AIR QUALITY CODE OF PRACTICE
UPSTREAM OIL AND GAS INDUSTRY

CONSULTATION DRAFT

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GLOSSARY

Acid Gas	Gas ~~that~~ containing~~s~~ hydrogen sulphide (H_2S), total reduced sulphur compounds (TRS), and/or carbon dioxide (CO_2) that is separated in the treating of solution or non-associated gas.
Air Pollutant	Any substance introduced directly or indirectly by man into the ambient air and likely to have harmful effects on human health and/or the environment as a whole.
Ambient Air	Air in the troposphere, excluding work places.
Ambient Sound Level (ASL)	The sound level that is a composite of different airborne sounds (ASL) from many sources far away from, and near, the point of measurement. The ASL does not include any energy-related industrial component and must be measured without it. The ASL must be measured under representative conditions. As with comprehensive sound levels, representative conditions do not constitute absolute worst-case conditions (i.e., the most quiet day in this case) but conditions that portray typical conditions for the area.
A-Weighted Sound Level	The sound level as measured on a sound level ~~meter~~ metre using a setting that emphasizes the middle frequency components similar to the frequency response of the human ear.
Background Concentration	A reading expressed as methane on a portable hydrocarbon detection instrument ~~which~~ that is taken at least three ~~meters~~ metres upwind from any components to be inspected and ~~which~~ is not influenced by any specific emission point.
Bagging	Enclosing an equipment component with a bag to measure its leak rate.
Basic Sound Level (BSL)	The A-weighted Leq sound level commonly observed to occur in the designated land-use categories with industrial presence. The BSL is assumed to be 5 dBA above the ASL.
C.S.A.—Z731	CSA Standard CAN/CSA—Z731—M91 Emergency Planning for Industry as published by the Canadian Standards Association.
Chemical Plant	Any facility engaged in producing organic or inorganic chemicals, and/or manufacturing products by chemical processes. Any facility or operation that has 282 as the first three digits in its four digit Standard Industrial Classification (SIC) Code, as defined in the Standard Industrial Classification Manual, is included.
Closed-vent System	A system that is not open to the atmosphere and is composed of piping, connections~~,~~ and, if necessary, flow inducing devices that transport gas or ~~vapor~~ vapour from a piece or pieces of equipment to a ~~vapor~~ vapour recovery or disposal system.

Commercial Natural Gas	A mixture of gaseous hydrocarbons~~,~~ with at least 80 percent methane,~~,~~ and less than 10 percent by weight volatile organic compounds.
Component	Any valve, fitting, pump, compressor, pressure relief device, hatch, sight-glass, ~~meter~~metre~~,~~ or open-ended lines. ~~They are f~~Further classified as a major component: A~~a~~ny 4-inch or larger valve, any 5-hp or larger pump, any compressor~~,~~ and any 4-inch or larger pressure relief device. Minor component: A~~a~~ny component ~~which~~ that is not a major component. Critical component: A~~a~~ny component ~~which~~ that would require the shutdown of the process unit if these components were shut down.
Compressor	A device used to compress gasses and/or ~~vapors~~vapours.
Concentration	Content of a specific substance in air expressed in parts per million by volume (ppm or ppmv).
Continuous Emission Monitoring System	The total equipment necessary for the determination of a gas or particulate matter concentration or emission rate using pollutant analyzer measurements and a conversion equation, graph~~,~~ or computer program to produce results in units of the applicable emission limitation or standard.
Emergency	An unplanned event requiring immediate action to prevent loss of life or property.
Emission Factor	The mass emission rate per component, applicable to populations of sources (valves, flanges, etc.), which has been determined by averaging field measurements of a number of similar components. It is used to characterize the emissions from a given individual component.
Energy Equivalent Sound Level (Leq)	The Leq is the average A-weighted sound level over a level (Leq) specified period of time. It is a single-number representation of the cumulative acoustical energy measured over a time interval. The time interval used should be specified in brackets following the Leq (e.g., Leq (9) is a 9-hour Leq). If a sound level is constant over the measurement period, the Leq will equal the constant sound level.
Fitting	A component used to attach or connect pipes or piping details~~,~~ including, but not limited to, flanges and threaded connections.
Fugitive Emissions	Any ~~hydrocarbon~~ emissions that are released into the atmosphere from any point other than a stack, chimney, vent~~,~~ or other functionally equivalent opening.
Gas Battery	A gas battery is a system or arrangement of surface equipment that receives primarily gas from one or more wells prior to delivery to a gas gathering system, to market~~,~~ or to other disposition. Gas batteries may include equipment for measurement and for separating inlet streams into gas, hydrocarbon liquid~~,~~ and/or water phases.

Gas Processing Plant	A facility engaged in the separation of liquids from field gas and/or fractionation of the liquids into gaseous products~~,~~ such as ethane, propane, butane, and natural gasoline. Excluded from the definition are compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquified natural gas units~~,~~ and field gas gathering systems unless these facilities are located at a gas processing plant.
Hatch	Any covered opening system that provides access to a tank or container.
In Gas/Vapour Service	Equipment in use ~~which contains~~containing process fluid that is in the gaseous state at operating conditions.
In Heavy Liquid Service	Equipment in use ~~which is~~ handling hydrocarbons with a vapour pressure less than 1.013 kPa (0.147 psia) at 20ºC.
In Light Liquid Service	Equipment in use ~~which contains~~containing a light hydrocarbon liquid with a vapour pressure greater than 1.013 kPa (0.147 psia) at 20ºC.
In Vacuum Service	Equipment in use ~~which is~~ operating at an internal pressure ~~which~~ that is at least 5 kPa below ambient pressure.
Inaccessible Component	Any component located over fifteen (15) feet above ground when access is required from the ground; or, any component located over six (6) feet away from a platform when access is required from the platform.
Inaccessible Source	Equipment ~~that~~ used for monitoring that is more than two (2) ~~meters~~ metres above a permanently available support surface; equipment that is unsafe to monitor and~~,~~ ~~which~~ could expose monitoring personnel to imminent hazard from temperature, pressure or explosive process conditions; a source cover protected or insulated.
Interference Equivalent	Positive or negative response caused by a substance or substances (the sum of which is sometimes taken) other than the one being measured, at a concentration substantially higher than that normally found in the ambient air.
Instrument Noise	The spontaneous, short duration deviations in output from the mean response, ~~which~~ that is independent of the input concentration, determined as the standard deviation about the mean.
Isokinetic Sampling	Particulate sampling when the velocity of the gas/particulate entering the sampling nozzle is exactly equal to the velocity of the approaching gas stream. This provides a uniform, unbiased sample of the pollutants being emitted by the source. Isokinetic source sampling most closely evaluates and defines various parameters in the stack~~,~~ as they actually exist at the time of sampling.

Leak	The concentration of a leaking contaminant as determined by a monitoring instrument at which action will be initiated to rectify the problem; that is, the point where a component is identified as a "leaker".
Leak Frequency	The percentage of leaking components over the total population of similar components.
Leak Minimization	Tightening or adjusting a component for the purpose of stopping or reducing leakage to the atmosphere.
Leaking Emission Factor	The per component mass emission rate associated with the population of sources (e.g. valves) with screening concentrations at or above the leak.
Leaking Source	A source whose screening concentration is greater than or equal to the leak definition.
Linearity	The maximum deviation within the measurement range, usually expressed as a percentage of full scale.
Major Gas Leak	The detection of total gaseous hydrocarbons for any component in excess of 10,000 ppm as methane above background.
Major Liquid Leak	A visible mist or continuous flow of liquid.
Mass Emission Rate	The quantity of ~~VOC~~ a volatile substance released to the atmosphere through the leak point, in terms of total mass per unit time.
~~*Maximum Achievable*~~ *Limit*	~~Regarding regulated hazardous air pollutant sources:~~ defined as two times the noise level.
Minor Gas Leak	The detection of total gaseous hydrocarbons for any component in excess of 1,000 ppm but not more than 10,000 ppm as methane above background.
Minor Liquid Leak	Any liquid leak ~~which~~ that is not a major leak and drips liquid organic compounds at the rate of more than three drops per minute or 1 cubic ~~centimeter~~ centimetre per minute.
Noise	Any sound exceeding the control criteria.
Non-emitting Source	A source whose screening value is 8 ppm or less.
Non-leaking Emission	The per component mass emission rate used to characterize the leaking sources.
Non-leaking Emitting Source	A source whose screening concentration is greater than 8 ppm above background but no more than 1,000 ppm.
Oil and Gas Production Facility	A facility at which crude petroleum and natural gas production and handling are conducted, as defined by Standard Industrial Classification code number 1311, Crude Petroleum and Natural Gas.

Oil / Bitumen Battery	A system or arrangement of tanks or more wells for the purpose of separation and measurement or other surface equipment or devices receiving the effluent from one or more sources.
Operating Temperature Range	The ambient temperature range within which the analyzer is capable of producing quality data.
Particulate Matter	~~Means any~~ Any substance, except uncombined water, that has definite physical boundaries at standard conditions, as measured by the methods in the code specified under each applicable section, or an equivalent or alternative method.
Passive Sampler	A device~~, which is~~ capable of taking samples of gas or ~~vapor~~ vapour pollutants from the atmosphere at a rate controlled by a physical process of diffusion through a static air layer or permeation through a membrane without involving the active movement of the air through the sampler.
Pipeline Transfer Station	A facility ~~which handles~~handling the transfer or storage of petroleum products or crude petroleum in pipelines.
Precision	The degree of agreement between repeated measurements of the same pollutant concentration by an instrument, expressed as a standard deviation about the mean over a period of seven or more days. This can be determined by statistically reviewing span check data over a period of seven or more days.
Pressure Relief Device (PRD)	A pressure relief valve or rupture disc.
Pressure Relief Event	A release from a pressure release device resulting when the upstream static pressure reaches the setpoint of the pressure release device. A pressure relief event is not a leak.
Pressure Relief Valve (PRV)	A valve ~~which~~ that is automatically actuated by upstream static pressure and used for safety or emergency purposes.
Process Unit	A manufacturing process ~~which~~ that is independent of other processes and is continuous when supplied with a constant feed of raw material and sufficient storage facilities for the final product.
Process Unit Shutdown	A work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than twenty-four (24) hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.
Pump	A device used to provide energy for transferring a liquid or gas/liquid mixture through a piping system from a source to a receiver.

Ranges	The available ranges which correspond to the full scale output of the instrument.
Refinery	A facility that processes petroleum, as defined by the Standard Industrial Classification Code number 2911, Petroleum Refining, and in Statistics Canada Standard Industrial Classification No. 3611 and No. 3612.
Regulatory Authority	One of the Land and Water Boards;~~,~~ ~~and/or~~ Resources, Wildlife and Economic Development (RWED) Environmental Protection Service;~~,~~ ~~and/or the~~ National Energy Board (NEB)~~,~~ and/or, Environment Canada.
Repair	Any corrective action for the purpose of eliminating leaks.
Response Factor (RF)	The ratio of actual concentration of a compound to observed concentration for the detector.
Response Time	The time delay after a step change in VOC concentration, at the input of a sampling system, to the time at which 90% of the corresponding final value is reached as displayed on the analyzer readout ~~meter~~metre.
Screening	The process of using a monitoring instrument to measure the concentration of a volatile substance being emitted from a component.
Seal	Packing gland or other material compressed around a moving rod, shaft~~,~~ or stem to prevent the escape of gas or liquid.
Setback	The distance in met~~e~~res from the centre line of a sour pipeline to an inhabited building or public facility.
Sound Level Metre	An instrument for measuring sound levels, which meets the specifications for a Type 2 ~~meter~~ ~~metre~~metre as described in CSA Standard Z107.1-1973.
Sour Gas	Gas that contains H_2S in sufficient quantities to pose a public safety hazard if released or to result in unacceptable off-lease odours if vented to the atmosphere.
Sour Pipeline	A pipeline containing hydrogen sulphide (H_2S) in concentrations of 1 mole % or more.
Span Drift	The percentage change in response to an up-scale pollutant concentration in a continuous, unadjusted operation, usually over a 24-~~-~~hour period.
Speciation	The identification of each of the chemical species in a VOC emission.
Sulphur Emissions	Air emissions containing compounds including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.
Unmanned Facility	A remote facility ~~which~~ that has no permanent sited personnel and is greater than five (5) miles from the closest manned facility, operated by the same company or corporation.

Unrestricted Rural	Dwellings located outside an urban centre that has more than eight (8) dwellings per square mile.
Urban Centre	A city, town, village or incorporated district with not less than 50 dwellings.
Valve	A device that regulates or isolates the fluid flow in a pipe, tube, or conduit by means of an external actuator.
~~Vapor~~ Vapour Control System	Any system not open to the atmosphere intended to collect and reduce volatile organic compound emissions to the atmosphere and ~~is~~ composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or ~~vapor~~ vapour from a piece or pieces of equipment to a ~~vapor~~ vapour recovery or disposal system.
Volatile Organic Compound (VOC)	Any organic compound containing at least one atom of carbon, except exempted compounds if specified.
Zero Drift	The maximum deviation of the response to zero air, usually over a 24-hour period.

ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AENV	Alberta Environment (formerly AEPA)
AEPA	Alberta Environmental Protection Agency (currently AENV)
BACTEA	Best Available Control Technology Economically Achievable
BMP	Best Management Practices
CAA	Clean Air Act
CAPP	Canadian Association of Petroleum Producers
CCD	Catalytic Combustion or Hot Wire Detectors
CCME	Canadian Council of Ministers of the Environment
CCPA	Canadian Chemical Producers Association
CEMS	Continuous Emission Monitoring System
CMA	Chemical Manufacturers Association (U.S.)
CPPI	Canadian Petroleum Products Institute (formerly PACE)
EIA	Environmental Impact Assessment
ENGO	Environmental Non-Government Organization
EPA	Environmental Protection Agency (U.S.)
FE	Fugitive Emissions
FID	Flame Ionization Detectors
FVE	Fugitive VOC Emissions
GC	Gas Chromatograph
GHG	Greenhouse Gas
GNWT	Government of the Northwest Territories
HAP	Hazardous Air Pollutants
HVP	High Vapour Pressure
IPAC	Independent Petroleum Association of Canada
LDAR	Leak Detection and Repair
Leq	Energy Equivalent Sound Level
M	Molecular Weight
MACT	Maximum Achievable Control Technology
MTBF	Mean Time Between Failure
NAAQS	National Ambient Air Quality Standards
NDIR	Non-Dispersive Infrared Analyzer
NEB	National Energy Board
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGOs	Non-Government Organizations
NPRI	National Pollutant Release Inventory
NSPS	New Source Performance Standards
NWT	Northwest Territories
OVA	Organic Vapour Analyzer
PID	Photo Ionization Detectors
P&ID	Process and Instrumentation Diagrams
PSV, PRV	Pressure Safety or Relief Valve
PRD	Pressure Relief Device
QIP	Quality Improvement Program
ROC	Reactive Organic Compounds (non-methane, non-ethane)
RWED	Department of Resources, Wildlife and Economic Development
SIC	Standard Industrial Classification
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SV	Screening Value
TCS	Toxic Chemical Substances
THC	Total Hydrocarbons (including methane and ethane)

TLV	Threshold Limit Value
TQM	Total Quality Management
TRI	Toxic Release Inventory
TRS	Total Reduced Sulphur
TSP	Total Suspended Particulate
TWA	Time Weighted Average
VHAP	Volatile Hazardous Air Pollutant
VOC	Volatile Organic Compound

UNITS OF MEASUREMENT

Bcf	billion (10^9) cubic feet
ºC	centigrade, Celsius temperature scale
ºF	degree, Fahrenheit temperature scale
ºR	degree, Rankin temperature scale
Btu	British Thermal Unit
cal/s	calorie per second
cfm	cubic feet per minute
dBA	decibel measured on the "A-weighted" scale of a sound level ~~meter~~metre
g/s	gram per second
gr	grain
h	hour
K	absolute temperature in Kelvin
kg/h	kilogram per hour
km/h	~~kilometer~~ kilometre per hour
kPa	kiloPascal
kW/m^2	kiloWatt per square ~~meter~~metre
lb/ft^3	pound per cubic foot
lb/h	pound per hour
lb-mole	pound mole
lpm	litre per minute
lb/(s ft^2)	pound per second per square foot
m/s	~~meter~~ metre per second
MMBtu	million British Thermal Units
MMcf	million (10^6) cubic feet
mg	milligram
min	minute
mm	~~millimeter~~millimetre
ppb	parts per billion (by volume)
ppm	parts per million (by volume)
psi	pound per square inch
psig	pound per square inch gauge
s	second
scf	standard cubic feet
scf/h	standard cubic feet per hour
Tg	trillion (10^{12}) gram
µg/m^3	microgram per cubic ~~meter~~metre

~~1.0~~1. INTRODUCTION

Oil and gas exploration and production is increasing in the Northwest Territories (NWT). Already oil and gas production occurs in several areas in the NWT. Oil has been produced at Norman Wells since 1920 when Imperial Oil drilled their first well and ~~in 1921~~ built a small refinery (1921) processing approximately 50 m^3 of oil per day. However, it is only since the major expansion of the field in 1985 ~~,~~ and the completion of the 860-kilometre Norman Wells Pipeline to Zama Lake, Alberta, that the field has produced close to its potential. The field produces between 11 and 12 million barrels per year, ~~which are~~ valued between $250 and $300 million dollars per year~~,~~ at 1996 oil prices.

