IDENTIFICATION AND EVALUATION OF OPPORTUNITIES TO REDUCE METHANE LOSSES AT FOUR GAS PROCESSING PLANTS

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EXECUTIVE SUMMARY

A comprehensive directed inspection and maintenance (DI&M) measurement program has been conducted at four gas-processing plants in the western United States to identify potential sources of cost-effective opportunities for reducing natural gas losses and methane emissions due to fugitive equipment leaks and avoidable process inefficiencies or wastage. Raw natural gas is predominantly methane but may contain varying amounts of non-methane hydrocarbons (NMHC) and impurities or contaminants, such as hydrogen sulfide (H_2S), nitrogen (N_2), carbon dioxide (CO_2) and water vapor (H_2O). Losses of natural gas to the atmosphere result in direct emissions of these constituents. Losses of natural gas into flare systems or due to excess fuel consumption result in atmospheric emissions of CO_2 and other combustion products.

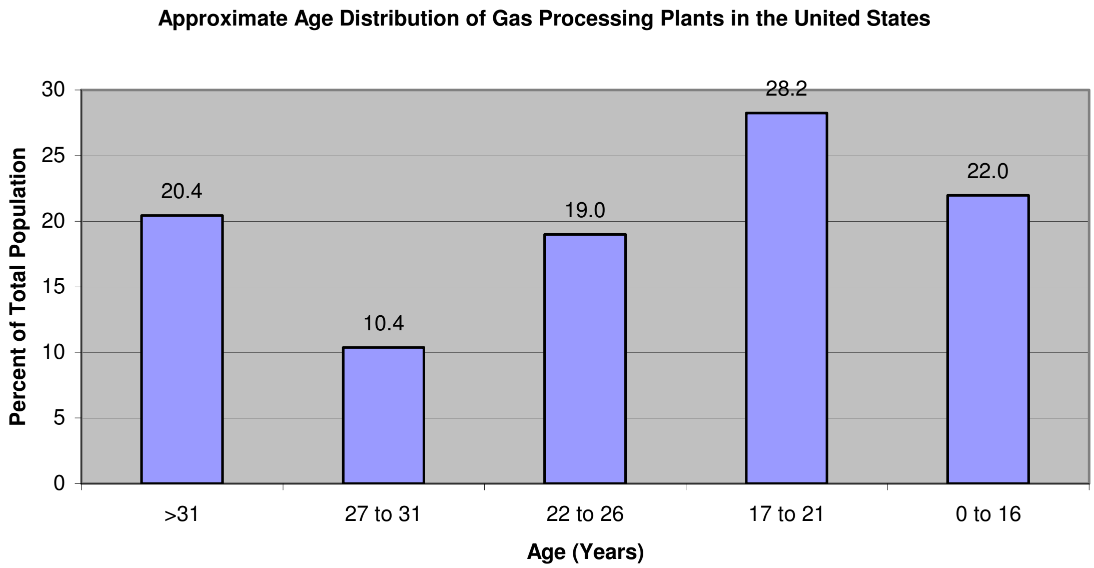
Here, cost effective opportunities to reduce natural gas losses are seen primarily as a prudent means of reducing methane and greenhouse gas (GHG) emissions (predominantly methane and CO_2), and to a lesser extent, non-methane hydrocarbon (NMHC) emissions. All GHG emissions are expressed as CO_2-equivalent emissions (CO_2E) and use a global warming potential of 21.0 for methane. A baseline assessment of the total natural gas losses and emissions of the target air pollutants at each host facility is provided, and the potential savings and emission reductions that may be achieved by reducing losses are highlighted. Additionally, total hydrocarbon (THC) emission factors are presented for fugitive equipment leaks and the active natural gas-fueled process equipment surveyed.

METHODOLOGY

All fieldwork was conducted during the fourth quarter of 2000. The work comprised a fugitive-emissions survey of all equipment components in hydrocarbon gas service, measurement and characterization of flows into all key vent and flare systems, and limited performance testing of natural gas-fueled combustion equipment at three of the four sites. Although not specifically targeted, any components in hydrocarbon-liquid or plant compressed air service that were noticeably leaking were tagged and brought to the attention of site personnel. Complete component counts were prepared for the surveyed equipment.

A total of 101,193 individual equipment components, 5 process vents, 28 natural gas-fueled compressor and generator engines, 7 process heaters, and 6 flare/vent systems were surveyed. Sufficient process information was collected to allow determination of total annual emissions from the compiled measurement results. Additionally, specific emission-control opportunities were identified, and a preliminary cost-benefit analysis was performed to evaluate these opportunities. The analysis takes into account the estimated cost of implementing repairs, the life of the repair, and the value of conserved gas. Input was solicited from site personnel to help ensure any site-specific constraints, costs associated with equipment/component isolation, and cost data were considered.

The four host facilities tested ranged from 20 to 50 years in age, with an average age of 35 years. In comparison, there are 726 (GRI, 1996) active gas processing plants in the United States, and the age distribution of these plants is depicted in the histogram below based on data adapted from a 1992 survey by GRI.



If it is arbitrarily assumed that the mean age of plants in the >31 years category (20.4 percent of the population) is 50 years (e.g., lean oil facilities have been around since the 1920's), then the average age of gas plants in the United States would be approximately 26 years. Only one of the four sites surveyed was in the 17 to 21 years category that comprises the largest population at greater than 28 percent. While it is assumed that the age of the facility is strongly related to the amount of leakage found, other contributing factors include how well the facility is maintained, frequency of maintenance practices, sweet vs. sour operations, operating practices, facility margins, etc. that may have an even larger impact on loss opportunities.

OVERVIEW OF THE EMISSIONS INVENTORY

Total atmospheric emissions of methane from all sources at the combined sites are estimated at 5,104.4 tonnes per year (t/y) (or 727.9 mscfd). Corresponding GHG and NMHC emissions are estimated at 558,527.7 t/y CO_2E and 9,509.3 t/y (1,369.3 mscfd), respectively. While the primary focus of this study was to identify GHG (methane) loss opportunities, consideration of NMHC losses also, added notably to the cost-effectiveness of implementing a DI&M program at gas processing facilities. The majority of the methane emissions resulted from fugitive equipment leaks (82.0 percent). Incomplete combustion by natural gas-fuelled equipment and flares were also noteworthy sources of methane emissions (10.1 percent and 1.6 percent, respectively). The major sources of GHG emissions are fuel consumption by compressor engines and process heaters (79.6 percent), fugitive equipment leaks (15.7 percent), rejection of raw carbon dioxide from the produced natural gas via the amine regeneration vents (2.6 percent), and flare/vent systems surveyed (1.8 percent). The dominant source of NMHC emissions is storage losses.

OVERVIEW OF THE NATURAL GAS LOSSES

The combined value of all natural gas losses at the sites, including direct atmospheric emissions, gas leakage into flare systems, and excess fuel consumption by process equipment, is estimated at $2,249,500 per year (or $562,375 per year per plant) based on the fourth quarter 2000 long-term contract price for natural gas of $4.50/mscf.

Overall, it is estimated that up to 94.9 percent of total natural gas losses are cost-effective to reduce. This would result in corresponding emission reductions of 79.5 percent for methane, 16.7 percent for GHG, and 95.7 percent for NMHC. The relatively low impact on GHG emissions is due to the significant contribution of CO_2 emissions from fuel consumption to total GHG emissions at the sites.

If solely control opportunities having less than a certain payout period (i.e., 0.5, 1, 2, or 4 years) are implemented, the estimated percent total natural gas loss reduction, including unnecessary fuel consumption, and corresponding reductions in methane and GHG emissions are as follows:

Pollutant	< 6 months (Percent)	< 1 year (Percent)	< 2 years (Percent)	< 4 years (Percent)
Total Natural Gas Loss Reduction	78.8	92.3	93.1	94.9
Methane Emission Reduction	71.9	78.1	79.2	79.5
GHG Emission Reduction	14.6	16.3	16.5	16.7
NMHC Emission Reduction	88.0	91.0	94.0	95.7

These estimates do not include the cost of identifying and evaluating natural gas loss reduction opportunities; however, such costs are typically small compared to the net benefit obtained. For example, the current survey costs, when expressed in terms of the number of components in gas service at each facility, were approximately $1.25 per component which is only slightly more than the cost of conventional volatile organic compounds (VOC) Leak Detection and Repair (LDAR) programs.

Actual costs on a per-component basis will vary between facilities and will tend to increase with the relative number of vents, combustion sources and control opportunities identified, the complexity of the operation, the remoteness of the facility, and the severity of conditions. The current study identified more than $20 in gross savings, or $13 in net savings (i.e., after repair or control costs), per component for control opportunities having a less than a 1-year payback based on a gas value of $4.50 per mscf. Consideration of opportunity identification costs reduces the net savings by only about 10 percent. If a value is assigned to the resulting GHG credits, work is done as a routine commercial service rather than as a study, and efforts are focused on the plant areas most likely to offer meaningful control opportunities, improved economics would apply.

The main cost-effective control opportunities identified at the sites are as follows:

- **Fugitive Equipment Leaks**: Approximately 2.6 percent of the equipment components (approximately 2,630 out of 101,193) in natural gas service were determined to be leaking (i.e., had a screening value of 10,000 ppm or more) at the combined sites. Components in vibrational, high-use or heat-cycle gas service were the most leak prone. The majority of the identified natural gas losses from fugitive equipment leaks are attributed to a relatively small number of these leaking components. Valves were the greatest contributor to this source category, accounting for 30.0 percent of the total, followed by connectors (24.4 percent), compressor seals (23.4 percent), open-ended lines (11.1 percent), crankcase vents on compressors and compressor engines (4.2 percent), and pressure relief devices (3.5 percent). The remaining 3.4 percent was from pump seals, flow meters, blowdowns and regulators.

  It is estimated that implementing all cost-effective equipment-repair or replacement opportunities identified would reduce natural gas losses from fugitive equipment leaks by 95.0 percent and result in gross annual cost savings of approximately $1,135,785 (i.e., based on a gas value of $4.50/mscf applicable at the time the data were analysed). This amounts to 53.2 percent of total practical loss reduction opportunities identified for all source categories at the plants, and a gross average annual value of $283,946 per site (or site-specific values ranging between $180,686 and $333,377). Less significant losses and fewer loss-reduction opportunities would be expected at newer plants.

  Though gas prices fluctuate, economic opportunities exist even at lower values of natural gas. For instance, if a value of $2.00/mscf for natural gas were applied, the total emissions reduction from cost-effective repair opportunities would be reduced to 85.4 percent. The corresponding gross annual value of the total natural gas losses from these opportunities is $453,962 or an average of $113,490 per site.

  Fixing the 10 greatest emitting cost-effective-to-repair components at each site (refer to Appendix II for a ranked listing emission rates by payout period) would reduce natural gas losses by approximately 481.8 mscfd or 35.2 percent.

- **Flaring**: Total residual gas flows in the flare or main vent system at each of the sites (i.e., flows outside of blowdown or emergency relief events) amounted to 334.16 mscfd. In several cases the flows from individual systems were sufficient to potentially justify installing a flare-gas recovery unit. Another option is to target the actual source or sources of the residual gas flow in these systems (e.g., possibly excess purge gas consumption, and leaking pressure-relief devices, drains and blowdown valves connected to the flare header). However, these causes are often difficult to isolate, usually required a major plant shutdown to fix, and are likely to reoccur. Installing flare-gas recovery units, where economic to do so, would reduce GHG emissions at the surveyed plants by approximately 8,165 tonnes CO_2E per year, and take less than a year to pay out. This amounts to 8.8 percent of total practicable loss reduction opportunities identified.

- **Natural Gas-Fueled Process Equipment**: While several of the compressor engines tested would have benefited from tuning, most units proved to be operating efficiently (i.e., air-to-fuel ratios and concentrations of combustibles in the flue gas were at or near values recommended by manufacturers). This likely reflects the greater attention typically given to combustion equipment at continuously manned facilities such as those surveyed. Greater opportunities are believed to exist for tuning heaters and engines used at unmanned field facilities. Total avoidable fuel consumption from servicing all economic-to-tune engines and heaters is estimated at 130.4 mscfd, which is equivalent to GHG emission reductions of 2,882.5 tonnes CO_2E per year.

  All of the natural gas-fueled engines surveyed were properly matched with the current process load requirements (i.e., the units were operating within the optimum portion of their performance curve). Notwithstanding this, situations may arise where engines are operated outside the optimum portion of their performance curve (e.g., due to changes in original load requirements caused by declining production, or initial mismatching of equipment to process applications) resulting in significantly higher operating costs.

- **Storage Tanks**: Tanks at three of the sites were checked for vapor losses in excess of normal weathered-product evaporation rates. Only one site showed abnormally high vapor losses from a storage tank. This tank was subsequently removed from hydrocarbon service and the stream was rerouted within the process. Isolation of the exact cause of the unusually high losses was beyond the scope of this project. Total vapor losses in this case amounted to 160.98 mscfd.

KEY FINDINGS

The study has been a success with all program participants having an opportunity to realize economic benefits from implementing a voluntary Directed Inspection and Maintenance (DI&M) program. The major sources of the target emissions in the natural gas processing industry are compressor engines, acid gas wastes, fugitive emissions from leaking process equipment, and, if present, glycol dehydrator vent streams. While it is not reasonable to extrapolate the results of this study to all gas processing facilities, it is clear that significant cost-effective opportunities to reduce natural gas losses and, thereby, atmospheric emissions, do exist at gas processing facilities. Based on the presented results and the nature of the oil and gas industry, the best opportunities tend to exist at older facilities, particularly where facilities have limited remaining life expectancies resulting in reduced motivation for capital and maintenance expenditures.

Other noteworthy findings and recommendations of the study include the following:

- The host facilities did not have accurate counts of their equipment components. Initial estimates provided by the sites were 40 percent lower, on average, than the physical counts developed during site visits. One probable explanation for the significant underestimate is that the facilities developed their counts from process drawings rather than conducting actual field counts. Such errors are usually related to the lack of detailed mechanical drawings for packaged process units (e.g., compressors and process heaters). Additionally, some facilities may not have considered components under ½ inch in size per NSPS KKK, whereas this study considered all component sizes.

- Sixty-nine percent of the engine and compressor crankcase vents surveyed (i.e., 25 of 36) were determined to be leaking. The average THC emission factor for these components was 0.883 kilogram per hour per source – the greatest value of any of the equipment component categories surveyed. In addition, the engine crankcase vents may emit products of incomplete combustion. In a number of cases, the emissions were discharged inside compressors buildings and work areas. This poses a potential health and safety risk.

- The experience of the largest facility was that most of the economical-to-control natural gas losses could be eliminated at no real cost. Typically, only simple low-cost repairs were required and could be implemented by existing staff, as time was available during normal working hours. Thus, there was no incremental labor charge, and material costs were minimal. The repair program was actually used as a team building exercise in which each shift competed against the others to determine which could implement the most emission reductions. Additionally, it served as an opportunity to train new staff in all the different process areas.

- This study has examined natural gas losses at only 0.6 percent of the estimated 726 gas processing plants in the United States, and has not necessarily captured the impact of all significant factors or facility characteristics (e.g., age, size, H_2S content, and climatic region). To better delineate the extent of natural gas control opportunities at gas processing plants and provide more statistically defensible results, additional facilities should be surveyed. At a minimum, it is recommended that data be compiled for each of the following three plant age categories, since this appears to be the most critical factor: new (less than 20 years old), medium (20 to 30 years old) and old (greater than 30 years old). Each sample group should contain at least 3 plants to allow standard deviations to be calculated and statistical tests to be performed between sample groups.

- It is recommended that a best management practice (BMP) be developed to assist companies in devising an optimum loss control program for their circumstances. Specific matters to be addressed include: impact of facility age and type on opportunity availability, source categories or facility areas on which to focus efforts for maximum benefit, control options, low-cost monitoring systems to facilitate predictive maintenance of key sources, generic costs and life expectancy of repairs by source type and service category.

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GLOSSARY

Blow-By	Gas from a piston cylinder that leaks past the piston rings into the crankcase.
Carbon Dioxide Equivalent (CO_2E) -	Carbon dioxide equivalent is an expression of the total emission of all greenhouse gases, based on the relative ability of the gases to trap heat in the atmosphere. Greenhouse gases are a group of compounds in the atmosphere that tend to absorb solar radiation and reradiate it back to the earth's surface. The most important of these are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Global warming potentials (GWPs) were developed as a simple measure of the global warming effects of the emission of various greenhouse gases relative to those of carbon dioxide. The current practice (IPCC, 1996) is to use a 100-year time horizon for global warming potentials. Therefore, the GWPs used in this document are: CO_2 = 1.0, CH_4 = 21.0 and N_2O = 310. Greenhouse gas emissions are converted to carbon dioxide equivalent (CO_2E) emissions by multiplying the mass emissions of each gas by the appropriate global warming potential and summing the CO_2E emissions. CO_2E emissions are expressed in metric tonnes.
Centrifugal Compressor Seal Systems -	Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used. The amount of leakage from a given seal will tend to increase with wear between the seal and compressor shaft, operating pressure and rotational speed of the shaft.
Combustion Efficiency -	The extent to which all input combustible material has been completely oxidized (i.e., to produce H_2O, CO_2 and SO_2). Complete combustion is often approached but is never actually achieved. The main factors that contribute to incomplete combustion include thermodynamic, kinetic, mass transfer and heat transfer limitations. In fuel rich systems, oxygen deficiency is also a factor. Also see thermal efficiency below.

Connectors -	A connector is any flanged or threaded connection, or mechanical coupling, but excludes all welded or back-welded connections. If properly installed and maintained, a connector can provide essentially leak-free service for extended periods of time. However, there are many factors that can cause leakage problems to arise. Some of the common causes include vibration, thermal stress and cycles, dirty or damaged contact surfaces, incorrect sealing material, improper tightening, misalignment, and external abuse.
Crankcase -	The crankcase on reciprocating engines and compressors house the crankshaft and associated parts, and typically a supply of oil to lubricate the crankshaft. Integral compressors have a single crankcase since the engine and compressor share a common crankshaft. Non-integral compressors typically have two crankcases, one on the engine side and another on the compression side.
Destruction Efficiency -	The extent to which a target substance present in the input combustibles has been destroyed (i.e., converted to intermediate, partially-oxidized and fully-oxidized products of combustion).
Flare and vent systems -	Venting and flaring are common methods of disposing of waste gas volumes at gas processing plants. The stacks are designed to provide safe dispersion of the effluent. Flares are normally used where the waste gas contains odorous or toxic components (e.g., hydrogen sulphide). Otherwise the gas is usually vented. Typically, separate flare/vent systems are used for high- and low-pressure waste gas streams.
Fugitive Emissions -	Unintentional leaks from equipment components including, but not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals. Fugitive sources tend to be continuous emitters and have low to moderate emission rates.
Gas Plant -	A gas processing plant is a facility for extracting condensable hydrocarbons from natural gas, and for upgrading the quality of the gas to market specifications (i.e., removing contaminants such as H_2O, H_2S and CO_2

and possibly adjusting the heating value).

Heat Rate -	The amount of heat energy (based on the net or lower heating value of the fuel) that must be input to a combustion device to produce the rated power output. Heat rate is usually expressed in terms of net J/kW·h.
Integral Compressor	A reciprocating compressor that shares a common crankshaft and crankcase with the engine.
Methane Leak	Greater than 10,000 parts per million when sampled with a dual-element hydrocarbon detector (i.e., catalytic-oxidation/thermal-conductivity).
Long-Term Contract Price of Natural Gas -	Historically, long-term contracts have been used by buyers to lock up a secure supply of natural gas and by sellers to reduce in the risk in developing a large reserve. During the 1960s and 70s, these contracts were established for terms of up to 20 to 25 years and the price of the gas was set at values determined by periodic negotiations. The recent trend is towards shorter contract durations, and most new long-term contracts index the gas price to spot market rates. Today, a typical long-term contract with a cogeneration plant is about 15 years. Given the interest in risk management by sellers and buyers, there is also a trend towards greater standardization of long-term contracts to facilitate hedging activity in the financial or the over-the-counter market
Open-ended Valves and Lines -	An open-ended valve is any valve that may release process fluids directly to the atmosphere in the event of leakage past the valve seat. The leakage may result from improper seating due to an obstruction or sludge accumulation, or because of a damaged or worn seat. An open-ended line is any segment of pipe that may be attached to such a valve and that opens to the atmosphere at the other end. Few open-ended valves and lines are designed into process systems. However, actual numbers can be quite significant at some sites due to poor operating practices and various process modifications that may occur over time. Some common examples of instances where this type of source may occur are listed below: • scrubber, compressor-unit, station and mainline

blowdown valves,

- supply-gas valve for a gas-operated engine starter (i.e., where natural gas is the supply medium),
- instrument block valves where the instrument has been removed for repair or other reasons, and
- purge or sampling points.

Power Output - The net shaft power available from an engine after all losses and power take-offs (e.g., ignition-system power generators, cooling fans, turbo chargers and pumps for fuel, lubricating oil and liquid coolant) have been subtracted. For heaters and boilers it is the net heat transferred to a target process fluid or system.

Pressure-Relief or Safety Valves - Pressure relief or safety valves are used to protect process piping and vessels from being accidentally over-pressured. They are spring loaded so that they are fully closed when the upstream pressure is below the set point, and only open when the set point is exceeded. Relief valves open in proportion to the amount of overpressure to provide modulated venting. Safety valves pop to a full-open positions on activation.

When relief or safety valves reseat after having been activated, they often leak because the original tight seat is not regained either due to damage of the seating surface or a build-up of foreign material on the seat plug. As a result, they are often a source of fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure.

Gas that leaks from a pressure-relief valve may be detected at the end of the vent pipe (or horn). Additionally, there normally is a monitoring port located on the bottom of the horn near the valve.

Products of Incomplete Combustion - These are any compounds, excluding CO_2, H_2O, SO_2, HCl and HF, which contain C, H, S, Cl or F and occur in combusted gases. These compounds may result from thermodynamic, kinetic or transport limitations in the various combustion zones. All input combustibles are potential products of incomplete combustion. Intermediate substances formed by dissociation and recombination effects may also occur as products of incomplete combustion (CO is often the most abundant combustible formed).

Pump Seals - Positive displacement pumps are normally used for pumping hydrocarbon liquids at oil and gas facilities. Positive displacement pumps have a reciprocating piston, diaphragm or plunger, or else a rotary screw or gear.

Packing, with or without a sealant, is the simplest means of controlling leakage around the pump shaft. It may be used on both the rotating and reciprocating pumps. Specially designed packing materials are available for different types of service. The selected material is placed in a stuffing box and the packing gland is tightened to compress the packing around the shaft. All packings leak and generally require frequent gland tightening and periodic packing replacement.

Particulate contamination, overheating, seal wear, sliding seal leakage and vibration will contribute to increased leakage rates over time.

Reciprocating Compressor Packing Systems - Packings are used on reciprocating compressors to control leakage around the piston rod on each cylinder. Conventional packing systems have always been prone to leaking a certain amount, even under the best of conditions. According to one manufacturer, leakage from within the cylinder or through any of the various vents will be on the order of 1.7 to 3.4 m^3/h under normal conditions and for most gases. However, these rates may increase rapidly as normal wear and degradation of the system occurs.

Standard Reference Conditions - Most equipment manufacturers reference flow, concentration and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.

