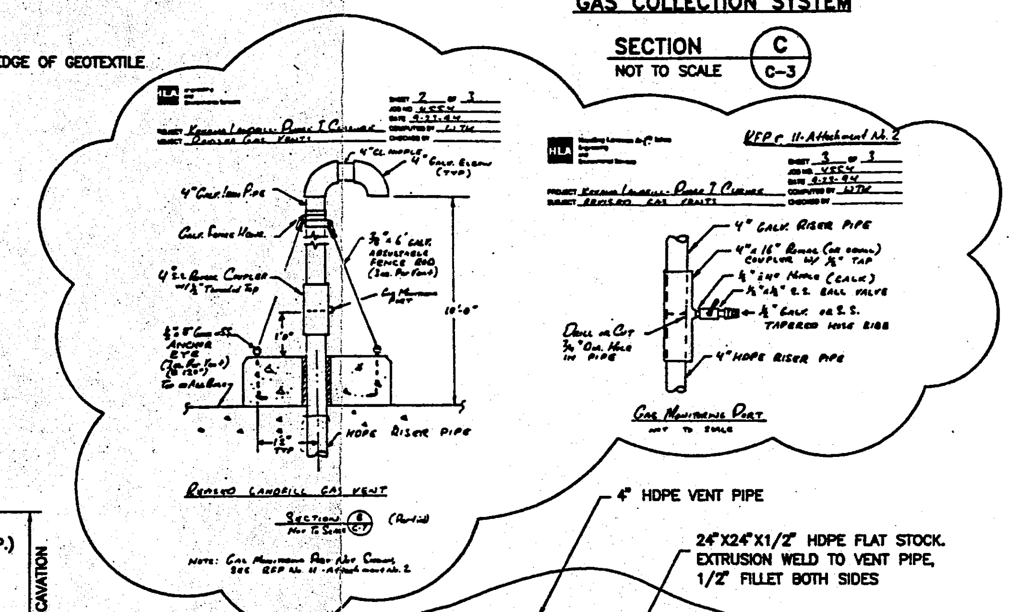
PLAN

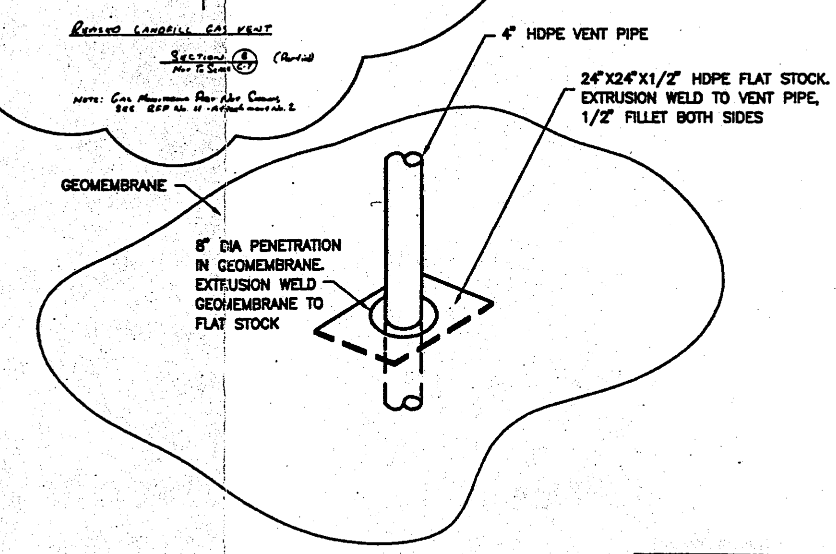
DETAIL (1) NOT TO SCALE C-3



LANDFILL GAS VENT

PLAN (2) NOT TO SCALE C-3





VENT PENETRATION

DETAIL (3) NOT TO SCALE C-3

RECORD DRAWINGS

These drawings have been revised to show significant changes which occurred during construction. Revisions are based on contractor red-lined drawings and other record information. These drawings are not intended to present all "As-Built" information, except where noted on individual drawings.

William T. Feeley — Prepared By — 1-31-96 Date

NO.	DATE	REVISIONS	BY	CHK
3	1/96	RECORD DRAWINGS	WTH	
2	6/94	ADJUSTED DESIGN BASED ON ACTUAL TOPOGRAPHIC SURVEY	WTH	
1	4/94	ISSUED FOR CONSTRUCTION	WTH	

DRAWN: JRL/JCL	PROJECT NO: 22924.703
ENGINEER:	SCALE: AS SHOWN
CHECKED:	APPROVED:
DATE:	DATE:

Harding Lawson Associates
Engineering and Environmental Services
235 Pearlridge Center, Phase 1 98-1005 Moanalua Road
Aiea, Hawaii 96701
(808)486-6009 Phone
(808)486-7184 Fax

PHASE I CLOSURE

KEKAHA SANITARY LANDFILL
COUNTY OF KAUAI
KEKAHA, HAWAII

LANDFILL GAS COLLECTION SYSTEM DETAILS AND SECTIONS

DRAWING: C-7
SHEET: 9 OF 12
REVISION NUMBER: 3
DATE: JANUARY 31, 1996

APPENDIX B

PHASE I LANDFILL'S LANDFILL GAS LABORATORY REPORTS

@ AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0601222C

Work Order Summary

CLIENT:	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way, Suite 100 Long Beach, CA 90806-6816	**BILL TO:**	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way, Suite 100 Long Beach, CA 90806-6816
PHONE:	562-426-9544	**P.O. #**	06-1126
FAX:	562-988-3183	**PROJECT #**	Kekaha Landfill
DATE RECEIVED:	01/13/2006	**CONTACT:**	Kyle Vagadori
DATE COMPLETED:	01/26/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	No. 21 Bag 3-L	Modified ASTM D-1945	Tedlar Bag
02A	No. 18 Bag 5-L	Modified ASTM D-1945	Tedlar Bag
03A	No. 9 Bag 5-L	Modified ASTM D-1945	Tedlar Bag
06A	No. 14 Bag 3-L	Modified ASTM D-1945	Tedlar Bag
07A	No. 23 Bag 1-L	Modified ASTM D-1945	Tedlar Bag
07AA	No. 23 Bag 1-L Duplicate	Modified ASTM D-1945	Tedlar Bag
08A	No. 6 Bag 1-L	Modified ASTM D-1945	Tedlar Bag
09A	No. 16 Bag 1-L	Modified ASTM D-1945	Tedlar Bag
10A	Lab Blank	Modified ASTM D-1945	NA
10B	Lab Blank	Modified ASTM D-1945	NA
11A	LCS	Modified ASTM D-1945	NA
11B	LCS	Modified ASTM D-1945	NA
11C	LCS	Modified ASTM D-1945	NA

CERTIFIED BY: Linda L. Freeman   DATE: 01/26/06

Laboratory Director

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
Modified ASTM D-1945
SCS Engineers
Workorder# 0601222C

Two 3 Liter Tedlar Bag, two 5 Liter Tedlar Bag, and three 1 Liter Tedlar Bag samples were received on January 13, 2006. The laboratory performed analysis via modified ASTM Method D-1945 for Methane and fixed gases in natural gas using GC/FID or GC/TCD. The method involves direct injection of 1.0 mL of sample. See the data sheets for the reporting limits for each compound.

On the analytical column employed for this analysis, Oxygen coelutes with Argon. The corresponding peak is quantitated as Oxygen.

Method modifications taken to run these samples include:

Requirement	***ASTM D-1945***	***ATL Modifications***
Normalization	Sum of original values should not differ from 100.0% by more than 1.0%.	Sum of original values may range between 75-125%. Normalization of data not performed.
Sample analysis	Equilibrate samples to 20-50° F. above source temperature at field sampling	No heating of samples is performed.
Sample calculation	Response factor is calculated using peak height for C5 and lighter compounds.	Peak areas are used for all target analytes to quantitate concentrations.
Reference Standard	Concentration should not be < half of nor differ by more than 2 X the concentration of the sample. Run 2 consecutive checks; must agree within 1%.	A minimum 3-point linear calibration is performed. The acceptance criterion is %RSD </= 25%. All target analytes must be within the linear range of calibration (with the exception of O2, N2, and C6+ Hydrocarbons).
Sample Injection Volume	0.50 mL to achieve Methane linearity.	1.0 mL.

Receiving Notes

Samples No. 23 Bag 1-L, No. 6 Bag 1-L and No. 16 Bag 1-L were received without documentation regarding collection date. The date on the sample tag was assumed to be the date of collection and was used to determine the extent of hold time.

Analytical Notes

There were no analytical discrepancies.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:

J - Estimated value.

E - Exceeds instrument calibration range.

S - Saturated peak.

Q - Exceeds quality control limits.

U - Compound analyzed for but not detected above the detection limit.

M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:

a-File was requantified

b-File was quantified by a second column and detector

r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L

Lab ID#: 0601222C-01A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011323	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 04:52 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	18
Nitrogen	0.10	68
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	9.0
Carbon Dioxide	0.010	3.8
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 91
Total Sp. Gravity = 0.96
Container Type: 3 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 18 Bag 5-L

Lab ID#: 0601222C-02A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011324	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/13/06 05:41 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.39
Nitrogen	0.10	7.1
Carbon Monoxide	0.010	Not Detected
Methane	0.00025	74
Carbon Dioxide	0.010	20
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0031
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 750
Total Sp. Gravity = 0.79

Methane is reported from file # 9011327 analyzed on 01-13-06 at a dilution factor of 2.50.
Container Type: 5 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 9 Bag 5-L

Lab ID#: 0601222C-03A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011325	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 06:03 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.46
Nitrogen	0.10	4.9
Carbon Monoxide	0.010	Not Detected
Methane	0.00025	73
Carbon Dioxide	0.010	24
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0035
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 740
Total Sp. Gravity = 0.82

Methane is reported from file # 9011326 analyzed on 01-13-06 at a dilution factor of 2.50.
Container Type: 5 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 14 Bag 3-L

Lab ID#: 0601222C-06A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011322	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 04:19 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	6.5
Nitrogen	0.10	27
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	48
Carbon Dioxide	0.010	20
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0020
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 480
Total Sp. Gravity = 0.90

Container Type: 3 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 23 Bag 1-L

Lab ID#: 0601222C-07A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011318	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/13/06 02:30 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	6.9
Nitrogen	0.10	40
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	37
Carbon Dioxide	0.010	17
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0023
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 370
Total Sp. Gravity = 0.92

Container Type: 1 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 23 Bag 1-L Duplicate

Lab ID#: 0601222C-07AA

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011319	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 02:52 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	6.9
Nitrogen	0.10	40
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	37
Carbon Dioxide	0.010	17
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0023
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 380
Total Sp. Gravity = 0.92

Container Type: 1 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 6 Bag 1-L

Lab ID#: 0601222C-08A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011320	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/13/06 03:15 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.89
Nitrogen	0.10	14
Carbon Monoxide	0.010	Not Detected
Methane	0.00020	60
Carbon Dioxide	0.010	27
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0011
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 610
Total Sp. Gravity = 0.89

Methane is reported from file # 9011328 analyzed on 01-13-06 at a dilution factor of 2.00.
Container Type: 1 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 16 Bag 1-L

Lab ID#: 0601222C-09A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011321	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/13/06 03:36 PM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	1.6
Nitrogen	0.10	20
Carbon Monoxide	0.010	Not Detected
Methane	0.00020	56
Carbon Dioxide	0.010	24
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	0.0043
Isobutane	0.0010	0.0012
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Total BTU/Cu.F. = 570
Total Sp. Gravity = 0.89

Methane is reported from file # 9011329 analyzed on 01-13-06 at a dilution factor of 2.00.
Container Type: 1 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222C-10A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011308b	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 10:36 AM

Compound	Rpt. Limit (%)	Amount (%)
Hydrogen	0.010	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222C-10B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011307	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 10:14 AM

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	Not Detected
Nitrogen	0.10	Not Detected
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	Not Detected
Carbon Dioxide	0.010	Not Detected
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222C-11A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011305b	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 09:27 AM

Compound	%Recovery
Oxygen	99
Nitrogen	100
Carbon Monoxide	98
Carbon Dioxide	102

Container Type: NA - Not Applicable

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222C-11B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011334b	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 10:25 PM

Compound	%Recovery
Hydrogen	97

Container Type: NA - Not Applicable

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222C-11C

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

File Name:	9011303	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 08:36 AM

Compound	%Recovery
Methane	98
Ethane	100
Ethene	99
Acetylene	97
Propane	94
Isobutane	101
Butane	103
Neopentane	103
Isopentane	97
Pentane	95
C6+	105

Container Type: NA - Not Applicable

@ **AIR TOXICS LTD.**

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0601222B

Work Order Summary

CLIENT:	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way Suite 100 Long Beach, CA 90806-6816	**BILL TO:**	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way Suite 100 Long Beach, CA 90806-6816
PHONE:	562-426-9544	**P.O. #**	06-1126
FAX:	562-988-3183	**PROJECT #**	Kekaha Landfill
DATE RECEIVED:	01/13/2006	**CONTACT:**	Kyle Vagadori
DATE COMPLETED:	01/18/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	No. 21 Bag 3-L	ASTM D-5504	Tedlar Bag
02A	No. 18 Bag 5-L	ASTM D-5504	Tedlar Bag
03A	No. 9 Bag 5-L	ASTM D-5504	Tedlar Bag
04A	Lab Blank	ASTM D-5504	NA
05A	LCS	ASTM D-5504	NA

CERTIFIED BY: Linda d. Freeman DATE: 01/18/06

Laboratory Director

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
ASTM D-5504
SCS Engineers
Workorder# 0601222B

One 3 Liter Tedlar Bag and two 5 Liter Tedlar Bag samples were received on January 13, 2006. The laboratory performed the analysis of sulfur compounds via ASTM D-5504 using GC/SCD. The method involves direct injection of the air sample into the GC via a fixed 1.0 mL sampling loop. See the data sheets for the reporting limits for each compound.

Receiving Notes

Samples were received past the recommended hold time of 24 hours. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Analytical Notes

Diethyl Sulfide coelutes with 2-Ethyl Thiophene. The corresponding peak is reported as 2-Ethyl Thiophene.

Definition of Data Qualifying Flags

Seven qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.
File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

Summary of Detected Compounds
SULFUR GASES BY ASTM D-5504 GC/SCD

Client Sample ID: No. 21 Bag 3-L

Lab ID#: 0601222B-01A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Carbonyl Sulfide	4.0	8.8
Dimethyl Sulfide	4.0	7.4
Carbon Disulfide	4.0	14

Client Sample ID: No. 18 Bag 5-L

Lab ID#: 0601222B-02A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	66
Carbonyl Sulfide	4.0	14 M
Methyl Mercaptan	4.0	9.0
Carbon Disulfide	4.0	20
tert-Butyl Mercaptan	4.0	4.6

Client Sample ID: No. 9 Bag 5-L

Lab ID#: 0601222B-03A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Carbonyl Sulfide	4.0	6.6 M
Methyl Mercaptan	4.0	6.6
Dimethyl Sulfide	4.0	47
Carbon Disulfide	4.0	9.3

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L

Lab ID#: 0601222B-01A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	b011309	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 01:39 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	8.8
Methyl Mercaptan	4.0	Not Detected
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	7.4
Carbon Disulfide	4.0	14
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

Container Type: 3 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 18 Bag 5-L

Lab ID#: 0601222B-02A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	b011310	Date of Collection: 1/10/06
Dil. Factor:	1.00	Date of Analysis: 1/13/06 02:09 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	66
Carbonyl Sulfide	4.0	14 M
Methyl Mercaptan	4.0	9.0
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	Not Detected
Carbon Disulfide	4.0	20
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	4.6
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

M = Reported value may be biased due to apparent matrix interferences.

Container Type: 5 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: No. 9 Bag 5-L

Lab ID#: 0601222B-03A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	b011311	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/13/06 02:39 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	6.6 M
Methyl Mercaptan	4.0	6.6
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	47
Carbon Disulfide	4.0	9.3
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

M = Reported value may be biased due to apparent matrix interferences.

Container Type: 5 Liter Tedlar Bag

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222B-04A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	b011304	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis:	1/13/06 08:12 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	Not Detected
Methyl Mercaptan	4.0	Not Detected
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	Not Detected
Carbon Disulfide	4.0	Not Detected
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222B-05A

SULFUR GASES BY ASTM D-5504 GC/SCD

File Name:	b011302	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/12/06 10:42 PM

Compound	%Recovery
Hydrogen Sulfide	113
Carbonyl Sulfide	83
Methyl Mercaptan	88
Ethyl Mercaptan	102
Dimethyl Sulfide	102
Carbon Disulfide	107
Isopropyl Mercaptan	93
tert-Butyl Mercaptan	106
n-Propyl Mercaptan	102
Ethyl Methyl Sulfide	102
Thiophene	78
Isobutyl Mercaptan	112
Diethyl Sulfide	86
n-Butyl Mercaptan	74
Dimethyl Disulfide	92
3-Methylthiophene	101
Tetrahydrothiophene	99
2-Ethylthiophene	86
2,5-Dimethylthiophene	79
Diethyl Disulfide	92

Container Type: NA - Not Applicable

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0601222A

Work Order Summary

CLIENT:	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way, Suite 100 Long Beach, CA 90806-6816	**BILL TO:**	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way, Suite 100 Long Beach, CA 90806-6816
PHONE:	562-426-9544	**P.O. #**	06-1126
FAX:	562-988-3183	**PROJECT #**	Kekaha Landfill
DATE RECEIVED:	01/13/2006	**CONTACT:**	Kyle Vagadori
DATE COMPLETED:	01/26/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	No. 21 Bag 3-L	Modified TO-15	Tedlar Bag
01AA	No. 21 Bag 3-L Duplicate	Modified TO-15	Tedlar Bag
02A	No. 18 Bag 5-L	Modified TO-15	Tedlar Bag
03A	No. 9 Bag 5-L	Modified TO-15	Tedlar Bag
04A	No. 20 Bag 1-L	Modified TO-15	Tedlar Bag
05A	No. 2 Bag 1-L	Modified TO-15	Tedlar Bag
06A	No. 14 Bag 3-L	Modified TO-15	Tedlar Bag
07A	Lab Blank	Modified TO-15	NA
08A	CCV	Modified TO-15	NA
09A	LCS	Modified TO-15	NA

CERTIFIED BY: Linda J. Freeman DATE: 01/26/06

Laboratory Director

Certfication numbers: AR DEQ - 03-084-0, CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
Modified TO-15
SCS Engineers
Workorder# 0601222A

Two 3 Liter Tedlar Bag, two 5 Liter Tedlar Bag, and two 1 Liter Tedlar Bag samples were received on January 13, 2006. The laboratory performed analysis via modified EPA Method TO-15 using GC/MS in the full scan mode. The method involves concentrating up to 0.2 liters of air. The concentrated aliquot is then flash vaporized and swept through a water management system to remove water vapor. Following dehumidification, the sample passes directly into the GC/MS for analysis.

Method modifications taken to run these samples are summarized in the below table. Specific project requirements may over-ride the ATL modifications.

Requirement	*TO-15*	*ATL Modifications*
Daily CCV	+- 30% Difference	</= 30% Difference with two allowed out up to </=40%.; flag and narrate outliers
Sample collection media	Summa canister	ATL recommends use of summa canisters to insure data defensibility, but will report results from Tedlar bags at client request
Method Detection Limit	Follow 40CFR Pt.136 App. B	The MDL met all relevant requirements in Method TO-15 (statistical MDL less than the LOQ). The concentration of the spiked replicate may have exceeded 10X the calculated MDL in some cases

Receiving Notes

Samples No. 20 Bag 1-L, No. 2 Bag 1-L and No. 14 Bag 3-L were received without documentation regarding collection date on the COC. The date on the sample tag was assumed to be the date of collection and was used to determine the extent of hold time.

Analytical Notes

All Quality Control Limit failures and affected sample results are noted by flags. Each flag is defined at the bottom of this Case Narrative and on each Sample Result Summary page. Target compound non-detects in the samples that are associated with high bias in QC analyses have not been flagged.

The reported LCS for each daily batch has been derived from more than one analytical file.

Samples No. 21 Bag 3-L, No. 21 Bag 3-L Duplicate, No. 18 Bag 5-L, No. 9 Bag 5-L, No. 20 Bag 1-L, No. 2 Bag 1-L and No. 14 Bag 3-L were transferred from Tedlar bags into summa canisters to extend the hold time from 72 hours to 14 days. Canister pressurization resulted in a dilution factor which was applied to all analytical results.

Dilution was performed on samples No. 9 Bag 5-L, No. 20 Bag 1-L and No. 14 Bag 3-L due to the presence of high level non-target species.

The reported result for Cumene in samples No. 21 Bag 3-L, No. 21 Bag 3-L Duplicate, No. 18 Bag 5-L, No. 9 Bag 5-L, No. 20 Bag 1-L, No. 2 Bag 1-L and No. 14 Bag 3-L may be biased high due to co-elution with a non target compound with similar characteristic ions. Both the primary and secondary ion for Cumene exhibited potential interference.

Definition of Data Qualifying Flags

Eight qualifiers may have been used on the data analysis sheets and indicates as follows:

B - Compound present in laboratory blank greater than reporting limit (background subtraction no performed).

J - Estimated value.

E - Exceeds instrument calibration range.

S - Saturated peak.

Q - Exceeds quality control limits.

U - Compound analyzed for but not detected above the reporting limit.

UJ- Non-detected compound associated with low bias in the CCV

N - The identification is based on presumptive evidence.

File extensions may have been used on the data analysis sheets and indicates as follows:

a-File was requantified

b-File was quantified by a second column and detector

r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L

Lab ID#: 0601222A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011812	Date of Collection:	1/10/06
Dil. Factor:	8.08	Date of Analysis:	1/18/06 07:06 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	4.0	Not Detected	20	Not Detected
Freon 114	4.0	Not Detected	28	Not Detected
Chloromethane	16	Not Detected	33	Not Detected
Vinyl Chloride	4.0	Not Detected	10	Not Detected
1,3-Butadiene	4.0	Not Detected	8.9	Not Detected
Bromomethane	4.0	Not Detected	16	Not Detected
Chloroethane	4.0	Not Detected	11	Not Detected
Freon 11	4.0	Not Detected	23	Not Detected
Ethanol	16	Not Detected	30	Not Detected
Freon 113	4.0	Not Detected	31	Not Detected
1,1-Dichloroethene	4.0	Not Detected	16	Not Detected
Acetone	16	18	38	44
2-Propanol	16	22	40	55
Carbon Disulfide	4.0	Not Detected	12	Not Detected
3-Chloropropene	16	Not Detected	50	Not Detected
Methylene Chloride	4.0	190	14	660
Methyl tert-butyl ether	4.0	Not Detected	14	Not Detected
trans-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Hexane	4.0	17	14	60
1,1-Dichloroethane	4.0	Not Detected	16	Not Detected
2-Butanone (Methyl Ethyl Ketone)	4.0	Not Detected	12	Not Detected
cis-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Tetrahydrofuran	4.0	Not Detected	12	Not Detected
Chloroform	4.0	Not Detected	20	Not Detected
1,1,1-Trichloroethane	4.0	Not Detected	22	Not Detected
Cyclohexane	4.0	18	14	61
Carbon Tetrachloride	4.0	Not Detected	25	Not Detected
2,2,4-Trimethylpentane	4.0	11	19	52
Benzene	4.0	Not Detected	13	Not Detected
1,2-Dichloroethane	4.0	Not Detected	16	Not Detected
Heptane	4.0	26	16	110
Trichloroethene	4.0	Not Detected	22	Not Detected
1,2-Dichloropropane	4.0	Not Detected	19	Not Detected
1,4-Dioxane	16	Not Detected	58	Not Detected
Bromodichloromethane	4.0	Not Detected	27	Not Detected
cis-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
4-Methyl-2-pentanone	4.0	Not Detected	16	Not Detected
Toluene	4.0	6.9	15	26
trans-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
1,1,2-Trichloroethane	4.0	Not Detected	22	Not Detected
Tetrachloroethene	4.0	Not Detected	27	Not Detected
2-Hexanone	16	Not Detected	66	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L

Lab ID#: 0601222A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011812	Date of Collection: 1/10/06	
Dil. Factor:	8.08	Date of Analysis: 1/18/06 07:06 PM	

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	4.0	Not Detected	34	Not Detected
1,2-Dibromoethane (EDB)	4.0	Not Detected	31	Not Detected
Chlorobenzene	4.0	Not Detected	18	Not Detected
Ethyl Benzene	4.0	Not Detected	18	Not Detected
m,p-Xylene	4.0	Not Detected	18	Not Detected
o-Xylene	4.0	Not Detected	18	Not Detected
Styrene	4.0	Not Detected	17	Not Detected
Bromoform	4.0	Not Detected	42	Not Detected
Cumene	4.0	5.0	20	25
1,1,2,2-Tetrachloroethane	4.0	Not Detected	28	Not Detected
Propylbenzene	4.0	Not Detected	20	Not Detected
4-Ethyltoluene	4.0	Not Detected	20	Not Detected
1,3,5-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,2,4-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,3-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,4-Dichlorobenzene	4.0	Not Detected	24	Not Detected
alpha-Chlorotoluene	4.0	Not Detected	21	Not Detected
1,2-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,2,4-Trichlorobenzene	16	Not Detected	120	Not Detected
Hexachlorobutadiene	16	Not Detected	170	Not Detected

Container Type: 3 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	102	70-130
1,2-Dichloroethane-d4	103	70-130
4-Bromofluorobenzene	106	70-130

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L Duplicate

Lab ID#: 0601222A-01AA

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011820	Date of Collection:	1/10/06
Dil. Factor:	8.08	Date of Analysis:	1/19/06 02:04 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	4.0	Not Detected	20	Not Detected
Freon 114	4.0	Not Detected	28	Not Detected
Chloromethane	16	Not Detected	33	Not Detected
Vinyl Chloride	4.0	Not Detected	10	Not Detected
1,3-Butadiene	4.0	Not Detected	8.9	Not Detected
Bromomethane	4.0	Not Detected	16	Not Detected
Chloroethane	4.0	Not Detected	11	Not Detected
Freon 11	4.0	Not Detected	23	Not Detected
Ethanol	16	Not Detected	30	Not Detected
Freon 113	4.0	Not Detected	31	Not Detected
1,1-Dichloroethene	4.0	Not Detected	16	Not Detected
Acetone	16	18	38	42
2-Propanol	16	22	40	54
Carbon Disulfide	4.0	Not Detected	12	Not Detected
3-Chloropropene	16	Not Detected	50	Not Detected
Methylene Chloride	4.0	190	14	660
Methyl tert-butyl ether	4.0	Not Detected	14	Not Detected
trans-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Hexane	4.0	18	14	62
1,1-Dichloroethane	4.0	Not Detected	16	Not Detected
2-Butanone (Methyl Ethyl Ketone)	4.0	Not Detected	12	Not Detected
cis-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Tetrahydrofuran	4.0	Not Detected	12	Not Detected
Chloroform	4.0	Not Detected	20	Not Detected
1,1,1-Trichloroethane	4.0	Not Detected	22	Not Detected
Cyclohexane	4.0	18	14	64
Carbon Tetrachloride	4.0	Not Detected	25	Not Detected
2,2,4-Trimethylpentane	4.0	11	19	50
Benzene	4.0	Not Detected	13	Not Detected
1,2-Dichloroethane	4.0	Not Detected	16	Not Detected
Heptane	4.0	27	16	110
Trichloroethene	4.0	Not Detected	22	Not Detected
1,2-Dichloropropane	4.0	Not Detected	19	Not Detected
1,4-Dioxane	16	Not Detected	58	Not Detected
Bromodichloromethane	4.0	Not Detected	27	Not Detected
cis-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
4-Methyl-2-pentanone	4.0	Not Detected	16	Not Detected
Toluene	4.0	7.2	15	27
trans-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
1,1,2-Trichloroethane	4.0	Not Detected	22	Not Detected
Tetrachloroethene	4.0	Not Detected	27	Not Detected
2-Hexanone	16	Not Detected	66	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 21 Bag 3-L Duplicate

Lab ID#: 0601222A-01AA

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011820	Date of Collection: 1/10/06
Dil. Factor:	8.08	Date of Analysis: 1/19/06 02:04 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	4.0	Not Detected	34	Not Detected
1,2-Dibromoethane (EDB)	4.0	Not Detected	31	Not Detected
Chlorobenzene	4.0	Not Detected	18	Not Detected
Ethyl Benzene	4.0	Not Detected	18	Not Detected
m,p-Xylene	4.0	Not Detected	18	Not Detected
o-Xylene	4.0	Not Detected	18	Not Detected
Styrene	4.0	Not Detected	17	Not Detected
Bromoform	4.0	Not Detected	42	Not Detected
Cumene	4.0	5.1	20	25
1,1,2,2-Tetrachloroethane	4.0	Not Detected	28	Not Detected
Propylbenzene	4.0	Not Detected	20	Not Detected
4-Ethyltoluene	4.0	Not Detected	20	Not Detected
1,3,5-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,2,4-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,3-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,4-Dichlorobenzene	4.0	Not Detected	24	Not Detected
alpha-Chlorotoluene	4.0	Not Detected	21	Not Detected
1,2-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,2,4-Trichlorobenzene	16	Not Detected	120	Not Detected
Hexachlorobutadiene	16	Not Detected	170	Not Detected

Container Type: 3 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	100	70-130
1,2-Dichloroethane-d4	103	70-130
4-Bromofluorobenzene	108	70-130

AIR TOXICS LTD.

Client Sample ID: No. 18 Bag 5-L

Lab ID#: 0601222A-02A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011813	Date of Collection:	1/10/06
Dil. Factor:	8.20	Date of Analysis:	1/18/06 08:01 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	4.1	Not Detected	20	Not Detected
Freon 114	4.1	44	29	310
Chloromethane	16	Not Detected	34	Not Detected
Vinyl Chloride	4.1	8.6	10	22
1,3-Butadiene	4.1	Not Detected	9.1	Not Detected
Bromomethane	4.1	Not Detected	16	Not Detected
Chloroethane	4.1	Not Detected	11	Not Detected
Freon 11	4.1	Not Detected	23	Not Detected
Ethanol	16	1400	31	2700
Freon 113	4.1	Not Detected	31	Not Detected
1,1-Dichloroethene	4.1	Not Detected	16	Not Detected
Acetone	16	170	39	400
2-Propanol	16	95	40	230
Carbon Disulfide	4.1	10	13	33
3-Chloropropene	16	Not Detected	51	Not Detected
Methylene Chloride	4.1	Not Detected	14	Not Detected
Methyl tert-butyl ether	4.1	Not Detected	15	Not Detected
trans-1,2-Dichloroethene	4.1	Not Detected	16	Not Detected
Hexane	4.1	220	14	770
1,1-Dichloroethane	4.1	Not Detected	16	Not Detected
2-Butanone (Methyl Ethyl Ketone)	4.1	7.4	12	22
cis-1,2-Dichloroethene	4.1	22	16	89
Tetrahydrofuran	4.1	Not Detected	12	Not Detected
Chloroform	4.1	Not Detected	20	Not Detected
1,1,1-Trichloroethane	4.1	Not Detected	22	Not Detected
Cyclohexane	4.1	170	14	580
Carbon Tetrachloride	4.1	Not Detected	26	Not Detected
2,2,4-Trimethylpentane	4.1	320	19	1500
Benzene	4.1	15	13	48
1,2-Dichloroethane	4.1	Not Detected	16	Not Detected
Heptane	4.1	180	17	740
Trichloroethene	4.1	4.1	22	22
1,2-Dichloropropane	4.1	Not Detected	19	Not Detected
1,4-Dioxane	16	Not Detected	59	Not Detected
Bromodichloromethane	4.1	Not Detected	27	Not Detected
cis-1,3-Dichloropropene	4.1	Not Detected	19	Not Detected
4-Methyl-2-pentanone	4.1	Not Detected	17	Not Detected
Toluene	4.1	20	15	74
trans-1,3-Dichloropropene	4.1	Not Detected	19	Not Detected
1,1,2-Trichloroethane	4.1	Not Detected	22	Not Detected
Tetrachloroethene	4.1	Not Detected	28	Not Detected
2-Hexanone	16	Not Detected	67	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 18 Bag 5-L

Lab ID#: 0601222A-02A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011813	Date of Collection: 1/10/06	
Dil. Factor:	8.20	Date of Analysis: 1/18/06 08:01 PM	

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	4.1	Not Detected	35	Not Detected
1,2-Dibromoethane (EDB)	4.1	Not Detected	32	Not Detected
Chlorobenzene	4.1	Not Detected	19	Not Detected
Ethyl Benzene	4.1	Not Detected	18	Not Detected
m,p-Xylene	4.1	7.0	18	30
o-Xylene	4.1	Not Detected	18	Not Detected
Styrene	4.1	Not Detected	17	Not Detected
Bromoform	4.1	Not Detected	42	Not Detected
Cumene	4.1	29	20	140
1,1,2,2-Tetrachloroethane	4.1	Not Detected	28	Not Detected
Propylbenzene	4.1	Not Detected	20	Not Detected
4-Ethyltoluene	4.1	Not Detected	20	Not Detected
1,3,5-Trimethylbenzene	4.1	Not Detected	20	Not Detected
1,2,4-Trimethylbenzene	4.1	Not Detected	20	Not Detected
1,3-Dichlorobenzene	4.1	Not Detected	25	Not Detected
1,4-Dichlorobenzene	4.1	Not Detected	25	Not Detected
alpha-Chlorotoluene	4.1	Not Detected	21	Not Detected
1,2-Dichlorobenzene	4.1	Not Detected	25	Not Detected
1,2,4-Trichlorobenzene	16	Not Detected	120	Not Detected
Hexachlorobutadiene	16	Not Detected	170	Not Detected

Container Type: 5 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	101	70-130
1,2-Dichloroethane-d4	111	70-130
4-Bromofluorobenzene	107	70-130

AIR TOXICS LTD.