Natural gas has been produced by four wells around Fort Liard area since 2000. The ~~three~~wells ~~of~~ operated by Chevron, Paramount and Ranger have been producing since the spring 2000. ~~and a~~A fourth well operated by Chevron started producing in November 2000. The gas from these wells flows into the Westcoast pipeline system in British Columbia. The Pointed Mountain field in the southern NWT has been producing gas since 1972. Its production is now in decline and the field is expected to be depleted in a few years. The Ikhil field ~~commenced~~ began providing natural gas for the town of Inuvik in the summer of 1999. Natural gas at Norman Wells is used locally and for re-injection to enhance oil recovery.

Verified deposits at NWT include ~~over~~ more than 1.75 billion barrels of oil and 11 trillion cubic feet of natural gas (excluding Arctic Island discoveries). The petroleum-bearing areas are located in the western NWT stretching from the Deh Cho starting at the Alberta/NWT border to the Mackenzie Delta/Beaufort Sea and on to the Sverdrup basin in the vicinity of Melville Island.

The federal government owns and manages more than 90~~%~~ percent of the petroleum subsurface rights in the NWT. The National Energy Board (NEB) is responsible for ~~regulation~~ regulating ~~of~~all petroleum activities such as drilling safety, field conservation of resources, efficient oil and gas field development, etc. ~~and so forth.~~

It is only a matter of time ~~when~~ before large-scale development of the oil and gas ~~industry~~ resources will take off in~~at~~ the NWT. ~~It is desired that the~~This industrial development should proceed in a manner benefiting ~~northern Canadians~~Northwest Territories residents while doing the least harm to the ~~northern~~ environment. Northern oil and gas production should also be considered as a transitional measure~~,~~ bridging to more sustainable energy generation and consumption measures.

To protect existing air quality by keeping green areas green, the Department of Resources, Wildlife and Economic Development (RWED), ~~of the~~ Government of the Northwest Territories (GNWT) has initiated the development of Air Quality Code of Practice for the upstream oil and gas industry. Development of the Code is a continuous process ~~during which it~~that will be continuously improved as a result of ~~government's incoming~~ new regulations and guidelines, consultation with the oil and gas industry~~,~~ and contributions by~~of~~ non-government organizations (NGOs)~~,~~ special interest groups ~~of special interest~~ and other stakeholders.

It should be clearly understood that there is an expectation on the part of the GNWT that each facility will make every effort to minimize emissions through implementation of strategies such as pollution prevention, best management practices and emission control technologies. Given the sensitivity of the northern environment, facilities should strive to surpass the goal of simply meeting the ambient air quality standards and ensure as minimal an impact as possible on ambient air quality.

The owner or operator of the facility should strive to exceed current NWT or CCME standards by using best management practices. If any document cited or referred to in this Code of Practice is amended or updated, the Code of Practice should be considered amended or updated unless otherwise stated by RWED.

Emission sources associated with oil and gas exploration and production include exploration, well-site preparation, drilling, waste pits, blowouts, well testing, gas/liquid separation and sulphur recovery.

In general, the primary factors affecting emissions and their estimation for sources in oil and gas field processing operations are:

- oil/gas composition;
- production rate/frequency of operation; and
- type of control/recovery, if any.

Primary gaseous pollutants of concern generated by the oil and gas industry are hydrogen sulphide (H_2S), methane (CH_4), volatile organic compounds (VOC) and hazardous air pollutants (HAP). For example, when using oil-based drilling muds, the mud will be dispersed in oil rather than water. When the mud passes through the shale shaker, the oil ~~vapors~~ vapours are exposed directly to the atmosphere. Waste pits storing hydrocarbon laden cuttings may be a source of VOC and HAP emissions.

Well blowouts, although infrequent, are considered process upsets and can also be a source of VOC, HAP, and CH_4 emissions. Well testing can result in VOC, HAP and CH_4 emissions. Emissions from gas/liquid separation processes include fugitive VOC and HAP from valves and fittings and from any operation upsets, such as pressure relief device releases due to overpressure.

Upstream gas and oil industry includes gas and oil wells, processing and storage facilities, and transmission and distribution facilities. Emissions primarily result from the normal operations of many natural gas system components~~,~~ such as venting and flaring at oil and gas wells, compressor station operations, gas processing facilities, sulphur recovery plants, gas-operated control devices~~,~~ and unintentional leaks (fugitive emissions). Gaseous emissions also occur during routine maintenance~~,~~ with additional emissions resulting from unplanned system upsets.

The technical nature of emissions from natural gas systems is well understood.~~, and e~~Emissions are largely amenable to technological solutions~~,~~ by mean of enhanced inspection and preventative maintenance, replacement of equipment with newer designs, improved rehabilitation and repair~~,~~ and other changes in routine operations. Reductions in emissions on the order of 20 to 80 percent are possible at particular sites, depending on site-~~-~~specific conditions. These reduction options can also result in improved safety, increased productivity through reduced losses~~,~~ and improved air quality.

Some components emitted by gas and oil facilities, such as methane and carbon dioxide, are greenhouse gases (GHG) and are major contributors to global warming. Canada is a signatory to the Kyoto Convention and is obliged to reduce emissions of GHG.

In addition to methane, raw natural gas contains undesirable impurities ~~which includes~~including, but ~~is~~ not limited to, water, hydrogen sulphide, volatile organic compounds like benzene and valuable compounds like ethane, propane and butane, and other compounds. Also, ~~such~~ gases such as nitrogen oxides and sulphur dioxide accompan~~ies~~y natural gas production and processing.

~~They~~ There are various removal methods for each of the natural gas components. For example, the four basic methods ~~are~~ employed for the dehydration of natural gas are~~:~~ ~~compressio~~compression~~n~~, treatment with drying substances;~~,~~ adsorption;~~,~~ and, refrigeration. Hydrogen sulphide (H_2S) and other sulphur compounds are objectionable in natural gas because they cause corrosion and ~~also~~ form air-polluting compounds when burned. The odour of hydrogen sulphide is very annoying to household customers. ~~Recent stringer~~ Stringent air pollution laws in most Canadian provinces require the removal of sulphur compounds before the gas is fed into the distribution system. Carbon dioxide (CO_2) in the gas is objectionable because it lowers the heating value of the gas. However, it is not an air pollutant although it is a green house gas that contributes to global warming.

~~contributing to the global warming.~~

~~3.1~~2.1 Introduction

~~3.1.1~~2.1.1 Gas flaring converts flammable, toxic~~,~~ or corrosive ~~vapors~~ vapours to less objectionable compounds by means of combustion. Flares are often used to control VOC emissions and to convert H_2S and reduced ~~sulfur~~ sulphur compounds to SO_2. Flares can be used to control emissions from storage tanks, loading operations, glycol dehydration units, vent collection systems~~,~~ and gas sweetening amine units. They can serve as a backup system for ~~sulfur~~ sulphur recovery units.

~~3.1.2~~2.1.2 Flaring is preferable to venting but should be considered only after exhausting all other alternatives of reusing the disposable gas. All efforts should be taken to eliminate, reduce and improve the efficiency of flaring. This should include, but not be limited to, exploring the following alternatives:

- thermal oxidation using high-efficiency enclosed combustion systems (e.g., incinerators, enclosed flares, or process heaters);
- electric power generation for consumption onsite or within an industrial system;
- cogeneration of steam and electricity for local applications;
- re-injection of gas into the producing reservoir;
- re-injection of gas with produced water;
- collection and delivery of waste gas to a nearby gas-gathering system; and
- pooling of flared gas resources or clustering gas from several batteries into a single location to achieve volumes sufficient to justify conservation or utilization schemes~~.~~.

~~3.1.3~~2.1.3 Flaring is a critical operation in many plants whose design ~~must~~ should be based on strict safety and environmental principles. It is associated with a wide range of energy activities or operations, including:

- oil, oil sands/crude bitumen~~,~~ and gas well drilling;
- initial oil, oil sands/crude bitumen~~,~~ and gas well completion or servicing clean-up flow-backs;
- gas well testing to establish reserves and determine productivity;
- disposal of gas associated with oil or oil sands/crude bitumen production while gas conservation is being evaluated and implemented;
- non-routine gas gathering, distribution system operations, maintenance pressure relief~~,~~ or reduction; and
- non-routine processing plant upset or emergency conditions.

~~3.2~~

~~3.3.1~~

- Pipe Flares: Vertical or horizontal pipes with external ignition pilot;
- Smokeless Flares: Vertical, single~~,~~ or multiple burners designed to properly mix adequate oxygen from the air with relieved ~~vapors~~ vapours for complete combustion; and
- Endothermic Flares: Elevated incinerators for low heat content streams.

~~3.3.3~~2.2.2 The flare system ~~shall~~ should be designed and operated to:

- eliminate any potential for thermal or overpressurization hazards;
- achieve sufficient atmospheric dispersion of the emissions to comply with all applicable occupational exposure limits, ambient air-quality objectives, and point-of-impingement standards;
- withstand wind effects;
- tolerate the maximum pressures and minimum and maximum temperatures which may be experienced through the system (the minimum temperatures should consider expansion cooling effects from any pressure-relief discharges into the flare system);
- prevent flashbacks;
- preclude liquids being directed to the flare tip;
- achieve continuous, reliable combustion of the flared gases, and provide smokeless combustion for the routine operating range of the system;
- comply with applicable Noise Control Directive; and
- comply with the applicable flare performance, sulphur recovery and flow measurement.

~~3.3.4~~2.2.3 The design of a flare system requires a detailed analysis of the possible situations that can cause emissions, thus establishing the maximum loading for emergency operations.

~~3.3.5~~2.2.4 Some of the different gas and vapour streams that may be directed to a flare system at an oil production facility are shown in Figure 2.1. A detailed engineering review is needed to determine which streams will actually be flared in each application. Sour streams may not be vented.

~~3.3.6~~2.2.5 The relieving ~~vapors~~ vapours from different equipment ~~must~~ should be collected in individual flare subheaders located near each process area. All subheaders ~~must~~ should be interconnected to a main flare header which leads to a knock out drum. Condensates carried over by ~~vapors~~ vapours are separated in this vessel. ~~Vapors~~ Vapours leaving the knock out drum from the top move up the flare stack where they are subsequently burned at the tip. The number of main flare headers and the individual subheaders connected to them depends upon the type of ~~vapors~~ vapours handled, temperature~~,~~ and back pressure limitation of the pressure relief valves.

~~3.3.9~~2.2.7 Sizing of the flare header can be accomplished with the following equation:

$$G_{ci} = 12.6\, P_0\, [M / \{(2Z-1)\, T_0\}]^{0.5}$$

where: G_{ci} = maximum mass flow, lb/(s ft^2)
P_0 = upstream pressure, psia
M = molecular weight
T_0 = Temperature, °R
Z = Compressibility Factor, dimensionless

~~3.3.10~~2.2.8 The following criteria should be checked while sizing flare headers:

- The back pressure developed at the downstream section of any pressure relief valve connected to the same header should not exceed the allowable limit i.e. 10% of the set pressure for conventional type and 30% of the set pressure for balanced type valves.
- Limit the line velocity to 0.6 Mach Number

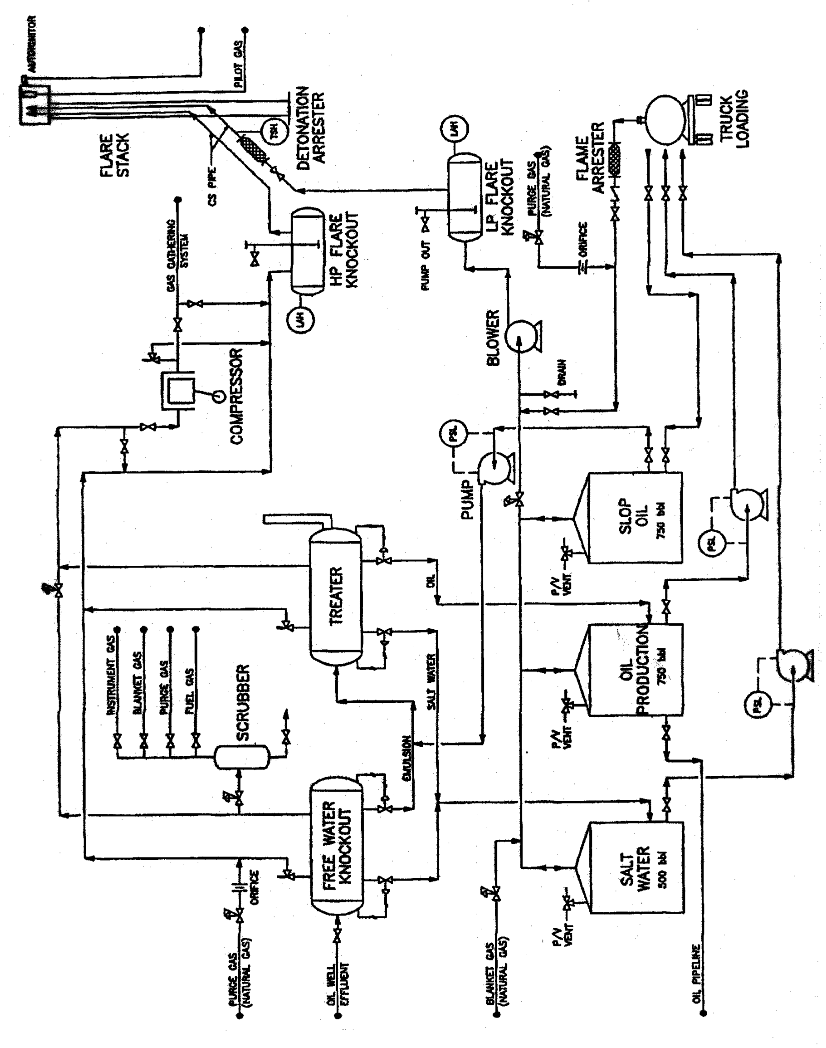

Figure 2.1 Flare stack arrangement for a fixed-roof storage tank and truck loading at an oil production facility.

~~3.4~~2.3 Design of Flare Stack and Accessories

~~3.4.1~~2.3.1 Some of the potential elements of a typical flare system are shown in Figure 2.2.

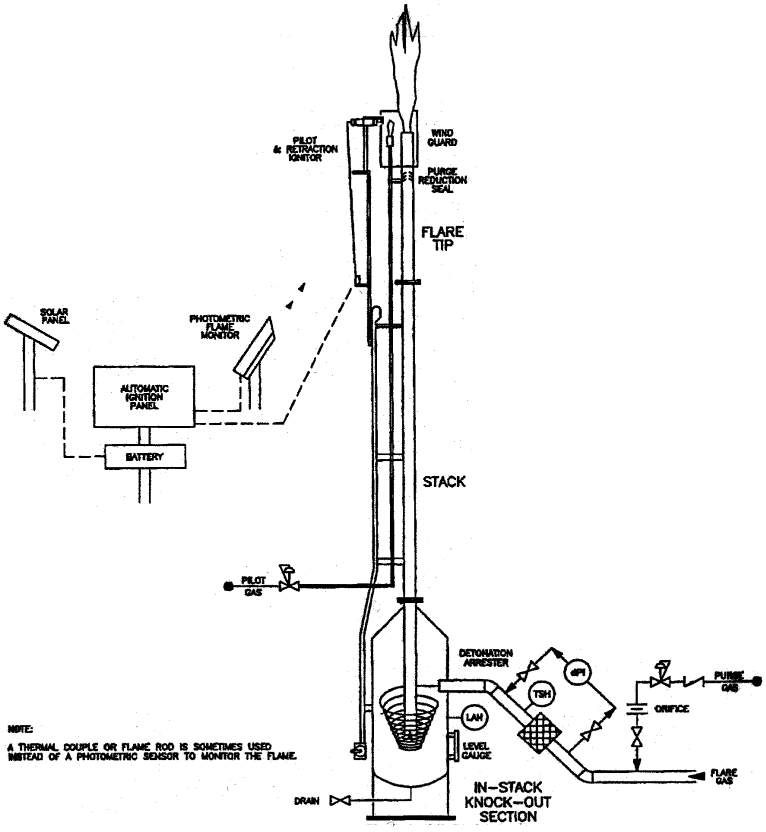

Figure 2.2 **Typical elements of a flare system.**

~~3.4.2~~2.3.2 Flare tips ~~shall~~ should be designed to provide good air/gas mixing. Use of multiple burner arrangements may be considered to achieve more highly aerated flames, which promotes smokeless combustion and improved combustion efficiency. Multiple tips may also be employed to reduce average exit velocities and thereby reduce flare noise and potentially radiant heat (i.e., through reduced flame length). Additionally, air or steam assist may be used to promote improved mixing. However, the latter form of flame assist is usually impractical to provide at oil production facilities. It is possible to quench the flare flame by excessive steam injection.