Thermal Efficiency - The percentage or portion of input energy converted to useful work or heat output. For combustion equipment, typical convention is to express the input energy in terms of the net (lower) heating value of the fuel. This results in the following relation for thermal efficiency:

$$\eta = \textit{Thermal Efficiency} = \frac{\textit{Useful Work/Heat Output}}{\textit{Net Heat/Energy Input}} \; x\, 100\%$$

Alternatively, thermal efficiency may be expressed in terms of energy losses as follows:

$$\eta = \left(1 - \frac{\Sigma Energy\ Losses}{Net\ Heat/Energy\ Input} \right) x\ 100\%$$

Losses in thermal efficiency occur due to the following potential factors:

- exit combustion heat losses (i.e., residual heat value in the exhaust gases),
- heat rejected to cooling jacket water and lubrication oil,
- radiation from hot surfaces of the equipment,
- air infiltration,
- incomplete combustion, and
- mechanical losses (e.g., friction losses and energy needed to run cooling fans and lubricating-oil pumps).

Total Hydrocarbons (THC) - All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.

Total Organic Compounds (TOC) - TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).

Valves - There are three main locations on a typical valve where leakage may occur: (1) from the valve body and around the valve stem, (2) around the end connections, or (3) past the valve seat. Leaks of the first type are referred to as valve leaks. Emissions from the end connections are classified as connector leaks. Leakage past the valve seat is only a potential source of emissions if the valve, or any downstream piping, is open to the atmosphere. This is referred to as an open-ended valve or line.

The potential leak points on each of the different types of valves are, as applicable, around the valve stem, body seals (e.g., where the bonnet bolts to the valve body, retainer connections), body fittings (e.g., grease nipples, bleed ports), packing guide, and any monitoring ports on the stem packing system. Typically, the valve-stem packing is the most likely of these parts to leak.

The different valve types include gate, globe, butterfly, ball, plug, and globe. The first two types are a rising-stem design, and the rest are quarter-turn valves. Valves may either be equipped with a hand-wheel or lever for manual operation, or an actuator or motor for automated operation.

Vented Emissions -	Vented emissions are releases to the atmosphere by design or operational practice, and may occur on either a continuous or intermittent basis. The most common causes or sources of these emissions are gas operated devices that use natural gas as the supply medium (e.g., compressor start motors, chemical injection and odorization pumps, instrument control loops, valve actuators, and some types of glycol circulation pumps), equipment blowdowns and purging activities, and venting of still-column off-gas by glycol dehydrators.
Volatile Organic Compounds (VOC) -	Any compound of carbon, ***excluding*** carbon monoxide, and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons.

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1.0 INTRODUCTION

An intensive fugitive emissions screening and measurement program was conducted during the fourth quarter of 2000 at four gas processing facilities in the western USA. The selected facilities were of various ages, types, and throughputs and were evaluated with a strong emphasis on natural gas losses from leaking equipment components in heat-cycle and vibration services. The facilities included sweet and sour gas processing, and a variety of processes including compression, separation, stabilization, deep cryogenic recovery and rejection, mole sieve and TEG/DEG dehydration, amine treatment, sulfur recovery, and flare systems.

The primary objective of the study was to demonstrate the cost-effectiveness of conducting a comprehensive leak detection and repair program at domestic gas production and processing facilities using GTI's HiFlow™ Sampler technology. Field measurements also included an assessment of emissions from continuous vents, combustion equipment, flare systems, and diagnostic checks of natural gas-fueled equipment. Such efforts are seen as an opportunity to achieve sensible and verifiable reductions in methane, GHG and NMHC emissions, as well as a potentially noteworthy economic opportunity for industry from product loss prevention and recovery.

Background information on key differences between the conventional Method 21 approach to leak detection and repair and the GTI approach used here is provided in Section 2 and Appendix VII. A more detailed description of the GTI approach and other measurement techniques employed, as well as an overview of the basic assessment methodology are presented in Section 3. Section 3 also delineates the economic criteria used to evaluate the identified emission control opportunities.

The results of the measurement program are presented in Section 4 and include an inventory of the determined emissions and natural gas losses, average emission factors, leak statistics, and an overview of the identified control opportunities. The conclusions and recommendations of this study are presented in Section 5, and all references cited are listed in Section 6. A detailed listing of all the identified equipment leaks is provided in Appendices I and II, ranked by emission rate and payout period, respectively. The following information is provided for each component: Site No., Tag No., Process Unit, Component Description, Emission Rate (10^3 m^3/y), Estimated Repair Costs ($), Net Present Value of Repair ($), CO_2E Emissions (t/y), and Repair Payback Period (y).

A detailed account of the combustion analysis results and efficiency testing for each tested unit is available in Appendix III. A summary of average equipment component schedules by type of process unit is provided in Appendix IV. The financial considerations and assumptions applied are summarized in Appendix V while the assumed component repair costs and mean repair life are provided in Appendix VI.

2.0 BACKGROUND

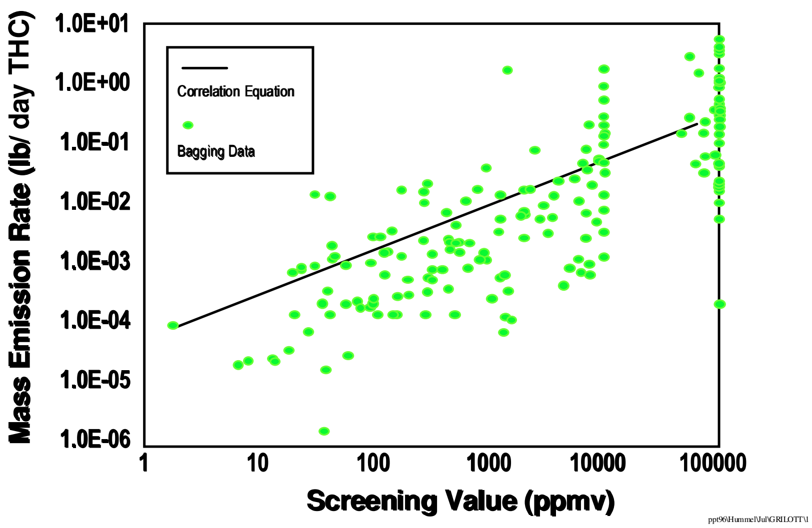
The New Source Performance Standards in 40 CFR Part 60 KKK provide the regulatory requirements for conducting a leak detection and repair program for the onshore natural gas processing industry. This standard is directed at controlling/reducing volatile organic compound (VOC) emissions and specifically excludes methane and ethane. Therefore, gas-processing facilities have typically only included the light liquid and refrigeration portion of the facility in a leak detection program. Subsequently, very little information pertaining to the remaining portion of the facility (i.e. non-regulated) and potential leakage was available. The objective of this project was to evaluate the leak potential and cost-effectiveness of implementing a leak detection and repair program at natural gas processing facilities.

Most leak detection and repair (LDAR) programs in the natural gas industry rely on US EPA Method 21. Depending on the selected detector, the concentration of either total hydrocarbons (THC) or volatile organic compounds (VOC's) in air from a leaking component is measured, and then a correlation equation is used to estimate the leak rate. The uncertainties in this technique are typically ± two orders of magnitude, but can be as great as three to four orders of magnitude. In a conventional leak detection and repair program for the control of fugitive emissions, U.S. EPA's Method 21 is utilized to screen the facility for leaks at a prescribed frequency (e.g. quarterly, bi-annually or annually). All components that screen above a given threshold (typically 10,000 parts per million) are to be repaired.

However, concentration is a weak surrogate for the actual leak rate and under Method 21 guidelines up to 10 times as many leaks are repaired than would be necessary to obtain a significant reduction in emissions. Also, the conventional approach does not provide an accurate measurement of either the baseline emissions from the facility or the amount of emissions reduced (error is ± 300%).

Concentration values measured using Method 21 are plotted against the leak rate in Figure 1. The scatter in the data is nearly ± two orders of magnitude. Consequently, by repairing all components that screen above 10,000 parts per million, resources are wasted on repairing components with extremely small leaks, while many components that screen less than 10,000 parts per million are not fixed even though they have a significant leak rate.

Figure 1 Leak Rate versus Concentration



Data collected by GTI (formerly the Gas Research Institute) show that only 10% of the fugitive components that screen above 10,000 parts per million at natural gas facilities are cost-effective to repair, while 20% of the fittings that screen less than 10,000 parts per million are cost-effective to repair and would ***not*** be repaired using standard Method 21 criteria.

Many leaks that are cost effective to repair are missed while many others, that are actually very small emitters, are repaired. Because the reduction in emissions cannot be accurately determined, the benefits of implementing an LDAR program cannot be evaluated. The problems with the current work practice result from Method 21's inability to provide an accurate estimate of the actual leak rate.

Additionally, the correlation equations only go to screening concentrations of 10,000 or 100,000 parts per million to match the corresponding upper detection limits of common screening devices Any leak above these screening concentrations has the same estimated leak rate (known as a "pegged source" emission factor). A large percentage of leaks screen above these concentrations but are not cost effective to repair. This is especially true in the natural gas industry.

GTI has significantly reduced the cost of applying leak detection and repair programs at natural gas facilities through use of the HiFlow™ Sampler and cost-efficient leak detection techniques and methodologies. GTI data has shown that when this procedure is implemented at natural gas compressor stations, emissions can be reduced by 80 to 90 percent with a payback period of 6 to 12 months.

With an estimate of the repair cost and the measured leak rate, leaks can be rank ordered by payback period. Since the data show that 10 percent of the leaks are responsible for 80 to 90 percent of the emissions from a facility, significant reductions can be achieved by repairing a relatively small number of leaks. In view of recent research and data which indicate that the HiFlow™ Sampler offers more robust estimates of actual leak rates, GTI is currently petitioning EPA for acceptance of an alternative work practice to Method 21.

3.0 METHODOLOGY

This section describes the site selection process and the methodology used by the study team to identify and evaluate cost-effective opportunities to reduce gas losses and methane and other GHG emissions at the selected gas processing facilities. The different measurement techniques considered for each type of primary source are delineated.

3.1 Site Selection

The four selected test facilities were chosen to provide a representative cross section of older gas plants with significant on-site compression since these types of facilities were expected to offer the greatest opportunities for cost-effective reduction of natural gas losses. As shown in Table 1, three sweet and one sour gas processing plants were selected. These plants range from 20 to 50 years in age, for an average age of 35. In comparison, the average age of gas processing facilities in the United States is estimated at 26 years. All of the plants have deep cut liquids extraction facilities, compression facilities, and mole sieve dehydration units.

Table 1. Summary of Surveyed Gas Plants.

Plant No.	Type	Age	Number of Components	Plant Throughput Gas (mmscfd)	NGL (bbl/d)	Condensate (bbl/d)	Water (bbl/d)
1	Sweet	35	16, 073	54	7,070	N/A	N/A
2	Sweet	50	14, 438	60	8,000	N/A	N/A
3	Sweet	20	56, 496	210	16,000	3,000	14
4	Sour	35	14, 186	120	11,430	N/A	N/A
TOTAL		Avg. 35	101,193				

The component counts presented in Table 1 above include components less than 1/2" nominal pipe size, which represent 13.8 percent of total components counted. The component counts are not complete for Sites 1, 2, and 4 since not all components in hydrocarbon liquid service were counted at these locations.

3.2 Emissions Survey

The main elements of each site survey included the following, as applicable:

- screening of equipment components to detect leaks,
- measurement of emission rates from identified leaking equipment components (i.e., leakers),
- measurement of emissions from continuous vents and residual flows from emergency vents during passive periods,
- developing counts of the surveyed equipment components,
- measurement of residual flare-gas rates,
- performance testing of natural gas-fueled combustion equipment,
- sampling of process and waste streams,

- development of the emissions inventory,
- determination of site-specific average emission factors for fugitive equipment leaks, and
- cost-benefit analysis of the identified control opportunities.

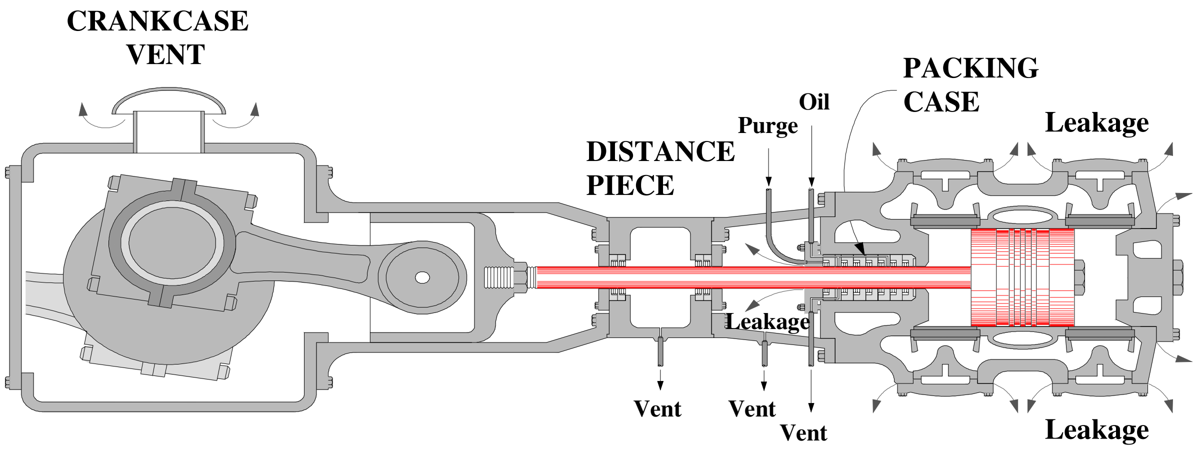
3.2.1 Component Screening

Equipment components on all process-, fuel- and waste-gas systems were screened for leaks. The types of components surveyed included flanged and threaded connections (i.e., connectors), valves, pressure-relief devices, open-ended lines, blowdown vents (i.e., during passive periods), instrument fittings, regulator and actuator diaphragms, compressor seals, engine and compressor crankcase vents (see Figure 2), sewer drains, sump, drain tank vents and tank hatch seals.

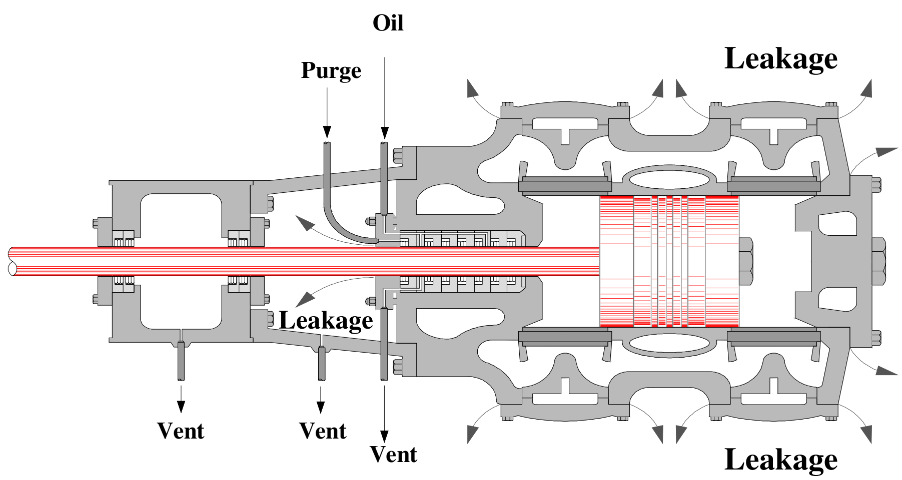
Components in light-liquid service generally were not screened since the focus was on natural gas losses. Furthermore, they do not contribute significantly to total hydrocarbon losses at gas processing plants due to their low average leak rates (US EPA, 1995) and relative numbers. Leak detection (or screening) was done using bubble tests with soap solution, portable hydrocarbon gas detectors (Bascom-Turner Gas Sentry CGI-201 and CGI-211 and a GMI Gas Surveyor3) and an ultrasonic leak detector (SDT International, SDT-120).

Bubble tests, as shown in Figure 3, were performed on the majority of components (including pipe threads, tubing connections and valves), since it is usually the fastest screening technique. Components that could not be screened using bubble tests included any in high-temperature service, certain flanged connections and open-ended lines. These were screened using the gas detectors. Ultrasonic detectors were found to be effective for leak detection in areas with low background noise levels in the ultrasonic range. In all cases a screening value of 10 000 ppm or greater was used as the leak definition. If a component was determined to be emitting by one of the alternative techniques (i.e., bubble tests or the ultrasonic leak detector), it was then screened using the hydrocarbon vapor analyzer to determine if the component would be classified as a leaker.

All identified leaking components were tagged, and the specific source of leakage and date were noted on each tag. The emission rates from all leakers in natural gas service were then determined using the procedures described in Sections 3.2.2 and 3.2.3. All leaker tags were left in place after the leak rate was quantified to simplify facility personnel follow-up action.



RECIPROCATING COMPRESSOR
PACKING & VENT SYSTEM



EXPANDED VIEW OF THE
COMPRESSOR HEAD

Figure 2. Cut-away view of natural gas compressor showing the potential leak points including the compressor seals and crankcase vent.

Figure 3 - Bubble test on leaking valve

The following basic information was recorded for each leaking component:

- Component Type
- Model or Style of Component
- Service
- Size
- Process Unit
- Process Stream
- Pressure and Temperature

3.2.2 Leak-Rate Measurements

The HiFlow™ Sampler was the primary method used to measure emission rates from leaking equipment components. Specific cases where the HiFlow™ Sampler was not used included any components leaking at rates above the upper limit of the unit (i.e., above about 14 m^3/h for the current HiFlow™ design) and most open-ended lines and vents. Either bagging or direct measurement techniques, as appropriate, were used in these cases (see Section 3.2.3). The following provides a brief description of the HiFlow™ Sampler.

The HiFlow™ Sampler was developed by GTI as an economic means of measuring the emission rate from individual leaking equipment components with sufficient accuracy to allow an objective cost-benefit analysis of each repair opportunity. To bag all leakers in order to differentiate between economic-to-repair and uneconomic-to-repair components is expensive and, therefore, is not normally done (typically, 6 to 15 leak-rate measurements per hour can be performed using the HiFlow™ Sampler compared to only 2 per hour using bagging techniques). Furthermore, compiling Method 21 (U.S. EPA, 1997) screening data for these components and then applying leak-rate correlations or stratified emission factors to the results does not provide sufficient accuracy for this purpose. The uncertainties in the correlation predictions on an individual component basis are ± two orders of magnitude and the use of stratified emission factors is even less reliable. In comparison, the results of HiFlow™ and bagging measurements contain uncertainties of only about ±10 to 15 percent. Accordingly, the HiFlow™ Sampler (shown in Figure 4) provides a practicable means of making objective repair decisions. The reliability and use of the HiFlow™ Sampler has been demonstrated in a number of studies (Howard *et al*., 1994; Lott *et al*., 1995).

The operating principle of the HiFlow™ Sampler is simple – a variable-rate induced-flow sampling system provides total capture of the emissions from a leaking component. An assortment of specially-designed attachments are provided for use as needed to ensure total emissions capture, or to help prevent interference from other nearby sources. A dual-element hydrocarbon detector (i.e., catalytic-oxidation/thermal-conductivity), inserted directly in the main sample line within the HiFlow™, measures hydrocarbon concentrations in the captured air stream ranging from 0.01 to 100 percent. A background sample-collection line and hydrocarbon detector allows the sample readings to be corrected for ambient gas concentrations, which is particularly important in buildings and confined areas. A thermal anemometer, also inserted directly into the main sample line, monitors the mass flow rate of the sampled air-hydrocarbon gas mixture. The HiFlow™ Sampler is intrinsically safe and is equipped with a grounding wire to dissipate any static charge that may accumulate as air passes through the sample collection line and instrument.

The battery-operated fan in the HiFlow™ Sampler can generate a maximum sampling velocity of approximately 366 m/min (1200 ft/min), which corresponds to a maximum leak rate measurement capacity of roughly 14 m^3/h (8.5 scfm). Increasing the sampling rate generally improves the leak capture efficiency up to the point of total capture. Increasing sampling rates beyond this point results in increased dilution of the emissions with ambient air. Excessive dilution may cause the pollutant concentration to either fall below the detection range of the sample detector or to decrease to background levels resulting in a zero reading. The sampling rate is adjusted manually using a backpressure valve mounted on the fan outlet. For large leaks, the backpressure valve is left open; while for small leaks, the airflow rate is reduced so that the hydrocarbon concentration is within the sensing range of the hydrocarbon detector.

The sample and background hydrocarbon detectors in the HiFlow™ Sampler were calibrated 100 percent methane and 2.5 percent methane-in-air to cover both ranges of the dual-element detector system. Zeroing of the detectors was done using ambient air upwind of the facilities. The calibrations were done prior to use of the HiFlow™ Sampler at each site, and then periodically thereafter to ensure that no significant drift occurred. The HiFlow™ Sampler is also calibrated periodically by releasing known flowrates of methane into the sampler inlet and comparing the leak rate measured by the HiFlow™ to the actual gas release rate determined using a bubblometer or diaphragm meter. A total of three correction factors are applied to the raw data collected.

Figure 4. GRI HiFlow™ Sampler

3.2.3 Measurement of Emissions from Vents and Open-ended Lines

The emission rates from open-ended lines and vents were measured using an appropriate flow-through measurement device (i.e., a precision rotary meter, diaphragm flow meter, or rotameter, depending on the flow rate) if total flow capture was safe and practicable to achieve and the resulting backpressure on the vent system could be tolerated. Otherwise flows were determined by measuring the velocity profile across the vent line and the flow area at that point.

Where flow capture was required custom-fabricated slip-on sheaths made of neoprene or plastic sheeting were used to connect a flow line to the end of the vent or open-ended line. The sheaths were easy to use and provided a reliable seal around the pipe. Nylon insert fittings and clear PVC tubing were used to conduct the vented gas from the sheath to the selected flow meter. Each flow measurement was typically averaged over a 10 to 20 minute time interval, depending on the amount and steadiness of the flow.

Flow velocities were measured using a pitot tube, hot-wire anemometer or thermal dispersion anemometer. The traverse points were selected in general accordance with US EPA Methods 1 and 1A.

When measuring flows from vents, a distinction was made between continuous and intermittent vent systems. Emissions from intermittent vents during inactive periods were defined as leakage. Emissions from continuous vent systems and intermittent vent systems during active periods were defined as vented emissions. Leakage from vents and open-ended lines was detected by screening using a hydrocarbon sensor.

3.2.4 Determination of Residual Flaring Rates

Flows in flare lines were determined using one of the following two methods, as presented in the order of decreasing reliability and preference:

- **Measurement of the Velocity Profile and Flow Area in the Flare Line** - this is the same approach as described in Section 3.2.3 for measuring flows in vent lines. It requires that a safe-to-access port exist on the stack, the common line to the flare or on each branch line connected to the flare system.

- **Backcalculation Based on Pressure Drops** - the pressure drop between the flare tip and a suitable upstream point on the flare line is measured and then the amount of flow required to produce that much pressure drop is determined by backcalculation. Ideally, at least several inches of water column pressure drop should be occurring to allow a reasonable estimation of the flow rate. If the flow velocities are too low there may not be any measurable pressure drop in the system but the flows can still be significant if the piping size is large.

In each case, the hydrocarbon concentration of the stream was either determined using a portable combustible-gas detector or was based on a detailed laboratory analysis of the flare gas (where available).