Client Sample ID: No. 9 Bag 5-L

Lab ID#: 0601222A-03A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011821	Date of Collection: 1/10/06
Dil. Factor:	11.7	Date of Analysis: 1/19/06 02:43 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	5.8	Not Detected	29	Not Detected
Freon 114	5.8	110	41	790
Chloromethane	23	Not Detected	48	Not Detected
Vinyl Chloride	5.8	12	15	32
1,3-Butadiene	5.8	Not Detected	13	Not Detected
Bromomethane	5.8	Not Detected	23	Not Detected
Chloroethane	5.8	12 J	15	31 J
Freon 11	5.8	Not Detected	33	Not Detected
Ethanol	23	1400	44	2700
Freon 113	5.8	Not Detected	45	Not Detected
1,1-Dichloroethene	5.8	Not Detected	23	Not Detected
Acetone	23	110	56	270
2-Propanol	23	120	58	300
Carbon Disulfide	5.8	Not Detected	18	Not Detected
3-Chloropropene	23	Not Detected	73	Not Detected
Methylene Chloride	5.8	Not Detected	20	Not Detected
Methyl tert-butyl ether	5.8	12 J	21	44 J
trans-1,2-Dichloroethene	5.8	Not Detected	23	Not Detected
Hexane	5.8	330	21	1200
1,1-Dichloroethane	5.8	Not Detected	24	Not Detected
2-Butanone (Methyl Ethyl Ketone)	5.8	6.0	17	18
cis-1,2-Dichloroethene	5.8	32	23	130
Tetrahydrofuran	5.8	Not Detected	17	Not Detected
Chloroform	5.8	Not Detected	28	Not Detected
1,1,1-Trichloroethane	5.8	Not Detected	32	Not Detected
Cyclohexane	5.8	270	20	920
Carbon Tetrachloride	5.8	Not Detected	37	Not Detected
2,2,4-Trimethylpentane	5.8	320	27	1500
Benzene	5.8	44	19	140
1,2-Dichloroethane	5.8	Not Detected	24	Not Detected
Heptane	5.8	220	24	900
Trichloroethene	5.8	6.1	31	33
1,2-Dichloropropane	5.8	Not Detected	27	Not Detected
1,4-Dioxane	23	Not Detected	84	Not Detected
Bromodichloromethane	5.8	Not Detected	39	Not Detected
cis-1,3-Dichloropropene	5.8	Not Detected	26	Not Detected
4-Methyl-2-pentanone	5.8	Not Detected	24	Not Detected
Toluene	5.8	22	22	84
trans-1,3-Dichloropropene	5.8	Not Detected	26	Not Detected
1,1,2-Trichloroethane	5.8	Not Detected	32	Not Detected
Tetrachloroethene	5.8	Not Detected	40	Not Detected
2-Hexanone	23	Not Detected	96	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 9 Bag 5-L

Lab ID#: 0601222A-03A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011821	Date of Collection:	1/10/06
Dil. Factor:	11.7	Date of Analysis:	1/19/06 02:43 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	5.8	Not Detected	50	Not Detected
1,2-Dibromoethane (EDB)	5.8	Not Detected	45	Not Detected
Chlorobenzene	5.8	Not Detected	27	Not Detected
Ethyl Benzene	5.8	12	25	51
m,p-Xylene	5.8	12	25	50
o-Xylene	5.8	Not Detected	25	Not Detected
Styrene	5.8	Not Detected	25	Not Detected
Bromoform	5.8	Not Detected	60	Not Detected
Cumene	5.8	26	29	130
1,1,2,2-Tetrachloroethane	5.8	Not Detected	40	Not Detected
Propylbenzene	5.8	Not Detected	29	Not Detected
4-Ethyltoluene	5.8	Not Detected	29	Not Detected
1,3,5-Trimethylbenzene	5.8	Not Detected	29	Not Detected
1,2,4-Trimethylbenzene	5.8	Not Detected	29	Not Detected
1,3-Dichlorobenzene	5.8	Not Detected	35	Not Detected
1,4-Dichlorobenzene	5.8	Not Detected	35	Not Detected
alpha-Chlorotoluene	5.8	Not Detected	30	Not Detected
1,2-Dichlorobenzene	5.8	Not Detected	35	Not Detected
1,2,4-Trichlorobenzene	23	Not Detected	170	Not Detected
Hexachlorobutadiene	23	Not Detected	250	Not Detected

J = Estimated value due to bias in the CCV.

Container Type: 5 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	98	70-130
1,2-Dichloroethane-d4	111	70-130
4-Bromofluorobenzene	106	70-130

AIR TOXICS LTD.

Client Sample ID: No. 20 Bag 1-L

Lab ID#: 0601222A-04A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011822	Date of Collection:	1/10/06
Dil. Factor:	11.7	Date of Analysis:	1/19/06 03:24 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	5.8	Not Detected	29	Not Detected
Freon 114	5.8	41	41	290
Chloromethane	23	Not Detected	48	Not Detected
Vinyl Chloride	5.8	16	15	40
1,3-Butadiene	5.8	Not Detected	13	Not Detected
Bromomethane	5.8	Not Detected	23	Not Detected
Chloroethane	5.8	18 J	15	48 J
Freon 11	5.8	Not Detected	33	Not Detected
Ethanol	23	1800	44	3400
Freon 113	5.8	Not Detected	45	Not Detected
1,1-Dichloroethene	5.8	Not Detected	23	Not Detected
Acetone	23	160	56	380
2-Propanol	23	120	58	300
Carbon Disulfide	5.8	8.8	18	28
3-Chloropropene	23	Not Detected	73	Not Detected
Methylene Chloride	5.8	Not Detected	20	Not Detected
Methyl tert-butyl ether	5.8	7.9 J	21	28 J
trans-1,2-Dichloroethene	5.8	Not Detected	23	Not Detected
Hexane	5.8	470	21	1600
1,1-Dichloroethane	5.8	Not Detected	24	Not Detected
2-Butanone (Methyl Ethyl Ketone)	5.8	8.9	17	26
cis-1,2-Dichloroethene	5.8	39	23	150
Tetrahydrofuran	5.8	Not Detected	17	Not Detected
Chloroform	5.8	Not Detected	28	Not Detected
1,1,1-Trichloroethane	5.8	Not Detected	32	Not Detected
Cyclohexane	5.8	240	20	840
Carbon Tetrachloride	5.8	Not Detected	37	Not Detected
2,2,4-Trimethylpentane	5.8	450	27	2100
Benzene	5.8	32	19	100
1,2-Dichloroethane	5.8	Not Detected	24	Not Detected
Heptane	5.8	320	24	1300
Trichloroethene	5.8	9.2	31	50
1,2-Dichloropropane	5.8	Not Detected	27	Not Detected
1,4-Dioxane	23	Not Detected	84	Not Detected
Bromodichloromethane	5.8	Not Detected	39	Not Detected
cis-1,3-Dichloropropene	5.8	Not Detected	26	Not Detected
4-Methyl-2-pentanone	5.8	Not Detected	24	Not Detected
Toluene	5.8	30	22	110
trans-1,3-Dichloropropene	5.8	Not Detected	26	Not Detected
1,1,2-Trichloroethane	5.8	Not Detected	32	Not Detected
Tetrachloroethene	5.8	Not Detected	40	Not Detected
2-Hexanone	23	Not Detected	96	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 20 Bag 1-L

Lab ID#: 0601222A-04A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011822	Date of Collection:	1/10/06
Dil. Factor:	11.7	Date of Analysis:	1/19/06 03:24 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	5.8	Not Detected	50	Not Detected
1,2-Dibromoethane (EDB)	5.8	Not Detected	45	Not Detected
Chlorobenzene	5.8	Not Detected	27	Not Detected
Ethyl Benzene	5.8	Not Detected	25	Not Detected
m,p-Xylene	5.8	7.8	25	34
o-Xylene	5.8	Not Detected	25	Not Detected
Styrene	5.8	Not Detected	25	Not Detected
Bromoform	5.8	Not Detected	60	Not Detected
Cumene	5.8	26	29	130
1,1,2,2-Tetrachloroethane	5.8	Not Detected	40	Not Detected
Propylbenzene	5.8	Not Detected	29	Not Detected
4-Ethyltoluene	5.8	Not Detected	29	Not Detected
1,3,5-Trimethylbenzene	5.8	Not Detected	29	Not Detected
1,2,4-Trimethylbenzene	5.8	Not Detected	29	Not Detected
1,3-Dichlorobenzene	5.8	Not Detected	35	Not Detected
1,4-Dichlorobenzene	5.8	Not Detected	35	Not Detected
alpha-Chlorotoluene	5.8	Not Detected	30	Not Detected
1,2-Dichlorobenzene	5.8	Not Detected	35	Not Detected
1,2,4-Trichlorobenzene	23	Not Detected	170	Not Detected
Hexachlorobutadiene	23	Not Detected	250	Not Detected

J = Estimated value due to bias in the CCV.

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	100	70-130
1,2-Dichloroethane-d4	110	70-130
4-Bromofluorobenzene	106	70-130

AIR TOXICS LTD.

Client Sample ID: No. 2 Bag 1-L

Lab ID#: 0601222A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011823	Date of Collection:	1/10/06
Dil. Factor:	8.08	Date of Analysis:	1/19/06 04:04 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	4.0	Not Detected	20	Not Detected
Freon 114	4.0	28	28	200
Chloromethane	16	Not Detected	33	Not Detected
Vinyl Chloride	4.0	21	10	53
1,3-Butadiene	4.0	Not Detected	8.9	Not Detected
Bromomethane	4.0	Not Detected	16	Not Detected
Chloroethane	4.0	16 J	11	41 J
Freon 11	4.0	Not Detected	23	Not Detected
Ethanol	16	2500 E	30	4700 E
Freon 113	4.0	Not Detected	31	Not Detected
1,1-Dichloroethene	4.0	Not Detected	16	Not Detected
Acetone	16	33	38	78
2-Propanol	16	150	40	360
Carbon Disulfide	4.0	8.3	12	26
3-Chloropropene	16	Not Detected	50	Not Detected
Methylene Chloride	4.0	6.0	14	21
Methyl tert-butyl ether	4.0	5.0 J	14	18 J
trans-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Hexane	4.0	370	14	1300
1,1-Dichloroethane	4.0	7.0	16	28
2-Butanone (Methyl Ethyl Ketone)	4.0	4.8	12	14
cis-1,2-Dichloroethene	4.0	55	16	220
Tetrahydrofuran	4.0	40	12	120
Chloroform	4.0	Not Detected	20	Not Detected
1,1,1-Trichloroethane	4.0	Not Detected	22	Not Detected
Cyclohexane	4.0	170	14	580
Carbon Tetrachloride	4.0	Not Detected	25	Not Detected
2,2,4-Trimethylpentane	4.0	200	19	930
Benzene	4.0	64	13	200
1,2-Dichloroethane	4.0	Not Detected	16	Not Detected
Heptane	4.0	250	16	1000
Trichloroethene	4.0	7.6	22	41
1,2-Dichloropropane	4.0	Not Detected	19	Not Detected
1,4-Dioxane	16	Not Detected	58	Not Detected
Bromodichloromethane	4.0	Not Detected	27	Not Detected
cis-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
4-Methyl-2-pentanone	4.0	Not Detected	16	Not Detected
Toluene	4.0	20	15	74
trans-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
1,1,2-Trichloroethane	4.0	Not Detected	22	Not Detected
Tetrachloroethene	4.0	Not Detected	27	Not Detected
2-Hexanone	16	Not Detected	66	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 2 Bag 1-L

Lab ID#: 0601222A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011823	Date of Collection: 1/10/06
Dil. Factor:	8.08	Date of Analysis: 1/19/06 04:04 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	4.0	Not Detected	34	Not Detected
1,2-Dibromoethane (EDB)	4.0	Not Detected	31	Not Detected
Chlorobenzene	4.0	Not Detected	18	Not Detected
Ethyl Benzene	4.0	10	18	43
m,p-Xylene	4.0	8.5	18	37
o-Xylene	4.0	4.2	18	18
Styrene	4.0	Not Detected	17	Not Detected
Bromoform	4.0	Not Detected	42	Not Detected
Cumene	4.0	22	20	110
1,1,2,2-Tetrachloroethane	4.0	Not Detected	28	Not Detected
Propylbenzene	4.0	Not Detected	20	Not Detected
4-Ethyltoluene	4.0	Not Detected	20	Not Detected
1,3,5-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,2,4-Trimethylbenzene	4.0	Not Detected	20	Not Detected
1,3-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,4-Dichlorobenzene	4.0	Not Detected	24	Not Detected
alpha-Chlorotoluene	4.0	Not Detected	21	Not Detected
1,2-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,2,4-Trichlorobenzene	16	Not Detected	120	Not Detected
Hexachlorobutadiene	16	Not Detected	170	Not Detected

J = Estimated value due to bias in the CCV.
E = Exceeds instrument calibration range.
Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	98	70-130
1,2-Dichloroethane-d4	108	70-130
4-Bromofluorobenzene	107	70-130

AIR TOXICS LTD.

Client Sample ID: No. 14 Bag 3-L

Lab ID#: 0601222A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011824	Date of Collection:	1/10/06
Dil. Factor:	10.6	Date of Analysis:	1/19/06 04:52 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	5.3	Not Detected	26	Not Detected
Freon 114	5.3	35	37	240
Chloromethane	21	Not Detected	44	Not Detected
Vinyl Chloride	5.3	14	14	36
1,3-Butadiene	5.3	Not Detected	12	Not Detected
Bromomethane	5.3	Not Detected	20	Not Detected
Chloroethane	5.3	24 J	14	63 J
Freon 11	5.3	Not Detected	30	Not Detected
Ethanol	21	62	40	120
Freon 113	5.3	Not Detected	41	Not Detected
1,1-Dichloroethene	5.3	Not Detected	21	Not Detected
Acetone	21	38	50	91
2-Propanol	21	33	52	82
Carbon Disulfide	5.3	5.6	16	17
3-Chloropropene	21	Not Detected	66	Not Detected
Methylene Chloride	5.3	460	18	1600
Methyl tert-butyl ether	5.3	5.8 J	19	21 J
trans-1,2-Dichloroethene	5.3	Not Detected	21	Not Detected
Hexane	5.3	560	19	2000
1,1-Dichloroethane	5.3	Not Detected	21	Not Detected
2-Butanone (Methyl Ethyl Ketone)	5.3	7.7	16	23
cis-1,2-Dichloroethene	5.3	22	21	88
Tetrahydrofuran	5.3	30	16	90
Chloroform	5.3	Not Detected	26	Not Detected
1,1,1-Trichloroethane	5.3	Not Detected	29	Not Detected
Cyclohexane	5.3	240	18	840
Carbon Tetrachloride	5.3	Not Detected	33	Not Detected
2,2,4-Trimethylpentane	5.3	260	25	1200
Benzene	5.3	40	17	130
1,2-Dichloroethane	5.3	Not Detected	21	Not Detected
Heptane	5.3	270	22	1100
Trichloroethene	5.3	12	28	62
1,2-Dichloropropane	5.3	Not Detected	24	Not Detected
1,4-Dioxane	21	Not Detected	76	Not Detected
Bromodichloromethane	5.3	Not Detected	36	Not Detected
cis-1,3-Dichloropropene	5.3	Not Detected	24	Not Detected
4-Methyl-2-pentanone	5.3	Not Detected	22	Not Detected
Toluene	5.3	28	20	100
trans-1,3-Dichloropropene	5.3	Not Detected	24	Not Detected
1,1,2-Trichloroethane	5.3	Not Detected	29	Not Detected
Tetrachloroethene	5.3	Not Detected	36	Not Detected
2-Hexanone	21	Not Detected	87	Not Detected

AIR TOXICS LTD.

Client Sample ID: No. 14 Bag 3-L

Lab ID#: 0601222A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011824	Date of Collection: 1/10/06
Dil. Factor:	10.6	Date of Analysis: 1/19/06 04:52 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	5.3	Not Detected	45	Not Detected
1,2-Dibromoethane (EDB)	5.3	Not Detected	41	Not Detected
Chlorobenzene	5.3	Not Detected	24	Not Detected
Ethyl Benzene	5.3	27	23	120
m,p-Xylene	5.3	21	23	93
o-Xylene	5.3	13	23	55
Styrene	5.3	Not Detected	22	Not Detected
Bromoform	5.3	Not Detected	55	Not Detected
Cumene	5.3	50	26	250
1,1,2,2-Tetrachloroethane	5.3	Not Detected	36	Not Detected
Propylbenzene	5.3	Not Detected	26	Not Detected
4-Ethyltoluene	5.3	Not Detected	26	Not Detected
1,3,5-Trimethylbenzene	5.3	Not Detected	26	Not Detected
1,2,4-Trimethylbenzene	5.3	10	26	50
1,3-Dichlorobenzene	5.3	Not Detected	32	Not Detected
1,4-Dichlorobenzene	5.3	Not Detected	32	Not Detected
alpha-Chlorotoluene	5.3	Not Detected	27	Not Detected
1,2-Dichlorobenzene	5.3	Not Detected	32	Not Detected
1,2,4-Trichlorobenzene	21	Not Detected	160	Not Detected
Hexachlorobutadiene	21	Not Detected	230	Not Detected

J = Estimated value due to bias in the CCV.

Container Type: 3 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	99	70-130
1,2-Dichloroethane-d4	107	70-130
4-Bromofluorobenzene	105	70-130

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011805	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/18/06 01:52 PM	

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	0.50	Not Detected	2.5	Not Detected
Freon 114	0.50	Not Detected	3.5	Not Detected
Chloromethane	2.0	Not Detected	4.1	Not Detected
Vinyl Chloride	0.50	Not Detected	1.3	Not Detected
1,3-Butadiene	0.50	Not Detected	1.1	Not Detected
Bromomethane	0.50	Not Detected	1.9	Not Detected
Chloroethane	0.50	Not Detected	1.3	Not Detected
Freon 11	0.50	Not Detected	2.8	Not Detected
Ethanol	2.0	Not Detected	3.8	Not Detected
Freon 113	0.50	Not Detected	3.8	Not Detected
1,1-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Acetone	2.0	Not Detected	4.8	Not Detected
2-Propanol	2.0	Not Detected	4.9	Not Detected
Carbon Disulfide	0.50	Not Detected	1.6	Not Detected
3-Chloropropene	2.0	Not Detected	6.3	Not Detected
Methylene Chloride	0.50	Not Detected	1.7	Not Detected
Methyl tert-butyl ether	0.50	Not Detected	1.8	Not Detected
trans-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Hexane	0.50	Not Detected	1.8	Not Detected
1,1-Dichloroethane	0.50	Not Detected	2.0	Not Detected
2-Butanone (Methyl Ethyl Ketone)	0.50	Not Detected	1.5	Not Detected
cis-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Tetrahydrofuran	0.50	Not Detected	1.5	Not Detected
Chloroform	0.50	Not Detected	2.4	Not Detected
1,1,1-Trichloroethane	0.50	Not Detected	2.7	Not Detected
Cyclohexane	0.50	Not Detected	1.7	Not Detected
Carbon Tetrachloride	0.50	Not Detected	3.1	Not Detected
2,2,4-Trimethylpentane	0.50	Not Detected	2.3	Not Detected
Benzene	0.50	Not Detected	1.6	Not Detected
1,2-Dichloroethane	0.50	Not Detected	2.0	Not Detected
Heptane	0.50	Not Detected	2.0	Not Detected
Trichloroethene	0.50	Not Detected	2.7	Not Detected
1,2-Dichloropropane	0.50	Not Detected	2.3	Not Detected
1,4-Dioxane	2.0	Not Detected	7.2	Not Detected
Bromodichloromethane	0.50	Not Detected	3.4	Not Detected
cis-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
4-Methyl-2-pentanone	0.50	Not Detected	2.0	Not Detected
Toluene	0.50	Not Detected	1.9	Not Detected
trans-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
1,1,2-Trichloroethane	0.50	Not Detected	2.7	Not Detected
Tetrachloroethene	0.50	Not Detected	3.4	Not Detected
2-Hexanone	2.0	Not Detected	8.2	Not Detected

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011805	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/18/06 01:52 PM	

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Dibromochloromethane	0.50	Not Detected	4.2	Not Detected
1,2-Dibromoethane (EDB)	0.50	Not Detected	3.8	Not Detected
Chlorobenzene	0.50	Not Detected	2.3	Not Detected
Ethyl Benzene	0.50	Not Detected	2.2	Not Detected
m,p-Xylene	0.50	Not Detected	2.2	Not Detected
o-Xylene	0.50	Not Detected	2.2	Not Detected
Styrene	0.50	Not Detected	2.1	Not Detected
Bromoform	0.50	Not Detected	5.2	Not Detected
Cumene	0.50	Not Detected	2.4	Not Detected
1,1,2,2-Tetrachloroethane	0.50	Not Detected	3.4	Not Detected
Propylbenzene	0.50	Not Detected	2.4	Not Detected
4-Ethyltoluene	0.50	Not Detected	2.4	Not Detected
1,3,5-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,2,4-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,3-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,4-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
alpha-Chlorotoluene	0.50	Not Detected	2.6	Not Detected
1,2-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,2,4-Trichlorobenzene	2.0	Not Detected	15	Not Detected
Hexachlorobutadiene	2.0	Not Detected	21	Not Detected

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	100	70-130
1,2-Dichloroethane-d4	106	70-130
4-Bromofluorobenzene	110	70-130

AIR TOXICS LTD.

Client Sample ID: CCV

Lab ID#: 0601222A-08A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011802	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/18/06 10:34 AM	

Compound	%Recovery
Freon 12	124
Freon 114	119
Chloromethane	108
Vinyl Chloride	106
1,3-Butadiene	86
Bromomethane	111
Chloroethane	134 Q
Freon 11	122
Ethanol	100
Freon 113	109
1,1-Dichloroethene	107
Acetone	91
2-Propanol	106
Carbon Disulfide	92
3-Chloropropene	99
Methylene Chloride	111
Methyl tert-butyl ether	131 Q
trans-1,2-Dichloroethene	94
Hexane	91
1,1-Dichloroethane	107
2-Butanone (Methyl Ethyl Ketone)	108
cis-1,2-Dichloroethene	110
Tetrahydrofuran	108
Chloroform	107
1,1,1-Trichloroethane	111
Cyclohexane	98
Carbon Tetrachloride	117
2,2,4-Trimethylpentane	102
Benzene	98
1,2-Dichloroethane	118
Heptane	99
Trichloroethene	107
1,2-Dichloropropane	104
1,4-Dioxane	98
Bromodichloromethane	106
cis-1,3-Dichloropropene	94
4-Methyl-2-pentanone	104
Toluene	99
trans-1,3-Dichloropropene	103
1,1,2-Trichloroethane	96
Tetrachloroethene	104
2-Hexanone	88

AIR TOXICS LTD.

Client Sample ID: CCV

Lab ID#: 0601222A-08A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011802	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/18/06 10:34 AM	

Compound	%Recovery
Dibromochloromethane	99
1,2-Dibromoethane (EDB)	93
Chlorobenzene	95
Ethyl Benzene	93
m,p-Xylene	92
o-Xylene	89
Styrene	105
Bromoform	102
Cumene	89
1,1,2,2-Tetrachloroethane	87
Propylbenzene	88
4-Ethyltoluene	94
1,3,5-Trimethylbenzene	81
1,2,4-Trimethylbenzene	80
1,3-Dichlorobenzene	88
1,4-Dichlorobenzene	82
alpha-Chlorotoluene	76
1,2-Dichlorobenzene	84
1,2,4-Trichlorobenzene	98
Hexachlorobutadiene	102

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	105	70-130
1,2-Dichloroethane-d4	105	70-130
4-Bromofluorobenzene	108	70-130

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222A-09A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011803	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/18/06 11:28 AM

Compound	%Recovery
Freon 12	107
Freon 114	102
Chloromethane	104
Vinyl Chloride	90
1,3-Butadiene	102
Bromomethane	104
Chloroethane	118
Freon 11	105
Ethanol	86
Freon 113	102
1,1-Dichloroethene	96
Acetone	102
2-Propanol	104
Carbon Disulfide	104
3-Chloropropene	104
Methylene Chloride	100
Methyl tert-butyl ether	136
trans-1,2-Dichloroethene	101
Hexane	97
1,1-Dichloroethane	98
2-Butanone (Methyl Ethyl Ketone)	119
cis-1,2-Dichloroethene	127
Tetrahydrofuran	111
Chloroform	98
1,1,1-Trichloroethane	96
Cyclohexane	102
Carbon Tetrachloride	100
2,2,4-Trimethylpentane	103
Benzene	91
1,2-Dichloroethane	110
Heptane	107
Trichloroethene	99
1,2-Dichloropropane	98
1,4-Dioxane	103
Bromodichloromethane	112
cis-1,3-Dichloropropene	100
4-Methyl-2-pentanone	113
Toluene	100
trans-1,3-Dichloropropene	108
1,1,2-Trichloroethane	94
Tetrachloroethene	104
2-Hexanone	89

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222A-09A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	1011803	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/18/06 11:28 AM	

Compound	%Recovery
Dibromochloromethane	105
1,2-Dibromoethane (EDB)	99
Chlorobenzene	92
Ethyl Benzene	94
m,p-Xylene	97
o-Xylene	89
Styrene	114
Bromoform	101
Cumene	76
1,1,2,2-Tetrachloroethane	79
Propylbenzene	82
4-Ethyltoluene	84
1,3,5-Trimethylbenzene	74
1,2,4-Trimethylbenzene	77
1,3-Dichlorobenzene	76
1,4-Dichlorobenzene	74
alpha-Chlorotoluene	70
1,2-Dichlorobenzene	69 Q
1,2,4-Trichlorobenzene	66 Q
Hexachlorobutadiene	73

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	102	70-130
1,2-Dichloroethane-d4	106	70-130
4-Bromofluorobenzene	109	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0601222D

Work Order Summary

CLIENT:	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way Suite 100 Long Beach, CA 90806-6816	**BILL TO:**	Mr. Benny Benson SCS Engineers 3900 Kilroy Airport Way Suite 100 Long Beach, CA 90806-6816
PHONE:	562-426-9544	**P.O. #**	06-1126
FAX:	562-988-3183	**PROJECT #**	Kekaha Landfill
DATE RECEIVED:	01/13/2006	**CONTACT:**	Kyle Vagadori
DATE COMPLETED:	01/25/2006		

FRACTION #	NAME	TEST
01AB	#14 A + B vials	Siloxanes
02AB	#21 A + B vials	Siloxanes
03A	Lab Blank	Siloxanes
04A	LCS	Siloxanes

CERTIFIED BY: Linda L. Freeman DATE: 01/25/06

Laboratory Director

LABORATORY NARRATIVE
Siloxanes
SCS Engineers
Workorder# 0601222D

Four Vial samples were received on January 13, 2006. The laboratory performed analysis for siloxanes by GC/MS. A sample volume of 1.0 uL was injected directly onto the GC column. Initial results are in ug/mL. The units are converted to total micrograms (ug) by multiplying the result (ug/mL) by the total volume (mL) contained in the impinger. See the data sheets for the reporting limits for each compound.

Receiving Notes

A Temperature Blank was included with the shipment. The temperature was measured and was not within 4 ± 2°C. Coolant in the form of blue ice was present. Internal stability studies at Air Toxics Ltd. indicate Siloxane compounds may be stable for up to five days from collection at room temperature. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Analytical Notes

Impinger volumes were measured at the laboratory using a graduated cylinder and documented in the analytical logbook.

A front and back impinger was received for each sample. Each impinger was analyzed separately. The results for each analyte were then additively combined and reported as a single concentration. The reported surrogate recovery is derived from the front impinger analysis only.

Sampling volume was supplied by the client. A sample volume of 30 liters was assumed for all QC samples.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated Value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

Client Sample ID: #14 A + B vials

Lab ID#: 0601222D-01AB

SILOXANES - GC/MS

File Name:	k011334	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/14/06 01:30 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Octamethylcyclotetrasiloxane (D4)	74	Not Detected	900	Not Detected
Decamethylcylopentasiloxane (D5)	59	Not Detected	900	Not Detected
Dodecamethylcyclohexasiloxane (D6)	98	Not Detected	1800	Not Detected
Hexamethyldisiloxane	130	Not Detected	900	Not Detected
Octamethyltrisiloxane	92	Not Detected	900	Not Detected

Air Sample Volume(L): 31.5
Impinger Total Volume(mL): 28.2

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	98	70-130

AIR TOXICS LTD.

Client Sample ID: #21 A + B vials

Lab ID#: 0601222D-02AB

SILOXANES - GC/MS

File Name:	k011336	Date of Collection:	1/10/06
Dil. Factor:	1.00	Date of Analysis:	1/14/06 02:18 AM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Octamethylcyclotetrasiloxane (D4)	79	Not Detected	960	Not Detected
Decamethylcylopentasiloxane (D5)	63	Not Detected	960	Not Detected
Dodecamethylcyclohexasiloxane (D6)	100	Not Detected	1900	Not Detected
Hexamethyldisiloxane	140	Not Detected	960	Not Detected
Octamethyltrisiloxane	99	Not Detected	960	Not Detected

Air Sample Volume(L): 29.1
Impinger Total Volume(mL): 27.8

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	99	70-130

AIR TOXICS LTD.

Client Sample ID: Lab Blank

Lab ID#: 0601222D-03A

SILOXANES - GC/MS

File Name:	k011327	Date of Collection: NA
Dil. Factor:	1.00	Date of Analysis: 1/13/06 10:40 PM

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Octamethylcyclotetrasiloxane (D4)	2.7	Not Detected	33	Not Detected
Decamethylcylopentasiloxane (D5)	2.2	Not Detected	33	Not Detected
Dodecamethylcyclohexasiloxane (D6)	3.7	Not Detected	67	Not Detected
Hexamethyldisiloxane	5.0	Not Detected	33	Not Detected
Octamethyltrisiloxane	3.4	Not Detected	33	Not Detected

Air Sample Volume(L): 30.0
Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	110	70-130

AIR TOXICS LTD.