~~3.4.3~~2.3.3 Ignition System

(a) All continuous flares ~~shall~~ should be equipped with an auto-ignition system capable of igniting or re-igniting the flare in all weather conditions including winds up to 30 m/s (or 108 km/h). Manual ignition systems ~~shall~~ should only be acceptable for flares used on manual blowdown or purging systems.

(b) The minimum energy needed for ignition increases with flow velocity and turbulence intensity. It also increases with the molecular weight of the flare gas. The use of a pilot is complementary to, and helps reduce the necessary energizing capacity of an auto ignition system (i.e., the auto-ignition system maintains the pilot while the pilot maintains the main burner flame).

(c) Auto-ignition systems may either be a continuous sparking design or an auto-sparking design with flame failure detection. Flame failure may be detected using thermocouples (flame rods) or photometric sensors. The latter type of sensor is available as either a ground-level or elevated option.

~~3.4.4~~2.3.4 A flare pistol is still an essential item to keep on hand as a contingency measure~~,~~ but should only be used as a last resort and is not a replacement for proper maintenance. The potential for fire hazards ~~shall~~ should be assessed and appropriate precautionary measures taken before each use of a flare pistol.

~~3.4.5~~2.3.5 Wind guards ~~shall~~ should be designed to minimize any potential for reduced burner performance.

~~3.4.6~~2.3.6 Flare Stack

(a) The height ~~must~~ should be at least 12 ~~meters~~ metres and ~~shall~~ should be sufficient to control thermal radiation and pollutant concentrations at ground level. Radiant heat density at ground level ~~shall~~ should not exceed 4.73 kW/m^2.

(b) ~~(b)~~ If the operational characteristics change significantly (i.e. flow rates or H_2S concentrations), the adequacy of the flare system ~~shall~~ should be reaffirmed and the nameplate and datasheet information updated as appropriate. Plume and cumulative dispersion modelling should be conducted for all new flares and existing flares to confirm that the resulting maximum ground-level pollutant concentrations meet the applicable ambient air quality objectives.

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~~3.4.7~~2.3.7 Knockout Drum

(a) The knockout drum ~~shall~~ should be sized, designed and operated in accordance with API Recommended Practice 521. It ~~shall~~ should have:

- provisions for prevention of freezing or exposure to excessive thermal radiation;
- means to indicate the level of liquid in the device and to remove the accumulated liquids;
- a high liquid level sensor which activates an alarm; and
- a high liquid level sensor which actives an emergency shutdown of the facility or otherwise stops flow of liquid to the drum.

(b) In addition, it ~~shall~~ should be designed for the maximum pressure that may occur due to flow resistance through the system. This may require compliance with the ASME Boiler and Pressure Vessel Code. If the knockout drum is buried, it ~~must~~ should comply with EUB Guide G-55.

(c) All lines ~~shall~~ should be sloped downwards toward the knockout drum.

~~3.4.8~~2.3.8 Flare-Gas Enrichment System

(a) All necessary measures ~~shall~~ should be taken either to preclude any potential for air-gas mixtures upstream of the flare tip~~,~~ or to ensure enrichment of the flare gas to above 170 percent, by volume, of the upper flammable limit. If used, the enriching system ~~shall~~ should be located as close as practicable to the vapour source and be designed to promote complete mixing of the gases within 20 pipe diameters of the enriching-gas injection point. To ensure enrichment, the system ~~shall~~ should either use analyzers to control the amount of enriching gas~~,~~ or ~~else~~ use a constant supply of enriching gas that will satisfy all potential situations. In the latter case, the injection rate ~~shall~~ should be controlled using a fixed orifice for maximum reliability.

(b) Any ~~vapors~~ vapours from tanker trucks, or other potential oxygen-containing vapour mixtures, to be displaced into the flare system ~~shall~~ should first be enriched as specified above.

~~3.4.9~~2.3.9 Flame and Detonation Arresters

(a) A detonation arrester ~~shall~~ should be installed downstream of the knockout drum and as close as practicable to the flare inlet wherever an engineering review indicates a reasonable potential for air ingress (e.g. where vapours from storage tanks are directed to the flare). The installation of a detonation arrester ~~shall~~ should not lessen the need to properly design and maintain flare systems to minimize the risk or air ingress.

(b) A flame arrester normally is not acceptable in these applications due to manufacturer’s restrictions on the maximum allowable distance a flame arrester may be installed upstream of the ignition source (i.e. the flare tip). Where an arrester is used, it ~~shall~~ should be installed to allow efficient drainage of condensate without impairing its performance. In addition, the arrester ~~shall~~ should be designed to operate over the full range of gas and ambient temperatures anticipated. This includes provisions against freezing as needed (e.g. providing a heated and insulated enclosure). If frequent fouling is a concern, a spare arrester should be provided in parallel along with adequate valving so each arrester can be isolated and cleaned without the need for a facility shutdown. There should be easy access to service the arresters.

~~3.4.10~~2.3.10 All blowers and fans used to move gases through the flare system ~~shall~~ should be designed according to the applicable area classification requirements of the Canadian Electrical Code~~,~~ and either be spark resistant or isolated from the gas source by an appropriate flame or detonation arrester.

~~3.5~~2.4 Other Design Considerations

~~3.5.1~~2.4.1 All laterals from the sub header to the main header or individual safety valves to sub headers should be from above. The laterals should be ~~self draining~~self-draining without pockets.

~~3.5.2~~2.4.2 The minimum exit velocity ~~shall~~ should be greater than 1 to 2 m/s to help promote flame stability. The maximum exit velocities for continuous flare systems ~~shall~~ should not, during routine flaring, exceed a value of 0.2 Mach or such lesser value as may be required to maintain a stable flame. Higher velocities will produce increased flame liftoff and, correspondingly, increased unburned hydrocarbon emissions.

~~3.5.3~~2.4.3 An adequate safety zone ~~shall~~ should be established around each flare system to avoid potential harm from fire or radiant heat to personnel, equipment and buildings during both normal and emergency or upset flaring conditions.

~~3.5.4~~2.4.4 The procedure to find the heat of radiation and allowable exposure levels for various structures and personnel are detailed in API 521.

~~3.5.5~~2.4.5 Local regulations should also be consulted to determine any additional requirements that may apply in forest areas.

~~3.5.6~~2.4.6 After the stack height has been established from radiation intensity values, the maximum permissible ground level concentration of toxic gases in the event of a flame blowout should be evaluated applying dispersion modelling tools (see Section 9). The concentrations should remain within the Ambient Air Quality Standards given in Table 9.1 or as advised in ~~Paragraph~~ Section 9.7.

~~3.5.7~~2.4.7 Electrical Requirements

(a) All electrical equipment, fittings and devices must show approval for that use by Canadian Standards Association (CSA). Additionally, the entire flare system shall be electrically grounded and electrically continuous.

(b) Where practicable access to the electric utility grid is unavailable, consideration ~~shall~~ should be given to use of solar cells and thermoelectric generators to power any electrical instrumentation that may be needed. These power sources ~~sometimes~~ are also sometimes used to provide for limited lighting and electrical heat tracing.

~~3.5.8~~2.4.8 The flare system piping and fittings ~~shall~~ should be in accordance with CSA Z662 at pipeline facilities and with ASME B31.3 at plants for all pressurized portions of the system.

~~3.5.9~~2.4.9 A flare or any other combustion device ~~that receives~~receiving gas ~~which~~ that may condense or freeze at ambient conditions ~~shall~~ should be designed to preclude any condensation between the knockout drum and the burner tip. Some potential means to help control condensation include:

- minimizing the distance between the knockout drum and the burner tip;~~,~~
- providing enough heating/pre-heating and insulation to keep the gas above its dewpoint temperature; and~~, and~~

- commingling the waste gas with lighter gas streams (e.g., with associated gas from the inlet separator) to lower the dewpoint temperature of the mixture to below the exit or pre-combustion temperature at the burner-tip~~.~~.

~~3.5.10~~2.4.10 Flare control panels ~~shall~~ should be placed at a safe distance away from the base of the stack to protect them from thermal radiation as warranted~~,~~ and to prevent burning in the event a process upset resulting in liquid carry-over through to the flare tip occurs.

~~3.6~~2.5 Site Operation and Maintenance

~~3.6.1~~2.5.1 To mitigate flare atmospheric impacts, the owner/operator should:

- conduct visual inspections of the flare system as part of normal operator rounds;
- maintain detailed records of these inspections;
- service, repair and replace flaring system components as required and in accordance with the manufacturer’s specifications and recommended procedures; and
- adequately train the facility personnel to operate and maintain the flare system.

~~3.6.2~~2.5.2 Where changes occur in the operation of a flare, operators ~~shall~~ should re-evaluate the flare design to ensure that it is still suitable for the intended application. Also, existing and proposed solution gas flares ~~must~~ should consider the requirements for sulphur recovery~~,~~ and seek relief from these requirements where circumstances may warrant.

~~3.6.3~~2.5.3 Luminosity Control

(a) The occurrence of visible flames may promote negative public reaction in some areas. This may be mitigated through public awareness programs, shielding or enclosure of the flame~~,~~ and/or luminosity control. The amount of luminosity may be reduced by increasing air enrichment in the flame through increased jet velocities or numbers of burners, increased mixing in the flame through air or steam assist~~,~~ or by using premixed air-fuel burner designs.

(b) Most open flares produce a bright yellow flame. This yellow luminosity is usually due to carbon particles (or soot) that form in the flame and radiate strongly at the high combustion temperatures. Sooty flames appreciably increase the radiant heat transfer from the flare causing a reduction in peak flame temperature, and an increase in the required safety zone around the flare.

~~3.6.4~~2.5.4 Solution Gas Flaring

(a) Solution gas is the gas often mixed with oil when oil is removed from the ground. It is a complex mixture of gases containing water and liquid hydrocarbons.

(b) Flaring of solution gas is intended to manage safety concern when the solution gas cannot be conserved or used. Flare systems commonly consist of a flare pipe equipped with a pilot light and ignition system. Solution gas is injected into the air through the flare stack. The flare tip is designed to mix the gas with air to encourage burning and provide a flame over a range of conditions. A series of burners may be used if the gas flow is very variable.

~~3.6.5~~2.5.5 Natural Gas Flaring During Well Testing

(a) Alternatives to flaring such as temporarily tying in the well into an existing raw gas gathering system or reinjection should be considered, if available. Adequate reasons should be provided for considering flaring, if an alternative is available.

(b) During well testing, natural gas can be flared if the gas is:
- low sulphur i.e. less than 1% H_2S; and
- high sulphur i.e. up to 5% H_2S and is discharged into the air through a flare stack that has a minimum height of 12 ~~meters~~metres.

(c) Prior to testing, a gas sample analysis should be obtained from the formation to be tested. If a sample is not available, then the operator should conduct a review of similar formations in the region to obtain a representative gas analysis. The sample with the highest concentration of H_2S should be used in the application for permit to operate unless a reasonable argument can be made for using an analysis with a lesser H_2S concentration. The value of the representative sample should be confirmed as soon as possible by conducting a gas sample analysis. This is needed to determine the accuracy of the representative sample used for permitting.

~~3.7~~2.6 Estimation of Flare Emissions

~~3.7.1~~2.6.1 The owner/operator of the flaring facility can estimate flare emissions of hydrocarbons (VOC and HAP) based on estimates that:

(a) 2.2% of tank emissions are flared and 2% of flared gases from production sites are unburned; therefore, flare emissions are equal to estimated tank emissions times $4.4 \cdot 10^{-4}$

(b) emission factor equal to 20 scf of methane per Mcf of flared gas

(c) in rare cases where flared gas is not ignited by the pilot flame or electronic igniter, the flare will vent temporarily

(d) tank emissions venting to flares can be estimated by
- direct measurement (stack sampling);
- using AP-42 emission factors published by EPA; and
- applying TANKS4 computer model.

~~3.7.2~~2.6.2 Estimating VOC and HAP emissions from sources venting to flares is based on the gas processing rate and the destruction and removal efficiency of the flare. The following equation can be applied:

$$E_x = Q \cdot y_x \cdot 1/C \cdot MW_x \cdot (1 - D/100)$$

where E_x = emission estimate of pollutant x, lb/h
Q = gas process rate, scf/h
y_x = mole fraction of pollutant x in inlet stream, lb-mole x/lb-mole
C = molar volume of ideal gas, 379 scf/lb-mole
MW_x = molecular weight of pollutant x
D = destruction and removal efficiency, %

~~3.8~~2.7 Gas Sweetening Plant Flaring

~~3.8.1~~2.7.1 When flaring or incineration is practiced at gas sweetening plants, the major pollutant of concern is SO$_2$. Most plants employ elevated smokeless flares or tail gas incinerators for complete combustion of all waste gas constituents~~,~~ including virtually 100% conversion of H$_2$S to SO$_2$. Small particulate, smoke~~,~~ or hydrocarbons result from these devices, and because gas temperatures do not usually exceed 650°C (1200°F), significant quantities of nitrogen oxides are not formed.

~~3.8.2~~2.7.2 2.7.2 Emission factors for gas sweetening plants with smokeless flares or incinerators are presented in Table 2.1. Factors are expressed in units of kilograms per 1000 cubic ~~meters~~ metres (kg/10^3 m^3) and pounds per million standard cubic feet (lb/10^6 scf).

Table 2.1 Emission Factors for Gas Sweetening Plants [a]

Process [b]	**Particulate**	**SO$_2$[c]**	**CO**	**Hydro-carbons**	**NO$_x$**
Amine					
kg/10^6 m^3 gas processed	Neg	26.98 S [d]	Neg	Neg [e]	Neg
lb/10^6 scf gas processed	Neg	1685 S [d]	Neg	Neg [e]	Neg

Neg = Negligible

[a] Factors are presented only for smokeless flares and tail gas incinerators on the amine gas sweetening process with no ~~sulfur~~ sulphur recovery or ~~sulfuric~~ sulphuric acid production present. Too little information exists to characterize emissions from older, less-efficient waste gas flares on the amine process or from other, less common gas sweetening processes.

[b] Factors are for emissions after smokeless flares (with fuel gas and steam injection) or tail gas incinerators.

[c] Assumes that 100% of the H$_2$S in the acid gas stream is converted to SO$_2$ during flaring or incineration and that the sweetening process removes 100% of the H$_2$S in the feedstock.

[d] S is the H$_2$S content of the sour gas entering the gas sweetening plant, in mole or volume percent. For example, if the H$_2$S content is 2%, the emission factor would be 26.98 times 2, or 54.0 kg/1000 m^3 (3370 lb/10^6 scf) of sour gas processed. Note: If H$_2$S contents are reported in ppm or grains (gr) per 100 scf, use the following factors to convert to mole %:

10,000 ppm H$_2$S = 1 mole % H$_2$S
627 gr H$_2$S/100 scf = 1 mole % H$_2$S

The m^3 or scf are to be measured at 60°F and 760 mm Hg for this application (1 lb-mol = 379.5 scf).

[e] Flare or incinerator stack gases are expected to have negligible hydrocarbon emissions. To estimate fugitive hydrocarbon emissions from leaking compressor seals, valves, and flanges, see Section 4.

~~3.9~~2.8 Approval, Notification and Reporting

~~3.9.1~~2.8.1 Flaring approval should be obtained from the appropriate regulatory authority. ~~This regulatory authority would be one of the Land and Water Boards and/or Resources, Wildlife and Economic Development (RWED).~~ Approvals would most likely be part of Land Use Permit or Water License. The approval application process would have ~~a~~ similar elements as those listed in *Guide 60: Upstream Petroleum Industry Flaring Guide* of EUB enclosed as Appendix A.

~~3.9.2~~2.8.2 An owner or operator should notify the regulatory authority 24 hours prior to planned flaring and immediately for ~~or within 24 hours of~~ emergency flaring. ~~Provided~~ Required information should include notification date, time, location, operating company, contact name and telephone number, flaring commencement time, duration, rate, total volume, percentage H_2S~~,~~ and reason for flaring.