The determination of flows in continuous flare systems allows a review of the economics associated with conserving the waste gas. The determination of residual flows for intermittent flare systems provides an indication of the combined purge gas flow rate and leakage rates into the flare system. To distinguish between purge gas flows and leakage, the minimum required purge gas rate was calculated using the procedure presented by Stone *et al.* (1992), and subtracted from the total residual flare rate. The difference was then taken to be leakage or potentially avoidable natural gas loss.

3.2.5 Performance Testing of Natural Gas-Fueled Equipment

Each natural gas-fueled engine and process heater or boiler was tested to identify avoidable inefficiencies resulting in excessive fuel consumption and emissions. The focus was on identifying situations where equipment were either in need of tuning or repairs, or were mismatched for the current process demands resulting in operation low on, or off of, the unit's published performance curve. The identification of opportunities to recoup waste heat from the units, or to reduce energy requirements through process modifications was beyond the scope of this project.

The testing done on each unit involved analyzing the flue gas, measuring the flue gas temperature, obtaining an analysis of the fuel gas composition, and where possible, measuring the flow rate of one or more of the following: fuel gas, combustion air, or flue gas. Additionally, the make and model of each unit, and ambient conditions (i.e., temperature and barometric pressure) at the site were recorded.

Typically, insufficient process data were available to allow a reliable estimate of the total amount of useful process work done by each unit, or to determine overall unit performance. Consequently, a simplified approach was taken in which the following parameters were evaluated and their departures from proper operating conditions were determined as an indication of opportunities for improvement:

- residual heat content of the discharged flue gas (i.e., stack losses),
- excess air setting, and
- concentration of carbon monoxide and unburned hydrocarbons in the flue gas.

Additionally, the crankcase vent on all reciprocating engines was checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) as this reduces cylinder compression resulting in inefficient operation and contributes to emissions of unburned and partially burned fuel. As a first approximation of the resulting performance loss, measurements were performed to quantify the amount of combustible gases emitted as blow-by from the crankcase vent. These results are presented as fugitive equipment leaks. On integral compressor units (i.e., compressor units where the engine and compressor share a common crankshaft and crankcase), emissions from the crankcase vent potentially include blow-by from the engine cylinders and leakage from the compressor seals, as shown in Figure 2, which has entered the crankcase through the distance piece.

In many cases, the engine crankcase was vented inside a building or work area. This poses a potential health and safety risk. Figure 5 depicts various venting configurations recommended by the engine manufacturers.

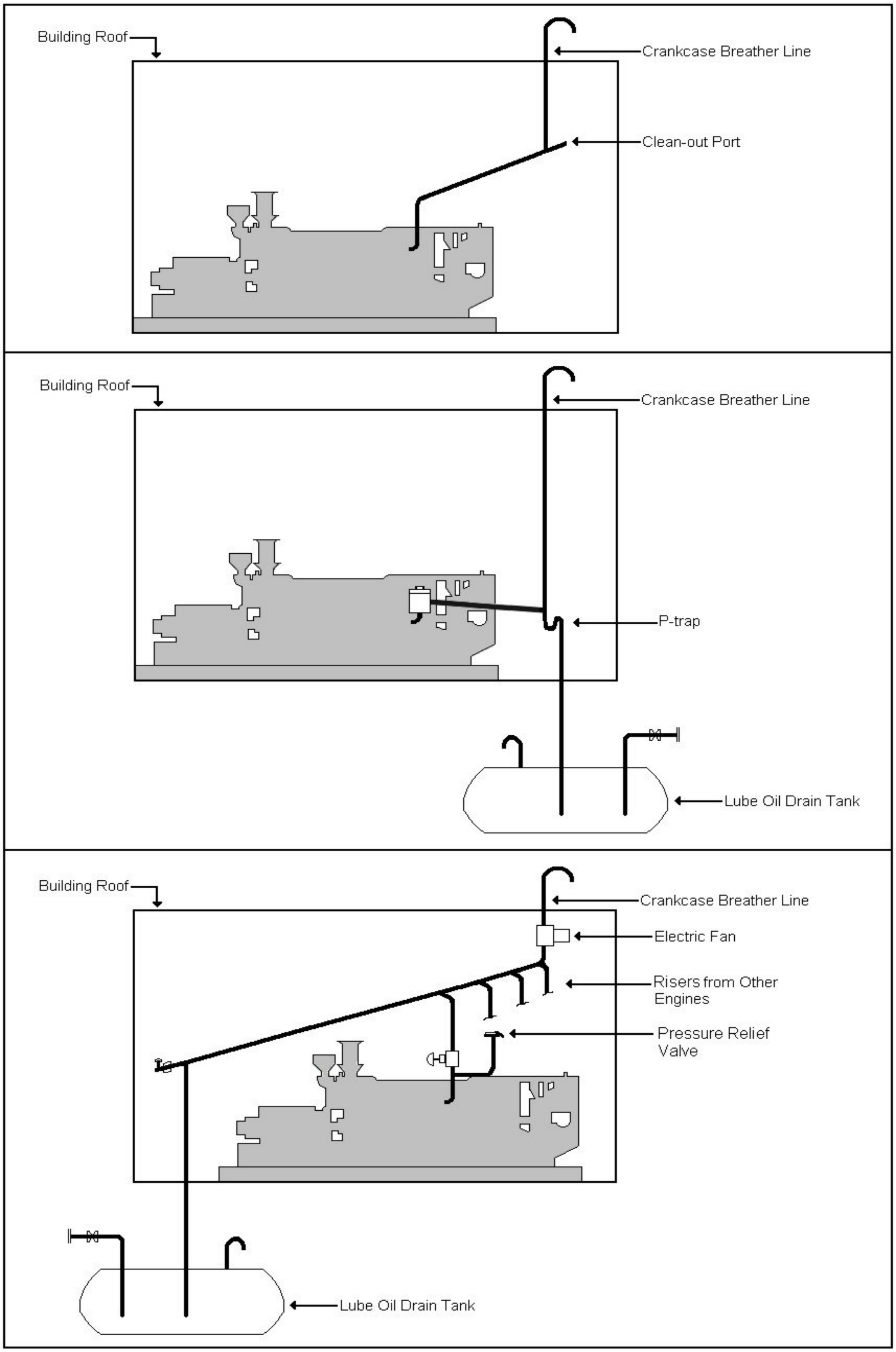


Figure 5. Typical crankcase vent configurations recommended by manufacturers for stationary compressor engines.

Where possible, equipment-specific emissions factors on either a kilogram-per-cubic-meter fuel basis (if the fuel consumption rate of the unit was known) or on a kilogram-per-day basis (if the flue gas flow rate was known) were generated for use in estimating total emissions of CO, NO_x, CO_2 and combustibles. A detailed summary of the calculations and a discussion of normal operating efficiencies and losses are provided in Appendix III.

The flue gas analyses were conducted using an Enerac 2000E Portable Combustion Analyzer equipped with detectors for O_2, CO, CO_2, NO_x, and combustibles, and thermocouples for measuring ambient and stack-gas temperatures. The flue gas was sampled either through a convenient sampling port on the exhaust stack or at the top of the stack.

3.2.6 Evaluation of Excess Emissions from Storage Tanks

Storage tanks are a potentially significant source of emissions due to evaporation losses, particularly where intentional boiling or flashing of the product occurs. However, other less recognized, and often unnoticed, contributions to atmospheric emissions or vapor losses from storage tanks may include the following:

- Leakage of process gas or volatile product past seats of drain or blowdown valves into the product header leading to the tanks.
- Inefficient separation of gas and liquid phases upstream of the tanks allowing some gas carry-through (by entrainment) to the tanks. This usually occurs where inlet liquid production (e.g., produced water) has increased significantly overtime resulting in a facility's inlet separators being undersized for current conditions.
- Piping changes resulting in the unintentional placement of high vapor pressure product in tanks not equipped with appropriate vapor controls.
- Overheating of storage tanks or rundown of hot product to tanks containing volatile material.
- Malfunctioning or improperly set blanket gas regulators and vapor control valves can result in excessive blanket gas consumption and, consequently, increased flows to the end control device (e.g., vent, flare or vapor recovery compressor). The blanket gas is both a carrier of product vapors and a potential pollutant itself (i.e., natural gas is usually used as the blanket medium for blanketed tanks at gas processing plants).
- Leaking hatches and pressure-vacuum valves is a common problem on tanks equipped with gas blanketing systems, and results in direct atmospheric emissions of product vapors and blanket gas.

Contributions of the last two types are accounted for under flare systems and fugitive equipment leaks, respectively. Contributions of the other types were determined by measuring venting rates (see Section 3.2.3) and comparing the observed emissions to calculated working losses for conditions at the time of testing.

3.2.7 Component Counts

Equipment component counts were prepared based on an initial review of the process and instrumentation drawings, followed by a subsequent walk-though inspection of each process unit at the site. In developing these counts, the following information was collected for each component:

- type of component (e.g., connectors, valves, control valves, pressure relief valves, pressure regulators, orifice meters, other flow meters, blowdowns, open-ended lines, etc.),
- component style (e.g., threaded and flanged connections, coupling, ball valves, plug valves, globe valve, gate valve, butterfly valve, pump seal, compressor seal, regulator, sampling connection, etc.),
- nominal size of the component,
- process temperature and pressure,
- component service (i.e., natural gas, light hydrocarbon liquid), and
- application (i.e., the process stream and unit on which they are used).

3.2.8 Development of Average Emission Factors

To determine the average emission factor for each type of component, the corresponding aggregate emissions were divided by the number of components. Total emissions are the sum of emissions from both leaking and non-leaking components. Emission rates for all leaking components (i.e., those with screening values of $\geq$ 10,000 ppm) were quantified using the methods described in Section 3.2.2. Non-leaking components were assigned the average non-leaking emission rates presented in the Protocol for Equipment Leak Emission Estimates (US EPA, 1995).

3.2.9 Emission Control Guidelines

There are currently no regulations or codes of practice that apply specifically to the control of methane emissions from fugitive equipment leaks from natural gas processing facilities. However, there are requirements for controlling leaks from equipment components in VOC service at gas processing plants (40 CFR Part 60, Subpart KKK), and for components in VOC and volatile hazardous air pollutant (VHAP) service in other industry sectors (e.g., petroleum refining and synthetic organic chemical manufacturing). Typically, these regulations require that the leak frequency not exceed 2 percent for any group of components excluding connectors (which may have a value up to 0.5 percent) and pump and compressor seals (which may have a value up to 10 percent).

3.3 Cost-Benefit Analysis

Practicable opportunities for reducing emissions due to fugitive equipment leaks and process venting are identified and assessed on a source-by-source basis. The net cost/benefit of each identified control option is expressed in dollars per tonne of CO_2-equivalent emission reduction on an annual basis. The information and assumptions regarding cost estimating, the value of the gas lost, and repair life used in this analysis are summarized below, while the financial discount rate and other financial considerations applied in this analysis are summarized in Appendix V. It should be noted that implementing a targeted DI&M program designed to quantify methane or total GHG opportunities resulted in identifying other hydrocarbon product loss prevention and recovery possibilities, further improving the economics of implementing such a program.

3.3.1 Cost Estimating

Detection and control costs are assessed on an individual-source or per-component basis according to the estimated average costs once at the site. True costs will vary with the location and layout of the facility, the amount of work to be performed, the type of service (i.e., sweet or sour), and the actual repairs or control measures required.

The basic cost to repair or replace a leaking equipment component is estimated based on the type and size of the component, typical billing rates quoted by the applicable types of service providers (e.g., compressor maintenance and repair companies, and valve repair and servicing companies) and the estimated amount of labour and materials required. Where possible, both direct and indirect contributions to these costs are considered. Direct contributions are the actual costs for parts, onsite labour, equipment, tools and disbursements, and are summarized in Appendix VI. Indirect contributions are losses in revenues due to any associated shutdowns or process interruptions required outside of normally scheduled facility turnarounds, and the value of any gas that is vented or flared as part of the specified repair or replacement activity. Where indirect costs are significant, it is assumed that the work will be left until the next scheduled plant turnaround. Otherwise, it is assume that the repairs are made within a short period of time following detection and evaluation of the leak.

It was assumed that a leak, once repaired, will remain fixed for some finite period of time, and then will reoccur. The mean time between failures is dependent on the type, style and quality of the component, the demands of the specific application, component activity levels (e.g., number of valve operations) and maintenance practices at the site. The estimated mean time between failures for each type of component is provided in Appendix VI. These values are very crude estimates based on the experiences of the authors and limited feedback from the host facilities. The relatively low mean time between failures for connectors reflects wear and tear on these components from inspection and maintenance of associated equipment units. In a formal leak detection and repair program, information on mean times between failures is tracked on an ongoing basis and is used to identify problem service applications and to evaluate the potential need for changes to component specifications and maintenance practices.

3.3.2 Value of Natural Gas

The value of natural gas, including vapors from natural gas liquids and propane, is taken to be \$4.50/mscf based on the long-term contract price of natural gas during the fourth quarter of 2000, or approximately \$158.95/10^3 m^3 or \$4.25/GJ for methane. In comparison, the spot price for natural gas at the same time was in excess of \$7.00/mscf. The market value of natural gas is subject to large fluctuations, and operators' actual economic opportunities are dependent on current natural gas prices.

Overall, the actual value of avoided natural gas losses is very site-specific and depends on many factors including the following:

- Local market pricing.
- Impact of emission reductions on specific energy consumption, equipment life, workplace safety, and system operability, reliability and deliverability.
- Contract terms.
- Remoteness of the facility.
- Concentration of contaminants and NMHCs in the gas.
- Applicable taxes and tax shields.

3.3.3 Repair Life

The mean time between failures is dependent on the type, style and quality of the component, the demands of the specific application, component activity levels (e.g., number of valve operations) and maintenance practices at the site. Arbitrary estimates of the mean time between failures for each type of component are provided in Appendix VI. These values are crude estimates and ultimately should be updated based on company-specific maintenance experiences. Component- and process-specific data for natural gas processing facilities should be compiled. In a formal leak detection and repair program, this type of information is tracked on an ongoing basis and is used to identify problem service applications and to evaluate the potential need for changes to component specifications and maintenance practices.

3.3.4 Cost Curves

A cost curve is used to show the approximate net cost associated with achieving different levels of emission reduction at a site. Each point on the curve represents the impact of implementing different emission-reduction measures. The presented costs do not account for the expense of finding and evaluating these reduction opportunities and, therefore, are slightly low (typically, these costs are small compared to the control costs). Furthermore, the costs are based on a mix of facility and vendor supplied data and consensus estimates developed in consultation with the facilities. As various control actions have different lifetimes, the credited emission reduction for each control option only includes the emission reduction achieved in the first year. Control measures that continue to remain in effect in subsequent years will have reduced costs per unit of emission reduction.

4.0 OVERVIEW OF THE RESULTS

This section provides an overview of the atmospheric emissions and natural gas losses determined for each of the four sites, and delineates the main cost-effective loss-reduction opportunities. Additionally, average total hydrocarbon (THC) emission factors and leak statistics are presented for fugitive equipment leaks at these facilities.

Tagged-component information and individual leak rates for all leaking components are presented in Appendices I and II. Detailed results of the performance tests done on all active combustion sources are provided in Appendix III.

4.1 Emission Inventory

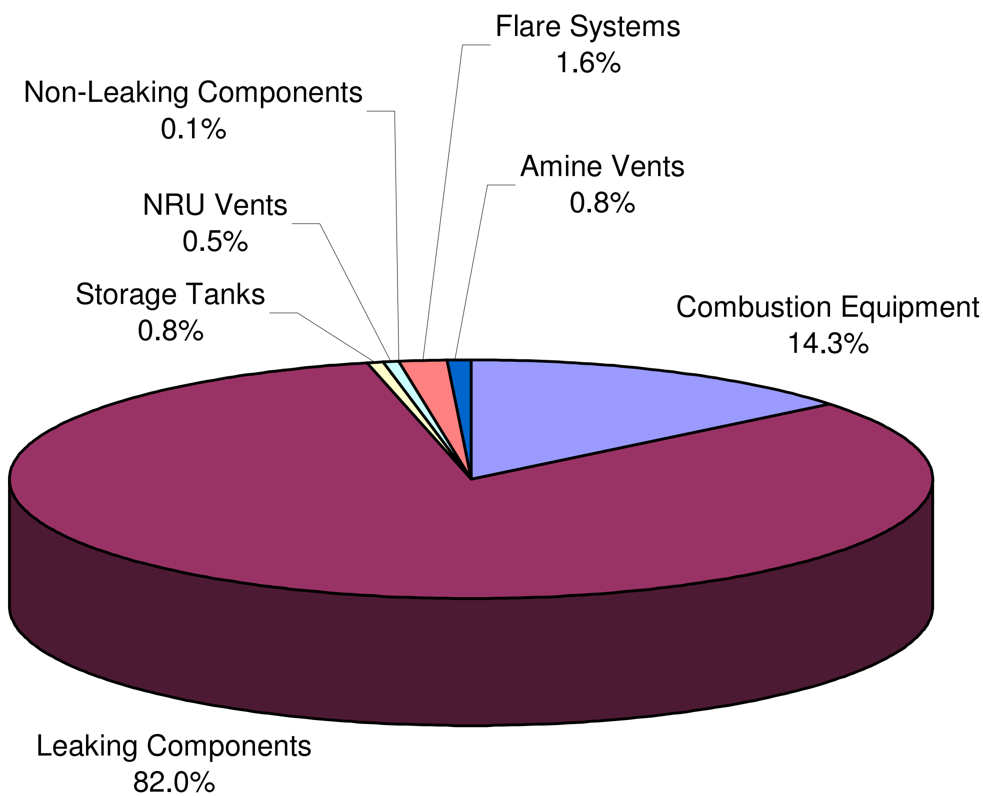
Total atmospheric emissions of methane, NMHC and GHG emissions from the four host gas processing plants amounted to 5,104.4 and 9,509.3 tonnes per year and 558,527.7 tonnes CO_2E per year, respectively. The relative distributions of these emissions by source category are presented in Figures 6 to 8. The carbon dioxide equivalent GHG emissions were calculated using the most recent 100-year global warming potentials (IPCC, 1996) (i.e., 1.0 for CO_2 and 21.0 for CH_4). The methane content of the measured THC emissions was determined based on typical gas analyses for the site and the analysis results for samples collected during the measurement program. Emissions of nitrous oxide were not evaluated but would be expected to contribute only a few percent to total GHG emissions at each site.

As shown in Figure 6, fugitive equipment leaks are the dominant source of methane emissions, accounting for 82 percent of the total. This is followed by incomplete fuel combustion (14.3 percent) incomplete flare gas combustion (1.6 percent), and a small amount (2.1 percent) from process vents and storage tanks.

Storage losses are the major source of NMHC emissions (58.1 percent) although fugitive equipment leaks are also a significant contributor (36.9 percent) (see Figure 7). The rest (5.0 percent) was contributed primarily by combustion equipment and vents.

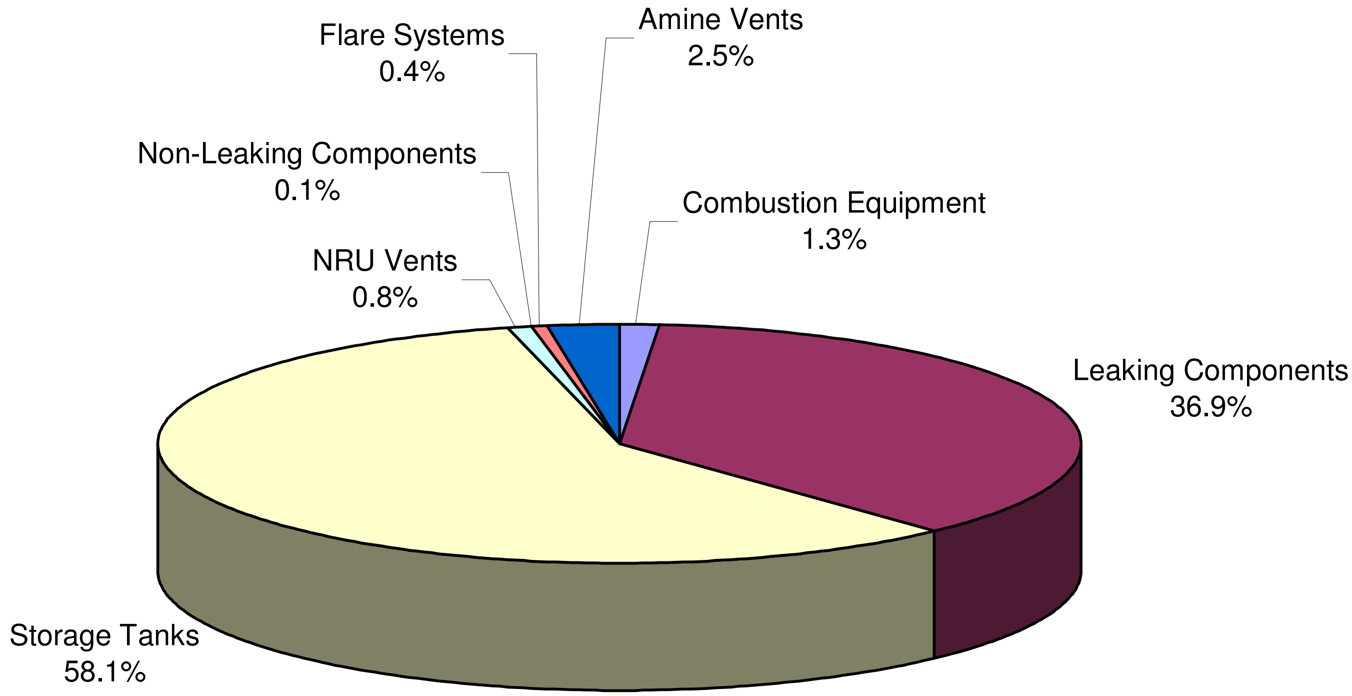
The GHG emissions are predominantly from fuel consumption by combustion equipment (79.6 percent) (see Figure 8). However, fugitive equipment leaks (15.7 percent), as well as process vents and storage tanks (4.7 percent) may generally offer more cost-effective control opportunities.