Client Sample ID: LCS

Lab ID#: 0601222D-04A

SILOXANES - GC/MS

File Name:	k011326	Date of Collection: NA	
Dil. Factor:	1.00	Date of Analysis: 1/13/06 10:16 PM	

Compound	%Recovery
Octamethylcyclotetrasiloxane (D4)	115
Decamethylcylopentasiloxane (D5)	115
Dodecamethylcyclohexasiloxane (D6)	Not Spiked
Hexamethyldisiloxane	92
Octamethyltrisiloxane	114

Air Sample Volume(L): 30.0
Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	110	70-130

APPENDIX B

INTERIM REPORT ON TASK 2:
ENERGY BASELINE EVALUATION AND
CHP AND ECONOMIC AND ENGINEERING OPTIONS

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 2
Energy Baseline Evaluation and
CHP Economic and Engineering Options

Prepared For:

County of Kauai
Office of Economic Development
Kauai, Hawaii

Prepared By:

SCS Energy
Long Beach, California

September 2006

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 2

TABLE OF CONTENTS

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 2

TABLE OF CONTENTS (continued...)

Section **Page**

Tables and Figures

Appendices

SECTION 1

INTRODUCTION

The County of Kauai Office of Economic Development engaged SCS Energy (SCS) to conduct a combined heat and power (CHP) feasibility study for the Pacific Missile Range Facility (PMRF). Task 2 of the work plan for this study calls for:

- Evaluation of all existing PMRF energy data, electric load profiles, and thermal load profiles for the purpose of establishing a facility baseline;
- Development of an inventory of major equipment;
- Identification of plans for equipment replacement, and site modifications and expansions;
- Development of economic and engineering options for a CHP project, including consideration of: replacement of the existing PMRF power plant with a new CHP plant; retrofitting the existing PMRF power plant; constructing a backup CHP plant; or other options determined by SCS to be viable;
- Identification of interconnection equipment/standards of the Kauai Island Utility Cooperative (KIUC);
- Identification of air emissions and air emissions standards that would govern modifications to the existing PMRF power plant or a new power plant; and
- Submittal of a Task 2 report.

SECTION 2

ENERGY BASELINE EVALUATION

Electric Power Distribution System

The Pacific Missile Range Facility (PMRF) provided SCS with single line diagrams and with utilities composite maps. The utilities composite maps show the physical locations of the main on-site electric power distribution lines, and the location of the larger transformers. The diagrams and drawings are not reproduced herein because of their size. The most relevant information shown on the diagrams and drawings is summarized below.

PMRF interconnects with Kauai Island Utility Cooperative (KIUC) at five locations. The power distribution systems at PMRF behind these connections to KIUC are not interconnected between each other within PMRF. The four larger interconnection points are as follows:

- The first interconnection is at the extreme southern end of PMRF, and is immediately adjacent to the Kekaha Landfill. The interconnection at this point is known to PMRF as "Kokole Point." The connection to KIUC is at 12.47 kV. The main distribution line within PMRF parallels Kokole Point Road, and continues through at 12.47 kV to the last significant point of use on this interconnection. At several locations, power is transformed down to 480 V, 240 V or 120 V. PMRF has two emergency generators on this circuit;
- The second interconnection point to KIUC by PMRF, moving northward, is known to PMRF as "Navy Housing." The connection at this point is at 12.47 kV. The main transmission line within PMRF is at 12.47 kV and it parallels Tartar Drive. The power is then transformed down to 480 V and lower voltages at various locations;
- The third interconnection point, moving northward, is known to PMRF as "PMRF Main Base." The interconnection to KIUC is at 12.47 kV. The distribution line into PMRF parallels Imiloa Road. At various locations, the voltage is transformed down to 4,160 V, 480 V and lower. The existing PMRF power plant is tied into this electrical distribution system. The power plant is located at the southern end of the electrical distribution system. The power plant generates power at 4,160 V. The power is stepped up to 12.47 kV at the power plant. The northern end of this distribution system provides electrical service to the main hangar; and
- The northern most point of connection to KIUC is at what PMRF calls the "North Gate." KIUC service is provided at 12.47 kV.

The shortest distance between the 12.47 kV line at the Kokole Point power distribution system and the power distribution system at Navy Housing is about 2,000 feet. An interconnection between these two power distribution systems could be accomplished through construction of an interconnecting transmission line paralleling Nohili Road. One of the points of interconnection to KIUC would need to be eliminated. In addition to the usual physical obstacles to be overcome in making such an interconnection, there are some ownership issues that will need to be addressed. Not all of the high voltage distribution line segments within PMRF are owned by PMRF, as some of the lines within PMRF are actually owned by KIUC.

The shortest distance between the 12.47 kV line at the northern end of the Navy Housing power distribution system and the southern end of the PMRF Main Base power distribution system is 10,000 feet. An interconnection between these two power distribution systems could be accomplished through the construction of an interconnecting transmission line paralleling Nohili Road. PMRF advises that it is likely that the transmission line would need to be installed underground, due to its proximity to the runway.

The northern end of the PMRF Main Base distribution system could be interconnected to the southern end of the North Gate distribution system through the installation of about 900 feet of 12.47 kV transmission line in an open field. Again, issues of PMRF and KIUC line ownership may cause administrative issues in addition to physical issues.

Electric Power Purchases

PMRF told SCS that only three of the points of interconnection with KIUC drew significant quantities of electric power -- PMRF Main Base; Navy Housing; and Kokole Point. PMRF provided SCS with copies of the KIUC electric bills for these three points of interconnection for September 2003 through April 2006.

SCS analyzed these bills and developed Table Nos. 2-1, 2-2 and 2-3. Table No. 2-1 summarizes key data for the PMRF Main Base point of service:

- The metered peak power demand (i.e., the highest running 15-minute average) is about 1,400 kW, and does not vary greatly by season;
- The average demand (total monthly kWh divided by total hours in a month) is about 700 kW to 800 kW;
- Power consumption is about 500,000 kWh to 600,000 kWh per month. In 2004 and 2005, total annual power consumption was 6,502,000 kWh and 6,493,200 kWh, respectively; and
- Electric power cost has ranged from a low of \$0.22/kWh in 2003 to a high of \$0.31/kWh in 2006.

Table No. 2-2 summarizes key data for the Navy Housing point of service:

- The metered peak power demand is about 700 kW, and does not vary greatly by season;
- The average demand is about 300 kW to 400 kW;
- Power consumption is about 250,000 kWh to 300,000 kWh per month. In 2004 and 2005, total annual power consumption was 2,985,600 kWh and 3,328,200 kWh, respectively;
- Electric power cost has ranged from a low of $0.21/kWh in 2003 to a high of $0.31/kWh in 2006.

Table No. 2-3 summarizes key data for the Kokole Point point of service:

- The metered peak power demand is about 95 kW, and does not vary greatly by season;
- The average demand is about 50 kW to 60 kW;
- Power consumption is about 35,000 kWh to 40,000 kWh per month. In 2004 and 2005, total annual power consumption was 441,032 kWh and 467,360 kWh, respectively;
- Electric power cost has ranged from a low of $0.22/kWh in 2003 to a high of $0.32/kWh in 2006.

Table No. 2-4 combines data from Table Nos. 2-1, 2-2 and 2-3 to provide the aggregated power consumption and cost for all three points of service.

On-Site Power Generation

Equipment Description

PMRF is currently operating an on-site power plant. The power plant employs six reciprocating engines. The engines designated Engine Nos. 1, 2 and 3 are Caterpillar Model 3412. The engines designated Engine Nos. 7 and 8 are Caterpillar Model 3508.

Engine Nos. 1, 2 and 3 have individual nameplate capacities of 300 kW. The engines were installed circa 1986-1987. Engine Nos. 7 and 8 have individual nameplate capacities of 600 kW. The engines were installed circa 1998-1999. The total installed capacity at the power plant is 2,100 kW.

All five engines generate power at 4,160 kV. The power is aggregated, is stepped up to 12.47 kV, and is delivered into the PMRF Main Base power distribution system. All five engines are fired on No. 2 fuel oil.

The generators on Engine Nos. 1, 2 and 3 are protected by Basler protective relays for over current and for ground fault over current. Brown Boveri protective relays provide protection for reverse power, differential power and regular sequence over current. Engine Nos. 7 and 8 are each equipped with a Beckwith M-3420, which performs all of the required protective functions.

The tie point to the PMRF distribution grid, which is essentially the tie to KIUC, is equipped with General Electric (GE) protective relays for over current, directional over current, and over current ground. These GE relays provide protection to PMRF's distribution grid, as contrasted to the previously described relays which individually protect the generators. The PMRF power plant has the ability to operate in parallel with or in isolation from KIUC.

Diesel Fuel Consumption

Table No. 2-5 tabulates monthly diesel oil consumption at the PMRF power plant for Federal Fiscal Years 2004 through 2006. The power plant uses about 10,000 gallons of diesel oil per month. Table No. 2-5 also tabulates the cost of the diesel oil. Diesel oil is stored in three underground 10,000-gallon tanks.

Power Generation

PMRF told SCS that the power plant operates Monday through Friday from 7:30 a.m. to 3:30 p.m. The power plant does not operate on federal holidays.

During SCS's site visit on January 10, 2006, SCS observed Engine Nos. 3, 7 and 8 to be operating at 160 kW, 210 kW and 210 kW, respectively. During SCS's site visit on August 3, 2006, SCS observed Engine Nos. 3, 7 and 8 to be operating at 160 kW, 260 kW and 260 kW, respectively.

PMRF provided SCS with a tabulation of total kWh produced (monthly basis) for Fiscal Years 2004 through 2006. Power production data is not available on an hourly or daily basis. SCS combined the power production data with diesel oil consumption and cost data to prepare Table Nos. 2-6, 2-7 and 2-8 to calculate:

- Average kWh produced per operating day;
- Power production cost, based on diesel fuel cost alone; and
- Engine heat rate (Btu of fuel consumed per kWh of electricity).

The average kWh produced per day is in general agreement with PMRF's statement that the engines run eight hours per day, and with SCS's observation that the power plant was producing 580 kW and 680 kW during SCS's site visits.

The cost of electric power production has increased from \$0.11/kWh to \$0.22/kWh, as a consequence of rising oil prices.

The heat rate of the engines averaged 11,125 Btu/kWh during the period covered by the tables. A heat rate of 11,125 Btu/kWh is equivalent to an efficiency of about 30.7 percent.

Thermal Energy Consumption

PMRF does not have a central plant for the production of steam, hot water or chilled water. PMRF does not have thermal energy plants that serve clusters of buildings. Virtually every building has its own hot water generation facilities, if a building requires hot water, or has its own stand-alone air conditioning system. PMRF spans a distance of over five miles from the Kokole Point to the North Hangar. As a consequence, the thermal loads are generally not close together. Most of the buildings are relatively small in size, and do not generate appreciable thermal loads.

Diagrams have been provided in Appendix A which show the physical locations of the buildings identified below.

Hot Water

PMRF has no use for steam. Consequently, there are no boilers at PMRF.

Hot water use at PMRF is limited to residential, restroom and cleanup purposes. There is no process demand for hot water. Hot water demands are small, and are widely distributed. Hot water is produced by domestic or small commercial hot water heaters. The hot water heaters use electricity, solar energy, and occasionally propane.

PMRF was able to identify only one significant concentrated hot water demand. It is centered at a hot water generator in Building 1262. The hot water generator serves the galley in Building 1262 and the Visitor Quarters in Building 1261.

The hot water generator has the following characteristics.

Manufacturer	Teledyne Laars
Input	400,000 Btu/hr
Output	324,000 Btu/hr
Hot Water Storage Tank Water Temperature	140° F
Hot Water Pumps	Two at ¾ hp
Propane Storage Tank	500 gallons

The above information was taken off of the nameplates on the equipment during a field inspection.

The propane at this location is used for cooking and for hot water heating. Records are not available for actual propane use at this location.

The galley is located about 10,000 feet from the existing PMRF power plant. It is not feasible to supply hot water to this location from the location of the existing PMRF power plant.

Chilled Water

Air conditioning is provided at PMRF for the purposes of personnel comfort and for equipment protection. The air conditioning is supplied through a wide range of equipment:

- Window-mounted units;
- Units with a condenser located outside a building with circulation of an organic coolant to indoor wall-mounted units;
- Units which duct cold air into the buildings; and
- Units which produce cold water (chillers), with the chilled water distributed through the buildings.

The buildings which are served by chillers offer the only reasonable opportunities for use of thermal energy generated by power production. The buildings served by chillers generally have the highest air conditioning loads, and chilled water can be produced from steam or hot water, using absorption chiller technology.

PMRF identified four buildings served by chillers -- Building 105, Building 130, Building 300 and Building 384. Technical information on the chillers was obtained, during a field inspection, from the nameplates on the equipment at these four buildings, and at four other buildings -- Building 1261, Building 1262, Building 1264, and Building 105ROCS.

The air conditioning equipment at Building 1261, Building 1262 and Building 1264, while not chillers, was inspected. Building 1262 is the galley, and Buildings 1261 and 1264 are located close to Building 1262. It was felt that a "thermal load cluster" might be established around Building 1262. It might be possible to satisfy such a thermal load cluster through waste heat from a "micro" power plant located at Building 1262. A fourth building, Building 105ROCS, was also inspected because it abuts Building 105, and it may present an opportunity to coordinate air conditioning loads with Building 105.

The following paragraphs summarize the information collected on the air conditioning systems at the eight buildings.

Building 105 is also known as the Range Operations Center. It is served by two air-cooled chillers, which are located adjacent to each other. Building 105 appears to have the largest cooling demand at PMRF. Building 105 is located only about 500 feet away from the existing PMRF power plant. The chillers are identical in characteristics and differ only in their serial number.

Type	Carrier
Model	30GOS-060-C610
Serial Nos.	1697F67756/1697F67775
Two Compressors	46.8 RLA and 65.4 RLA
Voltage	480 V

Carrier technical information indicates that each chiller has a maximum power draw of 70 kW and will produce 60 tons of cooling. At the time of the visit, cold water was being delivered at 49° F and warm water was returned at 61.5° F.

Building 105ROCS is immediately adjacent to Building 105. Building 105ROCS is served by an air-cooled condenser-type unit. The nameplate information on this unit is as follows:

Type	McQuay
Model	ACD115A27BH
Serial No.	TO3B2234
Compressor	29 amp minimum/35 amp maximum
Voltage	480 V
Condenser Fans	Eight at 1 ½ horsepower

It was not possible to contact the manufacturer for additional information. SCS estimates that the capacity of the unit is 115 tons. During the site visit, the unit appeared to be operating at 50 percent load.

Building 105ROCS was also being served by a temporary air-cooled chiller. The following nameplate information was collected:

Type	Carrier
Model	30RAN030DS-615PP
Serial No.	0306905088
Compressor	Two at 23.8 RLA
Voltage	480 V

Carrier technical information indicates that the capacity of this unit is 27 tons, and has a maximum power draw of 32 kW.

Building 130 is a radar building and the principal air conditioning requirement at this building is equipment cooling. Building 130 is only 100 feet away from the existing PMRF power plant.

The following nameplate information was obtained off of Building 130's air-cooled chiller:

Type	Technical Systems/RAE Corporation
Model	30A0LD20
Serial No.	1-96 F35801
Compressor	Minimum circuit capacity = 100 amps
Voltage	480 V

RAE technical information indicates that the capacity of this unit is 18 tons, with a maximum power draw of 20 kW.

Total installed cooling capacity for the above three buildings, which are all located within 500 feet of the existing PMRF power plant, is 280 tons.

Building 300 is a fire station and control tower. It is located about 2,700 feet north of the existing PMRF power plant. Its distance from the power plant makes its inclusion in a CHP project unlikely. Nameplate information on this unit is as follows:

Type	Carrier Aquasnap
Model	30RAN025 511 KV
Serial No.	1105403752
Compressors	Two at 40.8 RLA
Voltage	480 V

Carrier technical information indicates that the capacity of this air-cooled chiller is 24 tons, and it has a maximum power draw of 30 kW.

Building 384 is an aircraft hangar. It is located about 3,700 feet north of the existing PMRF power plant. Its distance from the power plant makes it unlikely that it could be included within a CHP project. Nameplate information on the chiller is as follows:

Type	Dunham-Bush
Model	AC60A
Serial No.	81069201A88B
Compressors	Two at 48.6 RLA
Voltage	480 V

During SCS's site visit, the cold water temperature was observed to be 54° F and the warm water being returned was 73° F. Dunham-Bush technical information indicates that the capacity of this air-cooled chiller is 60 tons.

Building 1262 is served by a relatively new air conditioning unit. Its nameplate information is as follows:

Type	Lennox L Series
Model	C8290
Serial No.	5605H 00801
Evaporator	5 hp
Fans	Four at 1/3 hp
Exhaust Fans	Two at 1/3 hp

Lennox technical information indicates that the capacity of this unit is 7 tons, with a maximum power draw of 10 kW.

Building 1261, about 200 feet east of Building 1262, is equipped with a direct expansion cooling unit. Nameplate information is as follows:

Type	McQuay Schneider
Model	LSL 117DH
Serial No.	WA00487-04
Fan Motors	Three at 1 hp
Compressor	25 hp

SCS could find no technical information on this unit, but estimates the capacity to be about 18 tons with a power requirement of about 20 kW.

Building 1264 is a recreation center. It is about 350 feet northeast of Building 1262. It employs a direct expansion cooling unit with the following nameplate information:

Type	Carrier
Model	Weathermaster
Serial No.	38AA-024-FSHA
Compressors	Two at 39.3 RLA

Carrier technical information indicates that the capacity of this unit is 24 tons, with a maximum power draw of 28 kW.

Building No. 1260 has an air-cooled condensing unit with a capacity of 12 tons. Nameplate information is as follows:

Type	McQuay
Model	AC2016AC12-ER11
Serial No.	STNU050900180
Fan Motors	One at 2 hp
Compressors	Two

The total installed cooling capacity, serving the above four buildings, which form a cooling cluster around and including Building 1262, is about 60 tons. Inclusion of these buildings in a "micro" CHP project located at Building 1262 would require that the equipment inside these buildings be retrofitted for chilled water.

Planned Facilities

PMRF indicated that there are no plans for new buildings at the base, no plans for modifying the existing PMRF power plant, and no plans for major upgrades to cooling facilities.

TABLE NO. 2-1
ELECTRIC POWER PURCHASES FROM KIUC
FROM SEPTEMBER 2003 TO APRIL 2006
PMRF MAIN BASE POINT OF SERVICE

Date		Days	Demand (kW)	kWh	Calculated Average kW	Monthly Bill ($)	Calculated $/kWh
Beginning	End						
9/17/2003	10/17/2003	30	1350	552600	768	$120,624.43	$0.22
10/17/2003	11/14/2003	28	1350	529800	788	$114,075.96	$0.22
11/14/2003	12/12/2003	28	1296	468000	696	$103,024.99	$0.22
12/12/2003	1/14/2004	33	1230	552600	698	$119,647.47	$0.22
1/14/2004	2/13/2004	30	1284	494400	687	$111,132.98	$0.22
2/13/2004	3/15/2004	31	1230	503400	677	$113,616.40	$0.23
3/15/2004	4/14/2004	30	1248	499200	693	$114,978.27	$0.23
4/14/2004	5/14/2004	30	1356	520200	723	$127,740.50	$0.25
5/14/2004	6/10/2004	27	1386	518400	800	$135,897.13	$0.26
6/10/2004	7/12/2004	32	1386	563400	734	$147,395.76	$0.26
7/12/2004	8/12/2004	31	1428	606600	815	$151,420.84	$0.25
8/12/2004	9/13/2004	32	1410	646800	842	$162,891.12	$0.25
9/13/2004	10/13/2004	30	1446	592800	823	$154,136.35	$0.26
10/13/2004	11/12/2004	30	1392	534600	743	$146,036.66	$0.27
11/12/2004	12/10/2004	28	1308	505200	752	$143,095.31	$0.28
12/10/2004	1/12/2005	33	1230	567000	716	$150,061.31	$0.26
1/12/2005	2/14/2005	33	1272	552000	697	$140,108.80	$0.25
2/14/2005	3/17/2005	31	1236	489000	657	$129,233.07	$0.26
3/17/2005	4/18/2005	32	1290	546600	712	$152,980.95	$0.28
4/18/2005	5/16/2005	28	1290	498000	741	$147,986.05	$0.30
5/16/2005	6/17/2005	32	1386	610800	795	$177,506.61	$0.29
6/17/2005	7/18/2005	31	1350	600000	806	$170,337.42	$0.28
7/18/2005	8/15/2005	28	1392	498000	741	$146,052.25	$0.29
8/15/2005	9/12/2005	31	1350	600000	806	$170,337.42	$0.28
9/12/2005	10/11/2005	29	1416	558600	803	$177,145.14	$0.32
10/11/2005	11/10/2005	30	1374	525600	730	$174,319.70	$0.33
11/10/2005	12/9/2005	29	1242	471600	678	$106,114.35	$0.23
12/9/2005	1/11/2006	33	1194	543000	686	$161,665.83	$0.30
1/11/2006	2/10/2006	30	1218	483000	671	$141,409.84	$0.29
2/10/2006	3/13/2006	31	1092	441600	594	$132,043.23	$0.30
3/13/2006	4/13/2006	31	1128	466800	627	$142,128.10	$0.30
4/13/2006	5/15/2006	32	1182	507000	660	$158,933.92	$0.31

TABLE NO. 2-2
ELECTRIC POWER PURCHASES FROM KIUC
FROM SEPTEMBER 2003 TO APRIL 2006
NAVY HOUSING POINT OF SERVICE

Date		Days	Demand (kW)	kWh	Calculated Average kW	Monthly Bill ($)	Calculated $/kWh
Beginning	End						
9/17/2003	10/17/2003	30	648	282000	392	$59,823.01	$0.21
10/17/2003	11/14/2003	28	630	245400	365	$52,198.95	$0.21
11/14/2003	12/12/2003	28	564	228600	340	$48,767.18	$0.21
12/12/2003	1/14/2004	33	552	258000	326	$54,775.89	$0.21
1/14/2004	2/13/2004	30	606	247200	343	$54,373.16	$0.22
2/13/2004	3/15/2004	31	570	248400	334	$54,543.51	$0.22
3/15/2004	4/14/2004	30	570	117600	163	$56,164.48	$0.48
4/14/2004	5/14/2004	30	576	253200	352	$59,967.99	$0.24
5/14/2004	6/10/2004	27	612	242400	374	$62,029.91	$0.26
6/10/2004	7/12/2004	32	600	285000	371	$71,409.33	$0.25
7/12/2004	8/12/2004	31	678	295800	398	$72,336.44	$0.24
8/12/2004	9/13/2004	32	672	306600	399	$76,311.09	$0.25
9/13/2004	10/13/2004	30	648	274800	382	$70,141.50	$0.26
10/13/2004	11/12/2004	30	612	256200	356	$68,148.63	$0.27
11/12/2004	12/10/2004	28	594	216600	322	$61,044.34	$0.28
12/10/2004	1/12/2005	33	546	241800	305	$63,866.64	$0.26
1/12/2005	2/14/2005	33	582	263400	333	$65,860.32	$0.25
2/14/2005	3/17/2005	31	546	246600	331	$63,146.76	$0.26
3/17/2005	4/18/2005	32	600	276600	360	$75,633.42	$0.27
4/18/2005	5/16/2005	28	672	255600	380	$75,512.68	$0.30
5/16/2005	6/17/2005	32	726	319200	416	$91,957.14	$0.29
6/17/2005	7/18/2005	31	750	318000	427	$90,144.03	$0.28
7/18/2005	8/15/2005	28	696	283800	422	$81,079.54	$0.29
8/15/2005	9/12/2005	28	726	292200	435	$86,731.84	$0.30
9/12/2005	10/11/2005	29	726	289200	416	$90,741.50	$0.31
10/11/2005	11/10/2005	30	660	277200	385	$90,249.42	$0.33
11/10/2005	12/9/2005	29	690	248400	357	$56,787.53	$0.23
12/9/2005	1/11/2006	33	690	258000	326	$77,961.21	$0.30
1/11/2006	2/10/2006	30	636	236400	328	$69,396.44	$0.29
2/10/2006	3/13/2006	31	588	243600	327	$71,925.27	$0.30
3/13/2006	4/13/2006	31	588	252600	340	$75,813.82	$0.30
4/13/2006	5/15/2006	32	630	270000	352	$83,960.09	$0.31

TABLE NO. 2-3
ELECTRIC POWER PURCHASES FROM KIUC
FROM SEPTEMBER 2003 TO APRIL 2006
KOKOLE POINT POINT OF SERVICE

Date		Days	Demand (kW)	kWh	Calculated Average kW	Monthly Bill ($)	Calculated $/kWh
Beginning	End						
9/17/2003	10/17/2003	30	94.8	42480	59	$9,238.12	$0.22
10/17/2003	11/14/2003	28	94.8	34560	51	$7,718.29	$0.22
11/14/2003	12/12/2003	28	82.8	35520	53	$7,785.00	$0.22
12/12/2003	1/14/2004	33	82.8	34800	44	$7,847.03	$0.23
1/14/2004	2/13/2004	30	82.8	34320	48	$7,819.30	$0.23
2/15/2004	3/16/2004	30	75.6	7952	11	$2,831.86	$0.36
3/16/2004	4/15/2004	30	82.8	38160	53	$8,867.58	$0.23
4/15/2004	5/14/2004	29	82.8	39000	56	$9,409.36	$0.24
5/14/2004	6/10/2004	27	91.2	34560	53	$9,182.35	$0.27
6/10/2004	7/12/2004	32	82.8	42840	56	$10,867.04	$0.25
7/12/2004	8/12/2004	31	94.8	46680	63	$11,447.76	$0.25
8/12/2004	9/13/2004	32	88.8	48840	64	$12,064.24	$0.25
9/13/2004	10/13/2004	30	93.6	40920	57	$10,670.11	$0.26
10/13/2004	11/12/2004	30	97.2	37920	53	$10,458.40	$0.28
11/12/2004	12/10/2004	28	78	34080	51	$9,662.03	$0.28
12/10/2004	1/12/2005	33	78	35760	45	$9,674.04	$0.27
1/12/2005	2/14/2005	33	78	39000	49	$9,869.36	$0.25
2/14/2005	3/17/2005	31	74.4	36840	50	$9,571.53	$0.26
3/17/2005	4/18/2005	32	76.8	40320	53	$11,092.83	$0.28
4/18/2005	5/16/2005	28	84	34320	51	$10,322.25	$0.30
5/16/2005	6/17/2005	32	84	42240	55	$12,212.19	$0.29
6/17/2005	7/18/2005	31	84	41520	56	$11,775.92	$0.28
7/18/2005	8/15/2005	28	94.8	41280	61	$11,970.93	$0.29
8/15/2005	9/12/2005	28	94.8	39960	59	$12,090.05	$0.30
9/12/2005	10/11/2005	29	87.6	39360	57	$12,448.62	$0.32
10/11/2005	11/10/2005	30	86.4	39840	55	$13,086.13	$0.33
11/10/2005	12/9/2005	29	81.6	35760	51	$8,269.85	$0.23
12/9/2005	1/11/2006	33	81.6	34920	44	$10,676.48	$0.31
1/11/2006	2/10/2006	30	81.6	32040	45	$9,634.17	$0.30
2/10/2006	3/13/2006	31	75.6	33840	45	$10,164.79	$0.30
3/13/2006	4/13/2006	31	86.4	33240	45	$10,396.75	$0.31
4/13/2006	5/15/2006	32	86.4	37200	48	$11,847.95	$0.32

TABLE NO. 2-4
ELECTRIC POWER PURCHASES FROM KIUC
TOTAL FROM THREE POINTS OF SERVICE

Time Scale			Bonham Air Field, Navy Housing and Scatter Station Summation				
Date		Days	Demand (kW)	kWh	Calculated Average kW	Monthly Bill ($)	Calculated $/kWh
Beginning	End						
9/17/2003	10/17/2003	30	2093	877080	1218	$189,685.56	$0.22
10/17/2003	11/14/2003	28	2075	809760	1205	$173,993.20	$0.21
11/14/2003	12/12/2003	28	1943	732120	1089	$159,577.17	$0.22
12/12/2003	1/14/2004	33	1865	845400	1067	$182,270.39	$0.22
1/14/2004	2/13/2004	30	1973	775920	1078	$173,325.44	$0.22
2/15/2004	3/16/2004	30	1876	759752	1055	$170,991.77	$0.23
3/16/2004	4/15/2004	30	1901	654960	910	$180,010.33	$0.27
4/15/2004	5/14/2004	29	2015	812400	1167	$197,117.85	$0.24
5/14/2004	6/10/2004	27	2089	795360	1227	$207,109.39	$0.26
6/10/2004	7/12/2004	32	2069	891240	1160	$229,672.13	$0.26
7/12/2004	8/12/2004	31	2201	949080	1276	$235,205.04	$0.25
8/12/2004	9/13/2004	32	2171	1002240	1305	$251,266.45	$0.25
9/13/2004	10/13/2004	30	2188	908520	1262	$234,947.96	$0.26
10/13/2004	11/12/2004	30	2101	828720	1151	$224,643.69	$0.27
11/12/2004	12/10/2004	28	1980	755880	1125	$213,801.68	$0.28
12/10/2004	1/12/2005	33	1854	844560	1066	$223,601.99	$0.26
1/12/2005	2/14/2005	33	1932	854400	1079	$215,838.48	$0.25
2/14/2005	3/17/2005	31	1856	772440	1038	$201,951.36	$0.26
3/17/2005	4/18/2005	32	1967	863520	1124	$239,707.20	$0.28
4/18/2005	5/16/2005	28	2046	787920	1173	$233,820.98	$0.30
5/16/2005	6/17/2005	32	2196	972240	1266	$281,675.94	$0.29
6/17/2005	7/18/2005	31	2184	959520	1290	$272,257.37	$0.28
7/18/2005	8/15/2005	28	2183	823080	1225	$239,102.72	$0.29
8/15/2005	9/12/2005	28	2171	932160	1387	$269,159.31	$0.29
9/12/2005	10/11/2005	29	2230	887160	1275	$280,335.26	$0.32
10/11/2005	11/10/2005	30	2120	842640	1170	$277,655.25	$0.33
11/10/2005	12/9/2005	29	2014	755760	1086	$171,171.73	$0.23
12/9/2005	1/11/2006	33	1966	835920	1055	$250,303.52	$0.30
1/11/2006	2/10/2006	30	1936	751440	1044	$220,440.45	$0.29
2/10/2006	3/13/2006	31	1756	719040	966	$214,133.29	$0.30
3/13/2006	4/13/2006	31	1802	752640	1012	$228,338.67	$0.30
4/13/2006	5/15/2006	32	1898	814200	1060	$254,741.96	$0.31

TABLE NO. 2-5
DIESEL OIL CONSUMPTION AND COSTS
PMRF POWER PLANT

Month/Year	Fuel Gallons	Fuel Total Cost	Cost Per Gallon
Oct-03	11,251	$16,651.48	$1.48
Nov-03	7,786	$11,523.28	$1.48
Dec-03	8,956	$13,254.88	$1.48
Jan-04	9,042	$11,573.76	$1.28
Feb-04	9,873	$14,612.63	$1.48
Mar-04	11,341	$16,784.68	$1.48
Apr-04	10,547	$15,610.45	$1.48
May-04	9,679	$14,325.22	$1.48
Jun-04	12,950	$21,109.97	$1.63
Jul-04	16,651	$28,473.21	$1.71
Aug-04	10,335	$17,983.59	$1.74
Sep-04	10,051	$18,294.46	$1.82
Oct-04	12,102	$23,842.71	$1.97
Nov-04	10,757	$21,729.34	$2.02
Dec-04	7,662	$15,477.24	$2.02
Jan-05	8,123	$16,164.77	$1.99
Feb-05	13,877	$26,921.57	$1.94
Mar-05	11,660	$23,204.39	$1.99
Apr-05	12,504	$25,508.16	$2.04
May-05	9,348	$19,537.53	$2.09
Jun-05	10,075	$21,057.80	$2.09
Jul-05	11,631	$24,657.72	$2.12
Aug-05	17,617	$41,049.47	$2.33
Sep-05	10,227	$26,387.72	$2.58
Oct-05	10,219	$27,388.79	$2.68
Nov-05	12,327	$31,805.72	$2.58
Dec-05	5,904	$15,234.38	$2.58