~~3.9.3~~2.8.3 A report of the flaring and monitoring operations ~~must~~ should be submitted to the regulatory authority within three weeks of the flaring completion date. The report ~~must~~ should include:

- H_2S and SO_2 concentrations;
- the actual volume of gas flared;
- maximum and average flow rates;
- wind speed and direction; and
- dates and times monitoring occurred.

~~3.9.4~~2.8.4 When measurement does not occur on all streams, engineering estimates must be used to report any flared gas not measured.

~~3.9.5~~2.8.5 Upon request by the regulatory authority, all operators ~~must~~ should be able to provide a documented system for flare measurement and/or flare estimation. Operators must also be able to provide, upon request, information on flaring and related public complaints.

~~3.9.6~~2.8.6 The regulatory authority ~~will~~ may require operators, on the basis of audit and inspections, to examine flare fuel gas use in cases where it appears that fuel gas use is excessive. An operator could use an engineering estimate to determine the split between residue fuel gas (processed gas) and overhead fuel gas (gas from plant vessels). Excessive fuel gas use in the flare for flare pilots and purge gas can contribute significantly to fuel use.

~~3.10~~2.9 Additional Information

For additional information, the owner/operator ~~shall~~ should refer to enclosed (Appendix A) *Guide 60: Upstream Petroleum Industry Flaring Guide* published by Alberta Energy and Utilities Board in July 1999. Prior to implementing any recommendations given in Guide 60, the owner/operator ~~shall~~ should obtain approval from the regulatory authority.

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~~4.~~3. FUGITIVE EMISSIONS

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~~4.1~~3.1 Introduction

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~~4.1.1~~3.1.1 Fugitive emission refers to release of gaseous substances such as hydrocarbon ~~vapors~~ vapours from oil and gas production and processing equipment and evaporation of hydrocarbons from open areas, rather than through a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, process drains, cooling towers~~,~~ and oil/water separators. Agitator seals are to be treated as pump seals using similar emission factors. Connections to equipment or piping other than flanges would be threaded fittings and compression couplings. Open-ended lines should be closed by a terminal valve or a blind flange or otherwise plugged. Sampling connection systems should have closed purge or closed vent systems.

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~~4.1.2~~3.1.2 Fugitive emissions are attributable to the evaporation of leaked or spilled petroleum liquids and gases. Normally, control of fugitive emissions involves minimizing leaks and spills through equipment changes, procedure changes~~,~~ and improved monitoring, housekeeping, and maintenance practices. Controlled and uncontrolled fugitive emission factors for the following sources are listed in Table 3.1.

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Table 3.1 Fugitive Emission Factors for Oil and Gas Facilities

Component Type	Facility Type			
	Production Field		Gas Processing Plant	
	THC, lb/day	ROC/THC Ratio	THC, lb/day	ROC/THC Ratio
Gas/Condensate Service				
Valve	0.295	0.31	1.0580	0.38
Connector	0.070	0.31	0.0580	0.43
Compressor Seal	2.143	0.31	10.7940	0.20
Pump Seal	1.123	0.31	3.3000	0.79
Pressure Relief Valve	6.670	0.31	9.9470	0.07
Oil Service				
Valve	0.0041	0.56	0.4306	0.33
Connection	0.0020	0.56	0.0694	0.33
Pump Seal	0.0039	0.56	1.3080	0.33
Pressure Relief	0.2670	0.56	1.7400	0.33

Notes: THC, lb/day = total hydrocarbons (including methane and ethane), pounds per day
ROC = reactive organic compounds (non-methane, non-ethane)

~~4.1.3~~3.1.3 Fugitive emissions ~~that are~~ released through a stack, duct or other confined controlled enclosure or sources controlled by specific equipment~~,~~ as well as area sources~~,~~ are not covered by this Air Quality Code of Practice.

~~4.1.4~~3.1.4 A leak in this Code is defined as the detection of a VOC concentration of 10,000 ppmv or more at the emission source using a hydrocarbon analyzer according to EPA Method 21 (see Section 8)~~,~~ or equivalent. It can become more stringent over time and may vary for different equipment components.

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~~4.1.5~~3.1.5 Equipment carrying ~~volatile organic compounds (~~VOC~~)~~ streams should be monitored. VOC streams are process streams containing at least 10 % VOC by volume.

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~~4.1.6~~3.1.6 The primary objective of the Code is the reduction of fugitive VOC emissions. It is appropriate that priorities be given to the most cost-effective alternatives available for meeting the objective.

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~~4.2~~3.2 Fugitive Emissions Estimate Methodology

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~~4.2.1~~3.2.1 Depending on the required accuracy of fugitive emissions estimate and availability of information, the owner/operator of an oil/gas facility estimates equipment leaks from a specific production/processing unit by:

- average emission factor method;
- leak/no-leak emission factor method (screening ranges approach);
- application of EPA corrections; and
- development of unit-specific correlations.

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Details of each of the above method are provided in Appendix C *Protocol for Equipment Leak Emission Estimates.*

~~4.2.2~~3.2.2 Steps to calculate fugitive emissions:

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(a) Identify all the refinery processes where gaseous/volatile substances are present.

(b) Define precisely the process unit boundaries. The exact basis for the unit definition should be documented. A simplified facility process flow diagram can usually provide the basis for segregating a facility into process blocks or units.

(c) On the flow diagram identify the major process streams (leakpaths) entering and leaving the process unit. The actual screening and data collection can be done most systematically by following each stream. In each process stream within a unit boundary determine the number of fugitive emission components that are in the different service types (valves, flanges, connectors, pressure relief valves, etc.) - refer to leakpath component counting guide (Table 3.2).

Table 3.2 Leakpath Component Counting Guide

Component Type	Number of Associated Leakpaths
Flanges and Connections	Each flange or threaded connection shall be counted as 1 connection. Valve bonnets and flanges shall be counted as connections. Connections and flanges associated with compressors, pumps, relief devices and sight glasses should be counted as connections.
Valves	Each valve shall be counted as having 1 valve stem and three associated connections (Valve bonnet and two flange or threaded connections). Low emitting or bellows stem valves should be listed separately.
Pump Seals	Each pumping device shall be counted as a separate pump seal on pumps utilizing a common driver. Pumps equipped with tandem or dual mechanical seals should be listed separately.
Compressor Seals	Each compressor cylinder shall be counted as a separate compressor seal on multiple cylinder compressors. Compressor seals that are vented to vapour recovery should be listed separately.
Open Ended Lines	Open ended lines should be sealed with a plug or with two closed valves. However, each leakpath associated with sealed open ended lines should be counted consistent with the leakpaths "valves" and "connections" above up to and including the second valve stem.
Pressure Relief Device	Each pressure relief device (PRD) not equipped with or vented to an emission control device shall be counted as 1 PRD. PRDs vented to control devices or equipped with rupture disks should be listed separately.

(d) Once all the fugitive emission components along the major streams have been screened, the unit should be divided into a grid to identify stream properties~~,~~ such as the individual stream compositions containing fugitive substances, the type of substance (gas, light liquid~~,~~ or heavy liquid), total time of operation of the process unit in the time under consideration (month, quarter, year)~~,~~ and other associated activities. Ideally, a chemical analysis of the stream should be conducted, but this is often unrealistic. Other sources of stream composition information are operating personnel, crude or feedstock assays, product specifications~~,~~ and speciation profiles. In the absence of the site specific information, some general guidance on the types and chemical composition for a process unit input and output streams can be based upon the unit purpose and operating conditions

(e) Calculate fugitive emissions (FE) for each equipment type using the equation:

$$FE = A \cdot AAF \cdot N \cdot WF$$

where: A = activity rate (hours of operation)
AAF = applicable emission factor for the equipment type
N = number of pieces of equipment of the applicable equipment type in the stream
WF = average weight fraction of the fugitive substance in the stream

Above equation may be used several times for the same equipment type for different concentrations. Alternatively, weighted average concentration may be calculated from the A and WF values and used in one calculation.

~~4.2.3~~3.2.3 Fugitive emissions can be estimated using the exact screening values (SV) recorded for each component. These concentration values are then converted into an equivalent emission rate using a correlation or equation shown in Table ~~4~~3.3. More details concerning fugitive emission correlations are provided in Appendix C.

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Table ~~4~~3.3 Screening Value Range Emission Factors

Equipment Type	Correlation
Gas valves	Leak rate (kg/h) = $1.87 \times 10^{-6} (SV)^{0.873}$
Light liquid valves	Leak rate (kg/h) = $6.41 \times 10^{-6} (SV)^{0.797}$
Light liquid pumps	Leak rate (kg/h) = $1.90 \times 10^{-5} (SV)^{0.824}$
Connectors	Leak rate (kg/h) = $3.05 \times 10^{-6} (SV)^{0.885}$

~~4.2.4~~3.2.4 Calculate total annual fugitive emissions of a particular substance for all types of equipment and report to the regulatory authority following appropriate protocols.

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~~4.2.5~~3.2.5 All major, critical, inaccessible~~,~~ and unsafe to monitor components, except fittings, ~~shall~~ should be clearly identified in diagrams for inspection, repair, replacement~~,~~ and record keeping purposes as approved by the regulatory authority.

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~~4.3~~3.3 Area Leak Rate Measurement

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~~4.3.1~~3.3.1 There may be some instances where a whole process area may be monitored for leakage and when no leakage is observed, all of the contained equipment and components therein can be rated as non-leaking. It is also feasible to rigorously control some process area ventilation systems and to organize specific exhaust streams to monitor the flow and composition of those streams to allow calculation of total mass emission rates. Continuous emission monitoring of a process area or a building is preferred over attempting bagging or once-only isolation and measurement.

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~~4.3.2~~3.3.2 Equipment carrying VOC streams should be monitored. VOC streams are process streams containing at least 10% VOC by volume.

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~~4.3.3~~3.3.3 Leak detection and repair (LDAR) will be applied to pipe sizes greater than, or equal, to 1.875 cm nominal diameter (¾ inch).

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~~4.3.4~~3.3.4 Exemptions:

- Components that are inaccessible;
- Valves less than ¾" or 1.875 cm nominal size;
- Valves that are not externally regulated (i.e. check valves);
- Components that are of leakless design (i.e. sealless pumps, bellow seal valves, pumps with double mechanical seals and a barrier fluid at higher pressure than operating pump pressure);
- Open-ended lines equipped with a cap, blind, flange, plug or second valve;

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- Pressure relief valves, pumps~~,~~ and compressors that are equipped with a closed-vent system capable of capturing and transporting any leak to a ~~vapor~~ vapour control system;
- Components exclusively handling commercial natural gas;
- Components buried below ground;
- Components, except those at gas processing plants, exclusively handling fluids with a volatile organic compound concentration of 10 percent by weight or less~~,~~ or components exclusively handling liquids, if the weight percent evaporated is 10 percent or less at 150ºC (302ºF);
- Components at oil and gas production facilities handling liquids of less than 30 degree API gravity ~~which~~ that are located after the point of primary separation of oil and gas provided the separation vessel is equipped with a vapour recovery system and the pressure of the fluid is at atmospheric; and
- Components incorporated in lines operating exclusively under negative pressure.

~~4.3.5~~3.3.5 The owner or operator ~~will~~ should develop a plan for fugitive VOC emissions (FVE) reduction for approval six months after notification by the regulatory authority.

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~~4.3.6~~3.3.6 The owner/operator of a plant site may divide the plant site into manageable, distinct entities for the purpose of LDAR program implementation, management and reporting.

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~~4.4~~3.4 Oil Wellhead Fugitive Emissions

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~~4.4.1~~3.4.1 Oil wellheads are the aboveground extension of oil wells where production control and measurement facilities are located. Potential leak sources of a typical oil wellhead are assumed to be valves, flanges, small pipe connections~~,~~ and a polished rod stuffing box. Typical wellhead with identified potential leaks components is shown in Figure 34.1.

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~~4.4.2~~3.4.2 For light crude wellheads (API gravity above 20°), the emission factor is estimated to be 16.6 scf per well per day (source: the API No. 4638 Workbook).

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~~4.5~~3.5 Separators, Heater Treaters, and Header Fugitive Emissions

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~~4.5.1~~3.5.1 Additional sources of fugitive emissions in the production sector are: separators~~, which~~ that separate oil, gas and water; heater treaters~~, which~~ that separate crude oil and water; and, headers~~, which~~ that are collection points for oil or gas gathering lines. The operator should make every effort to minimize emissions through implementation of strategies such as pollution prevention, best management practices, and emission control technologies.

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~~4.5.2~~3.5.2 Fugitive emissions from these sources, based on component leak rates from the API 4638 Workbook and average component numbers for each of the three sources, varied from near zero to 0.59 scf per source.

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~~4.6~~3.6 Drilling Fugitive Emissions

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No data for methane losses during oil well drilling operations have been identified. No emissions will occur until a hydrocarbon bearing formation is entered, at which point most emissions will be vented rather than fugitive.

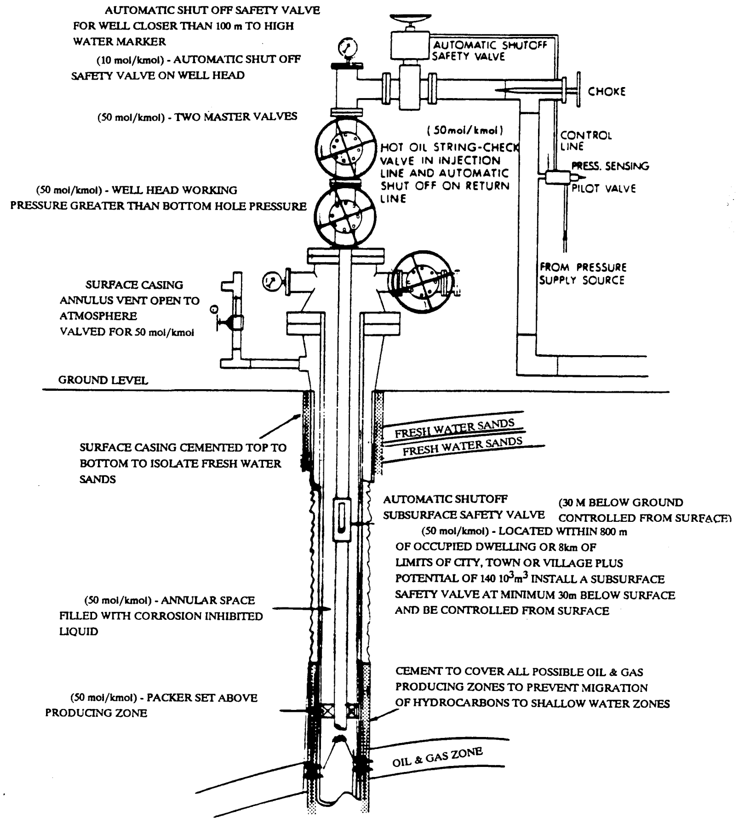

Figure 3.1 Oil wellhead with identified potential fugitive emission sources.

~~4.7~~3.7 Leak Detection and Repair

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~~4.7.1~~3.7.1 Leak detection and repair (LDAR) is required:

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(a) Quarterly for compressor seals and annually for all the other components.

(b) Immediately after repair for any component that was found to be leaking.

(c) Within 24 hours for a pressure relief valve that has been vented to the atmosphere.

~~4.7.2~~3.7.2 The leak frequency should not be more than 2% for any group of components monitored, excluding the category pumps/compressors.

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~~4.7.3~~3.7.3 The leak frequency of pumps/compressors should be less than 10% of the total number of pumps/compressors or three (3) pumps/compressors, whichever is greater.

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~~4.7.4~~3.7.4 If the leak frequency for a component (e.g. flanges) is less than 2% in two or more successive required LDARs monitoring, a statistical sampling method for that component, as approved by the regulatory authority, may be used to demonstrate that the component is in compliance with the 2% leak frequency.

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~~4.7.5~~3.7.5 The repair of leaks found during monitoring should start within 5 working days and complete within 15 working days unless a plant shutdown is required or the number of components requiring repair is beyond the current capability of the maintenance resources (a record of these exceptions and when they were corrected should be maintained).

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~~4.7.6~~3.7.6 All components subject to leak repair should be reinspected within one week of repairs.

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~~4.7.7~~3.7.7 Components, which cannot be repaired without a unit shutdown, should be identified and the repair planned for the next shutdown.

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~~4.8~~3.8 Compliance

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~~The owner/operator of an oil/gas production/processing facility will be in compliance when the requirements of the Code as defined in Paragraph 4.7 above are met.~~

~~4.8.2~~3.8.1 The owner/operator ~~shall~~ should maintain an inventory of sources and total emissions based upon the methodology in ~~Paragraph~~ Section 3.2 of this Code. The inventory ~~shall~~ should be available for review by the regulatory authority.

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~~4.8.3~~3.8.2 The results of emissions monitoring and evaluation should be reported to the regulatory authority in a pre-approved format.