Figure 6. Distribution of Methane Emissions by Source Category



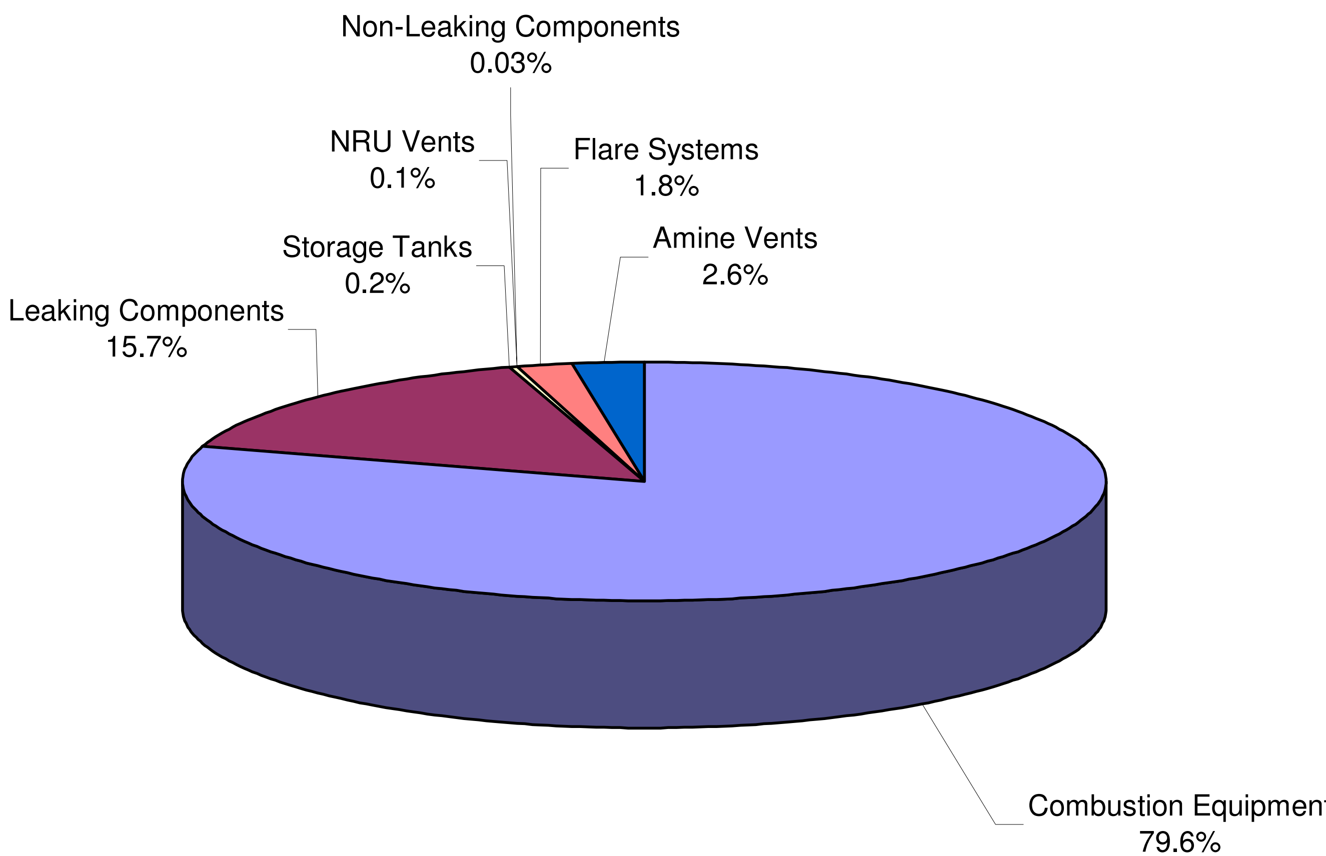
Total Methane Emissions = 5,104.4 tonnes per year

Figure 7. Distribution of Non-Methane Hydrocarbon Emissions by Source Category



Total NMHC Emissions = 9,509.3 tonnes per year

Figure 8. Distribution of Total GHG Emissions by Source Category



Total GHG Emissions = 558,527.7 tonnes CO_2E per year

4.2 Natural Gas Losses

A summary of total natural gas losses and their estimated value at the four sites is presented in Tables 2 and 3 below. The value of natural gas is taken to be \$4.50 per mscf (i.e., long-term contract price of natural gas in the fourth quarter of 2000, or approximately \$158.95/10^3 m^3 or \$4.25/GJ for methane). The determined gas losses include direct leakage and venting of natural gas to the atmosphere as well as losses into the process (e.g., excess fuel consumption by out-of-tune or inefficiently-operated engines and heaters, and gas leakage into flare systems). These latter losses lead to increased combustion emissions without any net process benefit.

The relative distribution of natural gas losses by source category is shown in Figure 9. Leaking equipment components are the greatest source of natural gas losses at the gas plants, accounting for more than 53 percent of the total. Other major sources include leakage into flare systems (24.4 percent), storage tanks (11.8 percent) and avoidable inefficiencies by combustion equipment (9.9 percent). As shown in Figure 10, most (30 percent) of the natural gas losses from equipment leaks are attributable to valve leakage (both block and control). Connectors, compressor seals and open-ended lines are also noteworthy sources, accounting for 24.4, 23.4 and 11.1 percent, respectively, of losses from leaking equipment components. The top ten leakers at each site contributed over half of the total natural gas losses from fugitive equipment leaks (refer to Table 4).

4.3 Fugitive Equipment Leaks

The following subsections characterize the fugitive equipment leaks for components in natural gas service at the surveyed gas plants.

4.3.1 Average Emission Factors

Average emission factors were determined for each type of equipment component in natural gas service at the surveyed sites. The results are presented in Table 5 and are compared to corresponding factors published by U.S. EPA (1995) for oil and gas production operations and by U.S. EPA and GRI (1996) for natural gas facilities. Overall, the developed average emission factors are greater than those for oil and gas production facilities, and more comparable to the previous values for natural gas facilities.

The average emission factors are simply the total emissions from all tested components divided by the total number of components of that type surveyed. Quantification of emissions from non-leaking components (i.e., components with screening values between zero and 10,000 parts per million) was not attempted. Instead, emissions from these components were assumed to be represented by the average no-leak emission rates presented in the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995).

Table 2. Summary of Natural Gas Losses from the Tested Gas Plants.			
Plant No.	**Natural Gas Losses (mmscfd)**	**Value of Gas Lost ($/y)**	**Percent of Throughput [1]**
1	173.3	285,000	0.27
2	213.4	351,000	0.29
3	638.8	1,049,000	0.27
4	347.5	571,000	0.25
Combined	1,373	2,256,000	0.27

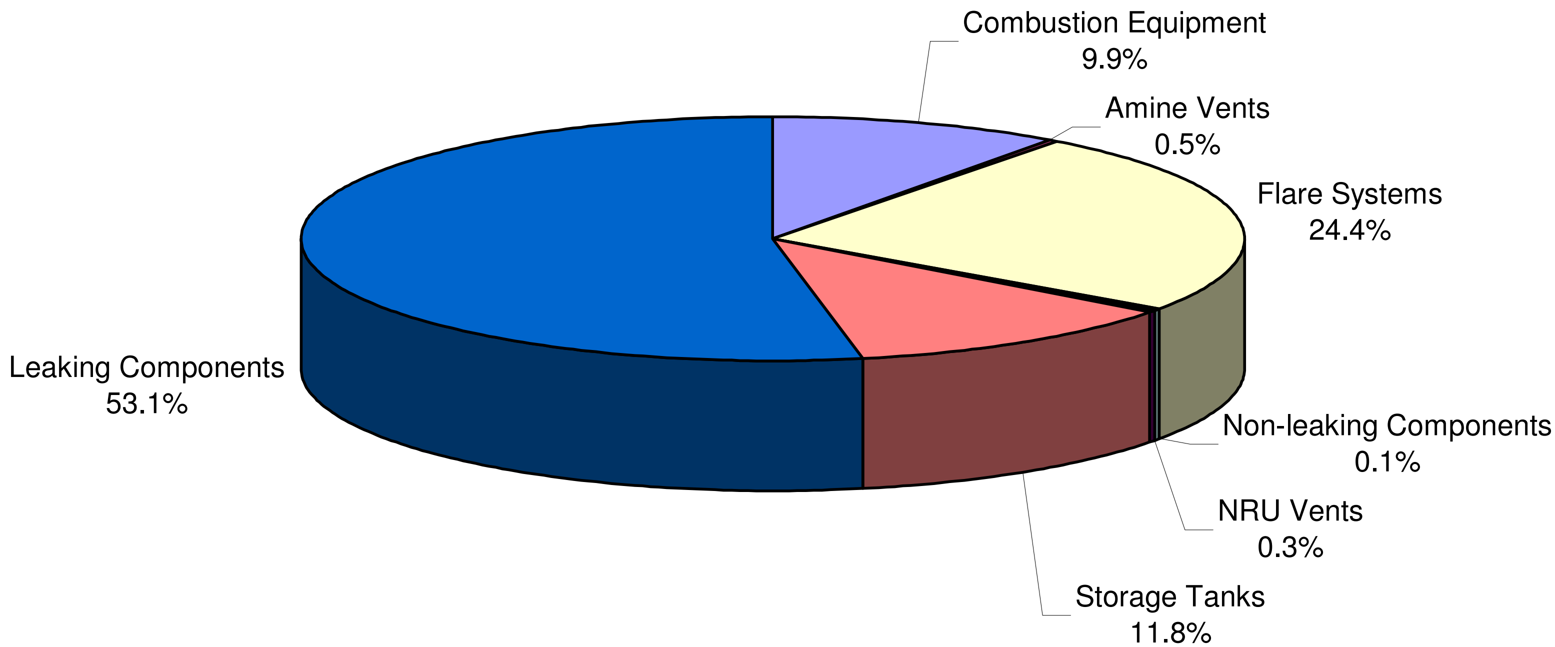
[1] Total equivalent gas throughput (i.e., gas sales plus LPG and NGL volumes expressed as equivalent gas volumes).

Table 3. Summary of Natural Gas Losses from Combined Data Gathered at Four Surveyed Gas Plants.		
Source	**Gas Losses (mscf/y)**	**Gross Value ($/y)**
Leaking Equipment Components	265,161.54	1,193,482
400 bbl Separator	58,758.74	264,471
NRU Vents	1,506.54	6,781
Non-Leaking Equipment Components	436.26	1,964
Flare Systems	120,811.13	543,766
Common Blowdown (Vent) Stack	2,507.10	11,284
Amine Vents	2,574.58	11,588
Avoidable Fuel Consumption by Combustion Equipment	49,374.46	222,233
Total	501,130.35	2,255,569

Table 4. Summary of Natural Gas Losses from the Top Ten Leakers[1].				
Plant No.	**Gas Losses from Top 10 Leakers (mscfd)**	**Gas Losses from all Equipment Leaks (mscfd)**	**Percentage Contribution by Top 10 Leakers**	**Percentage of Total Leakers**
1	43.8	122.5	35.7	1.78
2	133.4	206.5	64.6	2.32
3	224.1	352.5	63.6	1.66
4	76.5	211.3	36.2	1.75
Combined	477.8	892.84	53.5	1.85

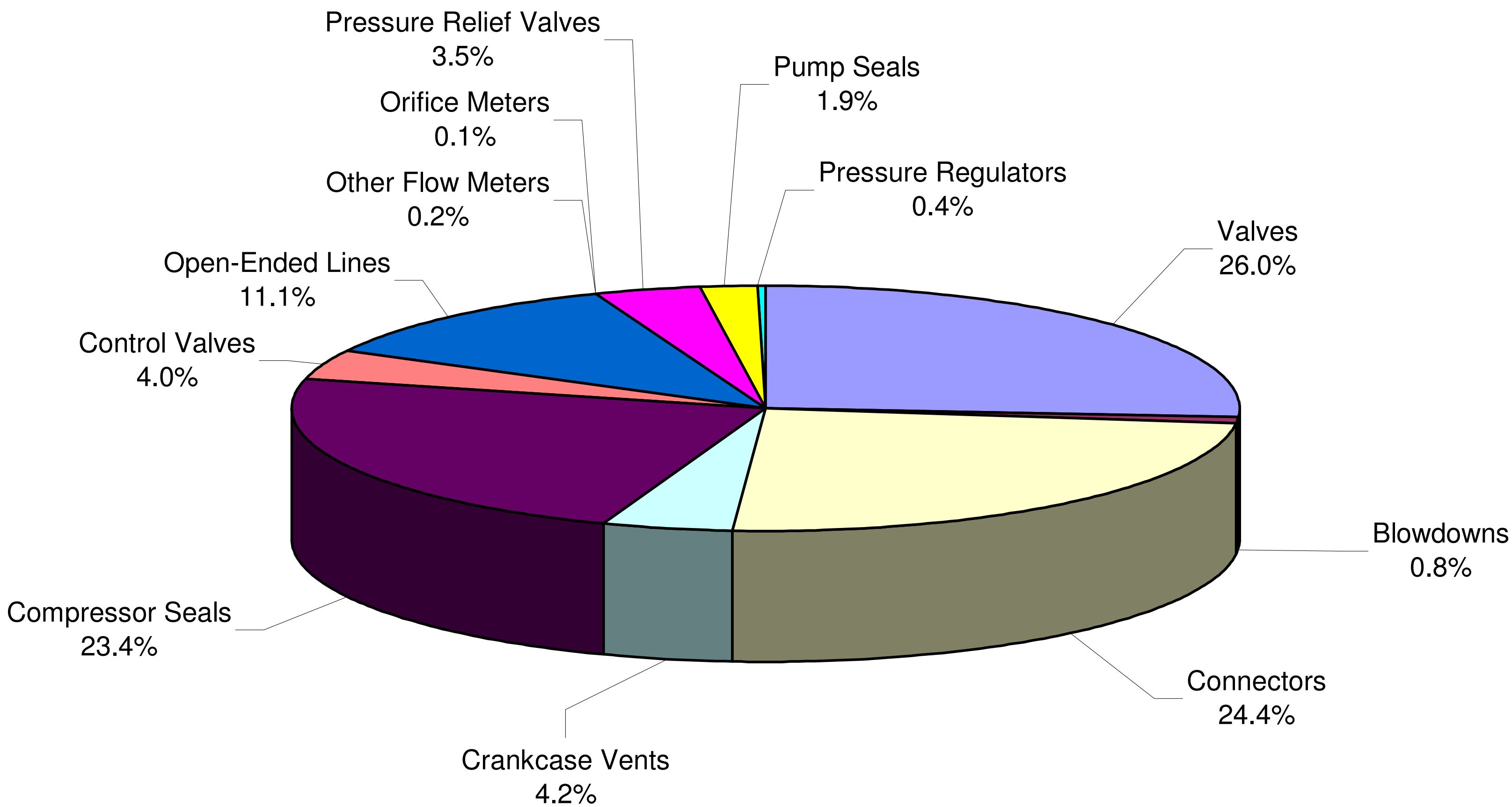
[1] Excluding leakage into flare systems.

Figure 9. Distribution of Natural Gas Losses by Source Category



Total Natural Gas Losses = 501,130 mscf per year

Figure 10. Distribution of Natural Gas Losses from Equipment Leaks by Type of Component



Total Natural Gas Losses = 266,100 mscf per year

Table 5.	**Comparison of average THC emission factors derived from data collected at the Test Sites to other published values.**		
Source	**Average Emission Factors (kg/h/source)**		
	Test Sites	**U.S. EPA**[1]	**U.S. EPA Gas Facilities**[2,3]
Connectors	2.22e-03	2.0e-04	3.048e-04
Block Valves	1.10e-02	4.5e-04	3.400e-03
Control Valves	4.85e-02	4.5e-04	N/A
Pressure Relief Valves	6.73e-02	8.8 e-03	2.238e-03
Pressure Regulators	1.74e-02	8.8 e-03	N/A
Orifice Meters	3.58e-03	8.8 e-03	N/A
Other Flow Meters	2.03e-01	8.8 e-03	N/A
Crank Case Vents	8.83e-01	N/A	N/A
Open-Ended Lines	5.18e-02	2.0e-03	9.015e-02
Pump Seals	1.67e-01	2.4e-03	N/A
Compressor Seals[4]	8.52e-01	8.8 e-03	1.172e+00
Blowdowns	8.78e-01	8.8 e-03	5.533e+00

N/A Emission factor for this source type is not available.

---- No components in this category were screened.

1 Source: U.S. EPA. 1995. Protocol for Equipment Leak Emission Estimates. Research Triangle Park, NC 27711.

2 Source: U.S. EPA and GRI. 1996. Methane Emissions from the Natural Gas Industry. Volume 8: Equipment Leaks. Research Triangle Park, NC 27711.

3 The factors presented in the column are for methane emissions only but should be comparable to, although slightly less than, the corresponding THC values for the applicable component categories. The factors presented in the other two columns are for THC emissions.

4 Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

4.3.2 Average Leak-Rate Trends

A statistical analysis of the compiled leak data was performed to identify any trends or correlations that could be used to help focus leak detection and control efforts. The effects of component type and style, process temperature and pressure, component size, application (i.e., type of process unit on which the component is used), and type of process stream (e.g., fuel gas, residue gas, acid gas, etc) were evaluated. In the following section, the average emission factors are given as total hydrocarbons on a kg/h/source basis to be consistent with published average emission factors (U.S. EPA, 1995). The main findings are as follows:

- Components in fuel gas service tend to leak more than components in process gas service. Additionally, components in sweet gas service leak more than those in sour service. This behavior is depicted in Figure 11. Each point on Figure 11 denotes the average emission factor for the corresponding type of component indicated on the horizontal axis. The integer shown adjacent to each emission factor value is the number of data used to develop the factor. The vertical line through each average emission factor denotes the 95-percent confidence limits based on the variance in the compiled data and number of data points assuming a normal distribution.

- The components with the greatest average emissions are crankcase vents on reciprocating compressors and compressor engines, compressor seals, and unit blowdown systems (see Figure 12). Although not normally identified as a source of fugitive emissions, crankcase vents on compressors are a potential source of fugitive emissions due to gas leakage from the rod packing case into the distance piece and past the rod wiper seals. The presence of process gas in the compressor crankcase indicates excessive backpressure on the distance piece vent, poor maintenance or performance of the rod wiper seals, or a combination thereof. Combustible gas in the crankcase of an engine indicates gas leakage past the piston rings in one or more of the engine cylinders. Manufacturers of natural gas-fueled compressor engines generally recommend that crankcase vents be vented outside the engine room[1]. In almost all cases observed the vents were discharged inside the building or shelter, although these areas were generally well ventilated. In one case the crankcase vent was connected to the air intake on the engine. A total of 36 crank case vents were tested for emissions: 21 on compressors, 4 on natural gas-fueled engines and 11 on integral compressor-engine units. As shown in Figure 13 average emissions were comparable in all three cases.

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1 According to one manufacturer, fumes will clog air filters and increase air inlet temperature, possibly causing engine damage. Problems in electrical equipment can be caused by exposure to the fumes. The fumes can also be a health hazard if discharged in a poorly ventilated room. Fumes must not be discharged into air ventilation ducts or exhaust pipes. They will become coated with oily deposits creating a fire hazard.