TABLE NO. 2-5 (continued...)
DIESEL OIL CONSUMPTION AND COSTS
PMRF POWER PLANT

Month/Year	Fuel Gallons	Fuel Total Cost	Cost Per Gallon
Jan-06	7,529	$17,168.17	$2.28
Feb-06	10,060	$22,937.71	$2.28
Mar-06	9,733	$22,677.89	$2.33
Apr-06	14,415	$33,587.64	$2.33
May-06	10,733	$27,155.24	$2.53
Jun-06	14,177	$36,860.20	$2.60

TABLE NO. 2-6
2004 POWER PRODUCTION, PLANT EFFICIENCY AND POWER PRODUCTION COSTS

Month	Total kWh	Days in Month	Average kWh Per Day	Average kW	Fuel Gallons	Fuel Total Cost	$/kWh	Btu/kWh
Oct-03	147,210	31	4,749	198	11,251	$16,651.48	$0.11	10,770
Nov-03	102,900	30	3,430	143	7,786	$11,523.28	$0.11	10,662
Dec-03	116,165	31	3,747	156	8,956	$13,254.88	$0.11	10,864
Jan-04	114,975	31	3,709	155	9,042	$11,573.76	$0.10	11,082
Feb-04	126,700	28	4,525	189	9,873	$14,612.63	$0.12	10,980
Mar-04	150,395	31	4,851	202	11,341	$16,784.68	$0.11	10,626
Apr-04	136,710	30	4,557	190	10,547	$15,610.45	$0.11	10,871
May-04	126,000	30	4,200	175	9,679	$14,325.22	$0.11	10,824
Jun-04	161,210	30	5,374	224	12,950	$21,109.97	$0.13	11,319
Jul-04	220,150	31	7,102	296	16,651	$28,473.21	$0.13	10,658
Aug-04	136,605	31	4,407	184	10,335	$17,983.59	$0.13	10,661
Sep-04	131,670	30	4,389	183	10,051	$18,294.46	$0.14	10,756

TABLE NO. 2-7
2005 POWER PRODUCTION, PLANT EFFICIENCY AND POWER PRODUCTION COSTS

Month	Total kWh	Days in Month	Average kWh Per Day	Average kW	Fuel Gallons	Fuel Total Cost	$/kWh	Btu/kWh
Oct-04	158,375	31	5,109	213	12,102	$23,842.71	$0.15	10,767
Nov-04	141,470	30	4,716	196	10,757	$21,729.34	$0.15	10,714
Dec-04	96,110	31	3,100	129	7,662	$15,477.24	$0.16	11,234
Jan-05	109,620	31	3,536	147	8,123	$16,164.77	$0.15	10,442
Feb-05	175,910	28	6,283	262	13,877	$26,921.57	$0.15	11,116
Mar-05	145,005	31	4,678	195	11,660	$23,204.39	$0.16	11,331
Apr-05	159,335	30	5,311	221	12,504	$25,508.16	$0.16	11,058
May-05	123,690	30	4,123	172	9,348	$19,537.53	$0.16	10,649
Jun-05	131,670	30	4,389	183	10,075	$21,057.80	$0.16	10,782
Jul-05	155,155	31	5,005	209	11,631	$24,657.72	$0.16	10,563
Aug-05	228,480	31	7,370	307	17,617	$41,049.47	$0.18	10,865
Sep-05	132,300	30	4,410	184	10,227	$26,387.72	$0.20	10,893

TABLE NO. 2-8
2006 POWER PRODUCTION, PLANT EFFICIENCY AND POWER PRODUCTION COSTS

Month	Total kWh	Days in Month	Average kWh Per Day	Average kW	Fuel Gallons	Fuel Total Cost	$/kWh	Btu/kWh
Oct-05	131,565	31	4,244	177	10,219	$27,388.79	$0.21	10,945
Nov-05	160,650	30	5,355	223	12,327	$31,805.72	$0.20	10,812
Dec-05	69,965	31	2,257	94	5,904	$15,234.38	$0.22	11,891
Jan-06	95,445	31	3,079	128	7,529	$17,168.17	$0.18	11,115
Feb-06	119,315	28	4,261	178	10,060	$22,937.71	$0.19	11,881
Mar-06	122,990	31	3,967	165	9,733	$22,677.89	$0.18	11,151
Apr-06	178,920	30	5,964	249	14,415	$33,587.64	$0.19	11,353
May-06	121,730	30	4,058	169	10,733	$27,155.24	$0.22	12,424
Jun-06	175,665	30	5,856	244	14,177	$36,860.20	$0.21	11,372

SECTION 3

ECONOMIC AND ENGINEERING OPTIONS FOR CHP

Utility Rates and Charges

KIUC currently charges a lump sum customer charge, a demand charge ($/kW), and an energy charge ($/kWh). The demand charge is multiplied by the larger of the peak demand at each customer's meter each month, or 75 percent of the eleventh month prior historical recorded peak. The energy charge is multiplied by the kWh consumed each month. As shown in Section 2, PMRF currently pays KIUC about $0.30/kWh for electric service (inclusive of demand charge, energy charge, and customer charge). Copies of recent KIUC rate sheets can be found in Appendix B.

The demand charge and the energy charge are the same for all hours during the day and for all months during the year. KIUC's rates do not vary with time-of-use (daytime versus nighttime) or by season (winter versus summer).

The biggest factor affecting the energy charge is the price of diesel oil. Most of KIUC's power is produced using diesel oil.

CHP Technical Alternatives

A number of technical alternatives are available for configuring a CHP project at PMRF. The alternatives include:

- Continue to use the existing reciprocating engines, fired on diesel oil, with the addition of heat recovery equipment;
- Convert the existing reciprocating engines to landfill gas firing, with the addition of heat recovery equipment;
- Install new landfill gas fueled reciprocating engines, microturbines or fuel cells, equipped with heat recovery. The new equipment could be installed at the location of the existing power plant or at another location; or
- Install new landfill gas fired reciprocating engines, microturbines or fuel cells, without heat recovery, at a site on or close to the landfill. The economic advantage to this alternative is that it would eliminate most or all of the landfill gas transmission pipeline, and it would reduce the compression equipment requirements. Evaluation of this alternative will be considered under the work plan's directive to consider "any other options determined by the Contractor to be viable." The power produced under this alternative could be put on KIUC's grid or PMRF's grid.

As discussed in Section 2, there is no demand for steam and there is no significant demand for hot water at PMRF. A heat demand could be created, however, by installation of absorption chillers to meet cooling loads that are currently met by other cooling technologies. The chillers would satisfy selected air conditioning loads, and reduce electric power consumption. Absorption chillers can use steam or hot water to produce chilled water. A central chilled water unit could be established immediately adjacent to the existing or new power production equipment, with chilled water delivered to the points of end use, or hot water could be delivered to absorption chillers, located at the points of end use.

Thermal energy can be recovered as hot water from a reciprocating engine's jacket water and lube oil cooler, or as hot water or as steam from the engine's exhaust stack. Hot water can be recovered from a microturbine's exhaust. Steam or hot water can be recovered from a fuel cell's exhaust.

Fuel Existing Engines on Diesel Oil with the Addition of Heat Recovery

Based on Caterpillar's data sheets for the Model 3508 engine, and SCS's assessment of the typical performance of heat exchangers installed in an engine's cooling water loop and stack, SCS estimates that 1.0 mmBtu/hr of hot water can be recovered from a Model 3508's jacket water and lube oil, and an additional 1.3 mmBtu/hr can be recovered from its exhaust, when the engine is operating at its full capacity of 600 kW. The Model 3412 engine will produce 0.5 mmBtu/hr of hot water from its jacket water and lube oil, and an additional 0.6 mmBtu/hr from its exhaust, again when operating at full output.

Currently, the engines operate only eight hours per day, the two 600 kW engines operate at about 40 percent of their rated capacity, and one of the three 300 kW engines operates at 60 percent of its rated capacity. The limited operating schedule of the engines greatly reduces the heat generation potential of the existing power plant. When operating at full output, the existing PMRF power plant could produce about 108 tons of cooling, using a single-effect hot water absorption chiller.

Buildings 105, 105ROCS and 130 represent a cluster of significant cooling loads. The buildings have an installed capacity of 205 tons of cooling. The basic CHP configuration to be considered under this alternative will be installation of a 108 ton absorption chiller at the existing PMRF power plant, and installation of insulated, underground cold water delivery and warm water return piping to serve these three buildings. It will be necessary to leave the existing electric drive cooling equipment in place at each building. The existing equipment will operate during the periods of time when the PMRF power plant is offline, and to supplement the cooling provided by the 108 ton chiller, during periods when the cooling load exceeds 108 tons.

While the cooling loads at Buildings 300 and 384, to the north, and Buildings 1262, 1261 and 1264, to the south, are too far away from the existing PMRF power plant to make delivery of chilled water economically feasible, the existing cooling loads in the immediate vicinity of the existing PMRF power plant could use all of the available waste heat from the existing power plant.

Fuel Existing Engines on Landfill Gas with the Addition of Heat Recovery

The existing reciprocating engines are diesel engines, as contrasted to spark-ignited engines. Natural gas fired engines and landfill gas fired engines are spark-ignited engines. It is possible to operate a diesel engine on a gaseous fuel, if properly configured, and if some diesel fuel is injected as a pilot fuel. Significant modifications must be made to the existing engines to allow them to use natural gas as a fuel.

The amount of landfill gas available at Kekaha Landfill in 2007 will support production of about 1,100 kW of power. Conversion of the two 600 kW engines to landfill gas firing would cover the amount of landfill gas currently available.

Caterpillar has never converted one of their diesel fired engines to landfill gas firing, and there are technical, performance and cost uncertainties associated with such a conversion. Due to these uncertainties, SCS recommends that further consideration not be given to this alternative.

New Reciprocating Engines Fired on Landfill Gas at Existing PMRF Power Plant

Engine Selection

The amount of landfill gas available in 2007 will support about 1,100 kW. By 2010, the amount of landfill gas available will support about 1,600 kW. By 2017, the amount of landfill gas available will support about 2,000 kW.

SCS will assume that two Caterpillar Model 3516 engines will be employed. Model 3516 is the most widely used landfill gas fired engine in the United States. It has a capacity of 820 kW, and a heat rate of 10,900 Btu/kWh (HHV). It requires a landfill gas supply pressure of 3 psig.

Heat Recovery

The amount of recoverable heat from the Model 3516's jacket water and lube oil is 2.5 mmBtu/hr per engine. The amount of heat recoverable from the exhaust stack is 1.1 mmBtu per engine. About 310 tons of cooling could be provided by the 7.2 mmBtu/hr of waste heat available from a 1,640 kW power plant.

The two new engines would be installed in a building in the vicinity of the existing PMRF power plant. The existing step-up transformer could be used to introduce power to the grid. The new landfill gas fired power plant would operate continuously, unlike the existing PMRF power plant. Excess power produced during the night or during the day would be sold to KIUC. As a result, chilled water could be produced continuously, rather than intermittently. The existing electric-drive chillers would remain in-place, and be used if the landfill gas fired power plant was offline for maintenance or was offline due to a landfill gas supply interruption. An online time of 95 percent, or better, can be expected for the landfill gas fired power plant. The power plant would be staffed during the daylight shift during the five weekdays, and would operate unattended at all other times. Power plant shutdowns or problems during the unattended hours would be addressed by the operator responding to an automatic callout on overtime.

A 205 ton single-effect, hot water absorption chiller would be installed, along with chilled water supply and return piping to Buildings 105, 105ROCS, and 103.

Air Emissions

Air emissions for two Model 3516 engines fired on landfill gas would be as follows:

Parameter	g/bhp-hr	Tons per Year
NO_x	0.60	18.6
CO	2.50	93.1
VOC	0.80	24.8
SO_x	0.01	0.3
Particulates	0.10	3.1

The above emission rates represent Best Available Control Technology (BACT) for landfill gas fired reciprocating engines.

Microturbines

Microturbines are available in the following incremental capacities -- 30 kW, 60 kW, 70 kW, and 250 kW. Microturbines are less efficient than reciprocating engines. They have a higher heat rate, 12,000 Btu/kWh (HHV) to 13,900 Btu/kWh (HHV), versus 10,900 Btu/kWh (HHV) for the Model 3516 engine. Microturbines are applicable to smaller projects (< 800 kW). The Model 3516 engine (820 kW) is the smallest engine commonly in use on landfill gas.

Microturbines are not a viable alternative to reciprocating engines for the main PMRF power plant because of their lower efficiency and their higher installed cost. The installed cost of a microturbine facility at an output in the vicinity of 800 kW would be about $2,200/kW versus $1,600/kW for a reciprocating engine plant.

Microturbines could be considered as the power generation component of a CHP project to serve Buildings 1261, 1262 and 1264. If landfill gas is piped to a new power plant, located in the vicinity of the existing PMRF power plant, the landfill gas transmission pipeline will pass

Building 1262 on the route to the new power plant. A landfill gas fired microturbine power plant could be installed in the vicinity of Building 1262.

United Technologies (UT) offers a microturbine package coupled with an absorption chiller. The smallest package offered by UT incorporates four 60 kW microturbines, and a double-effect, hot gas absorption chiller. The package can produce 120 tons of cooling and 1.1 mmBtu/hr of hot water. It would require 100 scfm of landfill gas.

A microturbine CHP plant serving Buildings 1261, 1262 and 1264 can be considered to be an optional, add-on project, to the above-described new power plant project. The microturbine CHP plant project would consist of the following elements:

- A UT microturbine CHP package, incorporating four 60 kW microturbines, an absorption chiller, and hot water recovery module;
- Hot water piping to interface with Building 1262's hot water generator;
- Chilled water supply and return piping to Buildings 1261, 1262 and 1264;
- Conversion of the air handling equipment in these buildings to accommodate chilled water; and
- A landfill gas treatment and pressure booster skid. The microturbines require a pressure of 80 psig. The microturbines also require a landfill gas which is 100 percent free of siloxane. The skid will incorporate an activated carbon vessel, a booster compressor, and an air-to-gas aftercooler.

The small CHP plant will be located in the vicinity of Building 1262. The microturbines will connect to the grid at 480 V. The Navy Housing grid will be able to absorb all of the power produced by the microturbines virtually all of the time.

The microturbines will consume about 100 scfm of landfill gas (about 3.0 mmBtu/hr). The consumption of fuel by the microturbines will reduce the amount of fuel available for the above-described new power plant, and reduce the amount of power it produces.

Air emissions from the microturbine CHP plant are expected to be as follows:

Parameter	Lbs/MWh	Tons per Year
NO_x	0.25	0.3
CO	0.25	0.3
VOC	2.18	2.5
SO_x	0.03	< 0.1
Particulates	0.33	0.4

The above air emission rates represent BACT.

Fuel Cells

Fuel cells offer the benefits of high efficiency and low air emissions. Fuel cells have been employed on one landfill gas fueled demonstration project. The installed cost of a biogas fueled fuel cell power plant is about four times more expensive than a reciprocating engine plant on a $/kW basis. The fuel cell's operation/maintenance costs are also much higher.

Fuel cells will not be given further consideration in this study because of their high cost and lack of experience on landfill gas.

Reciprocating Engines at or Close to the Landfill Without Heat Recovery

A reciprocating engine plant could be installed on the landfill grounds and interconnect directly to KIUC, or it could be installed just inside PMRF grounds and tie into the PMRF 12.47 kV line serving the Kokole Point power distribution system.

If PMRF owned a power plant at the landfill, it would be necessary to secure an agreement from KIUC to "wheel" power from the interconnection with KIUC at the landfill, through KIUC's power distribution system, to PMRF's points of interconnection with KIUC. Alternatively, the output of the power plant could be sold to KIUC.

If interconnected at Kokole Point, connecting transmission lines would need to be installed between Kokole Point and Navy Housing, and between the Navy Housing and the PMRF Main Base power distribution systems. It may also be necessary to reinforce some of the existing transmission lines within Kokole Point and Navy Housing. In addition, Navy Housing and PMRF Main Base would need to be disconnected from KIUC at their current points of interconnection.

In implementing the above interconnections, it is likely that some of the existing transmission lines and/or transformers will need to be upgraded to carry additional power. The costs of these upgrades must be factored into alternatives requiring interconnections inside of PMRF's grounds.

Engine Selection

Two Model 3516 engines would be employed.

Air Emissions

The air emissions under this alternative would be identical to the air emissions for the above-described new power plant at the site of the existing PMRF power plant.

Utility Interconnection Requirements

KIUC has been contacted, and they have supplied SCS with their interconnection requirements. The requirements are typical of those in use in the electric power industry. The construction cost estimates that will be developed by SCS for the next deliverable will include the cost of complying with these requirements.

SECTION 4

THERMAL ENERGY DISTRIBUTION ALTERNATIVES

The decisions discussed in Section 3, with respect to the configuration of the CHP alternatives, largely dictate the manner in which thermal energy will be distributed on this project.

The absorption chillers that will serve the chilled water cluster located near the existing PMRF power plant, and the potential chilled water cluster at Building 1262, are relatively small. It is clearly more practical to have one larger chiller, rather than three smaller distributed chillers at each of these locations. Distributed chillers would require that hot water be distributed, rather than chilled water. The decision to have central chillers dictates that thermal energy be distributed in the form of chilled water.

In addition to its cooling requirement, Building 1262 has a hot water requirement. The microturbine CHP plant can only produce hot water (not steam). Hot water will be distributed. Even if the production of steam was possible, hot water would be preferred since the end use is proximate to the microturbine, and since the thermal end use is for hot water.

SECTION 5

LANDFILL GAS PRESSURIZATION AND TREATMENT REQUIREMENTS

Based on the evaluation of economic and engineering options completed in Section 3, it may be possible to use landfill gas to fire reciprocating engines or microturbines. The reciprocating engines could be located at the landfill, close to the landfill on the PMRF grounds, or in the vicinity of the existing PMRF power plant. The microturbines would be located in the Navy Housing area in the vicinity of Building 1262.

The reciprocating engines will require a landfill gas supply pressure of about 3 psig. The landfill gas from Kekaha Landfill has low concentrations of hydrogen sulfide (H_2S), siloxane and other compounds that could be deleterious to a reciprocating engine. In addition, the reciprocating engine expected to be used, the Model 3516, has been proven to be tolerant of relatively high concentrations of deleterious compounds. It will be necessary to remove free moisture (i.e., water droplets) and particulate. Free moisture and particulates can be removed through use of a coalescing filter.

Microturbines are less tolerant to hydrogen sulfide and siloxane than reciprocating engines. Microturbine manufacturers require that siloxane not exceed non-detect levels. Siloxane is removed through treatment using activated carbon or silica gel. The landfill gas is processed through a vessel which holds a fixed bed of media. Microturbine manufacturers also require that the landfill gas be dried. Advanced moisture removal is usually accomplished by chilling the landfill gas and then reheating it to achieve a dew point suppression of at least 20° F. The heat used in reheating the landfill gas is waste heat from compression of the landfill gas. Microturbines require a landfill gas supply pressure of 80 psig.

If the reciprocating engines are located at the existing PMRF power plant, a 3.9 mile landfill gas transmission pipeline must be constructed from the Kekaha Landfill to the existing PMRF power plant. A long distance, landfill gas transmission pipeline typically operates at a line pressure of 80 psig (at its point of origin). The optimal operating pressure for a particular pipeline varies based on the economic tradeoff between pipeline cost (a function of its diameter) and the cost of compression (a function of pressure selected). An optimization analysis will be undertaken as part of this study, and the results presented in the Task 3 deliverable.

A sliding vane-type compressor is an appropriate selection for the quantity and pressure of landfill gas under consideration. A pipeline end point pressure of 5 psig will be employed, regardless of the point of origin pressure, ultimately selected by the optimization analysis. For this design concept, there will be no re-compression of landfill gas required at the existing PMRF power plant.

In order to avoid condensate accumulation in the landfill gas transmission line, the compression facility at the landfill will incorporate chilling of the landfill gas to 45° F and reheating by at least 30° F. A coalescing filter will also be provided. The landfill gas pressurization and treatment provided at the landfill will exceed the requirements of the reciprocating engines. A coalescing filter will, however, be located just prior to each engine to provide a final measure of protection.

If the new landfill gas fired power plant is located at the landfill, compression and treatment requirements are greatly simplified. A low pressure, positive displacement-type blower (5 psig maximum) will be employed. The discharge from the blower would be cooled in an air-to-gas cooler (i.e., a radiator). Free moisture would be separated in a moisture separator vessel, and by coalescing filters located at the engines.

If the new landfill gas fired power plant is located just far enough into PMRF grounds to allow its output to be interconnected into the PMRF power grid, then the point of origin compression requirement would increase to no more than 15 psig. A positive displacement-type blower would still be employed; however, chilling and reheating would be added to the process, to prevent condensate accumulation in the pipeline.

The pressure requirement of the microturbines could be met by increasing the pressure of the landfill gas provided by the compressor at the landfill (by 10 psig to 15 psig) to assure that the pressure in the landfill gas transmission pipeline delivered to the microturbines was at least 80 psig. An alternative to increasing the landfill gas pressure provided through the compressor at the landfill is to supply a small booster compressor to serve the microturbines, which would boost the landfill gas pressure from the pipeline pressure at that point on the pipeline to 80 psig. The booster compressor would be located at the microturbine location. The need for a booster compressor will be addressed in conjunction with the aforementioned optimization of pipeline operating pressure. A single activated carbon vessel would be installed to treat the landfill gas being sent to the microturbines. It would be located at the microturbines. The vessel would be about four feet in diameter and about ten feet tall.

SECTION 6

AIR PERMIT CONSIDERATIONS

The Hawaii State Department of Health (HSDH), Environmental Management Division, Clean Air Branch, will be responsible for issuing an air permit for the reciprocating engines and/or the microturbines that might be employed on this project. HSDH will require that Best Available Control Technology (BACT) be employed.

BACT for landfill gas fired reciprocating engines is currently recognized to be:

Parameter	g/bhp-hr
NO_x	0.60
CO	3.00
VOC (NMOC)	0.80
SO_x	0.01
Particulates	0.10

If Kekaha Landfill becomes large enough to be regulated under USEPA's New Source Performance Standards (NSPS) for municipal solid waste landfills, then a more stringent requirement for VOCs might be imposed -- the lesser of 98 percent destruction, or 20 ppmv (as hexane). The SO_x limit is a function of the expected maximum concentration of sulfur-bearing compounds in the landfill gas.

BACT for landfill gas fired microturbines is currently recognized to be:

Parameter	lbs/MWh
NO_x	0.25
CO	0.25
VOC (NMOC)	2.08
SO_x	0.03
Particulates	0.33

Again, SO_x is variable based on the actual quantity of sulfur present in the raw landfill gas.

The air emissions from the landfill gas fired reciprocating engines will be much lower than from the existing diesel engines, and projects recommended by this study would result in a net reduction of air emissions.

SECTION 7

CONCLUSIONS

The following alternatives will be carried forward for detailed technical and economic evaluations to be summarized in the next deliverable. The next deliverable, the Task 3 deliverable, will be prepared by SCS, and is due in October 2006:

Alternative No. 1-A: Fuel the existing engines on diesel oil, with the addition of heat recovery, and retain the current program of intermittent operation;

Alternative No.1-B: Fuel the existing engines on diesel oil, with the addition of heat recovery, and convert to full-time operation;

Alternative No. 2-A: New landfill gas fired reciprocating engines at existing PMRF power plant, with heat recovery to produce chilled water with an absorption chiller, with a microturbine CHP plant at Building 1262;

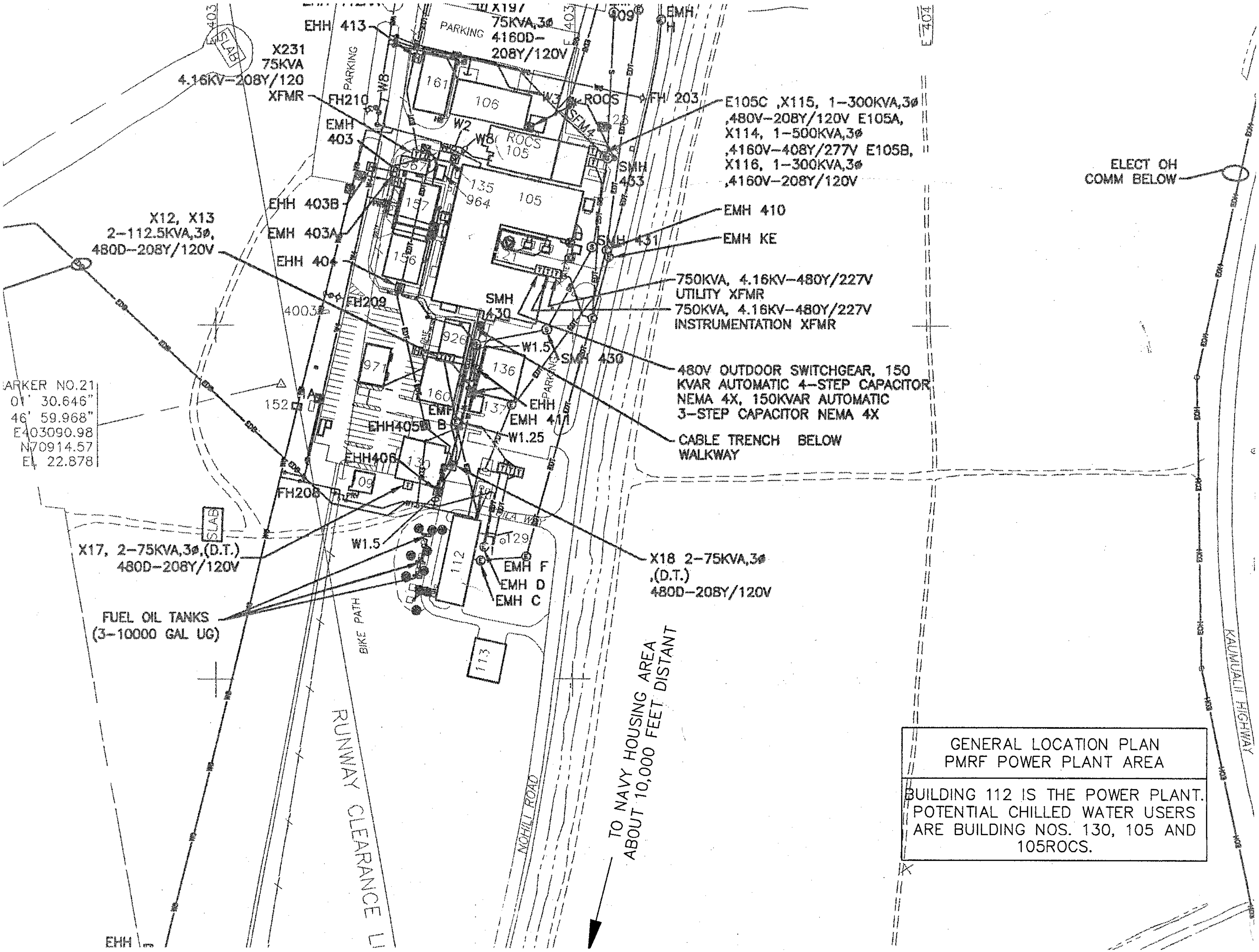
Alternative No.2-B: New landfill gas fired reciprocating engines at existing PMRF power plant, with heat recovery to produce chilled water with an absorption chiller, without a microturbine CHP plant at Building 1262;

Alternative No.3: New landfill gas fired reciprocating engines on PMRF grounds close to the landfill; and

Alternative No. 4: New landfill gas fired reciprocating engines at the landfill.

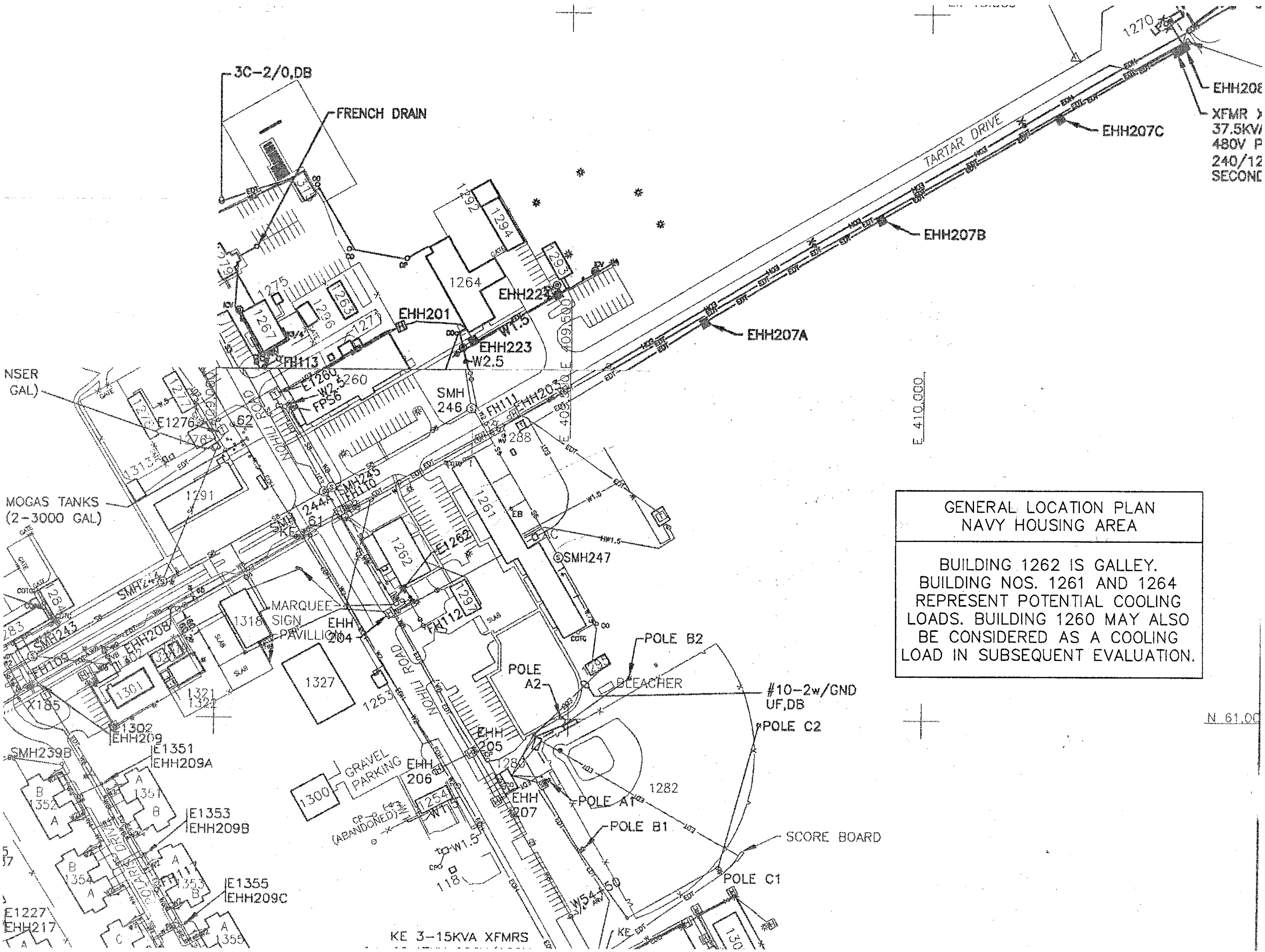
APPENDIX A

BUILDING LOCATION PLANS FOR PMRF



GENERAL LOCATION PLAN
PMRF POWER PLANT AREA

BUILDING 112 IS THE POWER PLANT. POTENTIAL CHILLED WATER USERS ARE BUILDING NOS. 130, 105 AND 105ROCS.