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~~4.9~~3.9 Non-Compliance

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~~4.9.1~~3.9.1 When the leak detection and repair program is not met, ~~then~~ the owner/operator ~~shall~~ should repeat a full monitoring survey of all component sources at the next leak detection cycle.

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~~4.9.2~~3.9.2 In the case where two consecutive full monitoring cycles (after the agreed upon compliance deadline) fail to show a leak frequency of 2% or less for components excluding the category of pumps/compressors, the regulatory authority may require the implementation of a Quality Improvement Program (QIP) for those categories of components not in compliance.

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~~4.9.3~~3.9.3 For the category pumps/compressors, if the leak frequency is greater than 10% of the total number of pumps/compressors or three (3) pumps/compressors, whichever is greater, the regulatory authority may require the implementation of a Quality Improvement Program (QIP).

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~~4.9.4~~3.9.4 Any liquid leak or gas leak of over 50,000 ppm detected by the authorized inspector ~~shall~~ should be considered as non-compliance.

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~~4.9.5~~3.9.5 Any major gas leak detected by the authorized inspector, within any continuous 24-hour period, and numbering in excess of the Leak Thresholds for that component listed below in Table ~~4~~3.4, ~~shall~~ may constitute non-compliance.

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Table 3.4 Leak Thresholds

Component	Max. No. of Leaks	
	< 200 components inspected	> 200 components inspected
Valves	1	0.5% of number inspected
Pumps	2	1% of number inspected
Compressors	1	1
PRDs	1	1
Other Components	1	1

The maximum number of leaks in Table 3.4 shall be rounded upwards to the nearest integer, where required.

~~4.10~~3.10 Record Keeping

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~~4.10.1~~3.10.1 Records are to be kept for at least three years or as required in a form easily accessible by the regulatory authority.

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~~4.10.2~~3.10.2 Records should identify all components sampled, leaking or non-leaking, provide measurement details and document repair and replacement activities for leakers. This requirement will serve as a baseline for the total plant fugitive VOC emissions estimate.

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~~4.10.3~~3.10.3 The method of data preparation and tools for storing field information from equipment monitoring will be the sole responsibility of the owner/operator.

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~~4.11~~3.11 Reporting

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~~4.11.1~~3.11.1 Reporting for compliance with performance guidelines ~~shall~~ should be done according to the requirements of the regulatory authority with a uniform reporting format.

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~~4.11.2~~3.11.2 The report and attachments submitted to the regulatory authority shall be available to the public.

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~~4.11.3~~3.11.3 Annual reports ~~shall~~ should be submitted to the regulatory authority by a date as specified by the regulatory authority.

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~~4.12~~3.12 Quality Management

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~~4.12.1~~3.12.1 Consideration should be given to a total quality management program which includes:

- identification of poor performing equipment and prompt repair and replacement of these units;
- an ongoing review and analysis of available technology;
- in-plant performance trials;
- frequent inspection of control valves, pumps and compressor seals; and
- screening of equipment that has been taken out of service as it is returned to service.

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~~4.12.2~~3.12.2 Records should be kept that identify all components sampled and provide measurement details for those found to be leaking. Records should document repair and replacement activities for leakers.

~~4.13~~3.13 Operating Practices

~~4.13.1~~3.13.1 The owner/operator should consider the use of best available technology when replacing components in high leak frequency service.

~~4.13.2~~3.13.2 The emphasis on fugitive VOC emissions (FVE) reduction should be on high leakers as a priority with a concerted effort to reduce those to an acceptable level.

~~4.13.3~~3.13.3 Equipment should be monitored by trained personnel.

~~4.13.4~~3.13.4 FVE should be measured recognizing the difficulties associated with weather conditions.

~~4.13.5~~3.13.5 Equipment monitoring should be carried out with an understanding of the variables associated with leak detection.

~~4.14~~3.14 Additional Information

Additional information concerning fugitive emissions estimation methods and emission factors for fugitive leaks can be found in:

~~(a)~~(a) Protocol for Equipment Leak Emission Estimates EPA-453/R-95-017, November 1995, enclosed as Appendix C.

~~(b)~~(b) Protocol for Equipment Leak Emission Estimates EPA-453/R-95-017: appendices, examples of calculations available at www.epa.gov/ttn/chief/efdocs/lks95_ap.pdf.

(c) CCME Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks. Pub. No: PN1106, October 1993.

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~~5.~~4. PIPELINE EMISSIONS

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~~3.1~~4.1 Introduction

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~~5.1.1~~4.1.1 ~~3.1.1~~ Air emission sources of oil and gas transmission and distribution sectors include fugitive pipeline leaks, vents from pressure relief valves and pipeline compressor gas turbines. Natural gas pipelines are sources of VOC, HAP~~,~~ and hydrocarbons contained in the material. The natural gas turbines driving compressors at the stations ~~driving compressors~~ also contribute to overall pipeline system emissions. Despite the advantages of gas-fired generation, turbine emissions remain a concern for both air quality regulators and pipeline operators. Pipeline compressor gas turbines operate in simple cycle and cannot use exhaust cleanup systems. As a result, they cannot achieve near-zero emissions and operators are often required to install more expensive electric motor drives in emissions sensitive areas. Small amounts of natural gas are also emitted at the pipeline station sites from equipment and instrument vents.

~~5.1.2~~4.1.2 ~~3.1.2~~ Pigging operations are a potential source of VOC, HAP~~,~~ and hydrocarbon emissions if residual ~~vapors~~ vapours are vented to the atmosphere rather than to a flare or incinerator. As the pig travels through the pipeline, residual ~~vapors~~ vapours are pushed through the line as well. If the ~~vapors~~ vapours are not routed to a control device, they escape through openings on the device such as hatches, doors~~,~~ or vents. Emissions can be significant depending on the amount and ~~vapor~~ vapours pressure of the product. Depending on the gas used to push the pig, the bleed-off step can also result in emissions if the gas is not vented to a control device.

~~5.2~~4.2 Facility Design

~~3.2.1~~4.2.1 To assure no leak operation, the pipeline system ~~shall~~ should be designed and constructed up to relevant standards, guidelines and specifications, including *CSA Standard Z662*.

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~~3.2.2~~4.2.2 Instrumentation and control system ~~must~~ should be in place to monitor process conditions and to detect the presence of fire, fumes, ~~vapors~~ vapours or natural gas. In remote operations, the automatic system should shut down the station without human intervention. At staffed sites, a shut down should also be initiated by emergency shutdown pushbuttons located throughout the site.

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~~3.2.3~~4.2.3 For a new development, the minimum setback for a sour pipeline, based on~~(?)~~ a ~~the~~ H_2S release level, ~~must~~ should follow the following guidelines:

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(a) For level 1 (release volume < 300 m^3 or release rate < 0.3 m^3/s) – 100 m.

(b) For level 2 (release volume 300-2000 m^3 or release rate 0.3-2 m^3/s) – 100 m for individual buildings and 500 m for urban ~~centers~~ centres or public facilities.

(c) For level 3 (release volume 2000-6000 m^3 or release rate 2-6 m^3/s) – 100 m for individual buildings, 500 m for unrestricted rural development and 1,500 m for urban ~~centers~~ centres or public facilities.

(d) For level 4 (release volume > 6000 m^3 or release rate > 6 m^3/s) – distances specified by the authorized representative of the GNWT but not less than in corresponding level 3 circumstances.

~~3.2.4~~4.2.4 A sour pipeline ~~must~~ should have check and block valves so located that the release of within acceptable limits in the event of a leak.

~~3.2.5~~4.2.5 A sour pipeline ~~must~~ should include emergency shut down devices that close on the failure of any control or operating component.

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~~3.2.6~~4.2.6 Signs ~~must~~ should be posted at all sour pipeline facilities warning of the possible presence of H_2S and advising ~~about~~ of protective gear requirements.

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~~3.2.7~~4.2.7 Open-ended lines and valves located at the end of pipelines ~~shall~~ should be sealed with a blind flange, plug, cap~~,~~ or a second closed valve at all times except during operation. Operation includes draining or degassing operations, connection of temporary process equipment, sampling of process streams, emergency venting~~,~~ and other normal operational needs.

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~~3.2.8~~4.2.8 Pipeline supports ~~shall~~ should be designed to support the pipe without causing excessive local stresses and without imposing excessive axial or lateral friction forces that might prevent the desired freedom of movement ~~that~~ and could result in cracks leading to emissions.

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~~3.2.9~~4.2.9 Design of transmission and distribution sectors with regards to emission mitigation should consider the following:

- using fixed/portable compressors for pipeline pumpdown;~~,~~
- installing ~~vapor~~vapour/fuel recovery systems;~~,~~
- replacing wet gas seals with dry seals;~~,~~
- monitoring/replacing compressor rod packing systems; and
- re-routing glycol skimmer gas.

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~~3.2.10~~4.2.10 A Memorandum of Understanding (MOU) for the Harmonization for Oil and Gas Pipelines has been signed between the G~~g~~overnments of NWT and Alberta. The owner or operator of a gas/oil facility may approach the regulatory authority for detailed information on the MOU pertaining to air quality.

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~~3.2.11~~4.2.11 For other aspects of Air Quality Code of Practice with respect to sour pipeline design and operation, the owner or operator might refer to B.C. Reg. 359/98 M349/98 *Sour Pipeline Regulation* under *Pipeline Act* included in Appendix B for further guidelines.

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~~3.3~~4.3 Site Operation and Maintenance

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The operator ~~shall~~should:

(a) Include pipeline break detection and emission control equipment in designing of a new facility or upgrading the existing one.

(b) Have in place pipeline leak or line-break detection and troubleshooting system.

(c) Prepare and implement pipeline leak detection and fugitive emissions monitoring program.

(d) Modify such program from time to time as experience dictates and as changes in operating conditions require.~~,~~

(e) In addition to being concerned about leaks and line breaks, pipeline operator ~~shall~~ should focus on limiting harmful exhaust emissions from compressor engines.

(f) Obtain component inventory of pipeline facilities and auxiliary equipment.

(g) Develop and maintain, with necessary updating, an emergency response manual that has the approval of the chief inspecting engineer.

~~3.4~~4.4 Inspections

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~~3.4.1~~4.4.1 Pressure control, pressure limiting~~,~~ and pressure-relieving systems (or devices) ~~must~~ should be inspected at least once per calendar year. Records of such tests and inspections and the records of any corrective action taken ~~must~~ should be retained by the operating company.

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~~3.4.2~~4.4.2 Any annual inspection frequency listed in ~~Paragraph~~ Section 4~~3~~.4.1 ~~shall~~ should revert to the inspection frequencies specified by the regulatory authority should any liquid leaks and major gas leaks exceed 0.5 percent of the total components inspected per inspection period.

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~~3.4.3~~4.4.3 All leaking components ~~shall~~ should be affixed with brightly ~~colored~~coloured, weatherproof tags showing the date of leak detection. The tags ~~shall~~ should remain in place until the components are repaired and reinspected.

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~~3.4.4~~4.4.4 A pressure relief valve ~~shall~~ should be inspected according to EPA Reference Method 21 within 3 calendar days after every pressure relief.

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~~3.4.5~~4.4.5 The operator ~~shall~~ should maintain an up-to-date leaks inspection log containing, at a minimum, the following:

- name, location, type of components, and description of any unit where leaking components are found;~~,~~
- date of leak detection, emission level (ppm) of leak, and method of leak detection;
- date and emission level of re-check after leak is repaired; and
- total number of components inspected, and total number and percentage of leaking components found by component types.

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~~3.5~~4.5 Detection and Emergency Response

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~~3.5.1~~4.5.1 Leak detection systems ~~must~~ should be tested annually to demonstrate continued effectiveness.

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~~3.5.2~~4.5.2 A leak identified by ~~Paragraph~~ Section 4~~3~~.5.1 ~~shall~~ should be any fluid leak, a visual or audible ~~vapor~~ vapour leak, the presence of bubbles using soap solutions~~,~~ or a leak identified by the use of a ~~vapor~~ vapour analyzer.

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~~3.5.3~~4.5.3 Any ~~vapor~~ vapour leak ~~which is~~ identified during the inspection of components ~~shall~~ emission concentrations according to EPA Reference Method 21 or equivalent.

~~3.5.4~~4.5.4 The owner/operator of a pipeline transporting HVP liquids ~~must~~ should periodically conduct emergency exercises (simulation leaks) structured to test the licensee's internal capabilities for initial response to the emergency procedures described in its emergency procedures manual (see ~~Paragraph~~ Section ~~3~~4.3.g) and to test any leak detection and supervisory control and data acquisition systems associated with the pipeline.

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~~3.5.5~~4.5.5 Pipeline valves that might be required during an emergency ~~must~~ should be inspected and partially operated at least once per calendar year.

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~~3.5.6~~4.5.6 The operator ~~shall~~ should maintain failure/repair record of the pipeline system.

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~~3.5.7~~4.5.7 An emergency planning zone ~~must~~ should be maintained for each sour pipeline. The emergency planning zone of a sour pipeline is the area within a parameter formed by using the hydrogen sulphide release rate in ~~meters~~ metres per second or volume in cubic ~~meters~~ metres for the sour pipeline and finding the corresponding distance in ~~kilometers~~ kilometres using the graphs set out in the BC Sour Pipeline Regulation (ref: Appendix B).

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~~3.5.8~~4.5.8 Leaks from components ~~shall~~ should be immediately minimized to the extent possible to stop or reduce leakage to the atmosphere.

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~~3.5.9~~4.5.9 All leaks ~~shall~~ should be minimized to the extent possible and ~~shall~~ should be replaced with Best Available Control Technology (BACT) equipment within one year or during the next process unit shutdown, not to exceed two (2) years.

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~~3.5.10~~4.5.10 Any repaired or replaced component ~~shall~~ should be re-inspected in accordance with EPA Method 21 by the operator within 30 days of the repair or replacement.

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~~3.6~~4.6 Notification

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The owner or operator should report a leak or break to the 24-Hour Spill Report Line, and to the regulatory authority~~National Energy Board (NEB) and RWED~~. ~~Also the~~The NEB should be notified if there is any contact damage. The Spill Line ~~should~~ shall be notified if there is a reasonable likelihood of a spill. The NWT ~~Spill Contingency Planning and Reporting Regulations~~ *Spill Contingency Planning and Reporting Regulations* should be used as an oil spill reference.

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~~3.7~~4.7 Estimation of Pipeline Emissions

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~~3.7.1~~4.7.1 Fugitive Emission Factors is an alternative method of total hydrocarbons (THC) emissions estimation (see Section ~~3~~4).

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(a) The fugitive emission factors for oil pipelines reported by PSI (Pipeline Seal & Insulator, Inc., Houston, TX) is estimated to be 25 scf of petroleum hydrocarbons per pipeline-mile per year. Total annual oil pipeline emissions in scf would be 25 times total length of the pipeline.

(b) Fugitive emissions for pumping stations from potentially leaking equipment components such as valves, fittings, pumps, compressors, connectors, can be calculated in the following steps:

- obtain detailed component counts for each facility;
- determine service type (gas/condensate or oil) for each component; and
- calculate total hydrocarbon emissions in lb/day by multiplying the number of specific component types by a relevant THC emission factor (EF) listed in Table 4~~3~~.1.

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Table 4~~3~~.1 Fugitive Emission Factors for Production Fields

Component Type	Emission Factor EF lb/day
Gas/Condensate Service	
Valve	0.295
Connection	0.070
Compressor Seal	2.143
Pump Seal	1.123
Pressure Relief Device	6.670
Oil Service	
Valve	0.0041
Connection	0.0020
Pump Seal	0.0039
Pressure Relief Device	0.2670

- where applicable, reduce uncontrolled emissions generated in step above by the emission reduction factors (fraction of Control Efficiency) given in Table 4~~3~~.2.

Table 4~~3~~.2 Emission Reduction Factors

Leak Path Type	Control Measure	Control Efficiency, %
Valve	Bellow design	100
Valve	Monthly monitoring	84
Valve	Low emission stem packing	Determined by supplier
Compressor Seal	Vented to Vapour Recovery System	100
Pump Seal	Dual/tandem seal	100
Pressure Relief Device	Vent to VRS or equip with rupture disk	100
All	Maintain at no detectable emission	100
Other	Proposed by operator	Determined by supplier

~~3.7.2~~4.7.2 Emissions Screening Procedure, which gives higher accuracy of emission estimates than emission factor method, uses screening values and correlation equations. To implement this method, the owner/operator shall carry out the following tasks:

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(a) Measure concentrations of hydrocarbons around components with portable hydrocarbon detection analyzer (FID) type, calibrated and certified.

(b) Measure background concentrations and deduct them from concentrations recorded in ~~Paragraph~~ Section ~~3~~4.7.2 (a).