Figure 11. Average THC Emissions for Connectors by Gas Stream

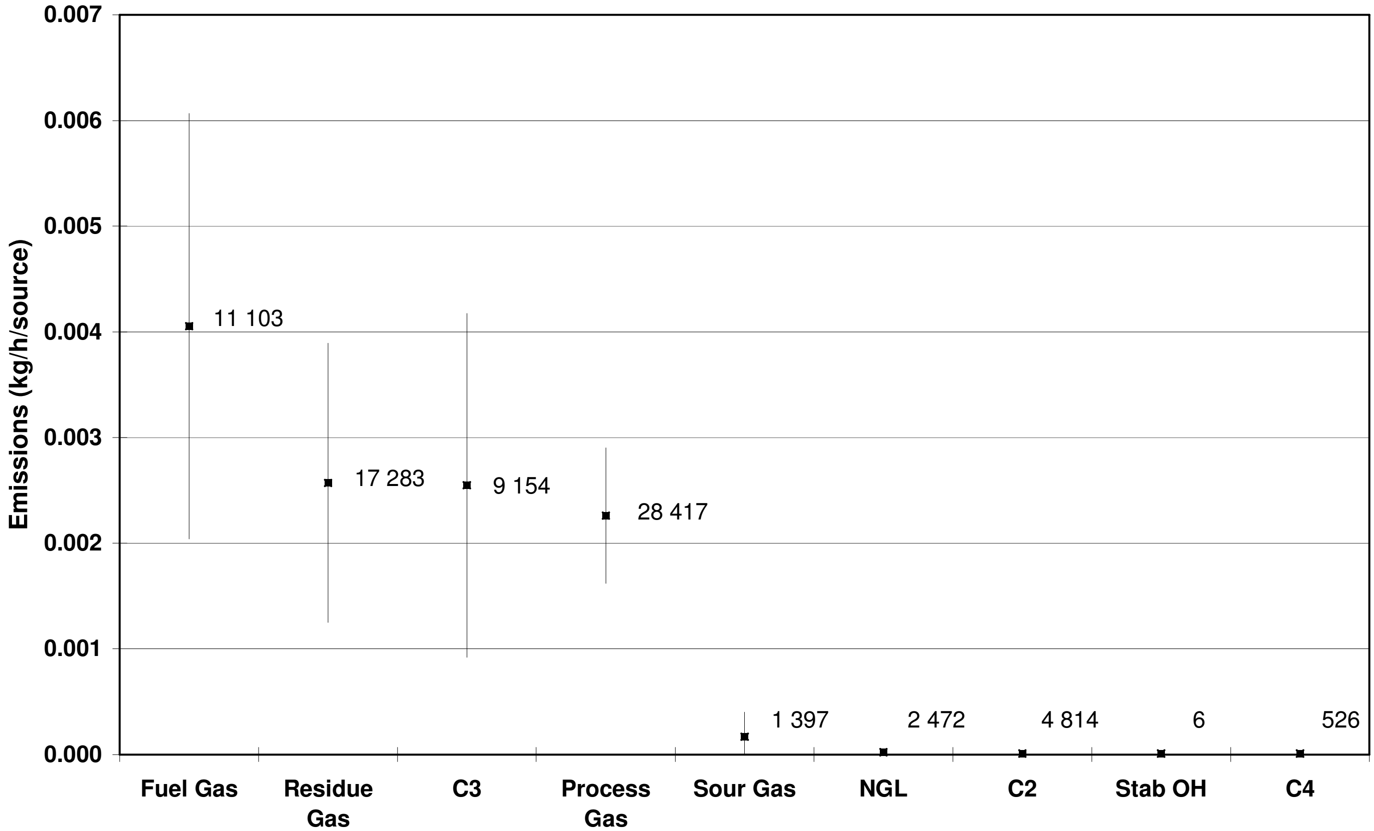


Figure 12. Average THC Emissions for Compressor Sources, Component Type

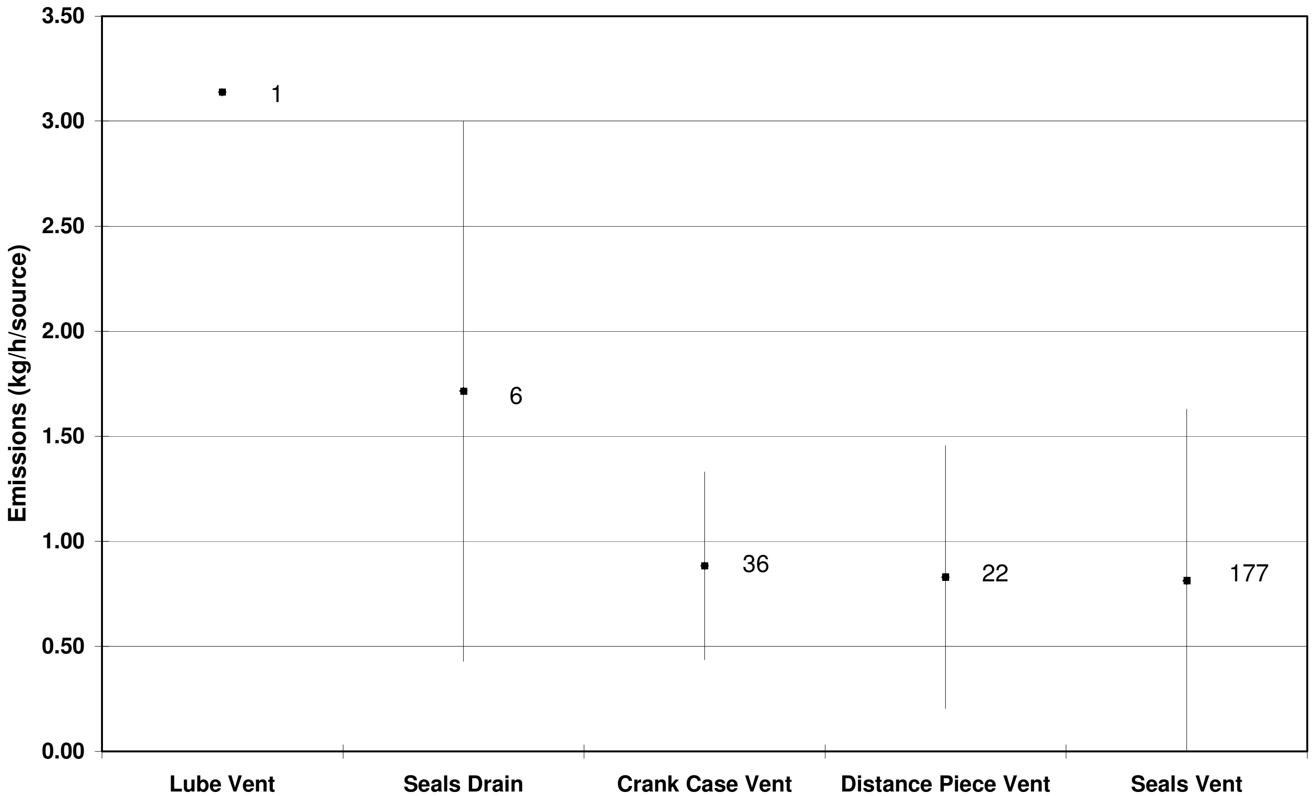
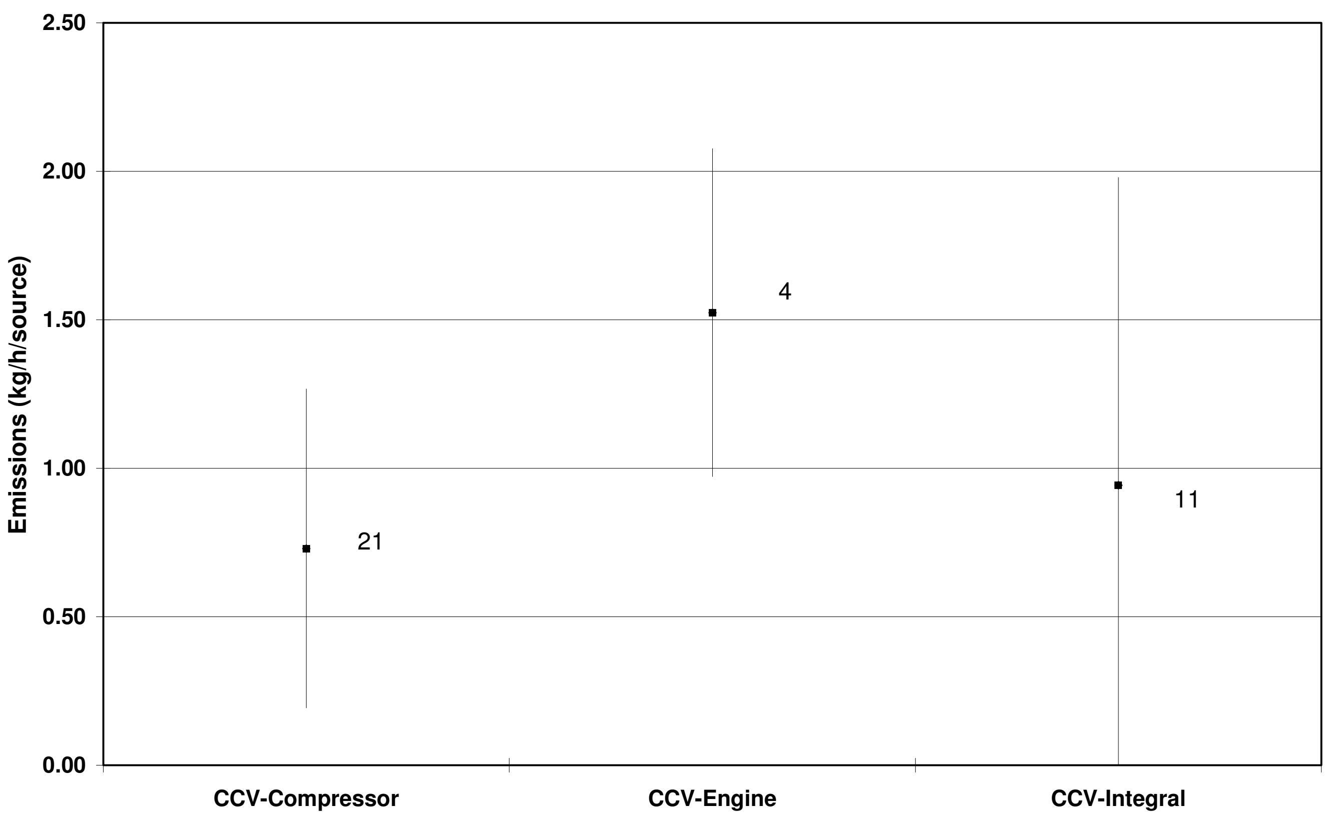


Figure 13. Average THC Emissions for Crank Case Vents by Type



On reciprocating compressors, emissions from the compressor seals are taken to be the sum of emissions from the packing case drains, the distance piece vents and the lube oil drain tank vent. Aggregate emissions from these sources are divided by the number of seals on the unit to determine the average leak rate per seal.

- The stem packing on control valves tends to leak more than on block valves. Hydra-mechanical governors[2] on compressor engines tended to be the most leak prone component in control valve service (see Figure 14).

- Components tend to have greater average emissions where subjected to frequent thermal cycling (tc), vibrations (v), or cryogenic service (c) (see Figures 15 and 16).

- All other parameters had little or no impact on average emissions.

4.3.3 Leak Frequencies

For service categories (e.g., VOC and VHAP) and industry sectors (e.g., gas processing plants, petroleum refineries and chemical plants) where leak monitoring is a regulatory requirement, the required frequency of leak monitoring is generally determined based on a facility's historical leak frequencies. While the specific requirements vary with the target industry sector and service category (e.g., see 40 CFR Part 60 and 63), fugitive equipment leaks are typically considered to be well controlled when the leak frequency for each component type (except connectors, compressor and pump seals) is 2 percent or less. For connectors, the value is 0.5 percent leakers or less, and for compressor and pump seals it is 10 percent leakers or less. Based on these guidelines, none of the categories for the combined plants would be considered adequately controlled (see Table 6). However, some categories at individual plants exceeded these guidelines (i.e., pressure relief valves and regulators at Site 1, regulators at Site 2, pump seals, orifice meters and other flow meters at Site 3 and other flow meters at Site 4). Compressor seals, crankcase vents, blowdown systems, pump seals, flow meters and valves are the most leak prone components.

2 The engine governor controls engine speed, and in some generator applications, generator load. Hydra-mechanical governors sense engine speed mechanically, and use the engine's oil pressure to hydraulically move the actuator controlling fuel flow to the cylinders.

Figure 14. Average THC Emissions for Control Valves by Component Type

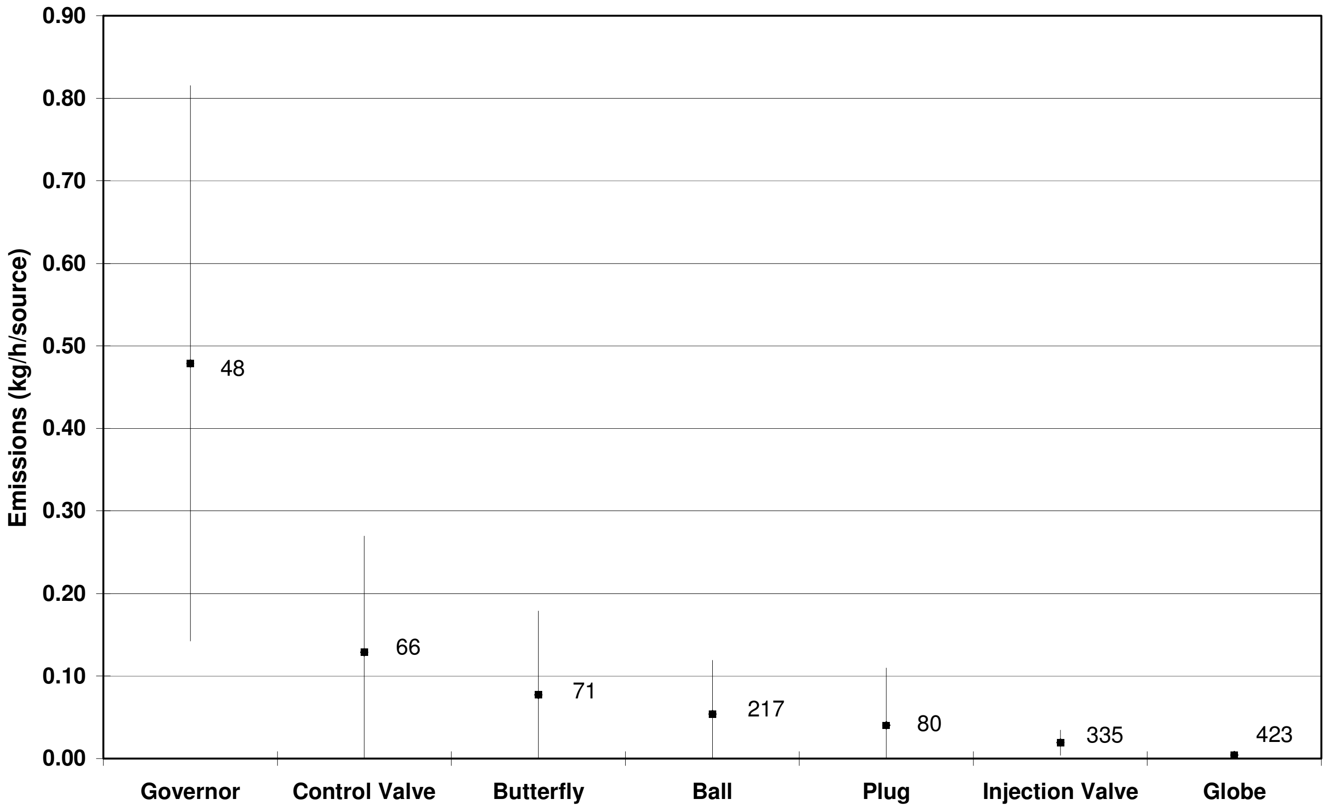


Figure 15. Average THC Emissions for Connectors by Process Unit

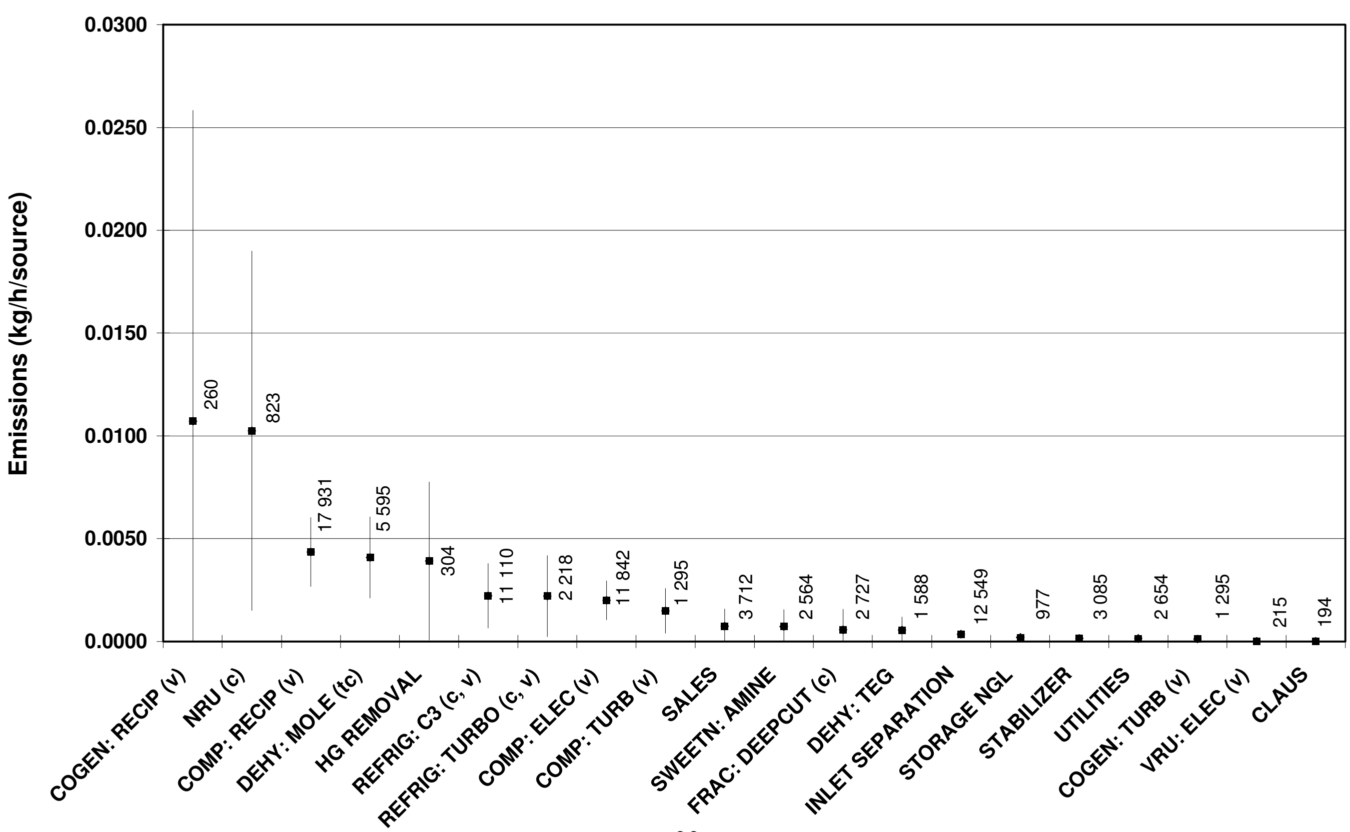


Figure 16. Average THC Emissions for Valves by Process Unit

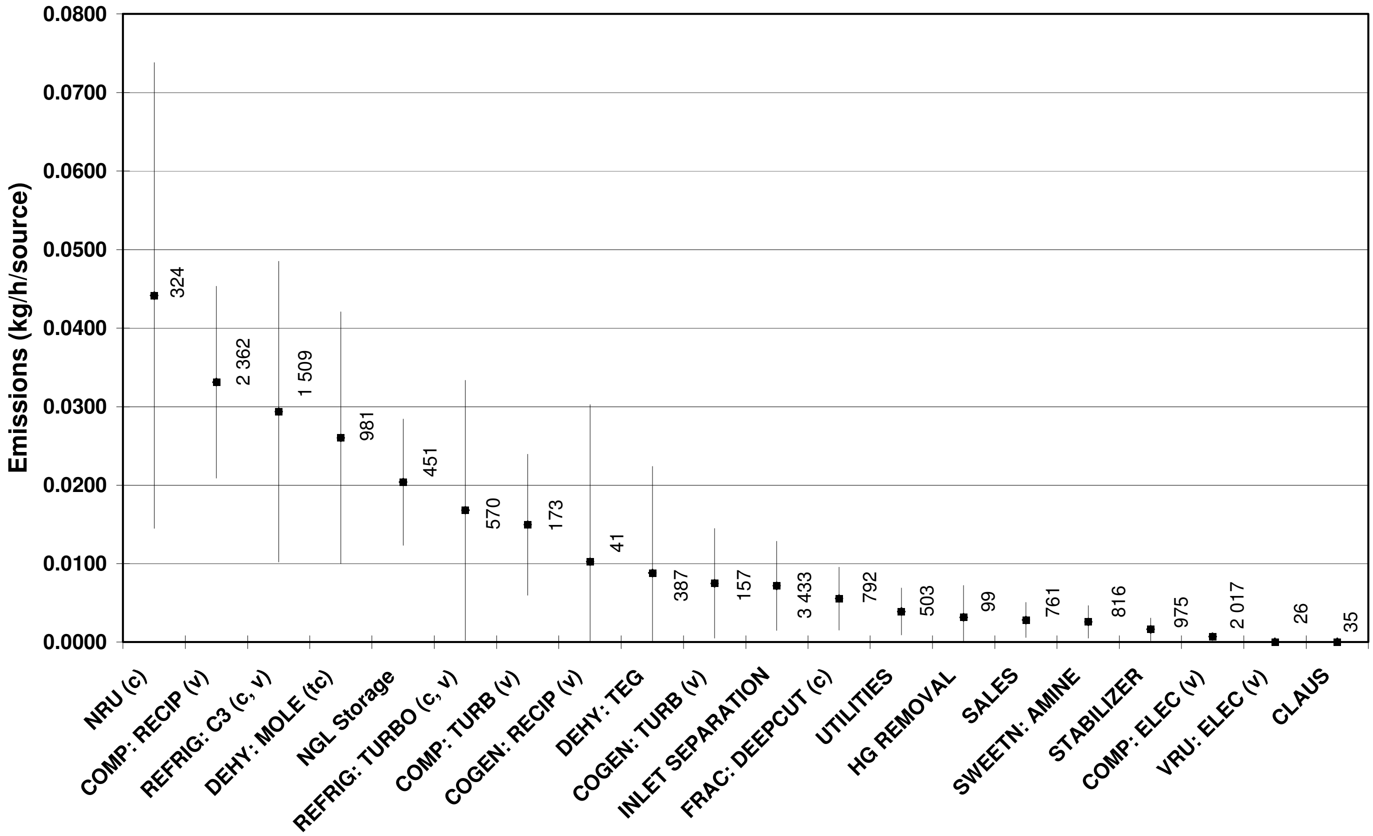


Table 6. Number of components and leak frequency at each of the four gas plants.

Component	Site 1			Site 2			Site 3			Site 4			Total		
	Total	Leakers	Leak Freq.	Total	Leakers	Leak Freq.	Total	Leakers	Leak Freq.	Total	Leakers	Leak Freq.	Total	Leakers	Leak Freq.
Connectors	12,936	222	1.71	12,191	219	1.80	46,134	397	0.86	10,885	187	1.72	82,146	1,025	1.25
Block Valves	2,427	237	9.77	1,567	134	8.55	8,771	453	5.16	2,371	249	10.50	15,136	1,073	7.09
Control Valves	170	35	20.59	241	47	19.50	632	32	5.06	197	27	13.71	1,240	141	11.37
Pressure Relief Valves	70	1	1.43	48	4	8.33	219	5	2.28	48	1	2.08	385	11	2.86
Regulators	29	0	0.00	11	0	0.00	108	4	3.70	21	2	9.52	169	6	3.5
Orifice Meters	11	1	9.09	34	3	8.82	80	0	0.00	42	7	16.67	167	11	6.59
Other Meters	5	1	20.00	0	---	---	1	0	0.00	1	0	0.00	7	1	14.29
Crankcase Vents	6	6	100	5	5	100	20	9	45.00	5	5	100	36	25	69.44
Open-ended Lines	366	40	10.93	301	19	6.31	384	26	6.77	559	73	13.06	1,610	158	9.81
Pump Seals	29	8	27.59	0	---	---	48	4	8.33	6	1	16.67	83	13	15.66
Compressor Seals	22	22	100	40	40	100	92	54	58.70	51	51	100.00	206	167	81.07

Blowdown Systems	0	---	---	0	---	---	6	2	33.33	0	---	---	6	2	33.33
Total	16,073	562	3.50	14,438	465	3.22	56,496	950	1.68	14,186	594	4.20	101,193	2,633	2.60

4.3.4 Component Counts

Prior to the start of the fieldwork, each host facility provided estimated counts of the total number of components in natural gas service at their site. During the fieldwork actual component counts were developed for these facilities. It is noteworthy that the plant estimates were generally much lower than the field counts as shown in Figure 17. On average the component counts were estimated at approximately 60 percent of the actual counts. One explanation is that the component counts supplied by facilities were intended to reflect total numbers of components in hydrocarbon gas and liquid service but likely would have excluded components less than 0.5” nominal pipe size (per Method 21). Overall, 13.8 percent of these component counts are components less than 0.5” nominal pipe size. The component counts are not complete for Sites 1, 2, and 4 since not all components in hydrocarbon liquid service were counted at these locations. This would tend to make the discrepancy even greater. It is likely that the facilities developed their counts largely from process drawings and did not have sufficient detail to capture all components.

A summary of the average component schedules by type of process unit is presented in Appendix IV.

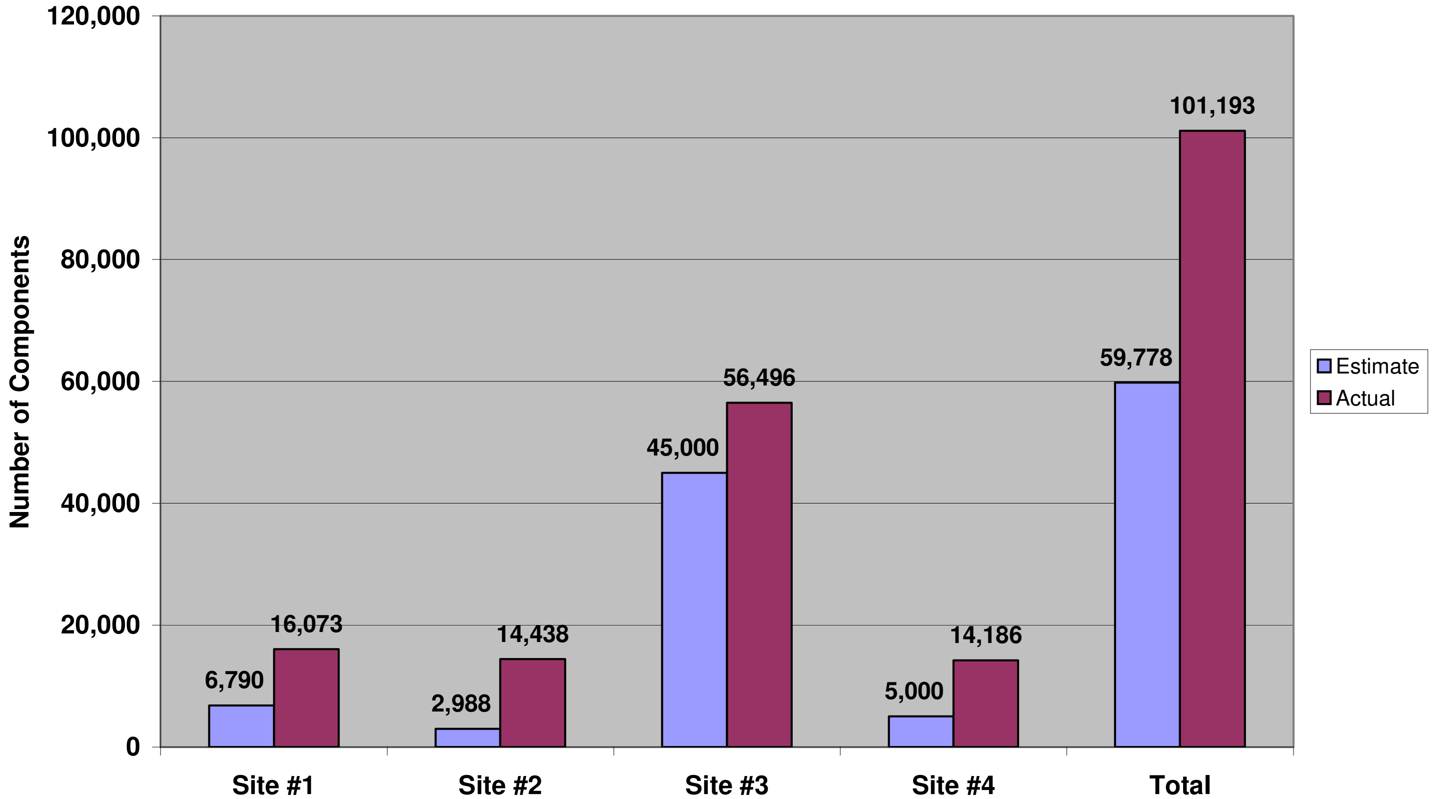
4.4 Control Opportunities

Practicable opportunities for reducing the identified natural gas losses were identified and assessed on a source-by-source basis. Overall, it is estimated that up to 94.9 percent of total natural gas losses could be avoided if all control opportunities with zero net cost or a positive payback are implemented (see Figure 18). This would result in corresponding reductions of 78.1 percent in methane emissions, 16.3 percent in GHG emissions, and 88.5 percent in NMHC emissions in the first year alone. Moreover, many of the control options have multi-year life expectancies resulting in significant emission reductions in subsequent years as well.