GENERAL LOCATION PLAN
NAVY HOUSING AREA
BUILDING 1262 IS GALLEY. BUILDING NOS. 1261 AND 1264 REPRESENT POTENTIAL COOLING LOADS. BUILDING 1260 MAY ALSO BE CONSIDERED AS A COOLING LOAD IN SUBSEQUENT EVALUATION.
3C-2/0,DB
FRENCH DRAIN
TARTAR DRIVE
NOHILL ROAD
EHH207A
EHH207B
EHH207C
EHH201
EHH223
EHH203
SMH 246
SMH247
MOGAS TANKS (2-3000 GAL)
MARQUEE SIGN
PAVILLION
POLE B2
POLE A2
POLE A1
POLE B1
POLE C1
POLE C2
BLEACHER
#10-2w/GND UF,DB
SCORE BOARD
GRAVEL PARKING
(ABANDONED)
KE 3-15KVA XFMRS
E 410,000
E 409,500
N 61,00
E1351
EHH209A
E1353
EHH209B
E1355
EHH209C
E1227
EHH217
SMH239B
EHH209
SMH243
SMH244
SMH245
FH109
FH110
FH111
FH112
FH113
X185
E1262
E1276
EHH 204
EHH 205
EHH 206
EHH 207
EHH208
1260
1261
1262
1264
1275
1282
1291
1292
1294
1296
1297
1300
1301
1318
1327
1352
1354
XFMR
37.5KV
480V
240/12
SECOND

APPENDIX B

RECENT KIUC RATE SHEETS

KAUA'I ISLAND UTILITY COOPERATIVE	Current Date:	31-Aug-06
	File No.:	2006-09
ENERGY RATE ADJUSTMENT CLAUSE	Supersedes Sheet Effective:	8/1/06
	Effective Date:	9/1/06

RATE DATA SHEET

	BASE RATES EFFECTIVE 01-Nov-98	(1) EFFECTIVE RATES 01-Sep-06
SCHEDULE "D" - RESIDENTIAL		
-Customer charge (per Customer, per month)	$9.72	$9.72
-All kWh per month (add to customer charge)	$0.17489	$0.34020
-The minimum monthly charge shall be	$12.16	$12.16
SCHEDULE "G" - GENERAL LIGHT & POWER SERVICE (Small Commercial):		
(Not greater than 30 kW demand and 10,000 kWh use per month)		
-Customer charge (per customer, per month)	$21.89	$21.89
-All kWh per month (add to customer charge)	$0.19118	$0.35745
-The minimum monthly charge shall be	$24.31	$24.31
SCHEDULE "J" - GENERAL LIGHT & POWER SERVICE (Large Commercial):		
(Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month)		
-Customer charge (per customer, per month)	$36.48	$36.48
-Demand charge per kW of monthly demand	$6.08	$6.08
-Energy charge (added to demand charge)		
-All kWh per month (add to customer charge)	$0.16031	$0.32658
-The minimum monthly charge shall not be less than	$182.37	$182.37
SCHEDULE "L" - LARGE POWER (Primary)		
(Demand greater than 100 kW - metered on primary side of meter)		
-Customer charge (per customer, per month)	$334.35	$334.35
-Demand charge per kW of monthly demand	$13.13	$13.13
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.14366	$0.30993
All over 400 kWh per kW of billing demand	$0.12540	$0.29167
-Minimum monthly charge: Customer + Demand Charge		
SCHEDULE "P" - LARGE POWER (Secondary)		
(Demand greater than 100 kW - metered on secondary side of meter)		
-Customer charge (per customer, per month)	$346.51	$346.51
-Demand charge per kW of monthly demand	$10.45	$10.45
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.15279	$0.31906
All over 400 kWh per kW of billing demand	$0.13324	$0.29951
-Minimum monthly charge: Customer + Demand Charge		
	Effective Annual Rate 01-Jan-06	Prior Month's Rate 01-Aug-06
SCHEDULE "Q" MODIFIED - COGENERATORS		
-Energy credit payment rate to customers (per kWh)	$0.14730	$0.18810
SCHEDULE "SL" - STREET LIGHTING		
(Depending on type of service)		
-All kWh per month (add to fixture charge)	$0.23339	$0.39860
-The minimum monthly charge shall be the fixture charge		
-Fixture charge (per fixture-per month multiplied by no. of fixtures)		
HPS 100 W (per fixture-per month)	$5.74	
HPS 150 W (per fixture-per month)	$5.74	
HPS 200 W (per fixture-per month)	$5.95	
HPS 250 W (per fixture-per month)	$5.95	
HPS 400 W (per fixture-per month)	$6.20	

ENERGY RATE ADJUSTMENT FACTORS:	
Schedule D, G, J, L, P, SL	$0.16464
Schedule Q	$0.04080

(See rate schedules for additional information)

MONTHLY EFFECTIVE RATES INCLUDE:	
(1) kWh increase to base energy rates for ENERGY RATE ADJUSTMENT CLAUSE	$0.16464
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule D	$0.000674
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule G	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule J	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule L	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule P	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule SL	$0.000576

RATE DATA SHEET

	BASE RATES EFFECTIVE 01-Nov-98	(1) EFFECTIVE RATES 01-Aug-06
SCHEDULE "D" - RESIDENTIAL		
-Customer charge (per Customer, per month)	$9.72	$9.72
-All kWh per month (add to customer charge)	$0.17489	$0.33619
-The minimum monthly charge shall be	$12.16	$12.16
SCHEDULE "G" - GENERAL LIGHT & POWER SERVICE (Small Commercial):		
(Not greater than 30 kW demand and 10,000 kWh use per month)		
-Customer charge (per customer, per month)	$21.89	$21.89
-All kWh per month (add to customer charge)	$0.19118	$0.35344
-The minimum monthly charge shall be	$24.31	$24.31
SCHEDULE "J" - GENERAL LIGHT & POWER SERVICE (Large Commercial):		
(Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month)		
-Customer charge (per customer, per month)	$36.48	$36.48
-Demand charge per kW of monthly demand	$6.08	$6.08
-Energy charge (added to demand charge)		
-All kWh per month (add to customer charge)	$0.16031	$0.32257
-The minimum monthly charge shall not be less than	$182.37	$182.37
SCHEDULE "L" - LARGE POWER (Primary)		
(Demand greater than 100 kW - metered on primary side of meter)		
-Customer charge (per customer, per month)	$334.35	$334.35
-Demand charge per kW of monthly demand	$13.13	$13.13
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.14366	$0.30592
All over 400 kWh per kW of billing demand	$0.12540	$0.28766
-Minimum monthly charge: Customer + Demand Charge		
SCHEDULE "P" - LARGE POWER (Secondary)		
(Demand greater than 100 kW - metered on secondary side of meter)		
-Customer charge (per customer, per month)	$346.51	$346.51
-Demand charge per kW of monthly demand	$10.45	$10.45
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.15279	$0.31505
All over 400 kWh per kW of billing demand	$0.13324	$0.29550
-Minimum monthly charge: Customer + Demand Charge		
	Effective Annual Rate 01-Jan-06	Prior Month's Rate 01-Jul-06
SCHEDULE "Q" MODIFIED - COGENERATORS		
-Energy credit payment rate to customers (per kWh)	$0.14730	$0.19600
SCHEDULE "SL" - STREET LIGHTING		
(Depending on type of service)		
-All kWh per month (add to fixture charge)	$0.23339	$0.39459
-The minimum monthly charge shall be the fixture charge		
-Fixture charge (per fixture-per month multiplied by no. of fixtures)		
HPS 100 W (per fixture-per month)	$5.74	
HPS 150 W (per fixture-per month)	$5.74	
HPS 200 W (per fixture-per month)	$5.95	
HPS 250 W (per fixture-per month)	$5.95	
HPS 400 W (per fixture-per month)	$6.20	

ENERGY RATE ADJUSTMENT FACTORS:	
Schedule D, G, J, L, P, SL	$0.16063
Schedule Q	$0.04870

(See rate schedules for additional information)

MONTHLY EFFECTIVE RATES INCLUDE:	
(1) kWh increase to base energy rates for ENERGY RATE ADJUSTMENT CLAUSE	$0.16063
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule D	$0.000674
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule G	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule J	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule L	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule P	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule SL	$0.000576

KAUA'I ISLAND UTILITY COOPERATIVE	Current Date:	30-Jun-06
	File No.:	2006-07
ENERGY RATE ADJUSTMENT CLAUSE	Supersedes Sheet Effective:	6/1/06
	Effective Date:	7/1/06

RATE DATA SHEET

	BASE RATES EFFECTIVE 01-Nov-98	(1) EFFECTIVE RATES 01-Jul-06
SCHEDULE "D" - RESIDENTIAL		
-Customer charge (per Customer, per month)	$9.72	$9.72
-All kWh per month (add to customer charge)	$0.17489	$0.34215
-The minimum monthly charge shall be	$12.16	$12.16
SCHEDULE "G" - GENERAL LIGHT & POWER SERVICE (Small Commercial):		
(Not greater than 30 kW demand and 10,000 kWh use per month)		
-Customer charge (per customer, per month)	$21.89	$21.89
-All kWh per month (add to customer charge)	$0.19118	$0.35939
-The minimum monthly charge shall be	$24.31	$24.31
SCHEDULE "J" - GENERAL LIGHT & POWER SERVICE (Large Commercial):		
(Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month)		
-Customer charge (per customer, per month)	$36.48	$36.48
-Demand charge per kW of monthly demand	$6.08	$6.08
-Energy charge (added to demand charge)		
-All kWh per month (add to customer charge)	$0.16031	$0.32852
-The minimum monthly charge shall not be less than	$182.37	$182.37
SCHEDULE "L" - LARGE POWER (Primary)		
(Demand greater than 100 kW - metered on primary side of meter)		
-Customer charge (per customer, per month)	$334.35	$334.35
-Demand charge per kW of monthly demand	$13.13	$13.13
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.14366	$0.31187
All over 400 kWh per kW of billing demand	$0.12540	$0.29361
-Minimum monthly charge: Customer + Demand Charge		
SCHEDULE "P" - LARGE POWER (Secondary)		
(Demand greater than 100 kW - metered on secondary side of meter)		
-Customer charge (per customer, per month)	$346.51	$346.51
-Demand charge per kW of monthly demand	$10.45	$10.45
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.15279	$0.32100
All over 400 kWh per kW of billing demand	$0.13324	$0.30145
-Minimum monthly charge: Customer + Demand Charge		
	Effective Annual Rate	Prior Month's Rate
SCHEDULE "Q" MODIFIED - COGENERATORS	01-Jan-06	01-Jun-06
-Energy credit payment rate to customers (per kWh)	$0.14730	$0.20250
SCHEDULE "SL" - STREET LIGHTING		
(Depending on type of service)		
-All kWh per month (add to fixture charge)	$0.23339	$0.40055
-The minimum monthly charge shall be the fixture charge		
-Fixture charge (per fixture-per month multiplied by no. of fixtures)		
HPS 100 W (per fixture-per month)	$5.74	
HPS 150 W (per fixture-per month)	$5.74	
HPS 200 W (per fixture-per month)	$5.95	
HPS 250 W (per fixture-per month)	$5.95	
HPS 400 W (per fixture-per month)	$6.20	

ENERGY RATE ADJUSTMENT FACTORS:	
Schedule D, G, J, L, P, SL	$0.16658
Schedule Q	$0.05520

(See rate schedules for additional information)

MONTHLY EFFECTIVE RATES INCLUDE:	
(1) kWh increase to base energy rates for ENERGY RATE ADJUSTMENT CLAUSE	$0.16658
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule D	$0.000674
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule G	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule J	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule L	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule P	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule SL	$0.000576

KAUA'I ISLAND UTILITY COOPERATIVE

ENERGY RATE ADJUSTMENT CLAUSE

Current Date:	31-May-06
File No.:	2006-06
Supersedes Sheet Effective:	5/1/06
Effective Date:	6/1/06

RATE DATA SHEET

	BASE RATES EFFECTIVE 01-Nov-98	(1) EFFECTIVE RATES 01-Jun-06
SCHEDULE "D" - RESIDENTIAL		
-Customer charge (per Customer, per month)	$9.72	$9.72
-All kWh per month (add to customer charge)	$0.17489	$0.34832
-The minimum monthly charge shall be	$12.16	$12.16
SCHEDULE "G" - GENERAL LIGHT & POWER SERVICE (Small Commercial):		
(Not greater than 30 kW demand and 10,000 kWh use per month)		
-Customer charge (per customer, per month)	$21.89	$21.89
-All kWh per month (add to customer charge)	$0.19118	$0.36557
-The minimum monthly charge shall be	$24.31	$24.31
SCHEDULE "J" - GENERAL LIGHT & POWER SERVICE (Large Commercial):		
(Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month)		
-Customer charge (per customer, per month)	$36.48	$36.48
-Demand charge per kW of monthly demand	$6.08	$6.08
-Energy charge (added to demand charge)		
-All kWh per month (add to customer charge)	$0.16031	$0.33470
-The minimum monthly charge shall not be less than	$182.37	$182.37
SCHEDULE "L" - LARGE POWER (Primary)		
(Demand greater than 100 kW - metered on primary side of meter)		
-Customer charge (per customer, per month)	$334.35	$334.35
-Demand charge per kW of monthly demand	$13.13	$13.13
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.14366	$0.31805
All over 400 kWh per kW of billing demand	$0.12540	$0.29979
-Minimum monthly charge: Customer + Demand Charge		
SCHEDULE "P" - LARGE POWER (Secondary)		
(Demand greater than 100 kW - metered on secondary side of meter)		
-Customer charge (per customer, per month)	$346.51	$346.51
-Demand charge per kW of monthly demand	$10.45	$10.45
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.15279	$0.32718
All over 400 kWh per kW of billing demand	$0.13324	$0.30763
-Minimum monthly charge: Customer + Demand Charge		
	Effective Annual Rate 01-Jan-06	Prior Month's Rate 01-May-06
SCHEDULE "Q" MODIFIED - COGENERATORS		
-Energy credit payment rate to customers (per kWh)	$0.14730	$0.18260
SCHEDULE "SL" - STREET LIGHTING		
(Depending on type of service)		
-All kWh per month (add to fixture charge)	$0.23339	$0.40672
-The minimum monthly charge shall be the fixture charge		
-Fixture charge (per fixture-per month multiplied by no. of fixtures)		
HPS 100 W (per fixture-per month)	$5.74	
HPS 150 W (per fixture-per month)	$5.74	
HPS 200 W (per fixture-per month)	$5.95	
HPS 250 W (per fixture-per month)	$5.95	
HPS 400 W (per fixture-per month)	$6.20	

ENERGY RATE ADJUSTMENT FACTORS:	
Schedule D, G, J, L, P, SL	$0.17276
Schedule Q	$0.03530

(See rate schedules for additional information)

MONTHLY EFFECTIVE RATES INCLUDE:	
(1) kWh increase to base energy rates for ENERGY RATE ADJUSTMENT CLAUSE	$0.17276
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule D	$0.000674
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule G	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule J	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule L	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule P	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule SL	$0.000576

KAUA'I ISLAND UTILITY COOPERATIVE

ENERGY RATE ADJUSTMENT CLAUSE

Current Date: 30-Apr-06
File No.: 2006-05
Supersedes Sheet Effective: 4/1/06
Effective Date: 5/1/06

RATE DATA SHEET

	BASE RATES EFFECTIVE 01-Nov-98	(1) EFFECTIVE RATES 01-May-06
SCHEDULE "D" - RESIDENTIAL		
-Customer charge (per Customer, per month)	$9.72	$9.72
-All kWh per month (add to customer charge)	$0.17489	$0.32476
-The minimum monthly charge shall be	$12.16	$12.16
SCHEDULE "G" - GENERAL LIGHT & POWER SERVICE (Small Commercial):		
(Not greater than 30 kW demand and 10,000 kWh use per month)		
-Customer charge (per customer, per month)	$21.89	$21.89
-All kWh per month (add to customer charge)	$0.19118	$0.34201
-The minimum monthly charge shall be	$24.31	$24.31
SCHEDULE "J" - GENERAL LIGHT & POWER SERVICE (Large Commercial):		
(Greater than 30 kW and less than 100 kW demand or 10,000 kWh per month)		
-Customer charge (per customer, per month)	$36.48	$36.48
-Demand charge per kW of monthly demand	$6.08	$6.08
-Energy charge (added to demand charge)		
-All kWh per month (add to customer charge)	$0.16031	$0.31114
-The minimum monthly charge shall not be less than	$182.37	$182.37
SCHEDULE "L" - LARGE POWER (Primary)		
(Demand greater than 100 kW - metered on primary side of meter)		
-Customer charge (per customer, per month)	$334.35	$334.35
-Demand charge per kW of monthly demand	$13.13	$13.13
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.14366	$0.29449
All over 400 kWh per kW of billing demand	$0.12540	$0.27623
-Minimum monthly charge: Customer + Demand Charge		
SCHEDULE "P" - LARGE POWER (Secondary)		
(Demand greater than 100 kW - metered on secondary side of meter)		
-Customer charge (per customer, per month)	$346.51	$346.51
-Demand charge per kW of monthly demand	$10.45	$10.45
-Energy charge (added to demand charge)		
First 400 kWh per kW of billing demand	$0.15279	$0.30362
All over 400 kWh per kW of billing demand	$0.13324	$0.28407
-Minimum monthly charge: Customer + Demand Charge		
	Effective Annual Rate 01-Jan-06	Prior Month's Rate 01-Apr-06
SCHEDULE "Q" MODIFIED - COGENERATORS		
-Energy credit payment rate to customers (per kWh)	$0.14730	$0.16810
SCHEDULE "SL" - STREET LIGHTING		
(Depending on type of service)		
-All kWh per month (add to fixture charge)	$0.23339	$0.38316
-The minimum monthly charge shall be the fixture charge		
-Fixture charge (per fixture-per month multiplied by no. of fixtures)		
HPS 100 W (per fixture-per month)	$5.74	
HPS 150 W (per fixture-per month)	$5.74	
HPS 200 W (per fixture-per month)	$5.95	
HPS 250 W (per fixture-per month)	$5.95	
HPS 400 W (per fixture-per month)	$6.20	

ENERGY RATE ADJUSTMENT FACTORS:	
Schedule D, G, J, L, P, SL	$0.14920
Schedule Q	$0.02080

(See rate schedules for additional information)

MONTHLY EFFECTIVE RATES INCLUDE:	
(1) kWh increase to base energy rates for ENERGY RATE ADJUSTMENT CLAUSE	$0.14920
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule D	$0.000674
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule G	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule J	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule L	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule P	$0.001630
(1) kWh increase to base energy rates for RESOURCE COST SURCHARGE - Schedule SL	$0.000576

APPENDIX C

INTERIM REPORT ON TASK 3:
FINDINGS AND RECOMMENDATIONS ON THE ECONOMIC EVALUATION OF ALTERNATIVES

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 3
Findings and Recommendations on the Economic Evaluation of Alternatives

Prepared For:

County of Kauai
Office of Economic Development
Kauai, Hawaii

Prepared By:

SCS Energy
Long Beach, California

November 2006

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 3

TABLE OF CONTENTS

Tables and Figures

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 3

TABLE OF CONTENTS (continued…)

Tables and Figures (continued…)

SECTION 1

INTRODUCTION

The County of Kauai Office of Economic Development engaged SCS Energy (SCS) to conduct a combined heat and power (CHP) feasibility study for the Pacific Missile Range Facility (PMRF). Task 3 of the work plan for this study calls for:

- Development of site plans for the alternatives selected for further study during Task 2. Six alternatives were selected for further study in Task 2;
- Development of capital and operation/maintenance cost estimates for the alternatives;
- Preparation of a present worth analysis, using the capital and operation/maintenance cost estimates. A twenty year life span is to be employed;
- Preparation of predictions of annual energy and cost savings;
- Recommendation of the optimal system; and
- Submittal of a Task 3 report.

SECTION 2

CONCEPTUAL DESIGNS

The Task 2 report, titled "Energy Baseline Evaluation and CHP Economic and Engineering Options," recommended that six alternatives be carried forward for more detailed study:

> <u>Alternative No. 1-A:</u> Fuel the existing PMRF engines on diesel oil, with the addition of heat recovery, and retain the current program of intermittent engine operation;
>
> <u>Alternative No.1-B:</u> Fuel the existing PMRF engines on diesel oil, with the addition of heat recovery, and convert to full-time operation;
>
> <u>Alternative No. 2-A:</u> New landfill gas fired reciprocating engines located at the existing PMRF power plant, with heat recovery to produce chilled water using absorption chillers, with a microturbine CHP plant near Building 1261;
>
> <u>Alternative No.2-B:</u> New landfill gas fired reciprocating engines located at the existing PMRF power plant, with heat recovery to produce chilled water using absorption chillers, without a microturbine CHP plant near Building 1261;
>
> <u>Alternative No.3:</u> New landfill gas fired reciprocating engines on PMRF grounds close to the landfill; and
>
> <u>Alternative No. 4:</u> New landfill gas fired reciprocating engines located at the landfill.

The subsections which follow describe the six alternatives.

<u>Alternative No. 1-A: Existing PMRF Power Plant with Heat Recovery and with Intermittent Operation</u>

Alternative No. 1-A continues to rely on diesel oil and the existing PMRF engines. Landfill gas would not be employed. The existing PMRF power plant would be converted into a CHP facility.

The two existing 600 kW engines would be retrofitted with hot water recovery equipment. The hot water recovery equipment would consist of water-to-water heat exchangers in the hot water lines to the engine radiators, and gas-to-water heat exchangers in the engine exhaust stacks. The radiators are located outside in the rear of the power plant building. The hot water would be delivered via insulated water piping to a single, new 80-ton absorption chiller located at the power plant. Chilled water would be delivered and returned from Buildings 130, 105 and 105ROCS by insulated, underground chilled water piping. Warm water exiting the absorption chillers would be returned to the diesel engines for reheating.

The existing electric chillers at Buildings 130, 105 and 105ROCS, and the air-cooled condenser unit at 105ROCS would remain as standby units to be pressed into service, if cooling was not available from the new absorption chiller, and to augment the output of the absorption chiller. The capacity of the absorption chiller is constrained by the amount of waste heat available, which is constrained by the fact that the engines usually operate at a maximum of 40 percent of their rated output. The total existing installed chiller capacity at the three buildings is 280 tons. The chilled water from the absorption chillers would be run through new water-to-water heat exchangers installed in the warm water return lines from the buildings. The ability to use chilled water for cooling, in addition to the cooling provided by the air-cooled condenser, would also need to be provided through augmentation of the air handling unit associated with the air-cooled condenser at Building 105ROCS. The electric chiller serving Building 105ROCS appears to be a temporary unit, or at least it is not yet permanently installed. The final details of the cooling arrangement for Building 105ROCS must be developed during detailed design, and the arrangement should be integrated with the future plan for the temporary chiller. A reasonable capital budget will be incorporated into the cost estimate for Alternative No. 1-A to cover uncertainties related to the final chiller configuration.

The energy and economic benefit of adding absorption chilling to the three buildings is a reduction in reliance on electric drive chilling. The reduced electric consumption would ultimately result in reduced diesel oil consumption. The reduction in electric consumption would only occur when the PMRF power plant was operating since hot water would only be produced when the diesel engines were running. The engines currently operate about 2,000 hours per year. The total installed electric drive cooling capacity in these three buildings is 280 tons. The maximum power draw is about 330 kW. Information on the cooling load factor is not available. A daytime load factor of 75 percent will be assumed for the weekday, daytime peak hours (2,000 hours). Based on this assumption, the 80 tons of chilling could always be absorbed, resulting in a reduction in electric power consumption of about 180,000 kWh per year. At an engine heat rate of 11,125 Btu/kWh, the consumption of 14,210 gallons per year of diesel oil would be avoided.

<u>Alternative No. 1-B: Existing PMRF Power Plant with Heat Recovery and with Continuous Operation</u>

PMRF has its greatest power requirement during the normal workday on weekdays. The PMRF power plant is run during this period. PMRF has some power requirement and some cooling requirement on nights and weekends. Alternative No. 1-B is physically the same as Alternative No. 1-A. It differs only in that the engines would continue to run during nights and weekends, at a reduced power output. Continuous operation of the PMRF power plant might be cost-effective, given its new ability to operate in a CHP mode. The purpose of considering this alternative is to evaluate the possibility of continuous operation.

An accurate assessment of whether or not the PMRF power plant should operate during off-peak hours requires knowledge of the power and cooling requirements during off-peak hours, and knowledge of how much of the power requirement is for cooling. The necessary information is not available. Since Alternative No. 1-A and Alternative No. 1-B are physically identical, the decision on whether or not to operate continuously could be made in the future, based on actual operating experience.

For the purposes of this study, it is only necessary to quantify the approximate potential net benefit. If there was a significant potential net benefit, it would enhance the attractiveness of Alternative No. 1-B, in comparison to the other five alternatives. Thus, a roughly quantified benefit at this point in the evaluation is still of use.

Under this alternative, it will be assumed that the diesel engines will operate at their full 1,200 kW, which the total demand of the PMRF main base area requires them to, and that the engines will also operate during the off-peak hours to match the required power demand. The size of the absorption chiller will be increased to 200 tons. The approximate impacts of operation in the above mode are as follows:

- Avoid the equivalent of 900,000 kWh per year in electric consumption for cooling;
- Generate an additional 5,275,000 kW per year on diesel oil;
- Consume an additional 417,000 gallons per year of diesel fuel at PMRF; and
- Reduce KIUC's consumption of diesel oil by 390,000 gallons per year.

A cooling load factor of 75 percent was assumed for the weekday, daytime peak hours. A load factor of 40 percent was assumed for the remaining hours.

<u>Alternative No. 2-A: New LFGTE Plant at Existing PMRF Power Plant With Microturbine CHP Facility</u>

A compressor skid would be located at the landfill. The compressor skid would incorporate the following elements:

- A first stage of pressurization (-50" wc to +5 psig) using centrifugal blowers;
- An interstage gas-to-air heat exchanger;
- A second stage of pressurization (+5 psig to +50 psig) with a sliding vane-type compressor;
- A post-compression gas-to-air heat exchanger;

- A gas-to-gas reheat heat exchanger, a gas-to-chilled water heat exchanger, and a chiller; and
- A final coalescing filter.

The compressor would consume an average of about 100 kW or 815,000 kWh per year.

A 6-inch diameter, below-grade HDPE pipeline would be constructed a distance of about 3.9 miles from the landfill to the existing PMRF power plant. The pipeline would generally parallel Nohili Road.

Two Caterpillar 3516 landfill gas fired reciprocating engines (820 kW x 2 = 1,640 kW) would be located in the vicinity of the existing PMRF power plant. The engines and their switchgear would be installed in a new sheet metal building with the approximate dimensions of 30 feet by 60 feet. Figure No. 2-1 shows a possible location for the building. The final location must be selected in cooperation with PMRF. The heat recovery element of Alternative No. 2-A would be essentially the same as that described for Alternative No. 1-A. The capacity of the chiller would be increased to 280 tons.

A microturbine CHP facility will be installed to provide cooling to Buildings 1260, 1261, 1262 and 1264, and hot water to Buildings 1261 and 1262. The microturbine CHP facility would consist of:

- Four 60 kW microturbines, a hot gas driven, double-effect absorption chiller, and a waste heat hot water generator;
- A landfill gas pressurization and treatment skid consisting of a sliding vane-type compressor (45 psig to 80 psig), and a fixed media (silica gel) non-regenerable siloxane treatment system;
- Below-ground, insulated, chilled water delivery and return water piping from the microturbine CHP facility to Buildings 1260, 1261, 1262 and 1264 and below ground, insulated hot water delivery and return water piping from the microturbine CHP facility to Buildings 1261 and 1262; and
- Connections and valving from the above chilled water and return water piping to the existing chilled water and return water piping associated with the chillers at Buildings 1260, 1261 and 1262. Modifications to the building cooling system at Building 1264 will be made to allow cooling to be supplied by the air-cooled condenser or the chilled water from the microturbine CHP facility.

The installed cooling capacity at Buildings 1260, 1261, 1262 and 1264 is about 60 tons. The full output capability of the microturbine CHP facility would be 120 tons of cooling or 1.1 mmBtu/hr of hot water. The capacity of the hot water generator at Building 1262, serving Buildings 1262 and 1261, is 0.34 mmBtu/hr. The microturbine CHP facility will be able to cover the peak cooling and hot water loads at all of the buildings.

At full output, in warm weather, the microturbine CHP facility will provide an average net power output of 180 kW. The power required by the booster compressor, the absorption chiller and the water pumps has been considered in arriving at the net power output. The microturbine CHP facility will require approximately 90 scfm of landfill gas.

The use of the landfill gas at the microturbine CHP facility represents landfill gas not available for use at the reciprocating engine power plant.

If it is assumed that the installed absorption chiller cooling capacity has a utilization factor of 40 percent on an annual basis, the substitution of absorption chilling for electric drive cooling will save the equivalent of about 250,000 kWh per year.

If it is assumed that the existing hot water generator has a utilization factor of 15 percent, then consumption of about 496 mmBtu per year of propane (or about 5,230 gallons) will be avoided.

The power requirement at the PMRF main base point of service averages 750 kW and peaks at about 1,400 kW. If a 1,640 kW (gross), 1,525 kW (net) landfill gas fired reciprocating engine power plant is located at the existing PMRF power plant, then about 5,346,000 kWh of “excess” power is available for export to KIUC through the PMRF main base point of service. Based on a preliminary appraisal of the on-site power distribution system, this could be accomplished without upgrading the distribution system. The approach would be as follows:

- The two new generators would produce power at 4,160 V and connect into the low voltage side of the 4,160 V/12.47 kV “KE feeder” transformer at the power plant; and
- The south loop breaker would be closed.

As an alternative to selling all of the excess power to KIUC, the Navy Housing point of service could be connected to the PMRF main base point of service. The Navy Housing point of service has an average demand of 350 kW and a peak demand of 700 kW. In order to service this load, it will be necessary to:

- Install about 5,500 feet of below-ground 12.47 kV cable due south of the PMRF power plant along Nohili Road;
- Install about 8,300 feet of above-ground 12.47 kV cable beyond the underground cable to the Navy Housing area. About 6,600 feet of this cable could be strung on existing poles; and
- Disconnect the KIUC Navy Housing point of service.

The above modifications will cost in the vicinity of $1,230,000. The benefit to PMRF is that the power transferred to the Navy Housing point of service would be worth a net of $0.264/kWh versus the $0.175/kWh KIUC pays for excess power produced by cogenerators. The marginal benefit to PMRF would be about $163,000 per year. The calculated benefit has been reduced by the consideration that about 180 kW of the average load of 350 kW is being satisfied by the microturbine CHP facility. The simple payback is about 7.5 years. It will be assumed that the interconnecting distribution line between the PMRF power plant and the Navy Housing area will be built.

The microturbine CHP facility will produce power at 480 V. It will be stepped up to 12.47 kV and connected into the nearest 12.47 kV power line.

The microturbine CHP facility has been tentatively located behind Building 1261. Figure No. 2-2 presents a tentative general arrangement plan for the microturbine CHP facility.

Alternative No. 2-A will accomplish the following:

- Produce an average of 12,210,100 kWh per year of renewable power over its 20-year life;
- Eliminate about 112,000 gallons per year of diesel oil consumption by the PMRF power plant; and
- Produce the equivalent of 714,000 gallons per year of diesel oil savings at KIUC's power plant through elimination of power purchases and through delivery of "excess" power to KIUC.

While the above outlines a technical approach to serving the Navy Housing area, a contractual issue also exists. Significant segments of the power distribution system within the Navy Housing area are not owned by PMRF. If the Navy Housing point of service is disconnected from KIUC, then these segments must be bought from KIUC. Whether KIUC would be willing to sell them at a reasonable price is not known. If this contractual issue could not be worked out, the tie line between the PMRF main base and the Navy Housing area would not be installed. If the interconnection was not installed, approximately 1,834,000 kWh per year would be shifted from the category of avoided KIUC power purchases to the category of delivery of excess power to KIUC. The $1,230,000 capital investment would be avoided, and PMRF would lose $163,000 per year in net revenue. It should also be noted that payment of any amount to KIUC, to resolve this contractual issue, would increase the projected payback period beyond 7.5 years.