(c) Calculate total hydrocarbon emissions in lb/day by multiplying screening value (SV, ppmv) by relevant correlation equation listed in Table 4~~3~~.3.

Table ~~3~~4.3 EPA Correlation Equations (lb/day)

Component	Correlation Equation*
Threaded Connections	7.99×10^{-5} $(SV)^{0.735}$
Flange	2.35×10^{-4} $(SV)^{0.703}$
Valve	1.21×10^{-4} $(SV)^{0.746}$
Open-end	1.14×10^{-4} $(SV)^{0.704}$
Pump Seal	2.55×10^{-3} $(SV)^{0.610}$
Other	6.98×10^{-4} $(SV)^{0.589}$

* *Source: US EPA Protocol for Equipment Leak Emission Estimates EPA-453/R-95-017*

(d) Summarize total hydrocarbon releases by adding releases from all fittings in each class of components providing that all were screened for SV.

~~3.7.3~~4.7.3 Methane leakage rates from crude pipelines are estimated to be essentially zero, since crude is nearly totally degassed in storage tanks and any crude leaks from production area piping are quickly repaired.

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~~3.8~~4.8 Stationary Combustion Turbine Emissions

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~~3.8.1~~4.8.1 The owner or operator should develop and operate various types of combustion turbines driving gas compressors or oil pumps in a manner ~~which~~ that restricts emissions of nitrogen oxides (NO_x), sulphur dioxide (SO_2)~~,~~ and carbon monoxide (CO) with emission targets specified by CCME in National Emission Guidelines for Stationary Combustion Turbines.

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~~3.8.2~~4.8.2 In the case where multiple new small combustion turbines are installed instead of a single large unit, the applicable unit size for the purposes of this Guideline will be the sum of the individual unit power ratings. While it is recognized that operational requirements may dictate the use of several units, multiple small units should not be used to evade the more stringent limits applicable to larger units.

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~~3.8.3~~4.8.3 In the case where a combustion turbine facility uses auxiliary burners, the Guideline limits apply to all fuel consumed by the facility, the fuel used in the auxiliary burners being treated as if it had been burned in the combustion turbine.

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~~3.8.4~~4.8.4 To determine the useful energy output over and above electrical or shaft power production, it is only necessary to measure the difference between the energy of the thermal fluids leaving and returning to the combustion turbine facility~~,~~ and to demonstrate that the bulk of this energy is extracted in a useful application. This avoids ~~having~~ the need to individually measure the energy consumed by each downstream thermal energy application process in determining the heat output allowance.

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~~3.8.5~~4.8.5 The CCME emission targets for stationary combustion turbines are:

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(a) Emissions of Nitrogen Oxides

The emission targets for various types of combustion turbines are determined by calculation of the allowable mass of NO_x (grams) per unit output of shaft or electrical energy (GigaJoules), as well as an allowance for an additional quantity of NO_x emitted if useful energy is demonstrated to be recovered from the facility's exhaust thermal energy during normal operation. Allowable emissions over the relevant time period equal:

$$(\text{Power Output} \cdot A) + (\text{Heat Output} \cdot B) = \text{Grams of } NO_2 \text{ Equivalent}$$

where: Power Output is the total electricity and shaft power energy production expressed in GigaJoules (3.6 GJ per MWh);
Heat Output is the total useful heat energy recovered from the combustion turbine facility;
"A" and "B" are the allowable emission rates, expressed in grams per gigajoule, for the facility's power and heat recovery components respectively, as summarized below.

Power output allowance "A" (g/GJ):

Turbine Type	Natural Gas	Liquid Fuel
Non-peaking		
< 3 MW	500	1250
3 – 20 MW	240	460
> 20 MW	140	380
Peaking		
< 3 MW	Exempt	Exempt
> 3 MW	280	530

Heat recovery allowance "B" for all type of turbines:

Fuel Type	B (g/GJ)
Natural Gas	40
Liquid	60
Solid-Derived	120

(b) Emissions of Carbon Monoxide

Emissions of CO corrected to 15 percent oxygen and on a dry volume basis should not exceed 50 parts per million at its power rating.

(c) Emissions of Sulphur Dioxide

Sulphur dioxide emissions for liquid and gaseous fuels for non-peaking units should not exceed 800 grams per gigajoule of output and for peaking units, 970 grams per gigajoule of output, all based on the lower heating value of the fuel.

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~~5.0~~5. VENTING

~~6.1~~5.1 Introduction

~~6.1.1~~5.1.1 Venting is the controlled release of gases into the atmosphere in the course of oil and gas production operations. These gases might be natural gas or other hydrocarbon vapours, water vapour, and other gases, such as carbon dioxide, separated in the processing of oil or natural gas.

~~6.1.2~~5.1.2 In venting, the natural gases associated with the oil production are released directly to the atmosphere and not burned. Safe venting is assured when the gas is released at high pressure and is lighter than air. Because of the strong mixing potential of high-pressure jets, the hydrocarbon gases discharged mix well with the air down to safe concentrations at which there is no risk of explosion.

~~6.1.3~~5.1.3 Venting emissions from oil and natural gas production facilities and natural gas transmission and storage facilities occur during the separation, upgrade, transport, and storage of crude oil, condensate, natural gas~~,~~ and related products and by-products.

~~6.1.4~~5.1.4 Examples of vented emissions are the continuous releases from vented storage tanks; occasional depressurizing of process equipment and piping prior to maintenance procedures; and, cycling releases from equipment that is driven by pressurized gas, such as pneumatic control devices and chemical injection pumps.

~~6.1.5~~5.1.5 Potential venting points at a gas and oil production plant are pointed out in Figure 5.1.

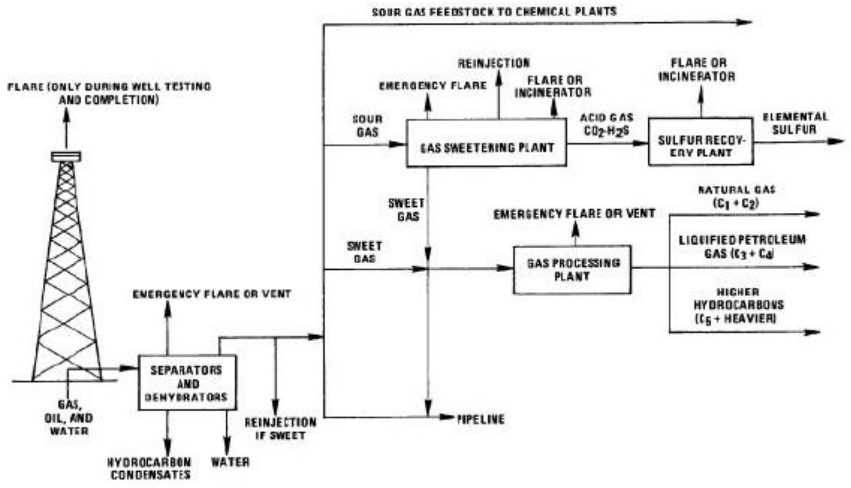

Figure 5.1 **Venting and flaring outlet at a gas and oil production plant.**

~~6.1.6~~5.1.6 Venting emission points at major oil and natural gas processing facilities includes process vents at certain size glycol dehydration units and tanks with flashing emission potential.

~~6.1.7~~5.1.7 In some cases, venting is the best option for disposal of the associated gas. For example, in some cases, a high concentration of inert gas is present in the associated gas. Without a sufficiently high hydrocarbon content, the gas will not burn and flaring is not a viable option. Sometimes the source of inert gas may come from the process systems. The purging of process systems with inert gas may, in itself; justify venting as the safest means of disposal.

~~6.1.8~~5.1.8 Venting takes place during routine maintenance that includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes (blowdown) for periodic testing or repair. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells (well workovers) and during replacement or maintenance of fittings.

~~6.1.9~~5.1.9 Venting is practiced during system upsets and accidents. The most common upset is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure. Release systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and reinjected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or send gases to flare systems where complete combustion may not be achieved.

~~6.1.10~~5.1.10 The frequency of system upsets varies with the facility design and the operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions. Emissions associated with accidents are also included in the category of upsets.

~~6.2~~5.2 Sources of Vented Emissions

~~6.2.1~~5.2.1 High-Bleed Pneumatic Device Vented Emissions~~.~~

The pressurized gas that is released from the crude in the separator is often used in a facility's process control systems. The gas is used to transmit signals between sensing and control devices and to drive automatic control valves for controlling liquid levels, flow rates~~,~~ and pressures. Pneumatic control valves are designed to bleed gas to the atmosphere as they cycle up and down to modulate the system being controlled. Venting from high-bleed pneumatic devices is the second largest source of methane emissions from the oil industry. It is calculated from the emission factor of 350 standard cubic feet per day (scfd) per device.

~~6.2.2~~5.2.2 Low-Bleed Pneumatic Device Vented Emissions~~.~~

Venting from low-bleed rate pneumatic controllers is estimated to be only 10 percent of the activity factor for high-bleed devices, or 35 scfd per device.

~~6.2.3~~5.2.3 Chemical Injection Pump Vented Emissions~~.~~

Chemical injection pumps are used to inject various chemicals into crude oil at the well site. The injected chemicals are used to break oil-water emulsions, inhibit corrosion, dewax paraffins, kill bacteria~~,~~ and control other processing problems. As in the case of pneumatic devices, the pressurized natural gas that is frequently available at oil production sites may be used to drive chemical injection pumps. The estimated average emission rate for each pump is 91 Mcf/y. The activity factor is computed by using the estimate that 25 percent of pumps are driven by gas. The remainder are driven mechanically or by electric motors or compressed air.

~~6.2.4~~5.2.4 Stripper Well Vented Emissions~~.~~

Stripper wells are those that produce fewer than ten barrels of oil a day. The average production rate for stripper wells is 2.1 barrels per day; approximately one-third of the stripper wells produce an average of one barrel of crude per day. Methane is emitted from the casing head valves on an estimated 80 percent of stripper wells that are left open to maximize oil flow. This is because gas pressure buildup in the well casing can restrict the already slow drainage of oil from the reservoir into the well. Based on an estimated gas/oil ratio of five scf of gas per barrel of crude, the annual total hydrocarbon gas emission is 3,832 scf per stripper well. Using the API speciation fraction of 0.612 for light oil methane content, the annual methane emission factor is 2,345 scf per stripper well.

~~6.2.5~~5.2.5 Storage Tank Vented Emissions~~.~~

Storage tank vented emissions, which come from tank farms associated with crude terminals and pipelines, are estimated to be 20.6 scf per 1,000 barrels of crude.

~~6.2.6~~5.2.6 Pumping Station Vented Emissions~~.~~

Very small amounts of methane are emitted from crude that is exposed to the atmosphere when pipeline pumping stations are dismantled for maintenance. It has been estimated that only 36.8 scf is released per station each year.

~~6.2.7~~5.2.7 Pipeline Pigging Vented Emissions~~.~~

Pigs, or scrapers, are cylindrical devices, equipped with blades and brushes, that are used to clean build-ups of water, rust, wax, sludge~~,~~ or other materials from pipelines. Pipeline pigging operations are a potential source of methane emissions when pig stations are opened to inject and recover pigs. CAPP estimates that the emission factor for pig stations is 39 scf per day per station.

~~6.2.8~~5.2.8 Other Vented Emissions~~.~~

There are several smaller sources of vented emissions in the oil and gas production sectors such as pressure vessel and compressor blowdowns, compressor starting~~,~~ and oil well completions and workovers. Total vented emissions from these sources are insignificant.

~~6.3~~5.3 Upset Vented Emissions

~~6.3.1~~5.3.1 Upset emissions are unintentional releases that occur when a process goes out of control. Examples of process upset emissions are releases from emergency pressure relief valves and oil well blowouts during oil well drilling operations.

~~6.3.2~~5.3.2 Process upset venting is the least significant source of methane emissions in the oil production sector. Upsets include offshore platform emergency shutdowns, pressure relief valve (PRV) releases~~,~~ and well blowouts.

~~6.3.3~~5.3.3 Pressure relief valves (PRVs) are usually installed on pressurized vessels to prevent catastrophic failure of the vessel from an uncontrolled pressure rise. In production facilities, the usual pressure vessels are separators and heater treaters. The emission factor of 34 scf/y per PRV has been used by the oil industry.

~~6.3.4~~5.3.4 Oil well blowout emissions occur when a drill bit enters a reservoir that is pressurized above the pressure level expected for the well depth. Normally anticipated pressures are approximately equal to the hydrostatic head of a column of salt water to the depth of the well. Higher pressures can be caused by water drives that have sources at higher altitudes than the well head or by geopressuring from soil overburden buildup on unconsolidated reservoir sands as can occur beneath river deltas. The emission factors are very uncertain though gas and oil industry. ~~(This sentence is incomplete).~~

~~6.3.5~~5.3.5 The owner or operator of any gas/oil production or processing facility during malfunction, startup, shutdown or scheduled maintenance could be excused of temporary noncompliance with applicable Ambient Air Quality Standards (AAQS) providing that:

(a) The inconsistency with any air quality control regulation results from a malfunction or damage to process or air pollution control equipment, result from unavoidable conditions during startup or shutdown, or result from scheduled maintenance.

(b) Repairs to the equipment causing the excess emissions are made with maximum reasonable effort, including the use of off-shift and overtime labour as needed.

(c) The emission of air contaminants is minimized as much as practicable during the period of excess emissions.

(d) Excess emissions do not occur with such frequency that careless, marginal or unsafe operation is indicated.

(e) The air contaminant is not of a nature or quantity which would endanger public health or safety.

~~6.3.6~~5.3.6 The owner or operator of the facility experiencing the malfunction, startup or shutdown~~,~~ ~~shall~~ should notify the regulatory authority verbally as soon as possible, but no later than 24 hours after the start of the next regular business day, and ~~shall~~ should submit written notification within 10 days following the initial occurrence of the excess emissions.

~~6.3.7~~5.3.7 In the case of scheduled maintenance, the owner or operator of the facility ~~shall~~ should notify the regulatory authority verbally no later than 24 hours prior to the initial occurrence of the excess emissions and ~~shall~~ should submit written notification within 10 days after the start of the next regular business day. The notification ~~shall~~ should include:

- the name of the firm experiencing the malfunction, startup, shutdown or scheduled maintenance and the name and title of the person reporting;

- the location of the facility at which the malfunction, startup, shutdown or scheduled maintenance occurred or is occurring;
- identification of the equipment involved and the emission point or points (including bypass) from which the excess emissions occurred or are occurring;
- the approximate, or if available, the specific time period that the facility was or will be experiencing excess emissions;
- identification of the air contaminant or contaminants and an estimate of the magnitude of excess emissions expressed in the units of the applicable emission limit for the air contaminant or contaminants of excess emission;
- the cause and nature of the malfunction condition or shutdown and the reasons why excess vent emissions occurred or are occurring; and
- the efforts taken to minimize emissions and efforts to repair or otherwise bring the facility into compliance with the applicable emission limits or other requirement.

~~6.3.8~~5.3.8 If the period of excess emissions extends beyond the submittal of the written notification, the owner or operator of the facility ~~shall~~ should also notify the regulatory authority in writing of the exact time period when the excess emissions no longer occurred.

~~6.4~~5.4 Estimation of Vented Emissions from Gas and Oil Systems

~~6.4.1~~5.4.1 Emission estimate from venting points shall be accomplished by direct measurement (see ~~Paragraph~~ Section 8) or by any of the simplified methods based on activity data, the emission factors~~,~~ and computer programs when it is not practical to ~~meter~~ metre vented or flared gas.

~~6.4.2~~5.4.2 Estimating methods must account for all gas flared or vented (expressed to the nearest 100 m^3/month) from the facility, including routine, emergency~~,~~ and maintenance operations and depressuring of vessels, compressors~~,~~ and pipelines.

~~6.4.3~~5.4.3 Estimates must be based on calculations that account for the volume, gas composition, temperature~~,~~ and initial and final pressures of systems vented or depressurized to flare.

~~6.4.4~~5.4.4 Procedures for estimating vented or flared volumes must be developed by a qualified technical person, documented~~,~~ and available for inspection by the regulatory authority.

~~6.4.5~~5.4.5 A formal system for logging and reporting flaring or venting incidents ~~must~~ should be in place and include procedures for reporting the information to the regulatory authority.

~~6.4.6~~5.4.6 The owner or operator will be expected to produce documented vents estimating procedures, reporting procedures~~,~~ and logs for review by the regulatory authority as required. The regulatory authority may require installation of ~~meters~~ metres in instances where there are repeated failures to demonstrate adequate flare or vent gas estimating and reporting systems.