4.4.1 Cost Curve for Reduction of GHG Emissions

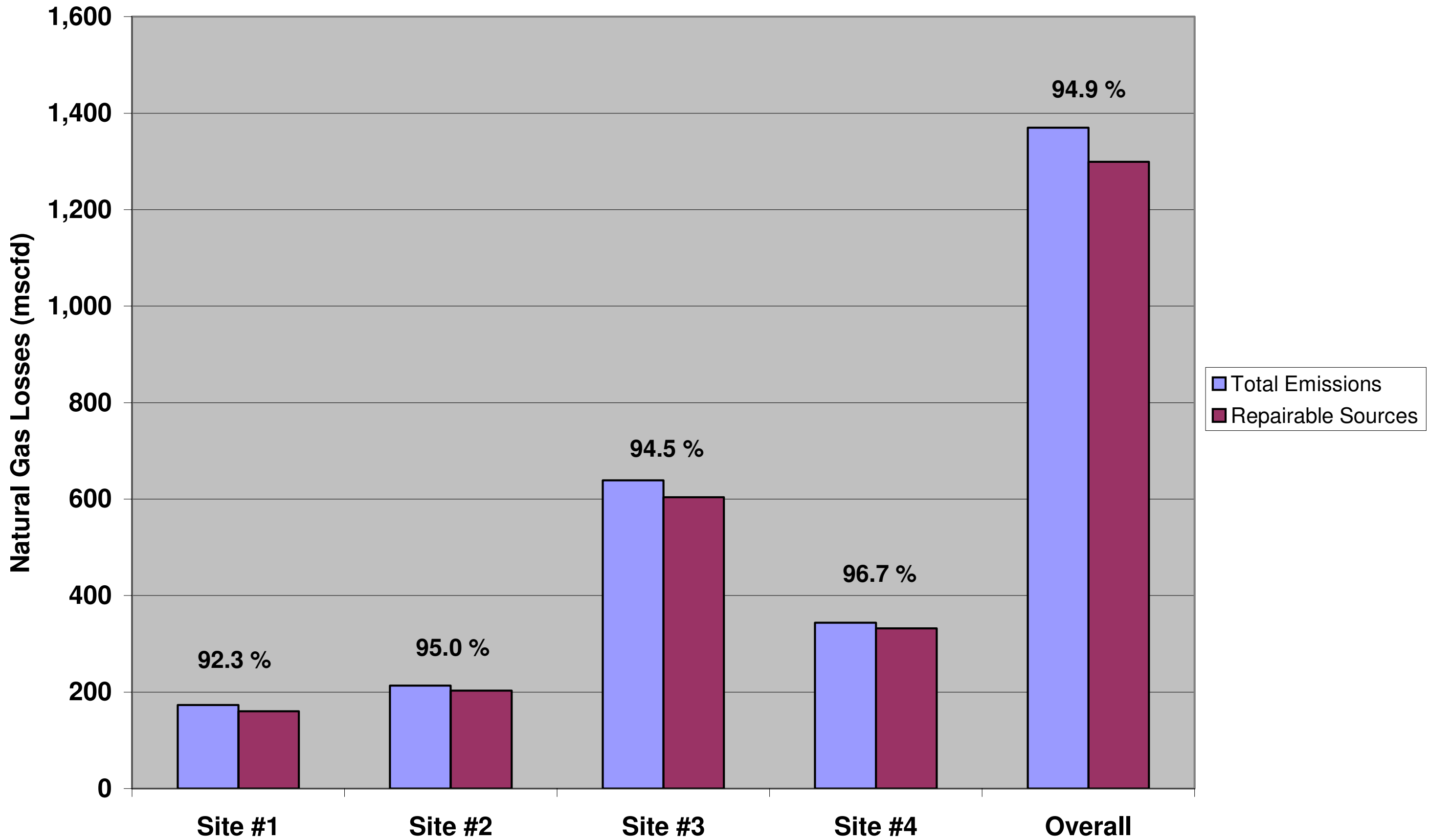
To further evaluate the control of natural gas losses as a means of reducing GHG emissions, it is useful to express the results in terms of a cost curve. Figure 19 presents the net annualized cost curve for implementation of the various opportunities identified at the four gas plants based on a value of $4.50 per mscf for the conserved natural gas. The net cost of each target control opportunity is calculated as the equalized annual implementation cost over the life of the project (i.e., the net present cost of the opportunity expressed as an equivalent series of equal annual payments over the life of the project) divided by the resulting average annual CO_2-equivalent emission reduction.

Figure 17. Comparison of Company Estimates to Actual Number of Components[1]



[1] Components of less than 0.5 inch nominal pipe size constitute 13.8 percent of the actual component counts. Company estimates may have excluded components less than 0.5 inch nominal pipe size (per Method 21).

Figure 18. Emissions from Economically Repairable Sources[1]



[1] Based on the long term contract price for natural gas during the fourth quarter of 2000 of $4.50 per mscf.

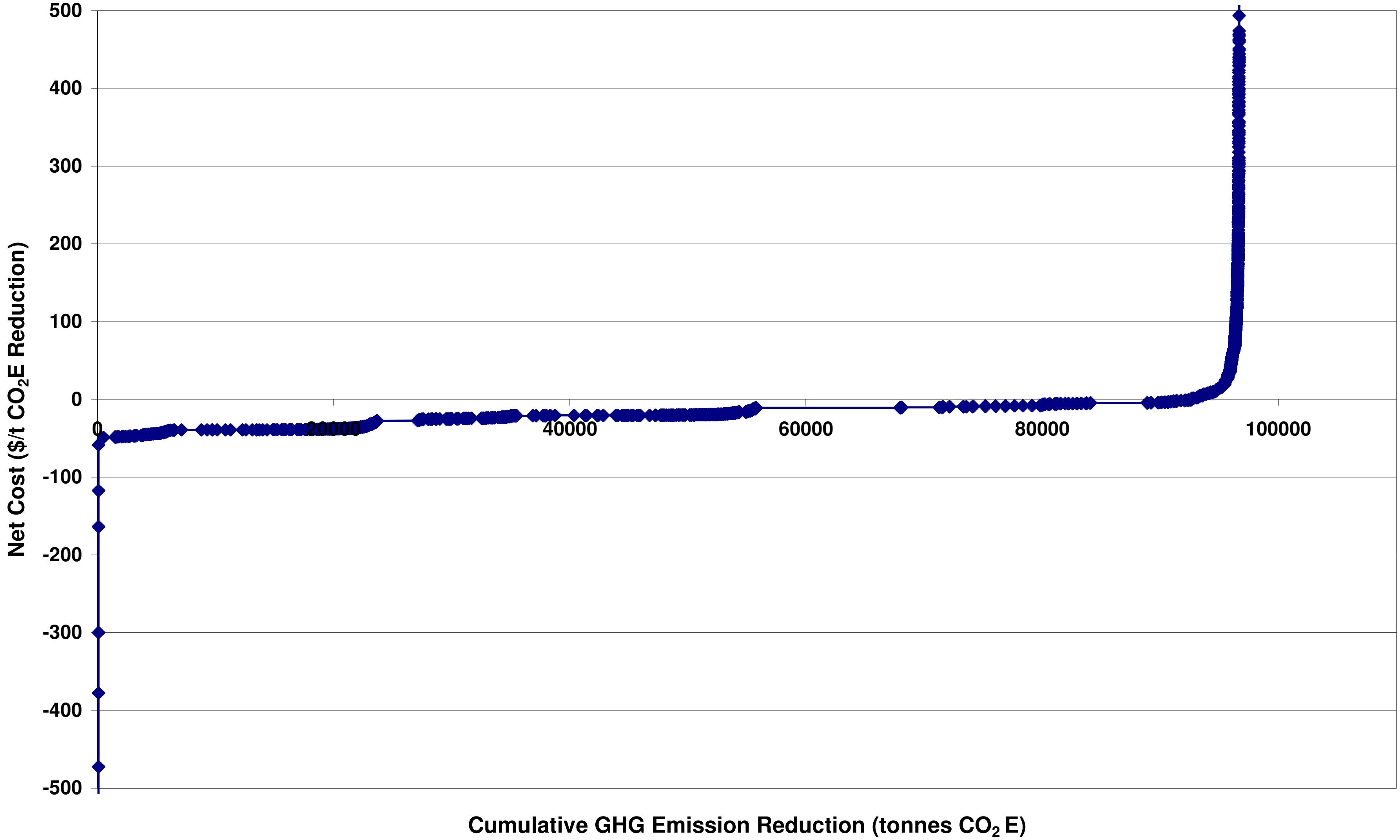


Figure 19. Net cost curve for cumulative CO_2 E emission reductions at surveyed gas plants.

Note. The cost of finding and evaluating these emission reduction opportunities is excluded.

Figure 19 shows that the incremental cost per tonne of CO_2E GHG emission reduction resulting from implementation of the available control opportunities in ranked order from most to least cost effective (i.e., see Table II-1 in Appendix II). The point at which the curve crosses over the abscissa axis (i.e., the axis of cumulative CO_2E GHG emission reduction) is the amount of CO_2E emission reduction that could be achieved if only opportunities with a zero cost or a positive payback are implemented (i.e., 92,622.4 tonnes CO_2E reduction per year). This reduction amounts to 16.6 percent of total estimated GHG emissions from the four gas plants.

If a value is assigned to GHG emission reduction credits, then companies may choose to pursue opportunities even further out on the cost curve. The shape of the cost curve shows that there are a few very attractive control opportunities, a large number of moderate control opportunities, and eventually a point of diminishing returns.

4.4.2 Control Opportunities With a Payback of 1 Year or Less

On a purely financial basis, opportunities to reduce natural gas losses must compete against other investment opportunities to receive funding. A common parameter used to evaluate opportunities is either the effective rate of return on the investment or the payback period. To justify equipment upgrades or process enhancements, companies often look for a payback period of 1 year or less. Accordingly, it is useful to consider only opportunities to reduce natural gas losses that have a payback period of 1 year or less.

If only these control opportunities are implemented, it is estimated that total natural gas losses, including unnecessary fuel consumption, would be reduced by 92.3 percent. Corresponding reductions in methane and GHG emissions would amount to 78.1 and 16.3 percent, respectively. Additionally, significant reductions in NMHC emissions would be achieved.

The 10 greatest individual control opportunities in the 1-year payback category are listed in Table 7. Collectively, they account for 49.6 percent of total natural gas losses in this category and 45.8 percent of total natural gas losses irrespective of payback period. The single largest source in the 1-year payback category and overall is leakage into the high-pressure flare system at Site 3.

Losses into flare systems may be minimized by either implementing a flare gas recovery system, or targeting the individual sources of the residual gas flow. The latter approach can be difficult to implement since causes are often difficult to isolate, usually require a major plant shutdown to fix (i.e., resulting in significant indirect costs), and are likely to reoccur. Likely candidates are excess purge gas, leaking pressure-relief devices, drains and blowdown valves and compressor start-gas vents that are connected to the flare header.

Table 7. Summary of top ten sources of natural gas losses identified.				
Tag	**Location**	**Source Type / Description**	**Loss Rate (mscfd)**	**Value of Lost Gas ($/y)**
	High-Pressure Flare System, Site 3	Residual Flaring	175.397	288,150
Direct	Oil-Water Separator Tank, Site 3	Flashing Losses / Venting through Thief Hatch	160.983	264,471
	Flare System, Site 4	Residual Flaring	121.144	199,021
Direct	Compressor Unit 3, Site 2	Compressor seals vent	86.110	141,486
Direct	Residue Gas Comp 4, Site 3	Compressor Seals (4)	22.526	37,007
	Re-Compressor Unit 5, Site 3	Unburned Fuel and Excess Fuel Consumption	12.743	20,930
	Re-Compressor Unit 3, Site 3	Unburned Fuel and Excess Fuel Consumption	11.682	19,187
3824	Re-compressor Yard Piping, Site 4	Plug Valve – leakage through valve body at bottom	11.544	18,694
3910C	Re-compressor Unit 3, Site 4	Union – Fuel Gas Line 6	11.100	18,236
	East Heat Medium Heater, Site 3	Unburned Fuel and Excess Fuel Consumption	10.652	17,496
Total			623.881	1,024,678

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The sources with the greatest natural gas losses were not necessarily the most economical to control. Based on the compiled test results, the greatest opportunities for cost-effective reduction of natural gas losses are from the control of leaking equipment components and leakage of process gas into vent and flare systems. However, actual opportunities may vary greatly between sites and not all gas plants will necessarily offer sufficient opportunities to justify the associated identification and control costs. In addition, actual economic opportunities are dependent on the value of natural gas, and will therefore vary with fluctuations in the market price of natural gas. Nonetheless, it is clear from the available data that significant opportunities do exist at some facilities and a rational approach to finding these opportunities may be economically attractive to industry.

While any economical-to-repair leaking components detected by such efforts should be repaired, average leak rates based on combined data from the four test sites suggest that the most cost-effective approach would be to generally focus on the following types of components:

- block and control valves,
- pressure relief valves,
- regulators,
- flange connections,
- crankcase vents,
- compressor seals, and
- compressor valve stems and valve caps.

Normally, flange connections would not be expected to be a key contributor at gas facilities. Their relative importance here is attributed to the use of mole sieve dehydrators at each of the sites, and the corresponding high leak potential in these applications (i.e., due to the thermal cycling of the mole sieve beds).

5.2 Recommendations

Specific recommendations for further work are as follows:

- Additional facility surveys should be conducted to determine the impact of facility age on the extent of cost-effective opportunities for reducing natural gas losses at gas processing plants. Additionally, the extent of opportunities at upstream facilities should be investigated (e.g., at gas-gathering compressor stations, gas batteries and well-site dehydration and metering facilities).

- The amount and composition of emissions from engine and compressor crankcase vents, and field practices for the design of these vent systems, should be examined more closely. In particular, the potential for air-toxic emissions from crankcase vents, especially those on engines, should be determined. Moreover, the practice of some companies to allow crankcase vents to exhaust into buildings and work areas, a practice manufacturers discourage, should be evaluated.

- There are a wide variety of available technologies as well as design and operating practices that would benefit companies in cost effectively reducing natural gas losses, however, these technologies and practices are under-utilized. One such example is the application of flow sensors, which can be installed on compressor seal vents at a relatively low cost. Flow sensors allow easy on-going detection of excessive leakage, and may also be applicable to crankcase and other vents. Only one of the four sites had installed seal vent flow sensors, and operators did not take advantage of the readings from these sensors. Additionally, emergency flare systems normally are not equipped with flow meters, so in-leakage and excessive purge gas consumption often goes unnoticed until losses produce a noticeably enlarged flame size. Historically, meters were not installed because conventional obstruction meters do not provide reliable readings over the wide flow ranges required and cause excessive backpressure in the system. Today, non-intrusive ultrasonic flow meters are available which overcome these problems. Moreover, ultrasonic techniques are available for identifying and quantifying leakage past valve seats into flare and vent systems.

  It is recommended that a best practices document be developed to better disseminate and encourage the compilation and use of this type of information. The document could also provide information needed by companies to develop site-specific programs for reducing their methane and non-methane hydrocarbon losses and greenhouse gas emissions (e.g., delineation of source categories or facility areas to focus efforts on for maximum benefit, generic cost data for evaluating control options, recommended frequency of monitoring efforts, and the typical life expectance of repairs by source type and service category).

6.0 REFERENCES CITED

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Appendix I

Site specific field measurement data for this appendix have been removed to protect business confidentiality. Please direct any questions to Roger Fernandez, EPA at fernandez.roger@epa.gov or (202) 343-9386.

Appendix II

Site specific field measurement data for this appendix have been removed to protect business confidentiality. Please direct any questions to Roger Fernandez, EPA at fernandez.roger@epa.gov or (202) 343-9386.

Appendix III

Combustion Analysis and Efficiency Testing Results

The compiled combustion data were input into a database to facilitate the calculation of the required parameters. Measured fuel and exhaust gas compositions were used to determine the air-to-fuel and exhaust-to-fuel ratios. Species mole balances and the following simple combustion relation were used:

$$Fuel + a \cdot Air \rightarrow b \cdot Flue + d \cdot H_2O$$

A carbon mole balance was used to determine *b*, a nitrogen balance to determine *a* and a hydrogen balance to determine *d*. These coefficients were then used to determine the flow rates of the unknown streams from the known flow.

Combustion efficiency is defined as the total enthalpy contained in the reactants minus the total enthalpy contained in the products divided by the energy content of the fuel. This may be written as follows:

$$\frac{\left(\dot{m}_{FUEL} \cdot h^f_{FUEL} + \dot{m}_{AIR} \cdot h^f_{AIR} - \dot{m}_{FLUE} \cdot h^f_{FLUE}\right)}{\dot{m}_{FUEL} \cdot LHV}$$

$\dot{m}$ is the molar flow rate of the stream (i.e., fuel, air, or flue gas) (kmole/h),

h^f is the heat of formation of the stream (MJ/kmole), and

LHV is the lower heating value of the fuel gas stream (MJ/kmole)

For ideal operation, combustion efficiencies calculated with this equation are expected to be in the range of 95 to 98 percent.

While combustion efficiency is useful in demonstrating how much of the energy in the fuel is converted to heat, it does not provide a complete description of how effectively the equipment is utilizing this energy. An energy balance on a typical reciprocating engine yields the following (based on manufacturers' heat load data):

- Energy from Fuel 100 %
- Useful Work 30 to 35 %
- Jacket Water and Oil Cooler 15 to 40 %
- Radiation 3.5 to 7.5 %
- Turbocharger After Cooler 1 to 6 %
- Exhaust 20 to 35 %

The heat loads for jacket water, oil cooler, turbocharger after cooler and radiation are typically determined by design or safe operating conditions. Heat lost to exhaust is a function of combustion efficiency and the quantity of combustion air that is required for efficient operation. Useful work is whatever is left over after all losses have been accounted. Since heat losses to jacket water, oil cooler, turbocharger after cooler and radiation are typically fixed by design, the amount of heat lost up the stack is a good indication of whether or not the unit is being operated in an efficient manner.

The situation is similar, although less complicated, for heaters/boilers and gas turbine engines. For heaters and boilers:

- Energy from Fuel 100 %
- Useful Work 70 to 85 %
- Radiation 2 to 5 %
- Exhaust 15 to 25 %

And for gas turbines:

- Energy from Fuel 100 %
- Useful Work 30 to 40 %
- Radiation 2 to 5 %
- Exhaust 60 to 70 %

Stack heat losses have been calculated using a simplified heat balance. The equation used is:

$$Fraction\ of\ \ Heat\ Lost = \frac{Stack\ \ Losses}{Heat\ \ Input}$$

where

Heat Input = Energy Content of Fuel + Sensible Heat in Fuel
+ Sensible Heat in Combustion Air

Stack Losses = Energy Content of the Exhaust Gas
+ Convective Stack Losses
+ Sensible Heat in the Exhaust Gas

The costs associated with the improper operation of combustion units are made up of two components: the value of any unburned fuel in the exhaust gas and the incremental fuel associated with operating at excessive air-to-fuel ratios. The former is determined by calculating the heating value of the unburned or partially burned components of the exhaust gas and assigning a value per GJ of energy equal to that of natural gas.

The cost associated with too much excess air is determined by comparing the measured air-to-fuel ratio with typical manufacturers' values. The loss is then calculated by determining the amount of heat required to heat the excess air from ambient temperature to the exhaust stack temperature.

The optimum air-to-fuel ratio varies significantly for reciprocating engines according to make and model of unit. Accordingly, specific manufacturers' values were used wherever possible. In the absence of manufactures' data, average values for the types of units tested were used. For heaters and boilers, 15 percent excess air was assumed to be sufficient for proper operation.

Gas Processing Plant 1

Equipment Information

Unit Identifier: Refrigerant Compressor 10
Engine Make and Model: Clark – HRA 8
Compressor Cylinders: 4 Stages: 2
Driver Cylinders: 8 Rated Power:

NOTE: Refrigeration Compressor Unit 10 is operated but a few days per year for peak shaving during the summer months, therefore, the cost of improper operation is expressed in $ per day rather than $ per year to reflect the limited number days per year the unit is in operation.