Alternative No. 2-B: New LFGTE Plant at Existing PMRF Power Plant Without Microturbine CHP Facility

From a physical facilities perspective, Alternative No. 2-B is Alternative No. 2-A without the microturbine CHP facility. The following non-physical impacts will occur:

- On-site electric power production will increase from an average of 12,210,000 kWh per year to 12,691,900 kWh per year, since the reciprocating engines are more efficient than microturbines;
- The 250,000 kWh of electric power consumption that would have been deferred by the microturbine CHP facility's satisfaction of the cooling loads of four buildings in the Navy Housing area would be lost. The net impact, on equivalent power production, would, however, still be a gain of 231,800 kWh per year. The above conclusion is counterintuitive. Elimination of the microturbine CHP facility actually enhances energy efficiency. The microturbine CHP facility proposed herein is the smallest commercially available unit. Only about 23 percent of the theoretically available tons of cooling are being productively used due to the lack of cooling load. The amount of cooling productively used cannot offset the inefficiency of the microturbine versus a reciprocating engine. A microturbine's heat rate is 14,300 Btu/kWh versus 10,900 Btu/kWh for a reciprocating engine;
- If an interconnection between PMRF main base and Navy Housing was not made, then more of the total power produced would be sold to KIUC versus the power being used at PMRF. This is because none of the Navy Housing point of connection would be served by PMRF self-generated power. In order to serve the Navy Housing point of service, the distribution system modifications discussed under Alternative No. 2-A would need to be made. The payback on this investment would reduce from 7.5 years to 4.3 years. It will be assumed that the distribution system modifications will be made. The above-discussed KIUC contractual issue must, of course, still be addressed; and
- Propane consumption would not be reduced by 5,230 gallons per year.

Alternative No. 2-B will accomplish the following:

- Produce an average of 12,691,900 kWh per year of renewable power over its 20-year life;
- Eliminate about 112,000 gallons per year of diesel oil consumption by the PMRF power plant; and
- Produce the equivalent of 729,000 gallons of diesel oil savings at KIUC's power plant through elimination of power purchases and the delivery of "excess" power to KIUC.

Alternative No. 3: New LFGTE Plant Near Landfill on PMRF

Under Alternative No. 3, a 1,640 kW landfill gas fired reciprocating engine power plant would be located along Kokole Point Road. A tentative location is shown on Figure No. 2-3. The power plant would not be equipped for heat recovery.

Because the power plant is located close to the landfill, it will be possible to eliminate the compressor skid at the landfill. A 12-inch diameter, 1,000-foot long, underground HDPE landfill gas delivery pipe would be extended from the landfill to the power plant location. The pipe would operate under a slight vacuum. Two or three low point sumps would be located along this pipe to collect condensate. The sumps would be equipped with pneumatic sump pumps. A 2-inch condensate return line, and a 2-inch compressed air line would be co-located with the landfill gas pipe in the landfill gas pipe trench. The condensate and air lines would originate at the landfill.

Landfill gas would be pressurized at the power plant with centrifugal blowers. The landfill gas would be cooled in an air-to-gas heat exchanger, and would then pass through a moisture separator and a coalescing filter, before entering the landfill gas pipeline.

In order to serve all three of PMRF's main KIUC points of service for the new power plant, it will be necessary to run a new 12.47 kV distribution line down Kokole Point Road to Nohili Road, and then along Nohili Road through the Navy Housing area, and then up to the existing PMRF power plant. The distribution line would cover a distance of 14,850 feet on new poles, 6,600 feet on existing poles, and 5,500 feet underground.

Power at the new power plant would be generated at 4,160 V. It would be stepped up to 12.47 kV at the new power plant. The KIUC service point at Navy Housing would be eliminated. The KIUC service point at PMRF main base would also be eliminated.

Alternative No. 3 would accomplish the following:

- Produce an average of about 12,057,300 kWh per year of power over its 20-year life;
- Eliminate about 112,000 gallons per year of diesel oil consumption by the PMRF power plant; and
- Produce the equivalent of 672,000 gallons of diesel oil savings at KIUC's power plant through elimination of power purchases and delivery of "excess" energy to KIUC.

Alternative No. 4: New LFGTE Plant at Landfill

Under Alternative No. 4, a 1,640 kW landfill gas fired reciprocating engine power plant would be installed at the landfill. It would not be equipped with heat recovery. The 1,000-foot long 12-inch diameter connecting pipe, required under Alternative No. 3, would be eliminated. The inlet vacuum of the centrifugal blowers would be lowered by one psig.

The power plant would interconnect directly to KIUC. The power plant would produce 12,057,300 kWh of renewable power per year, avoiding about 761,600 gallons per year of oil consumption at KIUC's central power plant.

The power plant at the landfill could be:

1) Owned by PMRF with the output sold to KIUC. The revenue generated at the landfill through sale of power to KIUC could offset the cost of power PMRF purchases from KIUC;
2) Owned by KIUC (with KIUC buying landfill gas from the County);
3) Owned by the County with sale of power to KIUC; or
4) Owned by a private developer, buying landfill gas from the County, and the private developer selling power to KIUC.

Because this study is addressing PMRF's needs, ownership by PMRF will be presumed; however, one of the other ownership configurations may result in more net revenue to the County.

Under the PMRF ownership configuration, it will be assumed that PMRF would receive 17.5¢/kWh for power sold to KIUC. KIUC makes an energy credit payment to cogenerators under KIUC's Schedule Q. The Schedule Q rate varies monthly and is benchmarked to the price of oil. The Schedule Q rate averaged 17.5¢/kWh in 2006. The project configuration technically does not satisfy the specific requirements of Schedule Q in that the power plant is not a cogeneration plant, and the credit would be applied to billings on meters not connected to the power plant. The power plant could nominally be converted into a cogeneration facility by finding a productive use for heat at the landfill (e.g., condensate or leachate evaporation).

A possibly more favorable scenario to PMRF would be for KIUC to accept the power generated by PMRF and to transmit ("wheel") it to PMRF's existing points of connection to PMRF. Under such an arrangement, KIUC would charge a fixed monthly $/kW charge or a ¢/kWh charge for transmission service. KIUC does not have a policy on wheeling and for this reason, it will be assumed that all power produced by PMRF will have a value of 17.5¢/kWh.

It should be noted that 17.5¢/kWh (wholesale) is substantially lower than the 29.4¢/kWh (average retail price) that PMRF paid KIUC for power in 2005/2006. It is also less than PMRF would net from on-site generation. The net value for on-site generated power would be about 28.0¢/kWh (29.4¢/kWh less KIUC charges for standby power). KIUC currently charges $5.00 per month per kW of standby demand, as is specified in KIUC's published Rider "S." KIUC's standby charge is roughly equivalent to 1.4¢/kWh.

On October 31, 2006, KIUC's Board of Directors adopted a resolution that would increase KIUC's standby charge for Schedule "P" customers to $37.47/kW. The proposed increase is subject to review and approval by the Hawaii Public Utilities Commission (PUC). The PUC can accept, modify or defer implementation of the proposed standby rate, until a certain percentage of load has been lost by KIUC to parties generating their own power. Under a worst case scenario, the standby charge could increase to the equivalent of 10.5¢/kWh in the future. KIUC's current Schedule P demand charge is $10.45/kW. Generally, a utility's standby charge is lower than its demand charge. A standby charge based on $10.45/kWh would be roughly equivalent to 3.0¢/kWh.

If it is assumed that PMRF will continue to operate its power plant as it is currently operated, the impact of Alternative No. 4 would be the delivery of an average of 12,057,300 kWh per year to KIUC, reducing KIUC's oil consumption by 761,600 gallons per year.

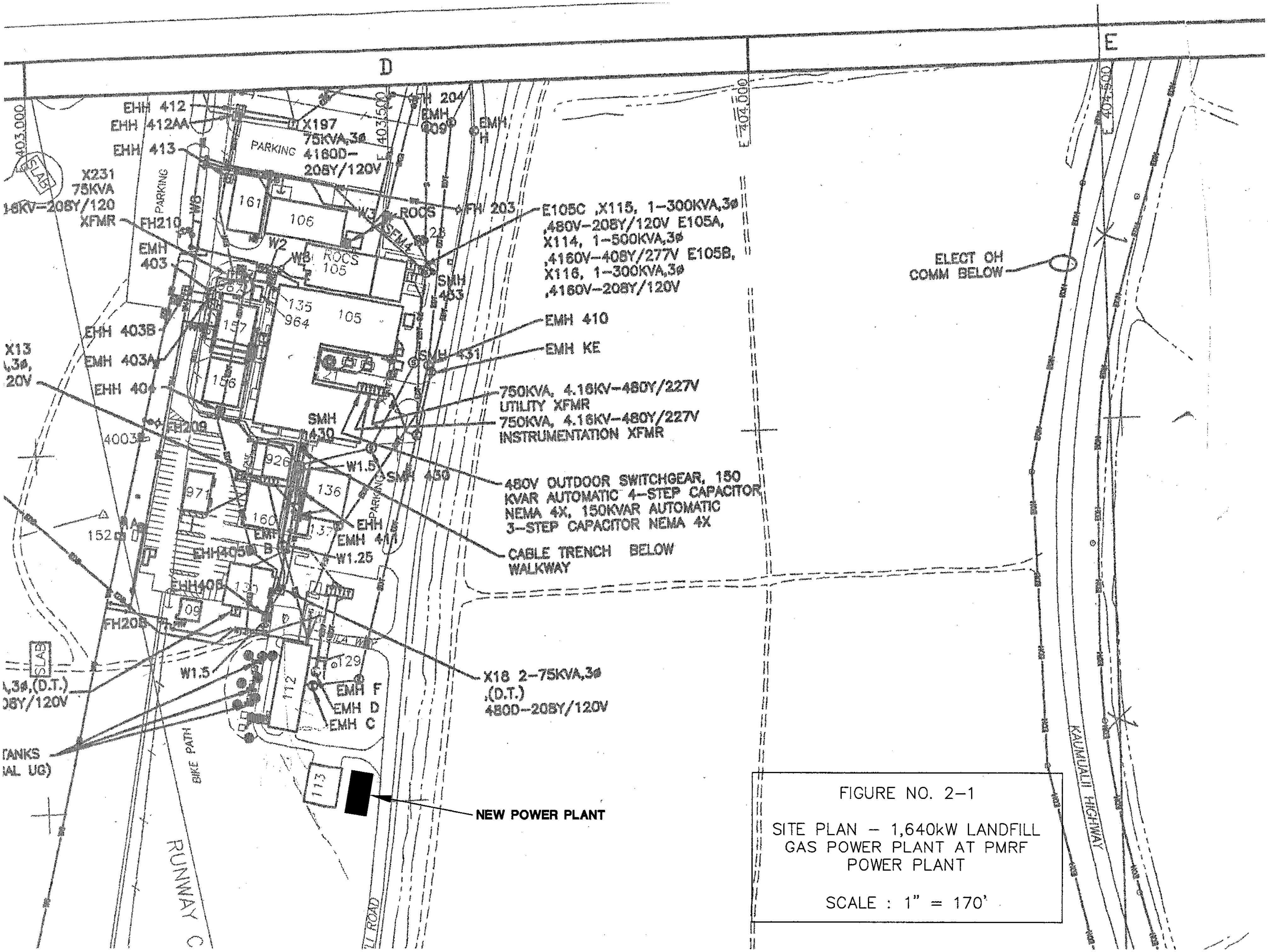


FIGURE NO. 2-1

SITE PLAN – 1,640kW LANDFILL GAS POWER PLANT AT PMRF POWER PLANT

SCALE : 1" = 170'

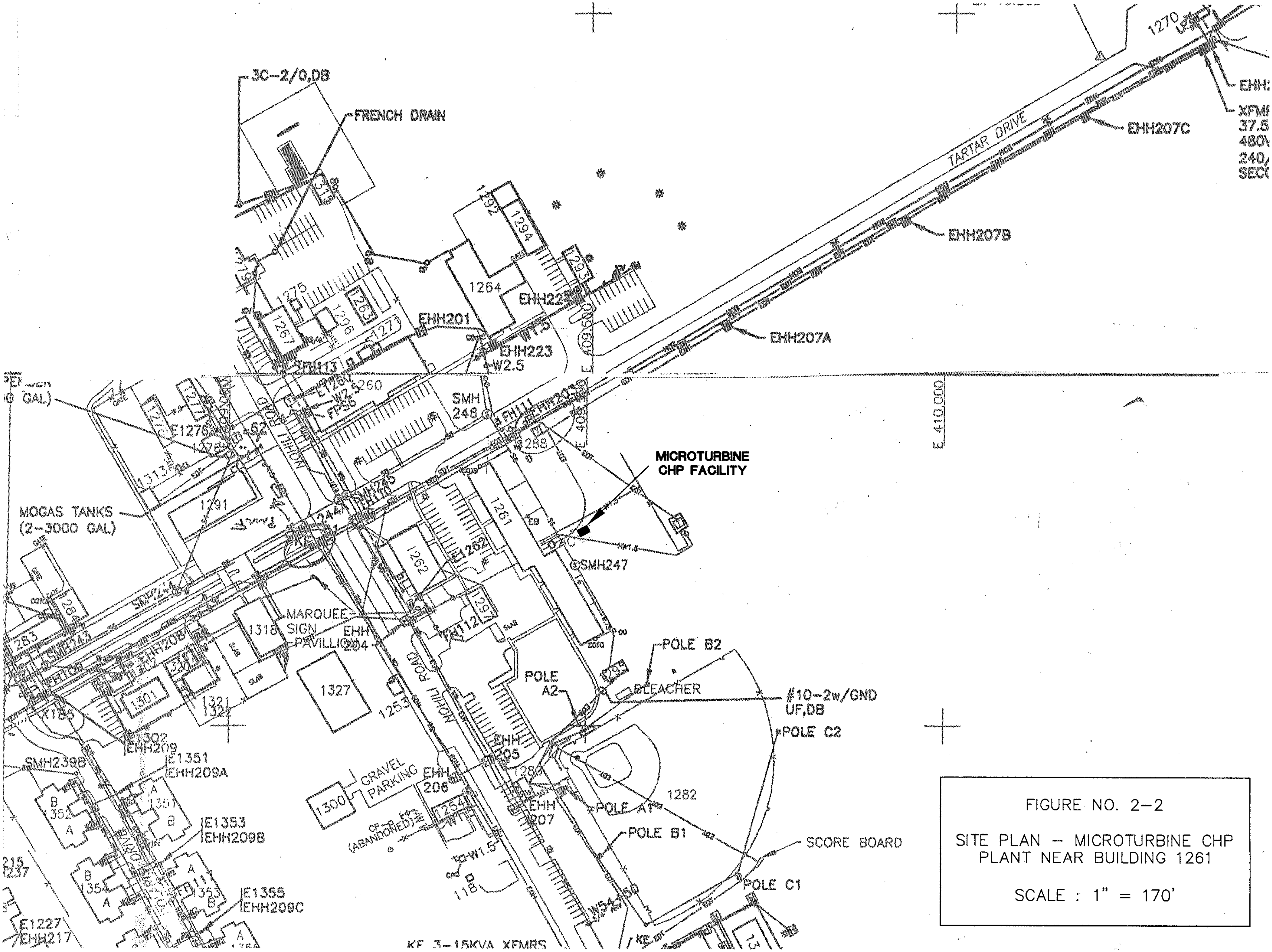


FIGURE NO. 2-2

SITE PLAN – MICROTURBINE CHP PLANT NEAR BUILDING 1261

SCALE : 1" = 170'

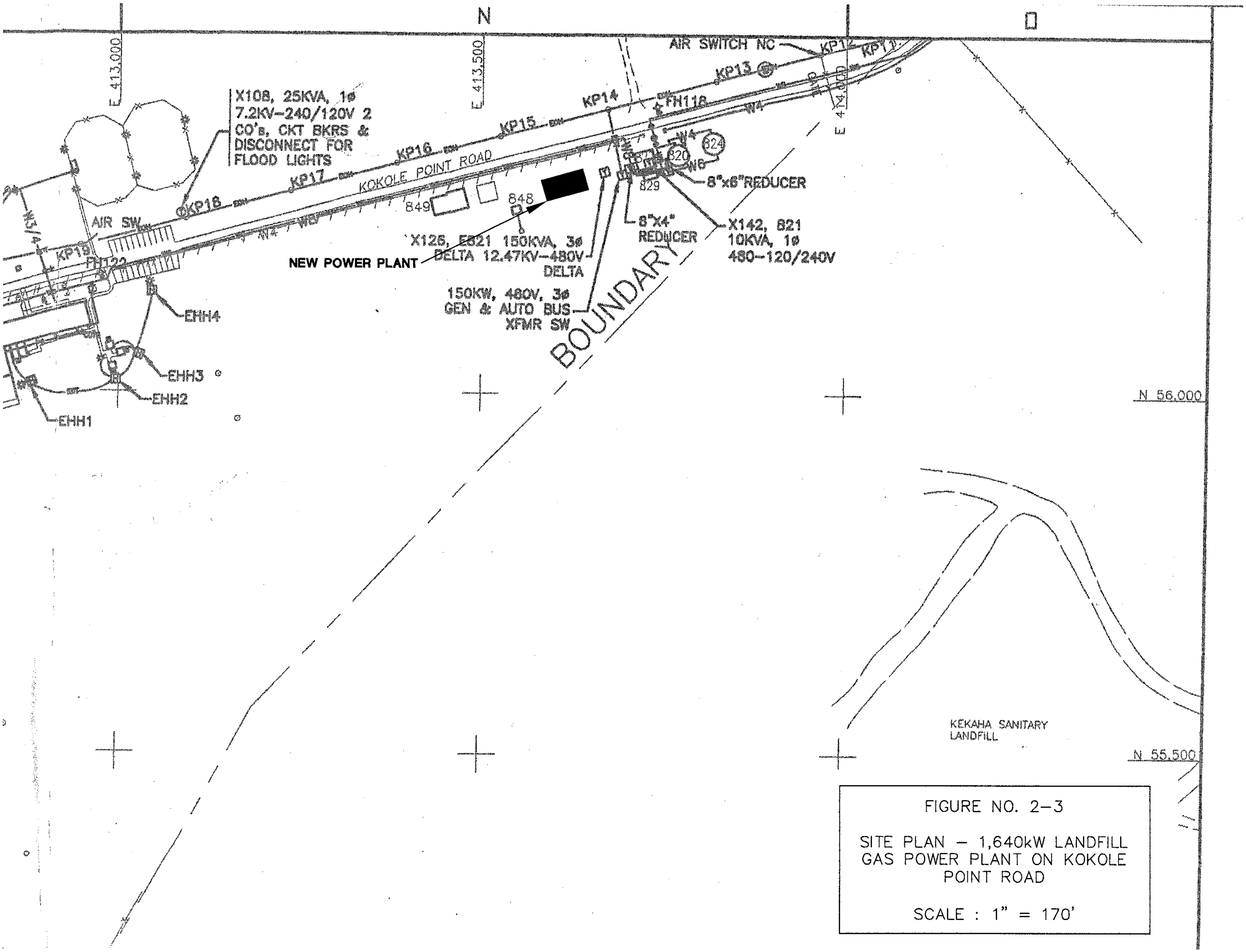


FIGURE NO. 2-3

SITE PLAN – 1,640kW LANDFILL GAS POWER PLANT ON KOKOLE POINT ROAD

SCALE : 1" = 170'

SECTION 3

CONSTRUCTION COSTS

Table No. 3-1 provides a construction cost estimate for each of the six alternatives. The paragraphs which follow provide an explanation of important line items found on Table No. 3-1.

The cost for the reciprocating engines includes the cost of two Caterpillar 3516 engine/generators and appurtenant equipment (radiators, silencers, etc.). The equipment cost, as with all other equipment costs cited on Table No. 3-1, also include contractor's markup, shipping cost and installation cost.

The cost for microturbines, applicable only to Alternative No. 2-A, includes four 60 kW microturbines, equipped with an absorption chiller and hot water recovery, as available from UTC.

The chillers, applicable to Alternative Nos. 1-A, 1-B, 2-A and 2-B, are single-effect, hot water absorption chillers.

The heat exchangers for Alternative Nos. 1-A and 1-B include water-to-water waste heat recovery exchangers installed in the cooling water loop of both of the existing 600 kW engines, an exhaust-to-hot water heat exchanger in both of the engines' exhaust stacks, and an air-to-hot water waste heat heat exchanger to match hot water production with absorption chiller heat demand.

The heat exchangers for Alternative Nos. 2-A and 2-B include the same heat exchange configuration described above; however, they are applied to two 820 kW engines.

The absorption chiller under Alternative No. 2-A does not require a hot water heat exchanger since it operates on hot exhaust gas. A small hot water heat exchanger will be employed to supply the hot water demands of two of the buildings served.

Pumps include hot pumps for the hot water recirculating pumps, for all alternatives, and chilled water pumps for Alternative No. 2-A's chilled water loop.

The landfill gas skid under Alternative No. 2-A and 2-B is identical and is a high-pressure skid equipped with chilling and reheat of the landfill gas. Alternative No. 2-A requires a booster compressor at the microturbine CHP facility. Alternative Nos. 3 and 4 do not require compression. They rely on a centrifugal blower with an air-to-gas aftercooler.

The largest component of the line item titled "Landfill Gas Piping" under Alternative Nos. 2-A and 2-B is the 3.9-mile landfill gas transmission pipeline from the landfill to the PMRF power plant.

The "PMRF Grid Improvements" line item pertains only to Alternative Nos. 2-A, 2-B and 3. Under Alternative No. 3, it is necessary to link Kokole Point to Navy Housing through to the PMRF main base to make maximum on-site use of the power which is being generated by Alternative No. 3's power plant. Under Alternative Nos. 2-A and 2-B, PMRF main base is linked with Navy Housing to provide the Navy Housing area with power.

TABLE NO. 3-1
CONSTRUCTION COST ESTIMATES FOR THE SIX ALTERNATIVES

	Alt No. 1-A Existing PMRF with Heat Recovery with Intermittent Ops	**Alt No. 1-B Existing PMRF with Heat Recovery with Continuous Ops**	**Alt No. 2-A New LFGTE at Existing PMRF With Microturbines**	**Alt No. 2-B New LFGTE at Existing PMRF Without Microturbines**	**Alt No. 3 New LFGTE Near Landfill on PMRF**	**Alt No. 4 New LFGTE at Landfill**
Major Mechanical Equipment						
Reciprocating Engines	$0	$0	$1,350,000	$1,350,000	$1,350,000	$1,350,000
Microturbines	$0	$0	$460,000	$0	$0	$0
Chillers	$148,000	$296,000	$355,000	$355,000	$0	$0
Heat Exchangers	$72,000	$108,000	$165,000	$115,000	$0	$0
Pumps	$16,000	$20,000	$33,000	$22,000	$0	$0
Landfill Gas Skid	$0	$0	$460,000	$420,000	$205,000	$195,000
Piping and Related						
Landfill Gas Piping	$0	$0	$604,000	$604,000	$83,200	$0
Hot Water Piping	$26,000	$39,000	$68,900	$42,900	$13,000	$13,000
Warm Water Piping	$13,000	$19,500	$48,100	$22,100	$13,000	$13,000
Chilled Water Piping	$71,500	$97,500	$201,500	$104,000	$0	$
Other Piping	$0	$0	$175,500	$162,500	$162,500	$162,500
Chilled Water Conversions	$13,000	$13,000	$26,000	$13,000	$0	$0
Civil						
Grading/Site Work	$0	$0	$117,000	$104,000	$52,000	$65,000
Foundations	$6,500	$13,000	$201,500	$182,000	$143,000	$143,000
Buildings	$0	$0	$175,500	$175,500	$175,500	$175,500
Electrical						
Transformers	$0	$0	$71,500	$52,000	$117,000	$117,000
Switchgear	$0	$0	$396,500	$357,500	$260,000	$260,000
Utility Interconnect	$0	$0	$0	$0	$0	$200,000
PMRF Grid Improvements	$0	$0	$1,230,000	$1,230,000	$2,130,000	$0
Power Conduit/Cable	$10,400	$15,600	$383,500	$331,500	$305,500	$292,500
Control Conduit/Cable	$2,600	$2,600	$188,500	$162,500	$162,500	$162,500
Control System	$10,400	$10,400	$182,000	$143,000	$104,000	$104,000
Landfill Gas Collection System						
Landfill Gas Collection System	$0	$0	$379,000	$379,000	$379,000	$379,000
Engineering/Technical						
Permits	$0	$0	$45,000	$45,000	$45,000	$45,000
Detailed Design	$40,000	$40,000	$415,000	$370,000	$380,000	$320,000
Construction Observation	$15,000	$15,000	$166,000	$166,000	$166,000	$166,000
Total	**$444,400**	**$689,600**	**$7,898,000**	**$6,908,500**	**$6,246,200**	**$4,163,000**
Contingency (10%)	$44,440	$68,960	$789,800	$690,850	$624,620	$416,300
GRAND TOTAL	**$488,840**	**$758,560**	**$8,687,800**	**$7,599,350**	**$6,870,820**	**$4,579,300**

SECTION 4

OPERATION/MAINTENANCE COSTS

Table Nos. 4-1, 4-2 and 4-3 summarize the operation/maintenance cost of the six alternatives. As discussed in Section 2, KIUC intends to increase its standby power charge. The standby power charge directly affects the net revenue produced by deferred power purchases. Table No. 4-1 employs the current (lowest) standby charge. Table No. 4-2 employs a standby charge roughly double the current standby charge, and equal to KIUC's demand charge for Schedule "P." Table No. 4-3 employs the proposed (highest) standby charge.

The line item titled "Fuel Cost" includes the impact of the incremental increase or decrease in PMRF diesel oil purchases, where such changes occur, at a diesel oil price of $2.44 per gallon. PMRF's cost of diesel fuel averaged $2.44 per gallon in 2005/2006. Landfill gas consumed by any alternative is costed at $1.00/mmBtu. The actual price for the landfill gas would be subject to negotiation between PMRF and the County. Increases or decreases to the price would directly affect the bottom line of the landfill gas fired alternatives.

Included in the line item titled "Electric Power" is the cost of power that might otherwise not be purchased from KIUC. Under Alternative Nos. 2-A and 2-B, the gas compression skid at the landfill would require power from KIUC. Alternative Nos. 3 and 4 avoid most of this cost since their landfill gas blowers would use self-generated power almost all of the time. The use of this self-generated power is considered in the net power output assigned to these two alternatives. If Alternative No. 2-A or 2-B is implemented, installation of a microturbine at the skid might be considered as an optimization step.

In the revenue section of Table No. 4-1, the following assumptions were made:

- The cost of propane is $2.50 per gallon;
- Deferred KIUC power purchases are valued at 28.0¢/kWh, 26.4¢/kWh and 18.9¢/kWh (current retail rate of 29.4¢/kWh less standby power charges of 1.4¢/kWh, 3.0¢/kWh and 10.5¢/kWh); and
- Power sold to KIUC is valued at 17.5¢/kWh (KIUC's cogenerator energy credit under Schedule Q for 2006).

TABLE NO. 4-1
ANNUAL OPERATION/MAINTENANCE COSTS FOR THE SIX ALTERNATIVES
LOW STANDBY POWER COST SCENARIO

	Alt No. 1-A Existing PMRF with Heat Recovery with Intermittent Ops	Alt No. 1-B Existing PMRF with Heat Recovery with Continuous Ops	Alt No. 2-A New LFGTE at Existing PMRF With Microturbines	Alt No. 2-B New LFGTE at Existing PMRF Without Microturbines	Alt No. 3 New LFGTE Near Landfill on PMRF	Alt No. 4 New LFGTE at Landfill
Fuel Cost (Diesel/Landfill Gas)	–$34,670	+$1,017,480	+$141,300	+$141,300	+$141,300	+$141,300
Electric Power	No change	No change	+$240,000	+$240,000	No change	No change
Other Consumables	+$7,000	+$10,000	+$15,000	+$11,000	+$2,000	+$2,000
Equipment Maintenance	+$7,000	+$50,000	+$190,000	+$150,000	+$140,000	+$140,000
Labor	No change	+$245,000	+$163,000	+$123,000	+$123,000	+$245,000
Miscellaneous Costs	No change	+$5,000	+$10,000	+$10,000	+$10,000	+$10,000
Total Annual Cost	**–$20,670**	**+$1,327,480**	**+$759,300**	**+$675,300**	**+$416,300**	**+$538,300**
Deferred Propane Purchases	No change	No change	–$13,070	No change	No change	No change
Deferred Diesel Purchases	No change	No change	–$273,300	–$273,000	–$273,000	No change
Deferred Power Purchases	No change	–$1,820,000	–$2,526,400	–$2,526,400	–$2,643,000	No change
Power Sold to KIUC	No change	No change	+$558,000	+$642,000	+$458,000	+$2,110,000
Total Revenue from Power	No change	+$1,820,000	+$3,084,400	+$3,168,400	+$3,101,000	+$2,110,000
Total Annual Revenue	**No change**	**+$1,820,000**	**+$3,370,770**	**+$3,441,400**	**+$3,374,000**	**+$2,110,000**
Net Annual Savings	**+$20,670**	**+$492,520**	**+$2,611,470**	**+$2,766,100**	**+$2,957,700**	**+$1,571,700**

TABLE NO. 4-2
ANNUAL OPERATION/MAINTENANCE COSTS FOR THE SIX ALTERNATIVES
MEDIUM STANDBY POWER COST SCENARIO

	Alt No. 1-A Existing PMRF with Heat Recovery with Intermittent Ops	**Alt No. 1-B Existing PMRF with Heat Recovery with Continuous Ops**	**Alt No. 2-A New LFGTE at Existing PMRF With Microturbines**	**Alt No. 2-B New LFGTE at Existing PMRF Without Microturbines**	**Alt No. 3 New LFGTE Near Landfill on PMRF**	**Alt No. 4 New LFGTE at Landfill**
Fuel Cost (Diesel/Landfill Gas)	–$34,670	+$1,017,480	+$141,300	+$141,300	+$141,300	+$141,300
Electric Power	No change	No change	+$240,000	+$240,000	No change	No change
Other Consumables	+$7,000	+$10,000	+$15,000	+$11,000	+$2,000	+$2,000
Equipment Maintenance	+$7,000	+$50,000	+$190,000	+$150,000	+$140,000	+$140,000
Labor	No change	+$245,000	+$163,000	+$123,000	+$123,000	+$245,000
Miscellaneous Costs	No change	+$5,000	+$10,000	+$10,000	+$10,000	+$10,000
Total Annual Cost	**–$20,670**	**+$1,327,480**	**+$759,300**	**+$675,300**	**+$416,300**	**+$538,300**
Deferred Propane Purchases	No change	No change	–$13,070	No change	No change	No change
Deferred Diesel Purchases	No change	No change	–$273,300	–$273,000	–$273,000	No change
Deferred Power Purchases	No change	–$1,716,000	–$2,382,000	–$2,382,000	–$2,492,000	No change
Power Sold to KIUC	No change	No change	+$558,000	+$642,000	+$458,000	+$2,110,000
Total Revenue from Power	No change	+$1,716,000	+$2,940,000	+$3,024,000	+$2,950,000	+$2,110,000
Total Annual Revenue	**No change**	**+$1,716,000**	**+$3,226,370**	**+$3,297,000**	**+$3,223,000**	**+$2,110,000**
Net Annual Savings	**+$20,670**	**+$388,520**	**+$2,467,070**	**+$2,621,700**	**+$2,806,700**	**+$1,571,700**

TABLE NO. 4-3
ANNUAL OPERATION/MAINTENANCE COSTS FOR THE SIX ALTERNATIVES
HIGH STANDBY POWER COST SCENARIO

	Alt No. 1-A Existing PMRF with Heat Recovery with Intermittent Ops	**Alt No. 1-B Existing PMRF with Heat Recovery with Continuous Ops**	**Alt No. 2-A New LFGTE at Existing PMRF With Microturbines**	**Alt No. 2-B New LFGTE at Existing PMRF Without Microturbines**	**Alt No. 3 New LFGTE Near Landfill on PMRF**	**Alt No. 4 New LFGTE at Landfill**
Fuel Cost (Diesel/Landfill Gas)	–$34,670	+$1,017,480	+$141,300	+$141,300	+$141,300	+$141,300
Electric Power	No change	No change	+$240,000	+$240,000	No change	No change
Other Consumables	+$7,000	+$10,000	+$15,000	+$11,000	+$2,000	+$2,000
Equipment Maintenance	+$7,000	+$50,000	+$190,000	+$150,000	+$140,000	+$140,000
Labor	No change	+$245,000	+$163,000	+$123,000	+$123,000	+$245,000
Miscellaneous Costs	No change	+$5,000	+$10,000	+$10,000	+$10,000	+$10,000
Total Annual Cost	**–$20,670**	**+$1,327,480**	**+$759,300**	**+$675,300**	**+$416,300**	**+$538,300**
Deferred Propane Purchases	No change	No change	–$13,070	No change	No change	No change
Deferred Diesel Purchases	No change	No change	–$273,300	–$273,000	–$273,000	No change
Deferred Power Purchases	No change	–$1,229,000	–$1,705,000	–$1,705,000	–$1,784,000	No change
Power Sold to KIUC	No change	No change	+$558,000	+$642,000	+$458,000	+$2,110,000
Total Revenue from Power	No change	+$1,229,000	+$2,263,000	+$2,347,000	+$2,242,000	+$2,110,000
Total Annual Revenue	**No change**	**+$1,229,000**	**+$2,549,370**	**+$2,620,000**	**+$2,515,000**	**+$2,110,000**
Net Annual Savings	**+$20,670**	**–$98,480**	**+$1,790,070**	**+$1,944,700**	**+$2,098,700**	**+$1,571,700**

SECTION 5

ENERGY SAVINGS AND PRESENT WORTH ANALYSIS

Table No. 5-1 summarizes the energy savings associated with each alternative from two points of view -- PMRF view and island-wide view.