~~6.4.7~~5.4.7 Venting from oil storage tanks is the largest source of methane emissions in the oil industry. These tanks hold crude oil that has flown through a separator (a pressure vessel used to separate well fluids into oil, gas, and water). When the crude enters the storage tanks, which are at atmospheric pressure, some of the dissolved gases and lighter liquid hydrocarbons flash off (~~vaporize~~vapourize). Most of these tanks are vented to the atmosphere, allowing methane and other gases to escape.

~~6.4.8~~5.4.8 Estimation of methane emission based on activity data requires calculation of activity level expressed in million Btu (MMBtu) from oil production data in barrels and gas production data in thousand cubic feet (Mcf) applying conversion factors given in Table 5.1.

Table 5.1 Conversion Factors to Million BTU (MMBtu)

Product Type	Unit of Production	Multiply by
Crude Oil	Barrels	5.800
Natural Gas	Thousand Cubic Feet	1.000

Median estimate of methane emissions in pounds is calculated from the formula:

Lbs CH_4 = Activity Level (MMBtu) x~~·~~ Emission Factor (median, lb CH_4/MMBtu)

Emission factors are given in Table 5.2.

Table 5.2 Methane Emission Factors for Oil and Gas Activities

Activity	Emission Factor (lb CH_4/MMBtu)		
	Low	High	Median
Gas Production	0.1069	0.1952	0.1510
Oil Production	0.0007	0.0116	0.0062
Oil & Gas Venting	0.0035	0.0163	0.0099

Another method of methane emissions estimation is based on the emission factor of 18 scf of CH_4 per barrel of oil.

~~6.4.9~~5.4.9 The use of a displacement equation is the preferred method for estimating VOC, HAP, and CH_4 emissions from emergency and process vents, gas actuated pumps, pressure/level controllers, blowdown, well blowouts~~,~~ and well testing. The displacement equation can also be used to estimate H_2S and CO_2 emissions from gas sweetening units venting to the atmosphere and for H_2S emissions from mud degassing operations. The following equations can be applied to estimate emissions when no chemical conversion occurs:

$$E_x = Q \cdot MW \cdot X_x \cdot 1/C$$

where:

E_x = Emissions of pollutant x
Q = Volumetric flow rate/volume of gas processed
MW = Molecular weight of gas
X_x = Mass fraction of pollutant x in gas
C = Molar volume of ideal gas, 379 scf/lb-mole at 60°F and 1 atmosphere

Speciated VOC emissions are calculated using the following equation:

$$E_x = E_{VOC} \cdot X_x$$

where:

E_x = emissions of pollutant x
E_{VOC} = total VOC, calculated using the E_x equation
X_x = mass fraction of species x in VOC

~~6.4.10~~5.4.10 Vented emissions can be calculated using computer models. They are the preferred emission estimation technique for glycol dehydrators, storage tanks, flash losses from black oil systems~~,~~ and volatile organic compounds (VOC) and hazardous air pollutants (HAP) losses from amine-based gas sweetening units venting to the atmosphere. Depending on the purpose of the inventory, the owner or operator of a gas/oil facility should check with the regulatory authority to confirm the model is acceptable. Two most common computer models are as follows:

(a) VOC and HAP emissions from glycol dehydrators can be estimated using the GLYCalc model. GLYCalc provides users the option of applying thermodynamic equations or the Rich/Lean method to estimate emissions. The model requires process-specific data to produce an accurate emission estimate. As with any emission estimation model, the user should be cautious when collecting this data to make sure the correct data is collected at the right point in the process line. In addition, models including GLYCalc offer default values for some parameters if process-specific data is not available. While simplifying the data collection process, use of defaults that are not appropriate for a particular unit may result in invalid or inaccurate emission estimates. In all cases, therefore, the user is encouraged to collect and use process-specific data to obtain the most accurate emission estimate. More information about GLYCalc as available on the Internet at www.gri.org/pub/env-new/final/products/gly4.html.

(b) A Windows-based computer software program TANKS4 estimates VOC and HAP emissions from fixed- and floating-roof storage tanks. TANKS is based on the emission estimation procedures from EPA's *Compilation of Air Pollutant Emission Factors (AP-42).* The program includes on-line help for every screen. The program uses chemical, meteorological, roof fitting, and rim seal data to generate emissions estimates for several types of storage tanks, including:
   - vertical and horizontal fixed roof tanks;
   - internal and external floating roof tanks;
   - domed external floating roof tanks; and
   - underground tanks.

   To use the program, the operator shall enter specific information about storage tank construction and the stored liquid. The program produces a report estimating VOC emissions. A batch mode of operation is available to generate a single report for multiple tanks. Current version 4.09 of the TANKS software is available at the Internet site www.epa.gov/ttn/chief/software/tanks/

~~6.5~~5.5 Venting Control

~~6.5.1~~5.5.1 To protect the atmosphere from vented air pollutant, the owner or operator of a gas or oil facility should consider a well-maintained ~~vapor~~vapour-recovery system consisting of:

(a) A ~~vapor~~vapour-gathering system capable of collecting the ~~vapor~~ vapour and gases discharged.

(b) A ~~vapor~~vapour-disposal system capable of processing the ~~vapor~~ vapour and gases so as to minimize emission of HAP to the atmosphere.

(c) Any other device that is at least as efficient to minimize the loss of vented ~~vapor~~ vapour or gas containing HAP to the atmosphere.

(d) A floating roof, consisting of an external floating roof, internal floating cover or covered floating roof~~, which is~~ equipped with a closure seal or seals maintained in good repair to close the space between the roof or cover edge and tank wall, if the stationary tank or other container is equipped with a floating roof.

~~6.5.2~~5.5.2 If continuous vent volumes are sufficient to support combustion, the gas should generally be burned in a flare to lower equivalent greenhouse gas CO_2 emissions, providing that releases are of 24 hours or less in duration.

~~6.6~~5.6 Sour Well Venting

~~6.6.1~~5.6.1 The classification of critical sour wells is based on two primary criteria, H_2S release rate potential and the wells' proximity to urban ~~centers~~centres. A critical sour well includes:

(a) Any well located within 500 m of the corporate boundaries of ~~located~~ an urban ~~center~~centre ~~from which~~ where the maximum potential H_2S release rate is from 0.01 m^3/s to 0.1 m^3/s. ~~and which~~

~~located within 500 m of the corporate boundaries of an urban centre~~

(b) Any well located within 1.5 km of the corporate boundaries of an urban centre ~~from which~~where the maximum potential H_2S release rate is from 0.1 m^3/s to 0.3 m^3/s. ~~and which is located within 1.5 km of the corporate boundaries of an urban centre~~

~~(c)~~(c)Any well located within 5.0 km of the corporate boundaries of an urban centre ~~from which~~where the maximum potential H_2S release rate is from 0.3 m^3/s to 2.0 m^3/s.~~and which is located within 5.0 km of the corporate boundaries of an urban centre~~

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~~6.6.2~~5.6.2 In instances where expected productivity or concentration of H_2S was not realized, as a result of reservoir depletion or any other factors that resulted in a reduction in the maximum H_2S release rate at the well, the regulatory authority will consider applications to remove the sour well critical designation. Applications to reclassify the well to a non-critical designation ~~shall~~ should be based on the most recent and complete information available.

~~6.7~~5.7 Glycol Dehydration Unit Process Venting

~~6.7.1~~5.7.1 This section applies to each glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85,000 standard cubic ~~meters~~ metres per day and with actual average benzene glycol dehydration unit process vent emissions equal to or greater than 0.90 tonnes per year. The owner or operator should follow the voluntary approach agreed to by a multi-stakeholder task force whereby the oil and gas industry committed to reduce and report on benzene emissions from natural gas dehydrators by implementing *Best Management Practices for the Control of Benzene Emissions from Glycol Dehydrators*.

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~~6.7.2~~5.7.2 The owner or operator ~~shall~~ should connect the process vent to a control device or control devices through a closed-vent system and the outlet benzene emissions from the control device(s) ~~shall~~ should be reduced to a level less than 0.90 tonnes per year.

~~6.7.3~~5.7.3 As an alternative to the requirements of ~~Paragraph~~ Section 5.7.2 ~~of this section~~, the owner or operator may comply with one of the requirements:

(a) Control air emissions by connecting the process vent to a process natural gas line.
(b) The total HAP emissions to the atmosphere from the glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices.
(c) Total benzene emissions to the atmosphere are reduced to a level less than 0.90 tonnes per year from the glycol dehydration unit process vent.

~~6.8~~5.8 Venting Requirements and Recommendations

~~6.8.1~~5.8.1 Where it is not practical to recover or flare gas, the regulatory authority may accept venting of small volumes of gas. Venting may be considered as an alternative for disposition of small gas volumes from compressor vents, instrument gas systems, pneumatic devices, dehydrators~~,~~ and storage tanks.

~~6.8.2~~5.8.2 Gas ~~shall~~ should not be vented if it constitutes an unacceptable fire or explosion hazard on or off the facility lease.

~~6.8.3~~5.8.3 Venting of gas containing H_2S to the atmosphere ~~must~~ should not result in exceedance of applicable Ambient Air Quality Guidelines for H_2S or Occupational Exposure Levels for H_2S.

~~6.8.4~~5.8.4 Stock tank vapours and other gas emissions from batteries receiving gas or having vapours containing more than 10 moles of H_2S per kilomole of gas ~~must~~ should be burned.

~~6.8.5~~5.8.5 Continuous venting of gas containing H_2S and other odorous compounds ~~must~~ should not result in odours outside the lease boundary.

~~6.8.6~~5.8.6 The true vapour pressure of hydrocarbon product stored in atmospheric storage tanks ~~shall~~ should not exceed a true vapour pressure of 83 kilopascals where such tanks are vented to the atmosphere.

~~6.8.7~~5.8.7 An appropriate flame arrester or equivalent safety device ~~must~~ should be used on all vent lines from oil storage tanks connected to flare stacks.If the owner or operator has reason to expect that the benzene content of vented gas exceeds 5 moles per kilomole, then site vent gas benzene emissions ~~must~~ should be assessed and, if necessary, controlled so that total benzene emissions for the facility or lease site will not exceed:

(a) 3.0 tonnes per year for new facilities.
(b) 5.0 tonnes per year for facilities commissioned prior to the issuance of this Code.
(c) Any other well which the regulatory authority classifies as a critical sour well having regard to the maximum potential H_2S release rate, the population density, the environment, the sensitivity of the area where the well is located~~,~~ and the expected complexities during the completion or servicing operation.

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~~8.1~~6.1 Introduction

~~8.1.1~~6.1.1 Hydrogen sulphide (H_2S) is a byproduct of processing natural gas and high-sulphur crude oils. The recovered hydrogen sulphide gas stream may be:

- v~~V~~ented;~~,~~
- flared in waste gas flares or modern smokeless flares;~~,~~
- incinerated;~~,~~ or
- utilized for the production of elemental sulphur or sulphuric acid.

If the recovered H_2S gas stream is not to be utilized as a feedstock for commercial applications, the gas is usually passed to a tail gas incinerator in which the H_2S is oxidized to SO_2 and is then passed to the atmosphere out a stack becoming an air contaminant.

~~8.1.2~~6.1.2 To protect the atmospheric environment from excessive H_2S emissions, the Claus process is used to convert H_2S to elemental sulphur. The Claus process is the most common conversion method in which approximately 90 to 95 percent of sulphur released by gas and oil industry is recovered. At normal operating temperatures and pressures, the Claus reaction is thermodynamically limited to 97 to 98 percent recovery.

~~8.1.3~~6.1.3 Components of gas processing facility which includes a sulphur plant are shown in Figure 6.1.

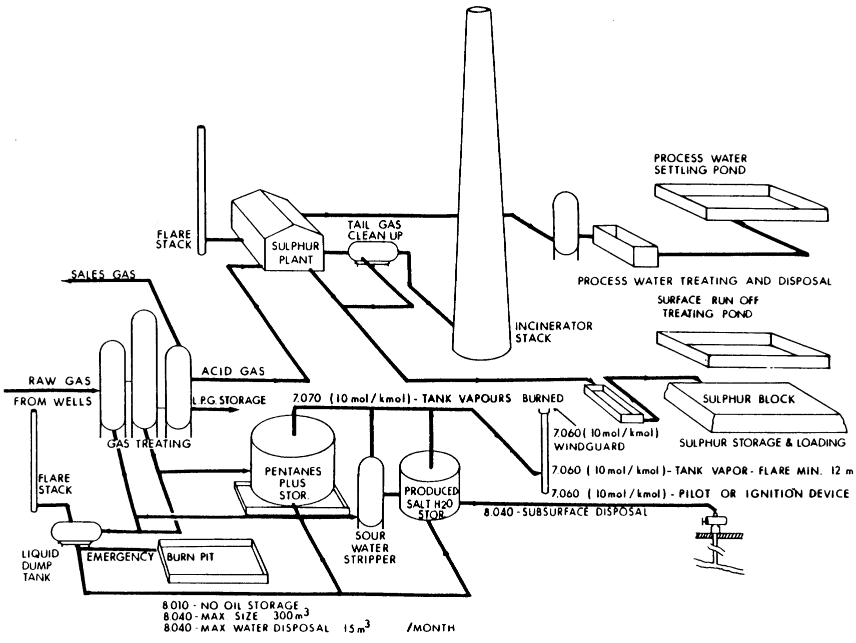

Figure 6.1 **Schematic diagram of gas processing plant with sulphur recovery unit.**

~~8.1.4~~6.1.4 The Claus process consists of multistage catalytic oxidation of hydrogen sulphide to sulphur. Figure 6.2 shows a typical Claus sulphur recovery unit.

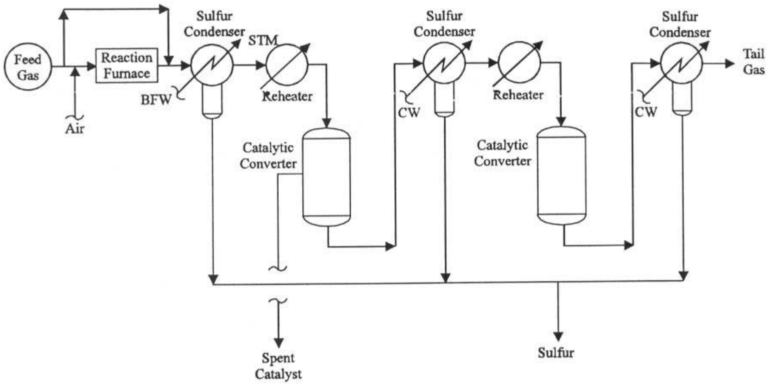

Figure 6.2 Typical Claus sulphur recovery unit.

CW = Cooling water. STM = Steam. BFW = Boiler feed water.

~~8.1.5~~6.1.5 Emission sources associated with the Claus sulphur recovery process include the tail gas stream still containing 0.8 to 1.5 percent ~~sulfur~~ sulphur compounds. They are usually incinerated or may be passed through a liquid redox sulphur recovery unit, fugitive emissions from equipment leaks, and emissions from maintenance activities. In addition, residual H_2S, carbonyl sulphide (COS), and carbon disulphide (CS_2) may also be released to the atmosphere from the recovered molten sulphur.

~~8.1.6~~6.1.6 In the liquid redox sulphur recovery process, vent gases from the oxidizer vessel are a potential source of emissions. Emissions associated with fixed bed adsorption or molecular sieve dehydration include fugitive emissions and emissions from maintenance activities which are considered minor sources of HAP emissions. Process heaters are often used to heat the regeneration stream, with the burner vents from these heaters being potential sources of HAP emissions. The redox sulphur recovery process is not addressed in this Air Quality Code of Practice because it contributes very little to overall emissions of oil and gas industry.

~~8.2~~6.2 **Emissions Estimate**

~~8.2.1~~6.2.1 Point Source Sampling

Direct point sampling is recommended for the accurate estimation of emissions to the atmosphere from ~~s~~a sulphur recovery plant ~~shall~~ following methodology described in ~~Paragraph~~ Section 8.4 of this Code. Results of source sampling are used to calculate H_2S and SO_2 emissions from the sulphur recovery process with the following equations for each compound:

(a) SO_2 emission estimate (E_{SO2}), lb/h

$$E_{SO2} = Q \cdot y_{SO2} \cdot F_S \cdot MW_S \cdot 1/C \cdot (MW_{SO2}/MW_S) \cdot F_{SO2} \cdot (1 - RE/100)$$

where: Q = gas process rate, scf/h
y_{SO2} = mole fraction of SO_2 in inlet gas stream
F_s = sulphur recovery factor (1 mole sulphur/mole SO_2)
MW_S = molecular weight of sulphur
C = molar volume of ideal gas, 379 scf/mole at 60°F and 1 atm
MW_{SO2} = molecular weight of SO_2
F_{SO2} = SO_2 production factor (1 mole SO_2/ 3 moles S)
RE = sulphur recovery efficiency, %

(b) H_2S emission estimate (E_{H2S}), lb/h

$$E_{H2S} = Q \cdot y_{H2S} \cdot F_S \cdot MW_S \cdot 1/C \cdot (MW_{H2S}/MW_S) \cdot F_{H2S} \cdot (1 - RE/100)$$

where: Q = gas process rate, scf/h
y_{H2S} = mole fraction of H_2S in inlet gas stream
F_s = sulphur recovery factor (1 mole sulphur/mole H_2S)
MW_S = molecular weight of sulphur
C = molar volume of ideal gas, 379 scf/mole at 60°F and 1 atm
MW_{H2S} = molecular weight of H_2S
F_{H2S} = H_2S production factor (2 mole H_2S/ 3 moles S)
RE = sulphur recovery efficiency, %

~~8.2.2~~6.2.2 Emission Factors

The general equation for emission estimation using emission factors is:

$$E = A \cdot EF \cdot (1 - ER/100)$$

where: E = emissions,
A = activity rate,
EF = emission factor, and
ER = overall emission reduction efficiency, %.