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	50 000
Oxygen (O_2)	123 000
Carbon Monoxide (CO)	967
Nitrous Oxide (NO)	1 415
Nitrogen Dioxide (NO_2)	609
Oxides of Nitrogen (NO_x)	2 024
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	259
Air Flow (m^3/h)	5 167
Exhaust Flow (m^3/h)	5 381
Combustion Efficiency[1] (%)	97.3
Stack Heat Losses[2] (%)	45.65
Unburned Fuel (%)	1.24

1 Air-to-fuel ratio of 10.5.
2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 827	48 806
Carbon Monoxide (CO)	20.1	738
Oxides of Nitrogen (NO_x)	0.251	6.80
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $163
Value of Unburned Fuel: $6
Total Cost of Improper Operation: $169
Volume of Unnecessary Fuel Consumption: N/A

Gas Processing Plant 1

Equipment Information

Unit Identifier:	Refrigerant Compressor 11		
Engine Make and Model:	Ingersol Rand – KVG		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders: 10		Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	114 000
Oxygen (O_2)	11 000
Carbon Monoxide (CO)	2663
Nitrous Oxide (NO)	961
Nitrogen Dioxide (NO_2)	31
Oxides of Nitrogen (NO_x)	991
Hydrocarbons (THC)	9 400

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	259
Air Flow (m^3/h)	2 513
Exhaust Flow (m^3/h)	2 753
Combustion Efficiency[1] (%)	96.7
Stack Heat Losses[2] (%)	26.01
Unburned Fuel (%)	2.25

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 799	48 637
Carbon Monoxide (CO)	24.35	658.1
Oxides of Nitrogen (NO_x)	9.88	267.0
Hydrocarbons (THC)	5.55	150.0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $4 877

Total Cost of Improper Operation: $4 877
Volume of Unnecessary Fuel Consumption: 5.037 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier: Refrigerant Compressor 12
Engine Make and Model: Waukesha
Compressor Cylinders: 4 Stages: 2
Driver Cylinders: 12 Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	2 428
Nitrous Oxide (NO)	1 124
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	0
Hydrocarbons (THC)	1 124

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	259
Air Flow (m^3/h)	2 370
Exhaust Flow (m^3/h)	2 611
Combustion Efficiency[1] (%)	95.2
Stack Heat Losses[2] (%)	19.86
Unburned Fuel (%)	3.56

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	$kg/10^3\ m^3$ of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 775	47 975
Carbon Monoxide (CO)	20.8	561
Oxides of Nitrogen (NO_x)	10.30	278
Hydrocarbons (THC)	16.43	444

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $9 420

Total Cost of Improper Operation: $9 420
Volume of Unnecessary Fuel Consumption: 7.951 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier:	Solar Turbine CM-503
Engine Make and Model:	Solar Turbine
Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	24 000
Oxygen (O_2)	168 000
Carbon Monoxide (CO)	51
Nitrous Oxide (NO)	71
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	71
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	1 053
Air Flow (m^3/h)	40 463
Exhaust Flow (m^3/h)	40 848
Combustion Efficiency[1] (%)	98.2
Stack Heat Losses[2] (%)	52.69
Unburned Fuel (%)	0.13

1 Air-to-fuel ratio of 40.

2 In the absence of heat recovery, turbine stack heat losses should be in the range of 60 to 70 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 867	50 464
Carbon Monoxide (CO)	2.17	58.5
Oxides of Nitrogen (NO_x)	3.23	87.3
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $860
Total Cost of Improper Operation: $860

Volume of Unnecessary Fuel Consumption: 1.193 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier:	Solar Turbine CM-504
Engine Make and Model:	Solar Turbine
Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	23 000
Oxygen (O_2)	170 000
Carbon Monoxide (CO)	21
Nitrous Oxide (NO)	50
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	50
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	1 053
Air Flow (m^3/h)	41 997
Exhaust Flow (m^3/h)	42 664
Combustion Efficiency[1] (%)	98.2
Stack Heat Losses[2] (%)	52.17
Unburned Fuel (%)	0.06

1 Air-to-fuel ratio of 40.

2 In the absence of heat recovery, turbine stack heat losses should be in the range of 60 to 70 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 870	50 545
Carbon Monoxide (CO)	0.934	25.3
Oxides of Nitrogen (NO_x)	2.38	64.4
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0

Value of Unburned Fuel: $371

Total Cost of Improper Operation: $371

Volume of Unnecessary Fuel Consumption: 0.515 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier: High Pressure Inlet Compressor CM-19

Engine Make and Model:

Compressor Cylinders: Stages:

Driver Cylinders: Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	12
Nitrous Oxide (NO)	1499
Nitrogen Dioxide (NO_2)	8
Oxides of Nitrogen (NO_x)	1507
Hydrocarbons (THC)	900

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	267
Air Flow (m^3/h)	2 501
Exhaust Flow (m^3/h)	2 7471
Combustion Efficiency[1] (%)	97.5
Stack Heat Losses[2] (%)	24.32
Unburned Fuel (%)	0.60

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 841	49 760
Carbon Monoxide (CO)	104.6	2.83
Oxides of Nitrogen (NO_x)	14.1	381
Hydrocarbons (THC)	4.23	114

Cost of Unnecessary Excess Air: $0

Value of Unburned Fuel: $1 972

Total Cost of Improper Operation: $1 972
Volume of Unnecessary Fuel Consumption: 1.378 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier: Low Pressure Inlet Compressor CM-13
Engine Make and Model: White Superior 825GTL
Compressor Cylinders: Stages:
Driver Cylinders: Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	73 000
Oxygen (O_2)	83 000
Carbon Monoxide (CO)	207
Nitrous Oxide (NO)	1 246
Nitrogen Dioxide (NO_2)	272
Oxides of Nitrogen (NO_x)	1 518
Hydrocarbons (THC)	3 200

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	267
Air Flow (m^3/h)	3 704
Exhaust Flow (m^3/h)	3 939
Combustion Efficiency[1] (%)	95.0
Stack Heat Losses[2] (%)	29.16
Unburned Fuel (%)	3.01

1 Air-to-fuel ratio of 28.
2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 795	48 527
Carbon Monoxide (CO)	2.92	78.8
Oxides of Nitrogen (NO_x)	25.1	678
Hydrocarbons (THC)	20.2	547

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $9 679

Total Cost of Improper Operation: $9 679
Volume of Unnecessary Fuel Consumption: 6.929 mscfd

Gas Processing Plant 1

Equipment Information

Unit Identifier: Low Pressure Inlet Compressor CM-14
Engine Make and Model: White Superior 825GTL
Compressor Cylinders: Stages:
Driver Cylinders: Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	67 000
Oxygen (O_2)	94 000
Carbon Monoxide (CO)	189
Nitrous Oxide (NO)	357
Nitrogen Dioxide (NO_2)	30
Oxides of Nitrogen (NO_x)	387
Hydrocarbons (THC)	3 300

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	267
Air Flow (m^3/h)	3 969
Exhaust Flow (m^3/h)	4 201
Combustion Efficiency[1] (%)	94.7
Stack Heat Losses[2] (%)	31.88
Unburned Fuel (%)	3.43

1 Air-to-fuel ratio of 28.
2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 788	48 319
Carbon Monoxide (CO)	2.89	78.0
Oxides of Nitrogen (NO_x)	6.59	178
Hydrocarbons (THC)	23.29	629

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $11 085

Total Cost of Improper Operation: $11 085
Volume of Unnecessary Fuel Consumption: 7.904 mscfd

Gas Processing Plant 1

Equipment Information
Unit Identifier: TEG Reboiler
Boiler Make and Model:
Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	72 000
Oxygen (O_2)	34 000
Carbon Monoxide (CO)	9
Nitrous Oxide (NO)	60
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	60
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	15.3
Air Flow (m^3/h)	165.1
Exhaust Flow (m^3/h)	178.9
Combustion Efficiency[1] (%)	98.3
Stack Heat Losses (%)	33.50
Unburned Fuel (%)	0.01
Thermal Efficiency (%)	66.5

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 853	50 098
Carbon Monoxide (CO)	93.6	2.53
Oxides of Nitrogen (NO_x)	0.669	18.1
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $519
Value of Unburned Fuel: $1
Total Cost of Improper Operation: $520
Volume of Unnecessary Fuel Consumption: 0.317 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	IR Compressor – Unit #1 G-41066/352587		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	4	Stages:	3
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	3 137
Nitrous Oxide (NO)	27
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	27
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	229
Air Flow (m^3/h)	2 124
Exhaust Flow (m^3/h)	2 339
Combustion Efficiency[1] (%)	97.5
Stack Heat Losses[2] (%)	23.05
Unburned Fuel (%)	1.66

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 801	48 806
Carbon Monoxide (CO)	27.2	738
Oxides of Nitrogen (NO_x)	0.251	6.80
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $2 346
Total Cost of Improper Operation: $2 346

Volume of Unnecessary Fuel Consumption: 3.155 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	IR Compressor – Unit #2 G-42003/352241		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	4	Stages:	3
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	164
Nitrous Oxide (NO)	96
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	96
Hydrocarbons (THC)	1 288

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	183
Air Flow (m^3/h)	1 690
Exhaust Flow (m^3/h)	1 860
Combustion Efficiency[1] (%)	97.3
Stack Heat Losses[2] (%)	20.61
Unburned Fuel (%)	0.95

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 824	49 439
Carbon Monoxide (CO)	1.42	38.4
Oxides of Nitrogen (NO_x)	0.888	24.1
Hydrocarbons (THC)	6.26	170

Cost of Unnecessary Excess Air: $0

Value of Unburned Fuel: $2 053

Total Cost of Improper Operation: $2 053
Volume of Unnecessary Fuel Consumption: 1.459 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	IR Compressor – Unit #3 G-48897/365094		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	3 793
Nitrous Oxide (NO)	69
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	69
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	226
Air Flow (m^3/h)	2 101
Exhaust Flow (m^3/h)	2 315
Combustion Efficiency[1] (%)	97.3
Stack Heat Losses[2] (%)	21.48
Unburned Fuel (%)	2.00

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 792	48 546
Carbon Monoxide (CO)	32.9	892
Oxides of Nitrogen (NO_x)	0.641	17.4
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $2 808

Total Cost of Improper Operation: $2 808
Volume of Unnecessary Fuel Consumption: 3.764 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Re-Compressor – Unit #1 G-42002/362292		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	3	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	120 000
Oxygen (O_2)	0
Carbon Monoxide (CO)	85
Nitrous Oxide (NO)	61
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	61
Hydrocarbons (THC)	1 134

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	142
Air Flow (m^3/h)	1 314
Exhaust Flow (m^3/h)	1 446
Combustion Efficiency[1] (%)	97.5
Stack Heat Losses[2] (%)	19.64
Unburned Fuel (%)	0.81

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	$kg/10^3\ m^3$ of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 827	49 523
Carbon Monoxide (CO)	0.734	19.9
Oxides of Nitrogen (NO_x)	0.565	15.3
Hydrocarbons (THC)	5.52	150

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $1 379

Total Cost of Improper Operation: $1 379
Volume of Unnecessary Fuel Consumption: 0.963 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Re-Compressor – Unit #2 210598		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	3	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	57 000
Oxygen (O_2)	111 000
Carbon Monoxide (CO)	556
Nitrous Oxide (NO)	36
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	36
Hydrocarbons (THC)	1 563

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	141
Air Flow (m^3/h)	2 412
Exhaust Flow (m^3/h)	2 534
Combustion Efficiency[1] (%)	95.7
Stack Heat Losses[2] (%)	22.95
Unburned Fuel (%)	2.79

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	$kg/10^3\ m^3$ of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 789	48 497
Carbon Monoxide (CO)	9.96	270
Oxides of Nitrogen (NO_x)	0.691	18.7
Hydrocarbons (THC)	15.8	427

Cost of Unnecessary Excess Air: $11 615
Value of Unburned Fuel: $4 334

Total Cost of Improper Operation: $15 949
Volume of Unnecessary Fuel Consumption: 10.304 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Re-Compressor – Unit #3		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	3	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	59 000
Oxygen (O_2)	107 000
Carbon Monoxide (CO)	608
Nitrous Oxide (NO)	32
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	32
Hydrocarbons (THC)	1 400

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	171
Air Flow (m^3/h)	2 834
Exhaust Flow (m^3/h)	2 991
Combustion Efficiency[1] (%)	96.0
Stack Heat Losses[2] (%)	22.55
Unburned Fuel (%)	2.52

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 794	48 624
Carbon Monoxide (CO)	10.5	285
Oxides of Nitrogen (NO_x)	0.592	16.1
Hydrocarbons (THC)	13.6	369

Cost of Unnecessary Excess Air: $13 317
Value of Unburned Fuel: $4 678

Total Cost of Improper Operation: $17 995
Volume of Unnecessary Fuel Consumption: 11.681 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Re-Compressor – Unit #4 400400		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	2	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	59 000
Oxygen (O_2)	106 000
Carbon Monoxide (CO)	572
Nitrous Oxide (NO)	12
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	12
Hydrocarbons (THC)	1 913

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	133
Air Flow (m^3/h)	2 165
Exhaust Flow (m^3/h)	2 280
Combustion Efficiency[1] (%)	95.3
Stack Heat Losses[2] (%)	23.87
Unburned Fuel (%)	3.13

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 782	48 303
Carbon Monoxide (CO)	9.73	264
Oxides of Nitrogen (NO_x)	0.219	5.93
Hydrocarbons (THC)	18.3	497

Cost of Unnecessary Excess Air: $10 399
Value of Unburned Fuel: $4 644

Total Cost of Improper Operation: $15 043
Volume of Unnecessary Fuel Consumption: 9.735 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Re-Compressor – Unit #5 400442		
Engine Make and Model:	Waukesha – L7042GSIU		
Compressor Cylinders:	2	Stages:	2
Driver Cylinders:	12	Rated Power:	1100 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	57 000
Oxygen (O_2)	111 000
Carbon Monoxide (CO)	479
Nitrous Oxide (NO)	35
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	35
Hydrocarbons (THC)	4 303

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	133
Air Flow (m^3/h)	2 211
Exhaust Flow (m^3/h)	2 328
Combustion Efficiency[1] (%)	91.1
Stack Heat Losses[2] (%)	25.71
Unburned Fuel (%)	6.31

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 720	46 608
Carbon Monoxide (CO)	8.29	225
Oxides of Nitrogen (NO_x)	0.649	17.6
Hydrocarbons (THC)	41.9	1 137

Cost of Unnecessary Excess Air: $9 851
Value of Unburned Fuel: $10 056

Total Cost of Improper Operation: $19 907
Volume of Unnecessary Fuel Consumption: 12.743 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Co-Gen #1 (West)
Engine Make and Model:	
Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	33 000
Oxygen (O_2)	153 000
Carbon Monoxide (CO)	31
Nitrous Oxide (NO)	132
Nitrogen Dioxide (NO_2)	13
Oxides of Nitrogen (NO_x)	144
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	7 097
Air Flow (m^3/h)	175 027
Exhaust Flow (m^3/h)	180 593
Combustion Efficiency[1] (%)	98.2
Stack Heat Losses[2] (%)	27.90
Unburned Fuel (%)	0.06

1 Air-to-fuel ratio of 35.

2 In the absence of heat recovery, turbine stack heat losses should be in the range of 60 to 70 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 563	50 255
Carbon Monoxide (CO)	0.844	27.1
Oxides of Nitrogen (NO_x)	4.40	142
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $2 257
Total Cost of Improper Operation: $2 257

Volume of Unnecessary Fuel Consumption: 3.660 mscfd

Gas Processing Plant 3

Equipment Information
Unit Identifier: Co-Gen #2 (East)
Engine Make and Model:
Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	35 000
Oxygen (O_2)	149 000
Carbon Monoxide (CO)	28
Nitrous Oxide (NO)	122
Nitrogen Dioxide (NO_2)	15
Oxides of Nitrogen (NO_x)	136
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	7 097
Air Flow (m^3/h)	164 481
Exhaust Flow (m^3/h)	170 141
Combustion Efficiency[1] (%)	98.2
Stack Heat Losses[2] (%)	22.65
Unburned Fuel (%)	0.05

1 Air-to-fuel ratio of 35.
2 In the absence of heat recovery, turbine stack heat losses should be in the range of 60 to 70 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 562	50 232
Carbon Monoxide (CO)	0.713	22.9
Oxides of Nitrogen (NO_x)	3.96	127
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $1 908
Total Cost of Improper Operation: $1 908

Volume of Unnecessary Fuel Consumption: 3.094 mscfd

Gas Processing Plant 3

Equipment Information
Unit Identifier: Glycol Reboiler (East) E2801/311-5-02
Boiler Make and Model: Taylor Forge Engineering Systems
Rated Power: 350 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	55 000
Oxygen (O_2)	113 000
Carbon Monoxide (CO)	0
Nitrous Oxide (NO)	31
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	31
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	56
Air Flow (m^3/h)	1 008
Exhaust Flow (m^3/h)	1 056
Combustion Efficiency[1] (%)	98.3
Stack Heat Losses (%)	23.51
Unburned Fuel (%)	0.00
Thermal Efficiency (%)	76.49

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 849	50 108
Carbon Monoxide (CO)	0	0
Oxides of Nitrogen (NO_x)	0.620	16.8
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $6 539
Value of Unburned Fuel: $0
Total Cost of Improper Operation: $6 539
Volume of Unnecessary Fuel Consumption: 3.980 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier: Glycol Reboiler (West) E2802/803790-2
Boiler Make and Model: Taylor Forge Engineering Systems
Rated Power: 350 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	90 000
Oxygen (O_2)	53 000
Carbon Monoxide (CO)	2
Nitrous Oxide (NO)	63
Nitrogen Dioxide (NO_2)	0
Oxides of Nitrogen (NO_x)	63
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	103
Air Flow (m^3/h)	1 200
Exhaust Flow (m^3/h)	1 293
Combustion Efficiency[1] (%)	98.3
Stack Heat Losses (%)	17.95
Unburned Fuel (%)	0.00
Thermal Efficiency (%)	82.05

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 845	50 002
Carbon Monoxide (CO)	0.069	1.86
Oxides of Nitrogen (NO_x)	0.774	21.0
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $3 280
Value of Unburned Fuel: $3
Total Cost of Improper Operation: $3 283
Volume of Unnecessary Fuel Consumption: 1.999 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier: Heat Medium Heater (East) L-73026
Boiler Make and Model: Cleaver Brooks CB700x-250
Rated Power: 3072 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	81 000
Oxygen (O_2)	69 000
Carbon Monoxide (CO)	0
Nitrous Oxide (NO)	38
Nitrogen Dioxide (NO_2)	5
Oxides of Nitrogen (NO_x)	42
Hydrocarbons (THC)	900

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	628
Air Flow (m^3/h)	8 054
Exhaust Flow (m^3/h)	8 618
Combustion Efficiency[1] (%)	97.3
Stack Heat Losses (%)	6.99
Unburned Fuel (%)	0.00
Thermal Efficiency (%)	93.01

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 828	49 541
Carbon Monoxide (CO)	0	0
Oxides of Nitrogen (NO_x)	0.627	17.0
Hydrocarbons (THC)	6.49	176

Cost of Unnecessary Excess Air: $9 713
Value of Unburned Fuel: $6 984
Total Cost of Improper Operation: $16 697
Volume of Unnecessary Fuel Consumption: 10.652 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier: Heat Medium Heater (West) L-73025
Boiler Make and Model: Cleaver Brooks CB700x-250
Rated Power: 3072 kW

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	81 000
Oxygen (O_2)	69 000
Carbon Monoxide (CO)	0
Nitrous Oxide (NO)	43
Nitrogen Dioxide (NO_2)	7
Oxides of Nitrogen (NO_x)	50
Hydrocarbons (THC)	500

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	533
Air Flow (m^3/h)	6 855
Exhaust Flow (m^3/h)	7 332
Combustion Efficiency[1] (%)	97.7
Stack Heat Losses (%)	7.31
Unburned Fuel (%)	0.50
Thermal Efficiency (%)	92.69

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 836	49 755
Carbon Monoxide (CO)	0	0
Oxides of Nitrogen (NO_x)	0.740	20.1
Hydrocarbons (THC)	3.619	98.1

Cost of Unnecessary Excess Air: $9 389
Value of Unburned Fuel: $3 301
Total Cost of Improper Operation: $12 690
Volume of Unnecessary Fuel Consumption: 7.963 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier:	Heater Treater (East)
Boiler Make and Model:	
Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	26 000
Oxygen (O_2)	165 000
Carbon Monoxide (CO)	140
Nitrous Oxide (NO)	4
Nitrogen Dioxide (NO_2)	7
Oxides of Nitrogen (NO_x)	10
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	24
Air Flow (m^3/h)	856
Exhaust Flow (m^3/h)	872
Combustion Efficiency[1] (%)	98.1
Stack Heat Losses (%)	27.64
Unburned Fuel (%)	0.34
Thermal Efficiency (%)	72.36

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 851	50 168
Carbon Monoxide (CO)	5.54	150
Oxides of Nitrogen (NO_x)	0.624	16.9
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $5 855
Value of Unburned Fuel: $50
Total Cost of Improper Operation: $5 905
Volume of Unnecessary Fuel Consumption: 3.632 mscfd

Gas Processing Plant 3

Equipment Information

Unit Identifier: Heater Treater (West)
Boiler Make and Model:
Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	23 000
Oxygen (O_2)	170 000
Carbon Monoxide (CO)	9
Nitrous Oxide (NO)	4
Nitrogen Dioxide (NO_2)	5
Oxides of Nitrogen (NO_x)	8
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	24
Air Flow (m^3/h)	938
Exhaust Flow (m^3/h)	953
Combustion Efficiency[1] (%)	98.3
Stack Heat Losses (%)	29.61
Unburned Fuel (%)	0.02
Thermal Efficiency (%)	70.39

1 Typical excess air of 15 percent.

Combustion Emission Factors

Pollutant	$kg/10^3\ m^3$ of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 861	50 455
Carbon Monoxide (CO)	0.399	10.8
Oxides of Nitrogen (NO_x)	0.554	15.0
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $6 464
Value of Unburned Fuel: $4
Total Cost of Improper Operation: $6 468
Volume of Unnecessary Fuel Consumption: 3.940 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Re-Compressor 1		
Engine Make and Model:	BA Clark – Integral HBA-T		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	6	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	51 000
Oxygen (O_2)	121 000
Carbon Monoxide (CO)	360
Nitrous Oxide (NO)	265
Nitrogen Dioxide (NO_2)	57
Oxides of Nitrogen (NO_x)	322
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	255
Air Flow (m^3/h)	4 999
Exhaust Flow (m^3/h)	5 210
Combustion Efficiency[1] (%)	98.0
Stack Heat Losses[2] (%)	35.00
Unburned Fuel (%)	0.44

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 864	49 615
Carbon Monoxide (CO)	7.42	198
Oxides of Nitrogen (NO_x)	7.79	207
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0

Value of Unburned Fuel: $715

Total Cost of Improper Operation: $715
Volume of Unnecessary Fuel Consumption: 0.978 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Re-Compressor 2		
Engine Make and Model:	BA Clark – Integral HBA-T		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	6	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	49 000
Oxygen (O_2)	125 000
Carbon Monoxide (CO)	243
Nitrous Oxide (NO)	151
Nitrogen Dioxide (NO_2)	15
Oxides of Nitrogen (NO_x)	166
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	255
Air Flow (m^3/h)	5 203
Exhaust Flow (m^3/h)	5 413
Combustion Efficiency[1] (%)	98.1
Stack Heat Losses[2] (%)	35.03
Unburned Fuel (%)	0.31

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 868	49 720
Carbon Monoxide (CO)	5.24	140
Oxides of Nitrogen (NO_x)	4.02	107
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $505

Total Cost of Improper Operation: $505
Volume of Unnecessary Fuel Consumption: 0.690 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Re-Compressor 3		
Engine Make and Model:	BA Clark – Integral HBA-T		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	6	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	49 000
Oxygen (O_2)	126 000
Carbon Monoxide (CO)	253
Nitrous Oxide (NO)	302
Nitrogen Dioxide (NO_2)	59
Oxides of Nitrogen (NO_x)	361
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	255
Air Flow (m^3/h)	5 265
Exhaust Flow (m^3/h)	5 473
Combustion Efficiency[1] (%)	98.1
Stack Heat Losses[2] (%)	34.51
Unburned Fuel (%)	0.33

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	$kg/10^3\ m^3$ of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 867	49 712
Carbon Monoxide (CO)	5.53	147
Oxides of Nitrogen (NO_x)	9.19	245
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $532

Total Cost of Improper Operation: $532
Volume of Unnecessary Fuel Consumption: 0.728 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Re-Compressor 4		
Engine Make and Model:	BA Clark – Integral HBA-T		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	6	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	51 000
Oxygen (O_2)	121 000
Carbon Monoxide (CO)	449
Nitrous Oxide (NO)	265
Nitrogen Dioxide (NO_2)	186
Oxides of Nitrogen (NO_x)	451
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	255
Air Flow (m^3/h)	5 003
Exhaust Flow (m^3/h)	5 215
Combustion Efficiency[1] (%)	97.9
Stack Heat Losses[2] (%)	32.94
Unburned Fuel (%)	0.55