The present worths of the six alternatives, under the three standby power cost scenarios, using a 20-year life and an eight percent discount factor, are summarized on Table Nos. 5-2, 5-3 and 5-4.

TABLE NO. 5-1
ANNUAL ENERGY SAVINGS ASSOCIATED WITH THE SIX ALTERNATIVES

	Alt No. 1-A Existing PMRF with Heat Recovery with Intermittent Ops	Alt No. 1-B Existing PMRF with Heat Recovery with Continuous Ops	Alt No. 2-A New LFGTE at Existing PMRF With Microturbines	Alt No. 2-B New LFGTE at Existing PMRF Without Microturbines	Alt No. 3 New LFGTE Near Landfill on PMRF	Alt No. 4 New LFGTE at Landfill
PMRF Perspective						
Propane Consumption (Gal)	No change	No change	–5,230	No change	No change	No change
Diesel Oil Consumption (Gal)	–14,210	+417,000	–112,000	–112,000	–112,000	No change
KIUC Power Purchases (kWh)	No change	–6,500,000	–9,021,000	–9,021,000	–9,441,000	No change
Island-wide Perspective						
Propane Consumption (Gal)	No change	No change	–5,230	No change	No change	No change
Diesel Oil Consumption (Gal)	–14,210	+27,000	–826,000	–841,000	–784,000	–761,600
Renewable Energy Production (kWh)	No change	No change	+12,210,100	+12,691,900	+12,057,300	+12,057,300

TABLE NO. 5-2
PRESENT WORTH OF THE SIX ALTERNATIVES
LOW STANDBY POWER COST SCENARIO

Alternative No. 1-A: Existing PMRF Power Plant with Heat Recovery and with Intermittent Operation	–$209,000
Alternative No. 1-B: Existing PMRF Power Plant with Heat Recovery and with Continuous Operation	+$4,077,000
Alternative No. 2-A: New LFGTE Plant at Existing PMRF Power Plant With Microturbine CHP Facility	+$16,952,000
Alternative No. 2-B: New LFGTE Plant at Existing PMRF Power Plant Without Microturbine CHP Facility	+$19,559,000
Alternative No. 3: New LFGTE Plant Near Landfill on PMRF	+$22,168,000
Alternative No. 4: New LFGTE Plant at Landfill	+$10,852,000

TABLE NO. 5-3
PRESENT WORTH OF THE SIX ALTERNATIVES
MEDIUM STANDBY POWER COST SCENARIO

Alternative No. 1-A: Existing PMRF Power Plant with Heat Recovery and with Intermittent Operation	–$285,900
Alternative No. 1-B: Existing PMRF Power Plant with Heat Recovery and with Continuous Operation	+$3,056,000
Alternative No. 2-A: New LFGTE Plant at Existing PMRF Power Plant With Microturbine CHP Facility	+$15,534,400
Alternative No. 2-B: New LFGTE Plant at Existing PMRF Power Plant Without Microturbine CHP Facility	+$18,141,000
Alternative No. 3: New LFGTE Plant Near Landfill on PMRF	+$21,685,900
Alternative No. 4: New LFGTE Plant at Landfill	+$10,852,000

TABLE NO. 5-4
PRESENT WORTH OF THE SIX ALTERNATIVES
HIGH STANDBY POWER COST SCENARIO

Alternative No. 1-A: Existing PMRF Power Plant with Heat Recovery and with Intermittent Operation	–$209,000
Alternative No. 1-B: Existing PMRF Power Plant with Heat Recovery and with Continuous Operation	–$1,725,000
Alternative No. 2-A: New LFGTE Plant at Existing PMRF Power Plant With Microturbine CHP Facility	+$8,887,000
Alternative No. 2-B: New LFGTE Plant at Existing PMRF Power Plant Without Microturbine CHP Facility	+$11,494,000
Alternative No. 3: New LFGTE Plant Near Landfill on PMRF	+$13,735,000
Alternative No. 4: New LFGTE Plant at Landfill	+$10,852,000

SECTION 6

CONCLUSIONS

The CHP alternative with the highest present worth is Alternative No. 2-B. It also offers the greatest island-wide reduction in diesel oil consumption.

Alternative No. 3 has a higher present worth than Alternative No. 2-B, but it does not employ CHP.

Alternative No. 2-B will be carried forward as the selected alternative.

APPENDIX D

INTERIM REPORT ON TASK 4:
FINAL ECONOMIC AND STRATEGIC FEASIBILITY STUDY

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 4
Final Economic and Strategic Feasibility Study

Prepared For:

County of Kauai
Office of Economic Development
Kauai, Hawaii

Prepared By:

SCS Energy
Long Beach, California

January 2007

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 4

TABLE OF CONTENTS

PACIFIC MISSILE RANGE FACILITY
COMBINED HEAT AND POWER FEASIBILITY STUDY

INTERIM REPORT ON TASK 4

TABLE OF CONTENTS (continued...)

Tables and Figures

SECTION 1

INTRODUCTION

The interim report on Task 3, titled "Findings and Recommendations on the Economic Evaluation of Alternatives," recommended that Alternative No. 2-B be implemented. Alternative No. 2-B contemplates construction of a landfill gas fired CHP facility at the location of the existing PMRF power plant, the installation of a landfill gas compression skid at the landfill, and the installation of a 3.9-mile landfill gas transmission pipeline, between the landfill and the PMRF power plant.

Task 4, which this report addresses, calls for the following items:

- Preparation of an optimized project configuration;
- Evaluation of economic feasibility;
- Recommendations on measurement, verification, and monitoring;
- Discussion of operation and maintenance considerations;
- Preparation of schematic equipment layouts;
- Identification of major equipment selection;
- Development of a project implementation plan; and
- Development of a project implementation schedule.

SECTION 2

OPTIMIZED CONFIGURATION

Summary of Recommended Project

The recommended project consists of the following major components:

- Installation of a landfill gas collection system at the Kekaha Landfill. The landfill gas collection system will consist of 39 landfill gas extraction wells, and related piping, as is more fully described in Section 5 of the "Interim Report on Task 1;"
- Installation of a landfill gas processing skid at the landfill. It will have a design capacity of 600 scfm and an operating pressure of 25 psig. It will chill the landfill gas to 45° F and reheat it to 65° F prior to introduction into the pipeline. A tentative location for the skid is shown on Figure No. 5-2 in Section 5 of the "Interim Report on Task 1;"
- A 3.9-mile, 6-inch diameter, landfill gas transmission pipeline from the landfill to the site of the existing PMRF power plant. The general alignment of the pipeline is shown on Figure No. 6-1 in Section 6 of the "Interim Report on Task 1;"
- A 1,640 kW landfill gas fired CHP plant, located adjacent to the existing PMRF power plant. The CHP plant will employ two 820 kW reciprocating engines, and engine appurtenant equipment, heat recovery equipment, and an absorption chiller. Table No. 2-1 provides a summary of the major equipment that will be employed at the CHP plant. The CHP plant would interconnect into the PMRF power distribution system at the existing PMRF power plant;
- Chilled water delivery equipment and piping to supply chilled water to Buildings 130, 105 and 105ROCS. The existing cooling equipment would remain at these locations to provide supplemental and standby cooling; and
- A 12.47 kV electrical distribution line, about 13,800 feet in length, between the PMRF power plant and the Navy Housing area, to allow the Navy Housing area to receive power from the CHP plant. Implementation of this element of the project requires resolution of certain power distribution line ownership issues in the Navy Housing area. These issues are discussed in Section 5 herein.

PMRF will probably keep the current PMRF power plant active in order to provide standby power.

Schematic Equipment Layout

The following figures are bound in the rear of Section 2:

- Figure No. 2-1: Process Diagram for Landfill Gas Compression Skid;
- Figure No. 2-2: Process Diagram for CHP plant;
- Figure No. 2-3: Schematic Site Plan for CHP Plant; and
- Figure No. 2-4: Schematic Equipment Layout for CHP Plant

Selection of Major Equipment

It is recommended that two Caterpillar 3516 reciprocating engines be employed. The engines have a gross power output of 820 kW and a gross heat rate of 10,900 Btu/kWh (HHV).

The final decision on the make and model of all other equipment should be made during detailed design and/or during construction. Table No. 2-1 lists other major pieces of equipment, along with their preliminary design ratings, and possible equipment suppliers.

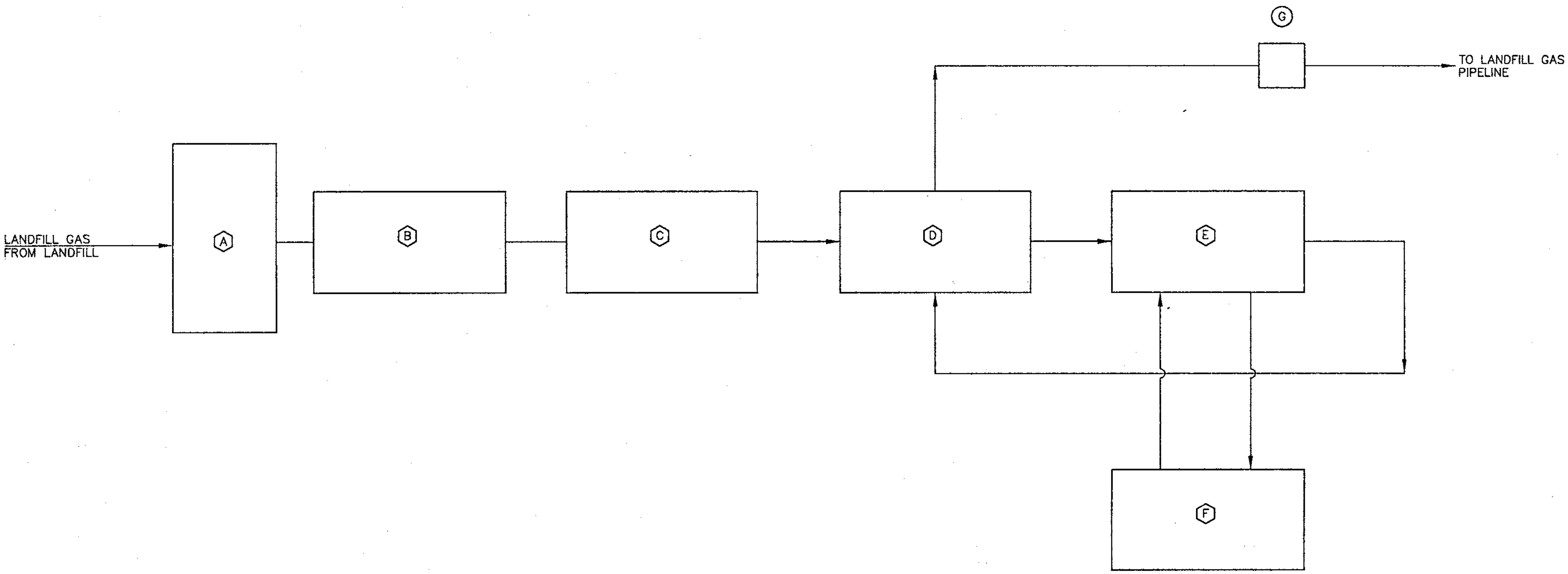
TABLE NO. 2-1
SUMMARY OF MAJOR EQUIPMENT

Equipment at Landfill	Design Criteria	Possible Suppliers
Landfill Gas Compressor	600 scfm. -50" wc inlet. 25 psig outlet. Sliding vane type.	AC or Fuller
Landfill Gas-to-Air Heat Exchanger		Americool
Landfill Gas-to-Landfill Gas Reheat Heat Exchanger		Elanco
Landfill Gas-to-Chilled Water Heat Exchanger		Elanco
Coalescing Filter (at Landfill Gas Skid)	5 microns at 99%. One at 600 scfm.	Dollinger

Equipment at Power Plant	Design Criteria	Possible Suppliers
Coalescing Filters (at Engines)	5 microns at 99%. Two at 300 scfm.	Dollinger
Hot Water Heat Exchangers at Engines		ITT
Hot Water Generators on Engine Exhaust		Cain Industries
Air-to-Water Excess Heat Heat Exchanger		AKG
Radiators for Engines		Young Touchstone
Absorption Chiller	280 tons	ITT

TABLE NO. 2-1 (continued...)
SUMMARY OF MAJOR EQUIPMENT

Equipment at Power Plant	Design Criteria	Possible Suppliers
Cooling Tower		Marley or BAC
Hot Water Pumps		ITT
Chilled Water Pumps		ITT
Chilled Water Heat Exchangers at Buildings		ITT
Switchgear	5 kV	ISO
Protective Relay Package	To satisfy KIUC requirements	Switzer or GE



A	MOISTURE SEPERATOR
B	SLIDING VANE COMPRESSOR
C	GAS–TO–AIR HEAT EXCHANGER
D	GAS–TO–GAS HEAT EXCHANGER
E	GAS–TO–WATER HEAT EXCHANGER
F	CHILLER
G	COALESCING FILTER

FIGURE NO. 2–1
PROCESS DIAGRAM FOR
LANDFILL GAS COMPRESSION SKID

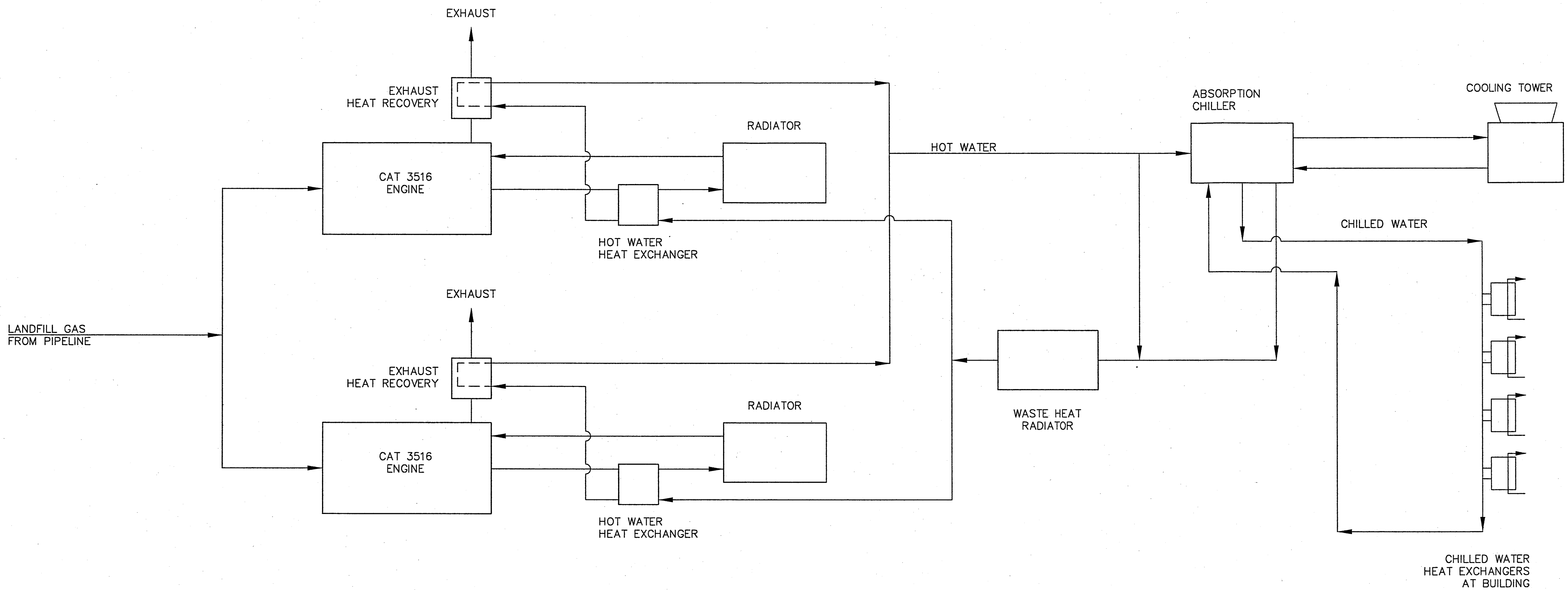


FIGURE NO. 2-2
PROCESS DIAGRAM FOR CHP PLANT

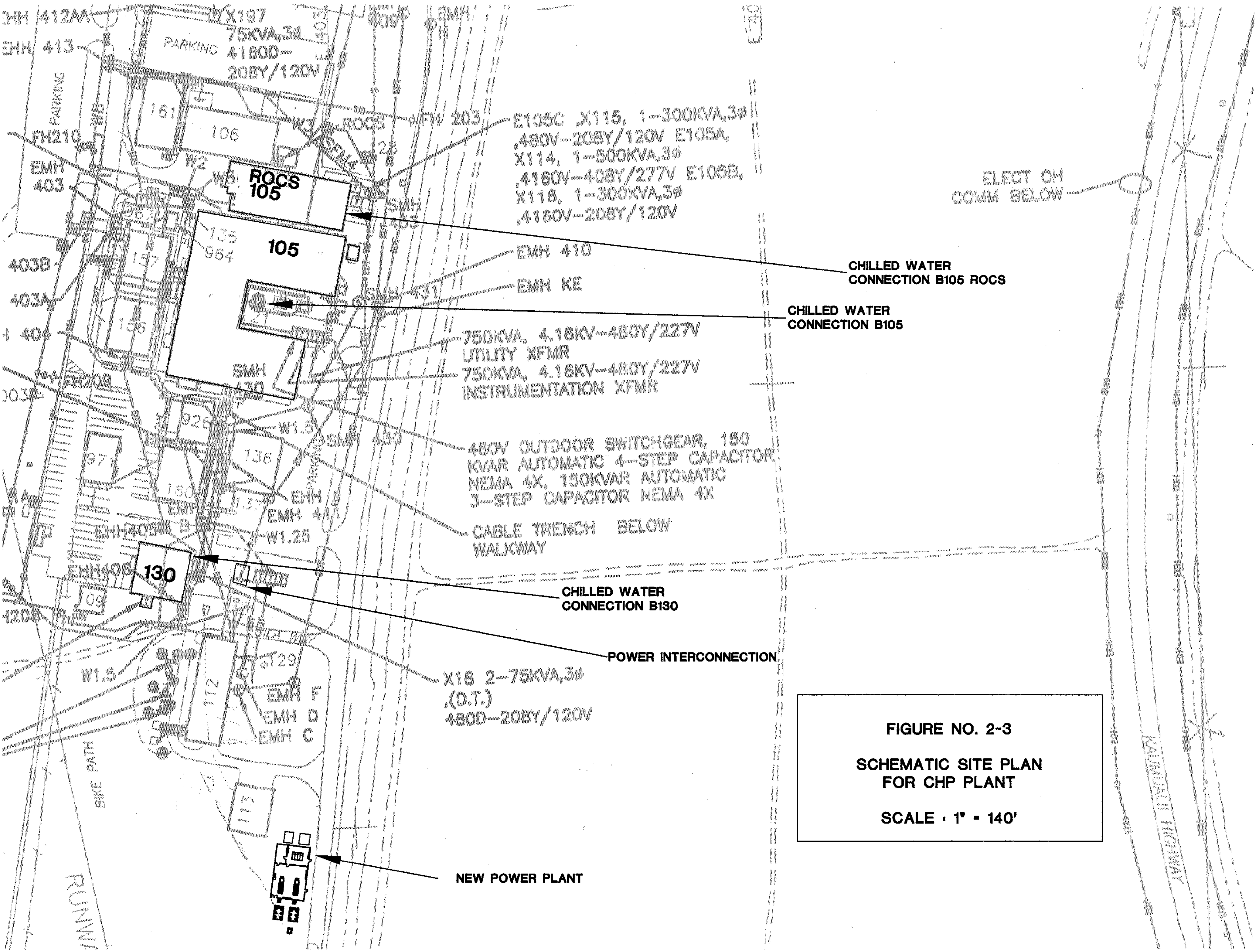
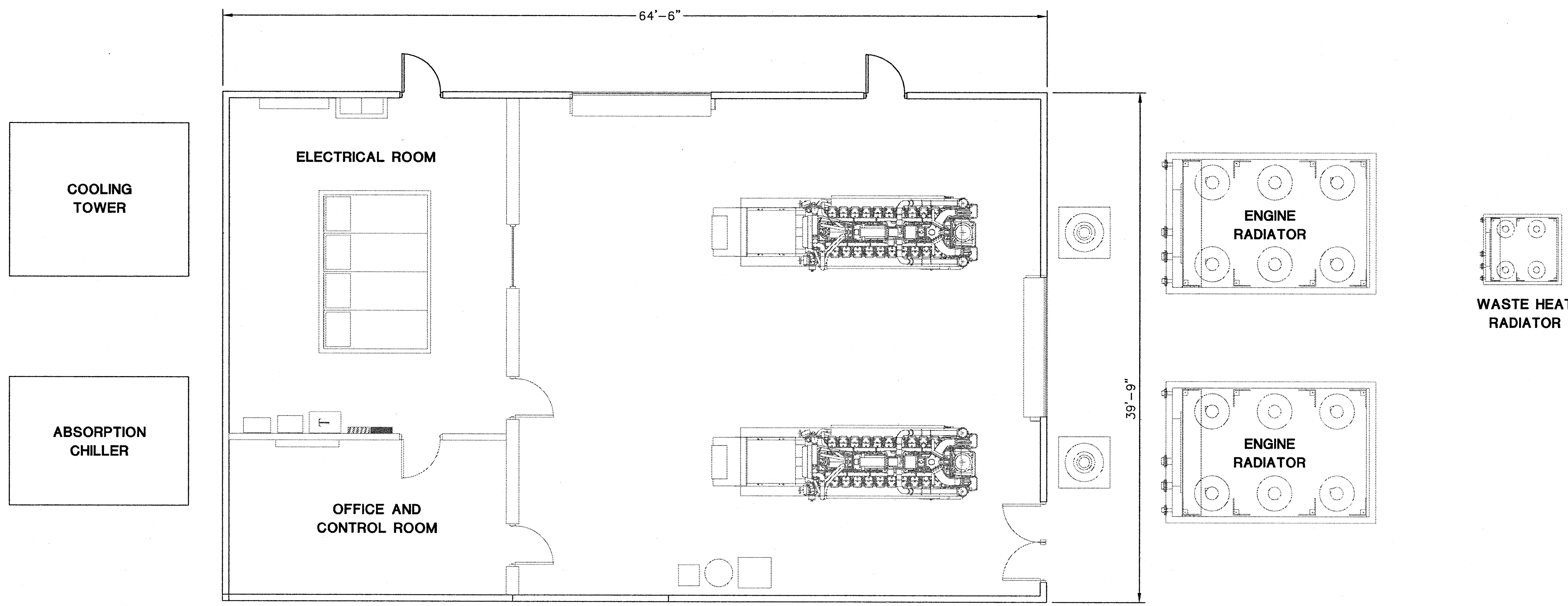


FIGURE NO. 2-3

SCHEMATIC SITE PLAN FOR CHP PLANT

SCALE : 1" = 140'



GRAPHIC SCALE
0 5 10 15
D SIZE : 1" = 5'
B SIZE : 1" = 10'

FIGURE NO. 2-4
SCHEMATIC LAYOUT FOR CHP PLANT

NAME –
EXPIRATION DATE: –
PROFESSIONAL ENGINEER
CA LIC. NO. –

NO.	REVISION	DATE

SHEET TITLE
CHP PLANT GENERAL ARRANGEMENT PLAN

PROJECT TITLE
PMRF CHP PLANT

CLIENT
COUNTY OF KAUAI
OFFICE OF ECONOMIC DEVELOPMENT

SCS ENERGY
3900 KILROY AIRPORT WAY, SUITE 100
LONG BEACH, CA 90806
PH. (562) 426-9544 FAX. (562) 427-0805

PROJ. NO. DSN. BY: JLP
DWN. BY: EA CHK. BY: JLP
ACAD FILE: – APP. BY:

DATE:
SCALE: AS SHOWN
DRAWING NO.
of

N:\Energy\Proposals and Pending Jobs\Hawaii Renewable\Drawing\Site Location.dwg Jan 31, 2007 – 4:55pm By: 2925dta

SECTION 3

ECONOMIC FEASIBILITY

Refined Cost Estimates

Table Nos. 3-1 and 3-2 present refined estimates of construction and operation/maintenance costs for the recommended plan.

Financial Model Runs

Table Nos. 3-3 through 3-5 are financial model run outputs for the recommended plan at a fixed landfill gas sale price of $1.00/mmBtu and at three different standby power costs ($5.00/kW; $10.45/kW; and $37.47/kW).

Table Nos. 3-6 through 3-8 are financial model run outputs for three other landfill gas sale prices -- $2.00/mmBtu; $3.00/mmBtu; and $4.00/mmBtu. In these model runs, the standby power cost was held constant at the medium standby power cost of $10.45/kW.

The financial models calculate internal rate of return as a measure of financial performance. The project is financially feasible under all of the scenarios that were evaluated.

The power sales rate for sale of power to KIUC (17.5¢/kWh) is the rate KIUC was willing to pay cogenerators for power under KIUC's Schedule Q in 2006.

TABLE NO. 3-1
REFINED CONSTRUCTION COST ESTIMATE
FOR THE RECOMMENDED PLAN

Major Mechanical Equipment	
Reciprocating Engines	$1,350,000
Chillers	$405,000
Heat Exchangers	$115,000
Pumps	$22,000
Landfill Gas Skid	$460,000
Piping and Related	
Landfill Gas Piping	$654,000
Hot Water Piping	$42,900
Warm Water Piping	$22,100
Chilled Water Piping	$104,000
Other Piping	$162,500
Chilled Water Conversions	$23,000
Civil	
Grading/Site Work	$104,000
Foundations	$182,000
Buildings	$175,500
Electrical	
Transformers	$52,000
Switchgear	$357,000
PMRF Grid Improvements	$1,230,000
Power Conduit/Cable	$331,500
Control Conduit/Cable	$162,500
Control System	$143,000
Landfill Gas Collection System	
Landfill Gas Collection System	$479,000
Engineering/Technical	
Permits	$45,000
Detailed Design	$370,000
Construction Observation	$166,000
Total	**$7,158,000**
Contingency (15%)	$1,073,700
GRAND TOTAL	**$8,231,700**

TABLE NO. 3-2
REFINED ESTIMATE OF ANNUAL OPERATION/MAINTENANCE COSTS FOR THE RECOMMENDED PLAN

Labor	$178,000
Equipment Maintenance	
Engine/Generators (Levelized)	$110,000
Landfill Gas Skid	$10,000
Heat Recovery/Chilled Water	$20,000
Electric Power	$180,000
Other Consumables	$20,000
Insurance	$50,000
Miscellaneous	$20,000
TOTAL ANNUAL	**$588,000**

TABLE NO. 3-3
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $1.00/MMBTU AND WITH LOW STANDBY POWER CHARGE ($5.00/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665
LFG PURCHASE PRICE ($/mmBtu)	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30
ANNUAL LFG COST	$103,627	$143,490	$150,128	$157,302	$163,947	$168,865	$173,931	$179,149	$184,524	$190,060
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207
STANDBY POWER CHARGE ($/kW)	$5.00	$5.15	$5.30	$5.46	$5.63	$5.80	$5.97	$6.15	$6.33	$6.52
STANDBY POWER COST	$91,512	$94,257	$97,085	$99,998	$102,998	$106,087	$109,270	$112,548	$115,925	$119,402
TOTAL O+M COST	**$783,139**	**$843,387**	**$871,022**	**$899,823**	**$928,744**	**$956,606**	**$985,304**	**$1,014,863**	**$1,045,309**	**$1,076,669**
NET REVENUE	**$2,089,384**	**$2,686,056**	**$2,799,148**	**$2,920,330**	**$3,034,766**	**$3,125,809**	**$3,219,583**	**$3,316,171**	**$3,415,656**	**$3,518,126**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$1.34	$1.38	$1.43	$1.47	$1.51	$1.56	$1.60	$1.65	$1.70	$1.75
ANNUAL LFG COST	$195,761	$201,634	$207,683	$213,914	$218,483	$216,660	$214,924	$212,888	$211,369	$209,568
NON-FUEL O+M COST	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$6.72	$6.92	$7.13	$7.34	$7.56	$7.79	$8.02	$8.26	$8.51	$8.77
STANDBY POWER COST	$122,984	$126,674	$130,474	$134,388	$138,420	$142,573	$146,850	$151,255	$155,793	$160,467
TOTAL O+M COST	**$1,108,969**	**$1,142,238**	**$1,176,505**	**$1,211,800**	**$1,246,306**	**$1,275,318**	**$1,305,341**	**$1,336,018**	**$1,368,193**	**$1,401,096**
NET REVENUE	**$3,623,669**	**$3,732,380**	**$3,844,351**	**$3,959,681**	**$4,052,720**	**$4,057,595**	**$4,064,580**	**$4,068,331**	**$4,080,243**	**$4,089,208**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$1.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	33.1%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$5.00		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

TABLE NO. 3-4
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $1.00/MMBTU AND WITH MEDIUM STANDBY POWER CHARGE ($10.45/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30	$1.34	$1.38	$1.43	$1.47	$1.51	$1.56	$1.60	$1.65	$1.70	$1.75
ANNUAL LFG COST	$103,627	$143,490	$150,128	$157,302	$163,947	$168,865	$173,931	$179,149	$184,524	$190,060	$195,761	$201,634	$207,683	$213,914	$218,483	$216,660	$214,924	$212,888	$211,369	$209,568
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$10.45	$10.76	$11.09	$11.42	$11.76	$12.11	$12.48	$12.85	$13.24	$13.63	$14.04	$14.47	$14.90	$15.35	$15.81	$16.28	$16.77	$17.27	$17.79	$18.32
STANDBY POWER COST	$191,260	$196,998	$202,908	$208,995	$215,265	$221,723	$228,375	$235,226	$242,283	$249,551	$257,038	$264,749	$272,691	$280,872	$289,298	$297,977	$306,916	$316,124	$325,607	$335,376
TOTAL O+M COST	**$882,887**	**$946,127**	**$976,845**	**$1,008,821**	**$1,041,011**	**$1,072,241**	**$1,104,409**	**$1,137,541**	**$1,171,667**	**$1,206,817**	**$1,243,022**	**$1,280,312**	**$1,318,722**	**$1,358,283**	**$1,397,183**	**$1,430,722**	**$1,465,407**	**$1,500,886**	**$1,538,008**	**$1,576,005**
NET REVENUE	**$1,989,636**	**$2,583,315**	**$2,693,326**	**$2,811,333**	**$2,922,499**	**$3,010,174**	**$3,100,479**	**$3,193,493**	**$3,289,298**	**$3,387,977**	**$3,489,616**	**$3,594,305**	**$3,702,134**	**$3,813,198**	**$3,901,842**	**$3,902,191**	**$3,904,513**	**$3,903,463**	**$3,910,429**	**$3,914,299**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$1.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	31.8%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$10.45		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

TABLE NO. 3-5
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $1.00/MMBTU AND WITH HIGH STANDBY POWER CHARGE ($37.47/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665
LFG PURCHASE PRICE ($/mmBtu)	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30
ANNUAL LFG COST	$103,627	$143,490	$150,128	$157,302	$163,947	$168,865	$173,931	$179,149	$184,524	$190,060
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207
STANDBY POWER CHARGE ($/kW)	$37.47	$38.59	$39.75	$40.94	$42.17	$43.44	$44.74	$46.08	$47.47	$48.89
STANDBY POWER COST	$685,791	$706,365	$727,556	$749,382	$771,864	$795,020	$818,870	$843,436	$868,739	$894,802
TOTAL O+M COST	**$1,377,418**	**$1,455,494**	**$1,501,493**	**$1,549,208**	**$1,597,610**	**$1,645,538**	**$1,694,904**	**$1,745,751**	**$1,798,124**	**$1,852,068**
NET REVENUE	**$1,495,105**	**$2,073,948**	**$2,168,678**	**$2,270,945**	**$2,365,900**	**$2,436,877**	**$2,509,983**	**$2,585,283**	**$2,662,841**	**$2,742,726**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$1.34	$1.38	$1.43	$1.47	$1.51	$1.56	$1.60	$1.65	$1.70	$1.75
ANNUAL LFG COST	$195,761	$201,634	$207,683	$213,914	$218,483	$216,660	$214,924	$212,888	$211,369	$209,568
NON-FUEL O+M COST	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$50.36	$51.87	$53.42	$55.03	$56.68	$58.38	$60.13	$61.93	$63.79	$65.70
STANDBY POWER COST	$921,646	$949,295	$977,774	$1,007,107	$1,037,320	$1,068,440	$1,100,493	$1,133,508	$1,167,513	$1,202,539
TOTAL O+M COST	**$1,907,630**	**$1,964,859**	**$2,023,804**	**$2,084,519**	**$2,145,206**	**$2,201,185**	**$2,258,984**	**$2,318,271**	**$2,379,913**	**$2,443,168**
NET REVENUE	**$2,825,008**	**$2,909,759**	**$2,997,051**	**$3,086,963**	**$3,153,820**	**$3,131,728**	**$3,110,936**	**$3,086,079**	**$3,068,523**	**$3,047,136**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$1.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	25.6%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$37.47		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

TABLE NO. 3-6
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $2.00/MMBTU AND WITH MEDIUM STANDBY POWER CHARGE ($10.45/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665
LFG PURCHASE PRICE ($/mmBtu)	$2.00	$2.06	$2.12	$2.19	$2.25	$2.32	$2.39	$2.46	$2.53	$2.61
ANNUAL LFG COST	$207,255	$286,979	$300,256	$314,605	$327,894	$337,731	$347,863	$358,299	$369,048	$380,119
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207
STANDBY POWER CHARGE ($/kW)	$10.45	$10.76	$11.09	$11.42	$11.76	$12.11	$12.48	$12.85	$13.24	$13.63
STANDBY POWER COST	$191,260	$196,998	$202,908	$208,995	$215,265	$221,723	$228,375	$235,226	$242,283	$249,551
TOTAL O+M COST	**$986,515**	**$1,089,617**	**$1,126,973**	**$1,166,123**	**$1,204,958**	**$1,241,107**	**$1,278,340**	**$1,316,690**	**$1,356,191**	**$1,396,877**
NET REVENUE	**$1,886,009**	**$2,439,826**	**$2,543,198**	**$2,654,030**	**$2,758,552**	**$2,841,308**	**$2,926,548**	**$3,014,344**	**$3,104,774**	**$3,197,918**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$2.69	$2.77	$2.85	$2.94	$3.03	$3.12	$3.21	$3.31	$3.40	$3.51
ANNUAL LFG COST	$391,523	$403,268	$415,366	$427,827	$436,965	$433,320	$429,848	$425,777	$422,739	$419,135
NON-FUEL O+M COST	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$14.04	$14.47	$14.90	$15.35	$15.81	$16.28	$16.77	$17.27	$17.79	$18.32
STANDBY POWER COST	$257,038	$264,749	$272,691	$280,872	$289,298	$297,977	$306,916	$316,124	$325,607	$335,376
TOTAL O+M COST	**$1,438,783**	**$1,481,946**	**$1,526,405**	**$1,572,197**	**$1,615,666**	**$1,647,382**	**$1,680,331**	**$1,713,775**	**$1,749,377**	**$1,785,573**
NET REVENUE	**$3,293,855**	**$3,392,671**	**$3,494,451**	**$3,599,284**	**$3,683,360**	**$3,685,531**	**$3,689,590**	**$3,690,574**	**$3,699,059**	**$3,704,732**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$2.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	30.2%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$10.45		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

TABLE NO. 3-7
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $3.00/MMBTU AND WITH MEDIUM STANDBY POWER CHARGE ($10.45/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$3.00	$3.09	$3.18	$3.28	$3.38	$3.48	$3.58	$3.69	$3.80	$3.91	$4.03	$4.15	$4.28	$4.41	$4.54	$4.67	$4.81	$4.96	$5.11	$5.26
ANNUAL LFG COST	$310,882	$430,469	$450,384	$471,907	$491,841	$506,596	$521,794	$537,448	$553,571	$570,179	$587,284	$604,902	$623,049	$641,741	$655,448	$649,980	$644,771	$638,665	$634,108	$628,703
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$10.45	$10.76	$11.09	$11.42	$11.76	$12.11	$12.48	$12.85	$13.24	$13.63	$14.04	$14.47	$14.90	$15.35	$15.81	$16.28	$16.77	$17.27	$17.79	$18.32
STANDBY POWER COST	$191,260	$196,998	$202,908	$208,995	$215,265	$221,723	$228,375	$235,226	$242,283	$249,551	$257,038	$264,749	$272,691	$280,872	$289,298	$297,977	$306,916	$316,124	$325,607	$335,376
TOTAL O+M COST	**$1,090,142**	**$1,233,107**	**$1,277,101**	**$1,323,426**	**$1,368,905**	**$1,409,972**	**$1,452,271**	**$1,495,840**	**$1,540,715**	**$1,586,936**	**$1,634,544**	**$1,683,581**	**$1,734,088**	**$1,786,111**	**$1,834,149**	**$1,864,042**	**$1,895,255**	**$1,926,663**	**$1,960,746**	**$1,995,140**
NET REVENUE	**$1,782,382**	**$2,296,336**	**$2,393,070**	**$2,496,728**	**$2,594,605**	**$2,672,443**	**$2,752,616**	**$2,835,195**	**$2,920,251**	**$3,007,858**	**$3,098,094**	**$3,191,037**	**$3,286,768**	**$3,385,371**	**$3,464,877**	**$3,468,871**	**$3,474,666**	**$3,477,686**	**$3,487,690**	**$3,495,164**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$3.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	28.5%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$10.45		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

TABLE NO. 3-8
PMRF CHP PROJECT
LFG PURCHASE PRICE OF $4.00/MMBTU AND WITH MEDIUM STANDBY POWER CHARGE ($10.45/kW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
LFG AVAILABLE AT 50% METHANE (scfm)	424	570	579	589	599	610	622	634	743	715
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	424	570	579	589	596	596	596	596	596	596
TOTAL POWER PRODUCTION (kWh/yr)	8,841,919	11,886,543	12,074,225	12,282,761	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736	12,428,736
AVOIDED KIUC POWER PURCHASES (kWh/yr)	8,841,919	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	0	2,865,543	3,053,225	3,261,761	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736	3,407,736
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294	$0.303	$0.312	$0.321	$0.331	$0.341	$0.351	$0.362	$0.372	$0.384
KIUC POWER SALES RATE ($/kWh)	$0.175	$0.180	$0.186	$0.191	$0.197	$0.203	$0.209	$0.215	$0.222	$0.228
VALUE OF AVOIDED KIUC POWER PURCHASES	$2,599,524	$2,731,739	$2,813,691	$2,898,102	$2,985,045	$3,074,597	$3,166,834	$3,261,839	$3,359,695	$3,460,486
REVENUE FROM POWER SOLD TO KIUC	$0	$516,514	$566,854	$623,737	$671,201	$691,337	$712,078	$733,440	$755,443	$778,106
DIESEL FUEL COST ($/GALLON)	$2.440	$2.513	$2.589	$2.666	$2.746	$2.829	$2.913	$3.001	$3.091	$3.184
DIESEL FUEL SAVINGS	$272,999	$281,189	$289,625	$298,314	$307,263	$316,481	$325,976	$335,755	$345,827	$356,202
TOTAL POWER REVENUE AND SAVINGS	**$2,872,524**	**$3,529,443**	**$3,670,171**	**$3,820,153**	**$3,963,510**	**$4,082,415**	**$4,204,888**	**$4,331,034**	**$4,460,965**	**$4,594,794**
ANNUAL LFG CONSUMED (mmBtu/yr)	103,627	139,310	141,510	143,954	145,665	145,665	145,665	145,665	145,665	145,665
LFG PURCHASE PRICE ($/mmBtu)	$4.00	$4.12	$4.24	$4.37	$4.50	$4.64	$4.78	$4.92	$5.07	$5.22
ANNUAL LFG COST	$414,509	$573,958	$600,511	$629,209	$655,788	$675,462	$695,725	$716,597	$738,095	$760,238
NON-FUEL O+M COST	$588,000	$605,640	$623,809	$642,523	$661,799	$681,653	$702,103	$723,166	$744,861	$767,207
STANDBY POWER CHARGE ($/kW)	$10.45	$10.76	$11.09	$11.42	$11.76	$12.11	$12.48	$12.85	$13.24	$13.63
STANDBY POWER COST	$191,260	$196,998	$202,908	$208,995	$215,265	$221,723	$228,375	$235,226	$242,283	$249,551
TOTAL O+M COST	**$1,193,769**	**$1,376,596**	**$1,427,228**	**$1,480,728**	**$1,532,852**	**$1,578,838**	**$1,626,203**	**$1,674,989**	**$1,725,239**	**$1,776,996**
NET REVENUE	**$1,678,754**	**$2,152,846**	**$2,242,942**	**$2,339,425**	**$2,430,658**	**$2,503,578**	**$2,578,685**	**$2,656,045**	**$2,735,727**	**$2,817,799**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LFG AVAILABLE AT 50% METHANE (scfm)	688	663	638	614	591	569	548	527	508	489
LFG REQUIRED AT 50% METHANE (scfm)	596	596	596	596	596	596	596	596	596	596
LFG CONSUMED AT 50% METHANE (scfm)	596	596	596	596	591	569	548	527	508	489
TOTAL POWER PRODUCTION (kWh/yr)	12,428,736	12,428,736	12,428,736	12,428,736	12,324,468	11,865,689	11,427,764	10,989,839	10,593,620	10,197,402
AVOIDED KIUC POWER PURCHASES (kWh/yr)	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000	9,021,000
EXCESS POWER TO KIUC (kWh/yr)	3,407,736	3,407,736	3,407,736	3,407,736	3,303,468	2,844,689	2,406,764	1,968,839	1,572,620	1,176,402
RATE FOR POWER USED ON-SITE ($/kWh)	$0.395	$0.407	$0.419	$0.432	$0.445	$0.458	$0.472	$0.486	$0.501	$0.516
KIUC POWER SALES RATE ($/kWh)	$0.235	$0.242	$0.250	$0.257	$0.265	$0.273	$0.281	$0.289	$0.298	$0.307
VALUE OF AVOIDED KIUC POWER PURCHASES	$3,564,300	$3,671,229	$3,781,366	$3,894,807	$4,011,651	$4,132,001	$4,255,961	$4,383,640	$4,515,149	$4,650,603
REVENUE FROM POWER SOLD TO KIUC	$801,450	$825,493	$850,258	$875,766	$874,439	$775,588	$675,876	$569,483	$468,524	$360,995
DIESEL FUEL COST ($/GALLON)	$3.279	$3.378	$3.479	$3.583	$3.691	$3.801	$3.915	$4.033	$4.154	$4.279
DIESEL FUEL SAVINGS	$366,888	$377,895	$389,232	$400,909	$412,936	$425,324	$438,084	$451,226	$464,763	$478,706
TOTAL POWER REVENUE AND SAVINGS	**$4,732,638**	**$4,874,617**	**$5,020,856**	**$5,171,481**	**$5,299,026**	**$5,332,913**	**$5,369,921**	**$5,404,349**	**$5,448,436**	**$5,490,304**
ANNUAL LFG CONSUMED (mmBtu/yr)	145,665	145,665	145,665	145,665	144,443	139,066	133,933	128,801	124,157	119,514
LFG PURCHASE PRICE ($/mmBtu)	$5.38	$5.54	$5.70	$5.87	$6.05	$6.23	$6.42	$6.61	$6.81	$7.01
ANNUAL LFG COST	$783,045	$806,537	$830,733	$855,655	$873,931	$866,640	$859,695	$851,553	$845,478	$838,271
NON-FUEL O+M COST	$790,223	$813,930	$838,347	$863,498	$889,403	$916,085	$943,567	$971,874	$1,001,031	$1,031,062
STANDBY POWER CHARGE ($/kW)	$14.04	$14.47	$14.90	$15.35	$15.81	$16.28	$16.77	$17.27	$17.79	$18.32
STANDBY POWER COST	$257,038	$264,749	$272,691	$280,872	$289,298	$297,977	$306,916	$316,124	$325,607	$335,376
TOTAL O+M COST	**$1,830,306**	**$1,885,215**	**$1,941,771**	**$2,000,024**	**$2,052,631**	**$2,080,702**	**$2,110,179**	**$2,139,551**	**$2,172,116**	**$2,204,708**
NET REVENUE	**$2,902,333**	**$2,989,402**	**$3,079,085**	**$3,171,457**	**$3,246,394**	**$3,252,211**	**$3,259,742**	**$3,264,798**	**$3,276,320**	**$3,285,596**

GROSS PLANT CAPACITY (kW)	1,640	INITIAL LFG COST ($/mmBtu)	$4.00	CAPITAL COST	$8,231,700
PLANT NET CAPACITY (kW)	1,525	LFG COST ESCALATION	3%		
PLANT AVAILABILITY	93%			PRE-TAX IRR	26.8%
NET PLANT HEAT RATE (Btu/kWh)(HHV)	11,720	INITIAL ANNUAL O+M COST	$588,000		
		O+M COST ESCALATION	3%		
RATE FOR POWER USED ON-SITE ($/kWh)	$0.294				
KIUC POWER SALES RATE ($/kWh)	$0.175	STANDBY POWER CHARGE	$10.45		
DIESEL FUEL COST $/GALLON)	$2.440	CHARGE ESCALATION	3%		
POWER SALES RATE ESCALATION	3%				

SECTION 4

OPERATION/MAINTENANCE CONSIDERATIONS

Measurement and Verification Requirements

The most important measurements of performance for this project are:

- Net power output (kW);
- Engine/generator heat rate (Btu/kWh); and
- Air emissions (g/bhp-hr).

The construction contract should require the contractor to guarantee these parameters. Compliance with the guarantees should be determined through an 8-hour performance test, undertaken no later than 30 days after commencement of initial operation of the power plant. Net power output and heat rate would be averaged over the 8-hour period. The air emissions test, a two to four hour test, would be conducted within the 8-hour test window.

Net power output would be measured using the permanent net power output meter housed in the power plant's switchgear. Heat rate would be measured by dividing the observed, average net power output (kWh/hour) by the observed, average fuel consumption. Fuel consumption will be determined using the power plant's permanent inlet flow meter and the plant's continuously recording methane analyzer. Fuel consumption (in mmBtu/hr) would be calculated by multiplying flow rate (scfm) times 60 minutes/hour times methane percentage times 1,012 Btu/ft^3, where 1,012 Btu/ft equals the higher heating value of methane.

Air emissions would be measured by a third-party testing firm, using portable equipment.

On an ongoing basis, the net power output and heat rate would be monitored for diagnostic purposes. The net power output might also be used for billing purposes, if PMRF employs an energy services contractor (ESCO) to implement the project, and/or to document the amount of renewable power produced on an ongoing basis.

The fuel consumption (mmBtu) would be used to determine payments due to the County under the landfill gas sale agreement, if compensation to the County was based on actual fuel consumption. Net power output could be used to determine compensation to the County if the landfill gas sale agreement called for compensation on the basis of percent of gross revenue (or revenue equivalent).

The amount of chilled water delivered by the power plant to PMRF is of secondary importance to the project; however, the delivery of chilled water adds value to the project, and measurement of chilled water delivery is worth identifying as an output to be monitored in routine operation. Chilled water flow (gpm) and temperature (°F) will be monitored using permanent power plant instrumentation, and tons of cooling can be calculated from these measurements. If PMRF engages an ESCO, these measurements may also provide a basis for billing.

The water in and out of the heat exchanger on each engine's exhaust will be continuously monitored to determine if gas side fouling of the heat exchanger is occurring.

Operation/Maintenance Considerations

SCS recommends that the power plant be staffed with two full-time operators. In a typical arrangement, the operators would work five days, eight hours per day, plus be on-call on the evenings and weekends. Alternative configurations are possible. At some of the plants SCS operates, SCS schedules the days on an offset basis (e.g., Sunday through Thursday and Tuesday through Saturday -- allowing for three days when two operators overlap). The operating budget for labor will provide for two operators plus ten percent for overtime hours.

The two operators would handle all scheduled engine maintenance at levels below a top-end overhaul (expected every 12 to 16 months). The local Caterpillar dealer would be called upon to provide additional staff to support the top-end overhauls. The in-frame overhaul (expected every four to five years) would be completely subcontracted to the local Caterpillar dealer.

The landfill gas compression skid would be inspected once per day and it would be monitored in the power plant control room, using the power plant's supervisory control and data acquisition (SCADA) system. The power plant SCADA system would communicate with the compressor skid's programmable logic controller (PLC) using a communication cable laid in the landfill gas transmission pipeline trench.

SECTION 5

PROJECT IMPLEMENTATION PLAN

There are three parties who could have a role in this project -- PMRF, KIUC and the County. PMRF is the energy consumer. PMRF could take responsibility for design, construction and operation of the power plant, or PMRF could assume the role of an energy customer only. If PMRF elects to continue as an energy customer only, then KIUC or the County or a private investor could design, construct and operate the project.

KIUC, being in the energy supply business, is probably the most likely candidate for project ownership, if PMRF elects not to own the project. The least role KIUC would have in the project would be that of a traditional utility, under which KIUC would provide standby power and purchase excess power. As mentioned in prior sections of this report, it may be necessary for PMRF to buy or lease some segments of KIUC power distribution lines, now owned by PMRF, that are located within PMRF.

The County is the owner of the energy resource. The likely role of the County is energy supplier to PMRF or KIUC. The County could bear the cost of wellfield installation as part of their day-to-day landfill operation, or the wellfield could be installed and operated/maintained by the energy purchaser. The County's desire or ability to enter into a sole source landfill gas sale agreement should also be determined. HRS 103D-102(b)(3) might allow the County to proceed with a sole source negotiation. If the County cannot, or desires not to, negotiate with PMRF or KIUC on a sole source basis, then the County must solicit proposals from any interested party using an advertised Request for Proposals.

As a first step in project development, PMRF, KIUC and the County should meet to discuss their potential roles in the project and execute a Memorandum of Understanding (MOU) to govern their agreed-upon relationship.

Work Plan for Future Tasks

The following steps are necessary to implement the project. The presumption has been made that PMRF will design, finance, own and operate the facilities associated with the project, or will engage an ESCO to implement the project on their behalf. If PMRF decides to employ an ESCO, then the additional step of selecting an ESCO needs to be added as the first step in the implementation plan.

- Negotiate a landfill gas sale agreement with the County;
- Negotiate with KIUC to obtain ownership of use of a few KIUC-owned power distribution line segments in the Navy Housing area;

- Design the landfill gas wellfield, the compressor skid, the landfill gas transmission line and the CHP power plant;
- File for and obtain a Hawaii Department of Health air permit for the engines;
- Prepare other environmental documentation;
- Obtain bids for construction;
- Construct the facilities;
- Perform startup and performance testing; and
- Commence commercial operation.

Negotiate a Landfill Gas Sale Agreement

The construction and operation/maintenance costs for the project assume that PMRF will install and operate the landfill gas collection system and compressor skid. The price paid to the County for the landfill gas must take into consideration the fact that PMRF, rather than the County, paid for these facilities. An alternative approach would be for the County to install and operate these facilities, and the price paid by PMRF to the County for the landfill gas would then be expected to be higher.

While compensation to the County could take several forms, the most common forms of compensation in the landfill gas to energy business are:

- The County would be paid on a $/mmBtu basis, using an agreed-upon $/mmBtu rate and actual mmBtu consumed (on a monthly basis); or
- The County would be paid on a percent of gross revenue basis (a percentage of the value of the power produced).

The second approach would be more difficult to employ, since the value of the power produced is based on net avoided cost, plus some power sale to KIUC, as compared to 100 percent power sale to KIUC, where the actual value of the power produced would be clearly known.

Negotiate with KIUC on Power Distribution Lines

As discussed in the Interim Report on Task 3, KIUC and PMRF have mixed ownership of the power distribution lines in the Navy Housing area. Most of the power distribution lines are owned by PMRF; however, the power distribution system is incomplete without KIUC's lines. There are five possible resolutions to this issue:

- KIUC could give the lines to PMRF;

- KIUC could sell the lines to PMRF;
- KIUC could lease the lines to PMRF;
- PMRF could install its own power distribution lines in the "missing" segments; or
- Service to the Navy Housing area could be eliminated from the project.

While elimination of the Navy Housing area will adversely impact project revenues, the impact on the project's financial viability will not be that great since a $1.23 million investment in a new power transmission line between the PMRF power plant and the Navy Housing area would be eliminated, and the power not consumed in the Navy Housing area would be sold to KIUC, albeit at a lower value.

During the discussions with KIUC about their power distribution lines in the Navy Housing area, PMRF should inquire as to whether KIUC would be willing to wheel (transmit) power from the PMRF power plant to the Navy Housing area through KIUC's existing, off-site distribution lines, and at what price KIUC would be willing to provide that service. It may be more cost-effective to pay KIUC for wheeling than to construct a $1.23 million power transmission line on-site.

Design Landfill Gas to Energy Facilities

The design of the project will be relatively straightforward since:

- With the exception of about 200 feet of pipeline, the landfill gas transmission pipeline is located on property owned by PMRF. The remaining 200 feet is on property owned by the County. The acquisition of rights-of-ways is not an obstacle to be overcome on this project; and
- The CHP power plant will use proven equipment and technologies. There are more than 200 landfill gas fired reciprocating engine power plants in operation in the United States. There are almost 100 landfill gas compressor skids and pipelines in operation in the United States.

The package of design drawings would include: flow sheets; piping and instrumentation diagrams; single line diagrams; site plans; building plans; mechanical equipment plans; piping plans; conduit and cable schedules; electrical equipment plans; conduit routing plans; and control system architecture drawings. Complete equipment and installation specifications would accompany the design drawings.

Obtain Air Permits and Other Environmental Approvals

The principal permit to be obtained for this project is an air permit from the Hawaii Department of Health (HDH). The proposed power plant will be located in an attainment area. As long as the power plant employs Best Available Control Technology (BACT), as is currently proposed, issuance of an air permit should be straightforward. If the power plant is owned by an ESCO, the ESCO would obtain its own permit.

The landfill is not currently large enough to be subject to USEPA's New Source Standards for Municipal Solid Waste Landfills (NSPS). For this reason, installation of a landfill gas collection system is optional, and a backup flare is not being installed. If the landfill becomes subject to NSPS in the future, the County will probably be required by HDH to install a backup flare.

It is believed that the need for an overall environmental review of the project can be satisfied by obtaining a negative declaration or a mitigated negative declaration. An environmental assessment, a brief summary of the project's net environmental impacts, must be prepared to support obtaining such a declaration.

Obtain Bids for Construction

Construction bids would be obtained through a formal, advertised solicitation, if PMRF owns the project, or through a less formal bidding process, if an ESCO owns the project. In either case, construction of the power plant, landfill gas transmission pipeline and compression skid, and the power transmission line improvements could be awarded to a single contractor or multiple contractors.

Construct the Facilities

Construction of the facilities would be undertaken by a contractor or contractors under the inspection of PMRF or the ESCO. Construction of a project of this type and magnitude would take about 12 months.

Startup and Performance Testing

The contractor or contractors would be responsible for achieving full mechanical completion, commissioning and full functional testing of the individual components of the project. PMRF or the ESCO would jointly conduct the performance tests with the constructor or contractors.

Commercial Operation

If the facilities were owned by PMRF, PMRF would probably engage a contractor to operate the facilities. The contract could be a new contract or could be an amendment to the contract PMRF currently has for operation of the current power plant. It is anticipated that the existing PMRF power plant would remain available to provide standby power. If the operation of the new power plant was combined with the operation of the existing PMRF power plant, it will be possible to achieve some synergy, and perhaps labor cost savings, that were not considered in the costs estimated in this report.

If an ESCO is selected to implement the project, it may be desirable to have the same ESCO assume responsibility for operating the existing PMRF power plant.

Project Development Schedule

Figure No. 5-1 presents a project development schedule. It anticipates commercial operation commencing on December 31, 2008.

Barriers to Implementation

There are no barriers to implementation of the project; however, the most contentious issues on a landfill gas to energy project are:

1) Negotiation of the landfill gas sale agreement; and
2) Project financing.

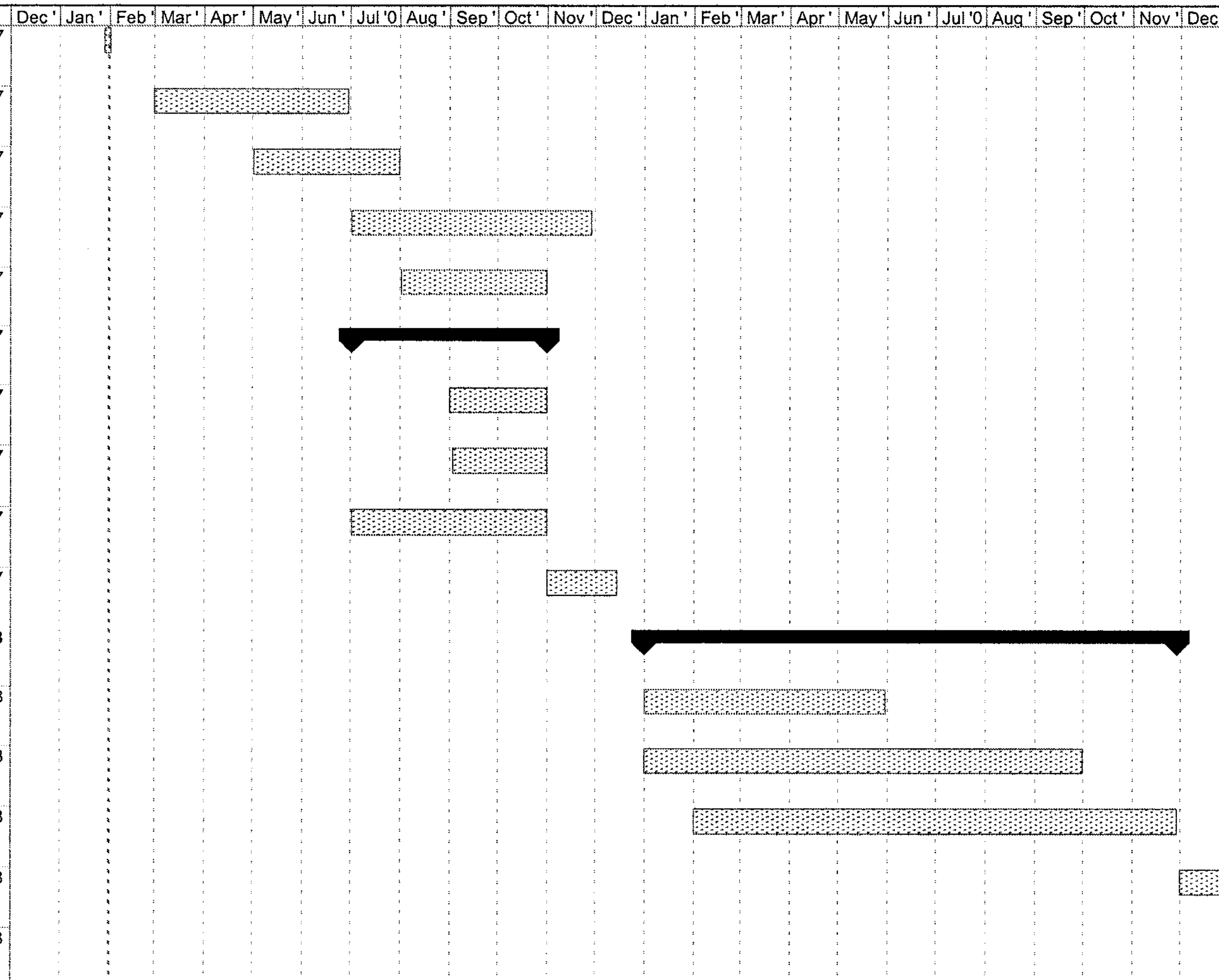
The second item appears to be the lesser of the two issues. If PMRF cannot obtain a capital authorization from the Navy, it could use an ESCO, who would commit his own capital to the project. Nevertheless, the ability of the Navy to secure funding and the correct type of funding could become a barrier to Navy implementation.

The first item is often a complex issue if a governmental entity, rather than a private enterprise, owns the landfill which will supply the landfill gas. The actual text of the landfill gas sale agreement is not difficult to develop, since templates from hundreds of operating landfill gas to energy projects exist in the public domain. The complexity involves two sub-issues:

- Does the sale of the landfill gas require that the right to use the landfill gas be offered to any party, through a formal request for proposal process, or is it possible to negotiate with a single party? (in this case PMRF or their ESCO); and
- The price to be paid for the landfill gas.

FIGURE NO. 5-1
PROJECT DEVELOPMENT SCHEDULE
PROPOSED PMRF CHP PROJECT

ID	Task Name	Start	Finish
1	Complete Feasibility Study	Mon 1/29/07	Thu 2/1/07
2	Negotiate LFG Sale Agreement	Thu 3/1/07	Fri 6/29/07
3	KIUC Power Lines Negotiation	Wed 5/2/07	Tue 7/31/07
4	Obtain Air Permit	Mon 7/2/07	Wed 11/28/07
5	Other Environmental Approvals	Thu 8/2/07	Wed 10/31/07
6	**Design Facilities**	**Mon 7/2/07**	**Wed 10/31/07**
7	Wellfield	Sat 9/1/07	Wed 10/31/07
8	Compressor/Pipeline	Mon 9/3/07	Wed 10/31/07
9	Power Plant	Mon 7/2/07	Wed 10/31/07
10	Obtain Construction Bids	Thu 11/1/07	Fri 12/14/07
11	**Construct Facilities**	**Tue 1/1/08**	**Fri 11/28/08**
12	Wellfield	Tue 1/1/08	Fri 5/30/08
13	Compressor/Pipeline	Tue 1/1/08	Tue 9/30/08
14	Power Plant	Fri 2/1/08	Fri 11/28/08
15	Startup/Testing	Mon 12/1/08	Tue 12/30/08
16	Commence Commercial Opera	Tue 12/30/08	Wed 12/31/08



PMRF CHP Project
Project No. 06205010.00