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 861	49 538
Carbon Monoxide (CO)	9.28	247
Oxides of Nitrogen (NO_x)	12.18	324
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0

Value of Unburned Fuel: $893

Total Cost of Improper Operation: $893
Volume of Unnecessary Fuel Consumption: 1.221 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Re-Compressor 5		
Engine Make and Model:	BA Clark – Integral HBA-T		
Compressor Cylinders:	4	Stages:	2
Driver Cylinders:	6	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	47 000
Oxygen (O_2)	127 000
Carbon Monoxide (CO)	438
Nitrous Oxide (NO)	326
Nitrogen Dioxide (NO_2)	167
Oxides of Nitrogen (NO_x)	493
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	255
Air Flow (m^3/h)	5 324
Exhaust Flow (m^3/h)	5 533
Combustion Efficiency[1] (%)	97.9
Stack Heat Losses[2] (%)	34.44
Unburned Fuel (%)	0.58

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 861	49 541
Carbon Monoxide (CO)	9.70	258
Oxides of Nitrogen (NO_x)	13.80	368
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $933

Total Cost of Improper Operation: $933
Volume of Unnecessary Fuel Consumption: 1.276 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier: Generator 1
Engine Make and Model:
Driver Cylinders: 12 Rated Power:

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	110 000
Oxygen (O_2)	12 000
Carbon Monoxide (CO)	984
Nitrous Oxide (NO)	39
Nitrogen Dioxide (NO_2)	10
Oxides of Nitrogen (NO_x)	49
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	223
Air Flow (m^3/h)	2 219
Exhaust Flow (m^3/h)	2 424
Combustion Efficiency[1] (%)	98.0
Stack Heat Losses[2] (%)	27.25
Unburned Fuel (%)	0.55

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 855	49 384
Carbon Monoxide (CO)	9.20	245
Oxides of Nitrogen (NO_x)	0.544	14.5
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $773
Total Cost of Improper Operation: $773

Volume of Unnecessary Fuel Consumption: 1.057 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Generator 2		
Engine Make and Model:			
Driver Cylinders:	12	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	111 000
Oxygen (O_2)	11 000
Carbon Monoxide (CO)	832
Nitrous Oxide (NO)	447
Nitrogen Dioxide (NO_2)	14
Oxides of Nitrogen (NO_x)	461
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	233
Air Flow (m^3/h)	2 213
Exhaust Flow (m^3/h)	2 418
Combustion Efficiency[1] (%)	98.0
Stack Heat Losses[2] (%)	24.76
Unburned Fuel (%)	0.46

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 857	49 444
Carbon Monoxide (CO)	7.75	206
Oxides of Nitrogen (NO_x)	4.67	124
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $651
Total Cost of Improper Operation: $651

Volume of Unnecessary Fuel Consumption: 0.890 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Generator 3		
Engine Make and Model:			
Driver Cylinders:	12	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	111 000
Oxygen (O_2)	11 000
Carbon Monoxide (CO)	332
Nitrous Oxide (NO)	198
Nitrogen Dioxide (NO_2)	7
Oxides of Nitrogen (NO_x)	205
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	233
Air Flow (m^3/h)	2 214
Exhaust Flow (m^3/h)	2 419
Combustion Efficiency[1] (%)	98.2
Stack Heat Losses[2] (%)	25.97
Unburned Fuel (%)	0.18

1 Air-to-fuel ratio of 10.5.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 865	49 639
Carbon Monoxide (CO)	3.09	82.6
Oxides of Nitrogen (NO_x)	2.08	55.4
Hydrocarbons (THC)	0.00	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $260
Total Cost of Improper Operation: $260

Volume of Unnecessary Fuel Consumption: 0.355 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Refrigerant Compressor 3		
Engine Make and Model:			
Compressor Cylinders:	5	Stages:	2
Driver Cylinders:	10	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	36 000
Oxygen (O_2)	145 000
Carbon Monoxide (CO)	89
Nitrous Oxide (NO)	1 514
Nitrogen Dioxide (NO_2)	631
Oxides of Nitrogen (NO_x)	2 145
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	342
Air Flow (m^3/h)	9 026
Exhaust Flow (m^3/h)	9 284
Combustion Efficiency[1] (%)	97.7
Stack Heat Losses[2] (%)	35.93
Unburned Fuel (%)	0.15

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 875	49 931
Carbon Monoxide (CO)	2.55	67.8
Oxides of Nitrogen (NO_x)	76.07	2 025
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $328

Total Cost of Improper Operation: $328
Volume of Unnecessary Fuel Consumption: 0.449 mscfd

Gas Processing Plant 4

Equipment Information

Unit Identifier:	Refrigerant Compressor 4		
Engine Make and Model:			
Compressor Cylinders:	5	Stages:	2
Driver Cylinders:	10	Rated Power:	

Measured Exhaust Gas Composition

Pollutant	Concentration (ppm)
Carbon Dioxide (CO_2)	38 000
Oxygen (O_2)	141 000
Carbon Monoxide (CO)	781
Nitrous Oxide (NO)	1 149
Nitrogen Dioxide (NO_2)	333
Oxides of Nitrogen (NO_x)	1 482
Hydrocarbons (THC)	0

Stream Flows at 15ºC and 101.325 kPa

Fuel Consumption (m^3/h)	342
Air Flow (m^3/h)	8 469
Exhaust Flow (m^3/h)	8 737
Combustion Efficiency[1] (%)	97.3
Stack Heat Losses[2] (%)	33.83
Unburned Fuel (%)	1.25

1 Air-to-fuel ratio of 30.

2 For well-tuned compressor engines stack heat losses should be in the range of 20 to 35 percent.

Combustion Emission Factors

Pollutant	kg/10^3 m^3 of Fuel Input	ng/J of Fuel Input
Carbon Dioxide (CO_2)	1 846	49 137
Carbon Monoxide (CO)	20.88	556
Oxides of Nitrogen (NO_x)	47.54	1 265
Hydrocarbons (THC)	0	0

Cost of Unnecessary Excess Air: $0
Value of Unburned Fuel: $2 693

Total Cost of Improper Operation: $2 693
Volume of Unnecessary Fuel Consumption: 3.681 mscfd

Appendix IV

Average Equipment Component Schedules for Natural Gas Processing Plants

Table IV-1. Summary of average equipment component schedules for processes at natural gas processing plants.																	
Process	**Number of Emission Sources Associated with the Process**																
	Gas Service											**Light Liquid Service**					
	V	**CV**	**C**	**R**	**PRV**	**OEL**	**OM**	**Other Meter**	**BD**	**CS**	**CCV**	**V**	**CV**	**C**	**PRV**	**OEL**	**PS**
Claus Plant	19	2	119	1	-	4	-	-	-	-	-	-	-	-	-	-	-
Cogeneration: Reciprocating	9	2	71	1	-	-	-	-	-	-	1	-	-	-	-	-	-
Cogeneration: Turbine	89	2	234	3	1	5	1	-	-	-	-	-	-	-	-	-	-
Compressor: Electric	142	8	866	-	6	2	-	-	1	9	1	8	1	5	-	-	-
Compressor: Reciprocating	67	21	623	2	4	19	-	-	-	6	1	2	-	3	-	1	-
Compressor: Turbine	100	10	646	1	3	11	16	-	-	1	-	-	-	-	-	-	-
Dehydration: Mole Sieve	141	19	825	1	5	13		-	-	1	-	-	-	-	-	-	-
Dehydration:	77	4	338	4	2	5	1	-	-	-	-	5	-	13	-	-	-

Table IV-1. Summary of average equipment component schedules for processes at natural gas processing plants.

Process	Number of Emission Sources Associated with the Process																
	Gas Service											Light Liquid Service					
	V	CV	C	R	PRV	OEL	OM	Other Meter	BD	CS	CCV	V	CV	C	PRV	OEL	PS
TEG																	
Flare	130	12	392	1	-	20	9	1	-	-	-	-	-	-	-	-	-
Fractionation: De-methanizer	38	1	77	-	-	7	-	-	-	-	-	15	1	77	1	2	1
Fractionation: De-ethanizer	52	3	211	-	2	7	1	-	-	-	-	56	4	197	-	14	2
Fractionation: De-propanizer	42	2	152	-	-	1	-	-	-	-	-	17	1	51	-	2	3
Fractionation: De-butanizer	23	1	69	-	-	6	-	-	-	-	-	3	-	3	-	1	1
Hg Removal	98		262	-	3	9	-	-	-	-	-	-	-	-	-	-	-
Inlet: Header	27	1	88	-	-	2	1	-	-	-	-	5	-	16	-	-	-
Inlet: Separation	46	2	175		1	2	1	-	-	-	-	14	1	56	-	-	-
NRU	83	12	189	-	5	9	1	-	-	-	-	-	-	-	-	-	-
Refrigeration	323	40	263	1	8	44	4	1	-	8	2	36	2	57	-	2	-

Table IV-1. Summary of average equipment component schedules for processes at natural gas processing plants.

Process	Number of Emission Sources Associated with the Process																
	Gas Service											Light Liquid Service					
	V	CV	C	R	PR V	OE L	OM	Othe r Mete r	BD	CS	CC V	V	CV	C	PR V	OE L	PS
: Propane			1														
Refrigeration : Turbo Expansion	77	8	242	1	2	8	-	-	-	1	-	15	2	48	1	2	-
Sales: NG	113	5	490	-	-	17	4	-	-	-	-	-	-	-	-	-	-
Sales: NGL	35	1	105	-	1	2		-	-	-	-	107	4	418	5	16	18
Stabilization	116	6	485	3	2	4	6	1	-	-	-	137	6	406	-	2	6
Storage: C5				-	3	-	-	-	-	-	-	-	-	-	-	-	-
Storage: NGL	63	2	125	-	1	1	-	-	-	-	-	12	-	1	-	-	2
Sweetening: Amine	177	7	541	1	8	7	2	-	-	-	-	4	1	15	-	1	-
Utilities	141	9	789	13	2	3	3	-	-	-	-	6	1	18	-	1	-
VRU: Electric	23	2	184	4	3	-	-	-	-	-	-	-	-	-	-	-	-

Appendix V

Financial Considerations and Assumptions

Financial Discount Rate

The discount rate and opportunity cost of equity in the gas industry is arbitrarily taken to be six percent. Most oil and gas ventures are expected to yield better than bank interest to compensate for the added risk involved.

Net Present Value (NPV)

The net present value of each target control option is the present value of benefits minus the present value of costs. The analysis period in each case is the expected life of the control measure (e.g., the average repair life or mean time between leak occurrences).

Payout Period

The payout period of each target control option is the number of periods (years) required to payout the net present value of the repair costs based on annual payments equal to the value of the net benefit of repairs.

Equalized Annual Value

The equalized annual value of each control option is the total value of the option (after capital and operating costs) expressed as an equivalent series of equal annual payments spread over the life of the project. Negative values indicate a net cost.

Value of GHG Reduction

The value of a GHG emission reduction option is simply calculated as the equalized annual value divided by the average annual CO_2-equivalent reduction.

Appendix VI

Basic Component Repair Costs and Mean Repair Life

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service.

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Compressor Seals	Reciprocating	-	2 000	1
	Centrifugal	-	2 000	1
Compressor Valve Covers	All	-	200	1
Compressor Variable Volume Pocket Stem	All	-	400	1
Compressor Cylinder End	All	-	400	1
Flanges	All	0.5 - 0.75 1 - 2.5 3 - 4 6 - 8 10 - 14 16 - 20 24 - 30 32	25 50 75 100 150 200 300 400	2
Lube Oil Vent	-	-	4 000	1
Open-Ended Lines	All	0.5 - 0.75 1 - 1.5 2 3 4 6 8 10 12 14 16 20 24 30	60 75 100 120 190 245 350 500 595 780 890 1 115 1 340 1 670	2
Orifice Meters	All	-	150	1
Other Flowmeters	All	-	150	5

Pressure Relief Valves	Threaded	0.5 - 0.75 1 – 2 2.5 3 4 6 8 10 12	79 84 95 107 135 203 270 338 405	2

Continued …

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (continued).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Pressure Relief Valves	Flanged	1 1.5 2 2.5 3 4 6 8 10 12 16 20	124 130 135 146 180 214 253 290 363 435 580 725	2
Pump Seal	All	-	500	1
Regulators	All	-	175	5
Threaded Connections	Pipe Thread	0.125 - 0.75 1 - 2.5 3 - 4 6 - 8 10 - 14 16 - 20 24 - 30 32	10 15 25 50 100 150 200 300	2
	Union	0.5 - 0.75 1 - 2.5 3 - 6	50 100 150	2
Tubing Connections	All	0.5 - 0.75 1 - 2.5	15 25	4

Valves	Ball	0.5 - 0.75 1 - 1.5 2 3 4 6 8 10 12 14 16 20	60 75 100 120 190 245 350 500 595 780 891 1 114	4

Continued …

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (continued).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Valves	Butterfly	0.5 - 0.75	120	2
		1 - 1.5	150	
		2	200	
		3	240	
		4	380	
		6	490	
		8	700	
		10	1 000	
		12	1 190	
		14	1 560	
		16	1 783	
		20	2 229	
	Control (all types)	0.5 - 2	130	2
		3	141	
		4	177	
		6	282	
		8	353	
		10	459	
		12	560	
		14	653	
		16	747	
		20	933	
		24	1120	
	Gate	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	
		16	920	
		20	1 000	

Continued …

Table VI-1. Summary of repair costs and mean life of repair for equipment components in natural gas and non-methane hydrocarbon service (concluded).

Source	Category	Size (inches)	Basic Repair Cost ($/source)	Mean Repair Life (years)
Valves	Globe	1 - 1.5	75	4
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	600	
		16	800	
		20	1 000	
		24	1 200	
	Governor	All	200	4
	Injector (fuel gas)	All	200	4
	Needle	0.125 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		2.5	125	
		3	150	
		4	200	
	Orbit	0.5 - 0.75	60	4
		1 - 1.5	75	
		2	100	
		3	120	
		4	190	
		6	245	
		8	350	
		10	500	
		12	595	
		14	780	

	Plug	0.5 - 0.75 1 - 1.5 2 3 4 6 8 10 12 14 16 20 24 30	60 75 120 150 200 255 300 394 480 560 640 800 960 1 200	4
Vents		1 - 4 6 - 30	2 000 5 000	1

Appendix VII

WORK PRACTICE
Alternative Means for Leak Detection and Repair in Natural Gas Processing
(High Flow Sampler Procedure)

1.0 Scope and Application.

1.1 Analytes.

Analyte	CAS No.
Volatile Organic Compounds (VOC)	No CAS number assigned

1.2 Scope. This work practice is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

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

2.0 Summary of Work Practice.

2.1 The work practice involves pre-screening using soap bubble testing (alternative screening procedure of Method 21) and, where the soap bubble procedure cannot be used, Method 21. If concentrations above the leak definition of 500 ppm are detected, the Hi-Flowϑ sampler is used to determine the mass emission rate. This determination differs from Method 21, which measures concentrations only.

2.2 Components with mass emissions equal to or greater than the equivalent leak definition in ppm are repaired. The equivalent mass rates are listed in Table 1 in Section 3.0.

3.0 ***Definitions.***

3.1 The definitions listed in Method 21 also applies to this work practice.

3.2 *Leak definition mass rate* means the local VOC mass rate that is equivalent to the *leak definition concentration* that indicates that a VOC emission (leak) is present. These equivalent mass rates were based on the *1995 Protocol for Equipment Leaks Emission Estimation* and *Demonstrating Alternative Work Practices for Fugitive*

Leak Detection and Repair Programs.. The equivalent emission mass rates of methane in terms of "scfm" are presented in Table 1.

Table 1. Equivalent Mass Rate Leak Definition

Component/Service Leak Definition	Valves/LL&G	Pump Seals/LL	Pressure Relief Devices/G
NSPS, ppm CH_4	10,000	10,000	10,000
scfm of CH_4	0.0018	0.0115	0.0026

4.0 Interferences. [Reserved]

5.0 Safety.

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

5.2 Hazardous Pollutants. Several of the compounds, leaks of which may be determined by this method, may be irritating or corrosive to tissues (e.g., heptane) or may be toxic (e.g., benzene, methyl alcohol). Nearly all are fire hazards. Compounds in emissions should be determined through familiarity with the source. Appropriate precautions can be found in reference documents, such as reference No. 4 in Section 16.0.

6.0 Equipment and Supplies.

A VOC monitoring instrument meeting the following specifications is required:

6.1 *Detector.* The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, conductivity, infrared absorption, and photoionization.

Note: Two detectors may be used to shorten sampling time by simultaneously analyzing the source and the background air.

6.1.1 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

6.1.2 The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration or its equivalent (see ____).

6.2 *Pump.* A 10-scfm battery-powered pump. An electric or pneumatic pump with a capacity of 10 scfm or greater to provide good capture efficiency may also be used. (***Note:*** Several pumps in parallel may be used to provide the capacity.)

6.3 *Flow Meter.* An intrinsically safe thermal anemometer capable of measuring flow rates over the full range with an accuracy of ±10 percent for air. Other flow meters, such as rotameters, turbine meters, venturi meters, orifices, and pitot tubes, may also be used.

6.4 *Flow Regulator.* Throttling valve, a bypass valve, or different number of pumps in parallel may be used to control the sample flow rate.

6.5 *Sampling Hoses.* An 8-ft primary sampling hose and a 12-ft extension hose made of a smooth-bore flexible urethane with a conductive wire (grounded) braided into the coils, approximately 1.5-inch inside diameter, and for collecting background air, a 1/4 inch polyvinyl plastic tubing "piggy-backed" on the hoses. Other flexible plastic hoses that are formulated and constructed to prevent static charge build up may also be used.

6.6 *Probe Tip/Extensions.* Probe or probe extension with outside diameter not to exceed 6.4 mm (1/4 inch), with a single end opening for admission of sample, for use in Method 21 sampling mode.

6.7 *Probe Tip Attachments.* Attachments that aid in the total capture of emissions from leaks. Some attachments that have been used successfully in developmental tests are: (a) a cone-shaped attachment that is split down one side for most valve sampling; (b) a long strap of Mylar plastic with Velcro to wrap around flange faces; and (c) a large sheet of anti-static plastic with patches of Velcro around the edges for large or odd shaped components. A tight fit is not necessary in these attachments. However, the areas open to the atmosphere must be small enough to provide leaking VOC from escaping the attachment.

6.8 *Intrinsically Safe Equipment.* The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

7.0 Reagents and Standards.

7.1 *Calibration and Performance Evaluation.*

7.1.1 Zero Gas. Air, less than 10 parts per million by volume (ppmv) VOC.

7.1.2 Calibration Gas. Methane, ____ ppmv, certified by the manufacturer to be within ±2 percent accuracy and with a specified shelf life. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life.

7.2 Soap Solution. Obtain commercially leak detection solution, or prepare by using concentrated detergent and water. Place in pressure sprayer or squeeze bottle.

8.0 Sample Collection, Preservation, Storage, and Transport.

8.1 *Instrument Performance Evaluation.*

8.1.1 Prepare the VOC instrument according to the procedures in Method 21, except that a response factor need not be determined. The gas being measured is natural gas and the instrument is being calibrated with methane, the principal component of natural gas.

8.1.2 Calibrate the instrument with methane. Introduce the calibration gas mixture to the analyzer and record the observed meter reading. Introduce zero gas until a stable reading is obtained. Make a total of three measurements by alternating between the calibration gas and zero gas.

8.1.3 Calibration Precision. The calibration precision test must be completed prior to placing the analyzer into service and at subsequent 3-month intervals or at the next use, whichever is later.

8.1.3.1 Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

8.1.3.2 The calibration precision shall be equal to or less than 10 percent of the calibration gas value.

8.1.4 Response Time. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

8.1.4.1 Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. After switching, measure the time required to attain 90 percent of the final stable reading. Perform this test sequence three times and record the results. Calculate the average response time.

8.1.4.2 The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter that will be used during testing shall all be in place during the response time determination.

8.2 *Pre-Screening Using Soap Solution.* Use the following procedure for those sources that do not have:

- Continuously moving parts, e.g., rotating shaft seals where soap solution is slung off.
- Very hot components (above boiling point of soap solution)
- Very cold components (below the freezing point of the soap solution)
- Components with seal area facing down (where soap solution will not readily pool)
- Components that process fluids that are liquid at ambient conditions (where liquid can leak through and float to the top of the soap solution before evaporating)
- Components with seal areas not easily accessible for observation.

8.2.1 Spray the soap solution over potential leak source and observe for soap bubbles.

8.2.2 If soap bubbles are not observed, the source is presumed to have no detectable emissions or leaks. If soap bubbles are observed, use the procedure in Section 8.2.

8.3 *Pre-Screening Using Method 21.* Use the following procedure for the following sources:

- All applicable sources.
- Those sources listed under Section 8.1.
- Those sources where soap bubbles are observed.

8.3.1 Use Method 21 to determine VOC concentration.

8.3.2 If the concentration is ≤500 ppm, the source is presumed to have no leaks. If the concentration is >500 ppm, use the procedure in Section 8. to determine whether corrective action should be taken.

8.4 *Determination of Mass Emission Rate.* Use the following procedure whenever the Method 21 prescreening results indicate a concentration of >500 ppm.

8.4.1 Use the Hi-Flowϑ to determine the mass emission rate

8.4.2 Attach the probe tip attachments suitable for the applicable source.

8.4.3 Turn on the pump, set the flow rate to 2 scfm, and record the concentration in ppm.

8.4.4 Reset the flow rate to 3 scfm, and record the concentration in ppm.

8.4.5 Measure the background concentration.

8.4.6 Calculate the mass emission rate according to the equation in Section 12. Compare the mass emission rates at each flow rate. If the difference is greater than 10 percent, do one of the following until the mass emission rates at two flow rates agree to within ±10 percent.

- check the probe attachment for tightness of fit and repeat the test,
- repeat the test at higher flow rates,

8.4.7 When the mass emission flow rates agree to within ±10 percent, average the results and compare the results to the criteria in Section 3. If greater, repair the leak.

9.0 Quality Control.

10.0 Calibration and Standardization.

10.1 *VOC Monitoring Instrument.* Calibrate the VOC monitoring instrument as follows. After the appropriate warm-up period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

10.2 *Flow Meter.* Calibrate the thermal anemometer according to the procedure in Method 2, except use the thermal anemometer in place of the Type S pitot tube. Measure the cross-sectional area of the manifold.

11.0 Analytical Procedures. [Reserved]

12.0 Data Analyses and Calculations.

12.1 *Mass Emissions.* Calculate the mass emissions by the following equation:

$$ER = FR * (SC - BC) * 10^{-6}$$

where:

ER = emission rate, scfm of CH_4
FR = sampling flow rate, scfm

SC = sample concentration, ppm
BC = background concentration, ppm

13.0 Method Performance.

13.1 *Lower Detection Limit.* The lower detection limit shall be at 100 ppm at a flow rate of 2 scfm.

13.2

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References.

1. Dubose, D.A., and G.E. Harris. Response Factors of VOC Analyzers at a Meter Reading of 10,000 ppmv for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81051. September 1981.

2. Brown, G.E., et al. Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-022. May 1981.

3. DuBose, D.A. et al. Response of Portable VOC Analyzers to Chemical Mixtures. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-110. September 1981.

4. Handbook of Hazardous Materials: Fire, Safety, Health. Alliance of American Insurers. Schaumberg, IL. 1983.

17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]