Table 6.1 shows emission factors and recovery efficiencies for modified Claus sulphur recovery plants (EPA, AP-42). Factors are expressed in units of kilograms per megagram (kg/Mg) and pounds per ton (lb/ton).

Table 6.1 Emission Factors for Claus Sulphur Recovery Plant

Number of Catalytic Stages	Average % Sulphur Recovery [a]	SO_2 Emissions	
		kg/Mg of Sulphur Produced	lb/ton of Sulphur Produced
1, Uncontrolled	93.5 [b]	139 [b, c]	278 [b, c]
3, Uncontrolled	95.5 [d]	94 [c, d]	188 [c, d]
4, Uncontrolled	96.5 [e]	73 [c, e]	145 [c, e]
2, Controlled [f]	98.6	29	57
3, Controlled [g]	96.8	65	129

[a] Efficiencies are for feed gas streams with high H_2S concentrations. Gases with lower H_2S concentrations would have lower efficiencies. For example, a 2- or 3-stage plant could have a recovery efficiency of 95% for a 90% H_2S stream, 93% for 50% H_2S, and 90% for 15% H_2S.

[b] Based on net weight of pure sulphur produced. The emission factors were determined using the average of the percentage recovery of sulphur. Sulphur dioxide emissions are calculated from percentage sulphur recovery by one of the following equations:

SO_2 emissions (kg/Mg) = 2000 · (100% recovery) / (% recovery)
SO2 emissions (lb/ton) = 4000 · (100%recovery) / (% recovery)

[c] Typical sulphur recovery ranges from 92 to 95%.

[d] Typical sulphur recovery ranges from 95 to 96%.

[e] Typical sulphur recovery ranges from 96 to 97%.

[f] Test data indicated sulphur recovery ranges from 98.3 to 98.8%.

[g] Test data indicated sulphur recovery ranges from 95 to 99.8%.recovery efficiencies. The efficiency depends upon several factors, including the number of catalytic stages, the concentrations of H2S and contaminants in the feedstream, stoichiometric balance of gaseous components of the inlet, operating temperature, and catalyst maintenance.

~~8.2.3~~6.2.3 The estimation method will be specified by the regulatory authority in the operation permit, emissions verification, public complaints, or for other reasons.

~~8.3~~6.3 Emissions Reduction

~~8.3.1~~6.3.1 Emissions reduction is required in order to meet sulphur emission criteria detailed in ~~Paragraph~~ Section 6.4 and to assure that ambient air quality guidelines applicable to ~~Northwest Territories~~NWT are met (see Table 9.1).

~~8.3.2~~6.3.2 Emissions reduction from the Claus process may be accomplished by:

(a) Extending the Claus reaction into a lower temperature liquid phase by adopting any of five processes currently available including the BSR/selectox, Sulfreen, Cold Bed Absorption, Maxisulf~~,~~ and IFP-1 processes. These processes take advantage of the enhanced Claus conversion at cooler temperatures in the catalytic stages. They give higher overall sulphur recoveries of 98 to 99 percent when following downstream of a typical 2- or 3-stage Claus sulphur recovery unit.

(b) Adding a scrubbing process to the tail end to the end of the Claus plant. Currently available are oxidation tailgas scrubbers and reduction tailgas scrubbers. The first scrubbing process is used to scrub SO_2 from incinerated tailgas and recycle the concentrated SO_2 stream back to the Claus process for conversion to elemental sulphur.

(c) There are at least 3 oxidation scrubbing processes: the Wellman-Lord, Stauffer Aquaclaus, and IFP-2. The Wellman-Lord process has been applied more often than the other two. This process uses a wet generative process to reduce stack gas sulphur dioxide concentration to less than 250 ppmv and can achieve approximately 99.9 percent sulphur recovery

~~(c)~~(d) Incinerating the hydrogen sulphide gases to form sulphur dioxide at a temperature of 650°C (1,200°F) or higher to assure that all of the H_2S is combusted. Proper air-to-fuel ratios are needed to eliminate pluming from the incinerator stack. The stack should be equipped with analyzers to monitor the SO_2 level. Dispersion modelling should be used to calculate the stack height required to comply with ambient air quality standards for SO_2 (see Section 9).

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~~8.4~~6.4 Compliance

~~8.4.1~~6.4.1 Sulphur recovery is required for all gas and oil plants where the plant inlet sulphur rate is:

(a) 2 tonnes per day (t/d) of sulphur or more; or

(b) less than 2 tonnes per day of sulphur if ambient air quality guidelines for sulphur compounds are not met.

~~8.4.2~~6.4.2 The sulphur recovery criteria will also apply to any oil and gas production facilities which use sour gas as a fuel and have air emissions from the combusted fuel equal to or greater than 2 t/d of sulphur.

~~8.4.3~~6.4.3 Sulphur recovery criteria and recommended Claus technologies for gas plants at various inlet sulphur rates ~~shall~~ should be as defined in Table 6.2.

Table 6.2 Sulphur Recovery Criteria for Gas Plants

Plant Inlet Sulphur Rate (t/d)	Minimum Sulphur Recovery [a]	Technology [b]
< 2	0	N/A
2 - < 10	89.7	2 stage Claus unit
10 - < 50	95.9	3 stage Claus unit
50 - < 2000	98.2 – 98.5 [c]	2-3 stage sub-dew point Claus unit
2000+	99.5	2-3 stage Claus plus selective absorption tail gas unit

[a] The minimum sulphur recovery criteria will be decreased in cases of poor acid gas quality (i.e. where the mole percentage of H_2S in the acid gas feed stream from the amine unit or equivalent is less than 40%). The minimum sulphur recovery will be decreased by 0.068% for every 1.0 mole % H_2S that the acid gas feed stream has less than 40 mole % H_2S. The regulatory authority may on occasion require operations which qualify for this relaxation to conduct sulphur recovery technology evaluations to explore if reducing or removing the relaxation is reasonable.

[b] Technologies are cited as examples of technology which typically could meet these requirements and are not intended as requirements or recommendations (see ~~Paragraph~~ Section 6.3).

[c] For plant sizes 50 - <2000 t/d, % sulphur recovery required = 98.2 + 0.187[log10(plant size/50)]

~~8.4.4~~6.4.4 The percentage of sulphur recovery shall be calculated and reported each calendar month on a three month rolling average basis. The 3 month rolling average must be greater than or equal to the sulphur recovery criteria. The three month rolling average will be calculated from the total weight of sulphur produced at the plant, the total weight of sulphur emitted from the stacks as recorded by the required continuous emission monitors, and the total of any other emissions of sulphur from the sour gas processing (e.g. flare) in the last three months as follows:

$$Ravg = [Wp /(Wp + Ws + Wd)] \cdot 100$$

where Ravg = 3 month rolling average sulphur recovery (%)
Wp = total weight of sulphur produced in the previous 3 months (tonnes)
Ws = total weight of sulphur emitted through the incinerator stack in the previous 3 months (tonnes)
Wd = total weight of sulphur emitted through the plant flare system in the previous 3 months (tonnes)

~~8.4.5~~6.4.5 Sulphur emissions from sulphur recovery plants of equal or greater than 20 tonnes per day capacity ~~shall~~ should be limited to 0.025 percent by volume (250 parts per million by volume [ppmv]). This limitation is effective at 0 percent oxygen on a dry basis if emissions are controlled by an oxidation control system or a reduction control system followed by incineration. This is comparable to the 99.8 to 99.9 percent control level for reduced sulphur.

~~8.4.6~~6.4.6 Sulphur emissions from sulphur recovery plants of less than 20 tonnes per day capacity ~~shall~~ should not exceed emissions to the atmosphere in excess of 10 gram of sulphur for every 100 gram of sulphur introduced into the plant.

~~8.4.7~~6.4.7 The owner or operator of a natural gas processing plant ~~shall~~ should not permit, cause~~,~~ or allow ~~sulfur~~ sulphur compounds to be emitted to the atmosphere unless the sulphur compound emission is from a stack of a sufficient physical height to prevent concentrations of sulphur compounds near ground level equal to or exceeding relevant ambient air quality objectives. The necessary physical stack height ~~shall~~ should be determined by appropriate dispersion modelling method following Section 9.

~~8.4.8~~6.4.8 The owner or operator of an existing natural gas processing plant ~~must~~ should file with the regulatory authority the following:

(a) The height of all stacks from which sulphur is emitted.

(b) The quantity of the sulphur emitted from each stack.

(c) The exit gas temperature for each stack.

(d) The total mass flow rate of the stack effluent gases (for flares, the total effluent mass flow rate shall consist of the stack effluent mass flow rate plus that amount of air required for complete combustion).

(e) Any other information the regulatory authority deems necessary to determine whether or not the physical height of any stack from which sulphur is emitted complies with the requirements of this ~~paragraph~~Section.

~~8.4.9~~6.4.9 This Section ~~shall~~ should not apply to a sulphur recovery plant for which a sulphur emission limitation is established by any other air quality control regulation.

~~8.4.10~~6.4.10 The regulatory authority ~~shall~~ should revoke any gas/oil processing plant's approval to operate if the processing plant exceeds by more than five hundred kilograms for any two consecutive quarterly periods the amount of ~~sulfur~~ sulphur to be released in plant processes as set forth in the ~~sulfur~~ sulphur release schedule contained in the approval. The regulatory authority should notify the owner or operator of the processing plant by certified mail of the revocation of the plant's approval.

~~8.5~~6.5 Reporting

~~8.5.1~~6.5.1 To aid the regulatory authority in determining compliance with this section, the owner or operator of a sulphur recovery plant to which this section applies ~~shall~~ should submit quarterly reports for the annual period, each report to be received by the authority within 45 days of the end of the quarterly period. The quarterly report ~~shall~~ should contain the following:

(a) The sulphur content of feedstock entering the sulphur recovery plant, determined no less frequently than three times per week and no more frequently than once every twenty-four hours.

(b) The ~~sulfur~~ sulphur content of all fuel burned in the plant and the amount of each type of fuel burned determined no less frequently than quarterly.

(c) The concentration of sulphur dioxide and hydrogen sulphide in the inlet and outlet gas stream or streams of the ~~sulfur~~ sulphur recovery plant determined no less frequently than monthly.

(d) The weight of the recovered sulphur, determined no less frequently than weekly.

~~8.5.2~~6.5.2 When the sulphur recovery plant has at some time during the operational quarterly period experiences excess emissions during malfunction, startup, shutdown, or scheduled maintenance, and complied with the notification requirements of a relevant regulation, quantities and time periods involved in the quarterly reports may be modified to exclude the time periods and the quantities involved during those time periods if the quantities are determined separately for those time periods and submitted in the quarterly report.

~~8.5.3~~6.5.3 The owner or operator ~~shall~~ should provide one month advance notice to the regulatory authority about any scheduled shutdown, maintenance, startup, etc. estimating amount of potential releases of sulphur-containing gases.

~~8.5.4~~6.5.4 ~~When a~~A leak, break, or malfunction ~~occurs~~ resulting in a release of SO_2 and H_2S ~~releases~~ to the atmosphere, shall immediately be reported to the NWT 24-Hour Spill Report Line and the regulatory authority.~~the owner/operator must inform in first 24 hour the regulatory authority providing estimate of releases and details of a mitigation program.~~

~~8.5.5~~6.5.5 If it appears necessary, the regulatory authority may require reports on a more frequent basis, but no more frequently than monthly.

~~8.5.6~~6.5.6 The regulatory authority may, upon the request of the owner or operator of a gas or oil processing plant, alter the sampling periods specified in this section.

~~8.5.7~~6.5.7 The owner or operator of a sulphur recovery facility that manufacture, process or otherwise use one or more of the National Pollutant Release Inventory (NPRI)-listed substances under prescribed conditions are required to report to the NPRI under the authority of the *Canadian Environmental Protection Act, 1999 (CEPA, 1999).*

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~~7.0~~7. NOISE

~~9.1~~7.1 Introduction

~~9.1.1~~7.1.1 With the growth of oil and natural gas operations in Northwest Territories, there are increasing sources of noise. Some of the most common are associated with compressor stations, processing plants, well batteries, well drilling and servicing, and transportation vehicles and construction equipment.

~~9.1.2~~7.1.2 It is not possible to eliminate all noise due to energy- related developments. However, if operators build proper sound-control features into their facilities, sound levels can be kept to acceptable minimums. The Government of Northwest Territories (GNWT) recognizes that protection from excessive upstream oil and gas industry-related noise is important to the quality of life in NWT.

~~9.1.3~~7.1.3 Although the regulatory authority requirements cannot guarantee that residents will not hear sounds from facilities or operations, the basic principles of noise control are clear:

- sound level increases ~~must~~ should be kept to acceptable minimums;
- overall quality of life for the neighbours of energy facilities ~~must~~ should not be impaired;
- wildlife should not be adversely affected by excessive noise; and
- indoor sound levels should not change significantly, particularly as they affect normal sleep patterns.

~~9.1.4~~7.1.4 The regulatory authority requires owners or operators to conduct noise impact assessments for all new facilities, as well as for modifications to existing facilities. In an assessment, an operator ~~must~~ should predict the amount of noise a proposed facility or modification will make, and if it exceeds the Permissible Sound Level, identify ways to reduce that noise. This helps to convince the regulatory authority that the effects of noise are anticipated and that noise abatement is part of the facility design.

~~9.1.5~~7.1.5 The regulatory authority endorses noise control directives of Alberta Energy and Utilities Board (EUB) which have been in effect since 1973. The latest updates, *Interim Directive (ID) 99-8: Noise Control Directive* and its companion, *Guide 38: Noise Control Directive User Guide*, both issued in November 1999, reflect the most current knowledge about noise control applicable to upstream oil and gas industry. The Guide 38 is enclosed as Appendix D.

~~9.2~~7.2 Noise Regulations

~~9.2.1~~7.2.1 Usually permissible noise levels are defined by bylaws for an administrative area where oil/gas facility is located. Typical permissible sound levels (PSL) existing in many municipalities are given in Table 7.1.

Table 7.1 Typical Bylaw Permissible Sound Levels

Area Category	dBA, Leq	
	Day Time	Night Time
Residential	55	45
Commercial	65	55
Industrial	75	70
Silence Zone / Parks	50	40

~~9.2.2~~7.2.2 In the absence of noise bylaw, the EUB Guide 38 Noise Control Directive should be used. The Guide specifies the following:

(a) New facilities planned for remote area should be designed to meet a target sound level of 40 dBA Leq at a distance of 1.5 km from the noise source, although this is not a mandatory requirement and as a target, this does not establish compliance should infringement occur.

(b) Permissible sound level may be derived from a Basic Sound Level (the BSL) value that includes a 5 dBA Leq allowance for industrial presence plus adjustments intended to more accurately reflect specific aspects of the facility and the environment. The minimum PSL for rural NWT is probably no less than 40 dBA Leq during nighttime. However, there may be pristine natural areas where an ambient adjustment may result in a lower PSL, while more developed areas may result in a higher PSL. The PSL is calculated as follows:

Permissible Sound Level = Basic Sound Level + Daytime Adjustment + Class A Adjustment + Class B Adjustment

The daytime period is 07:00 to 22:00, and the daytime adjustment is +10 dBA. Class A adjustment depends on the nature of the activity and/or the actual ambient sound level (ASL) in an area. Class B adjustment is influenced by people's responses to temporary activities. Details of adjustments calculation are given in Appendix D.

c) The Permissible Sound Levels do not apply in emergency situations. Planned maintenance or operational events may be considered temporary activities and thus qualify for a Class B adjustment. Prior to such events, operators should inform nearby residents of the potential for increased sound levels and should attempt to schedule the events during daytime hours to reduce the noise impact on neighbours.

d) A territorial, or municipal ~~and county competent~~ authority may delimit and publish control zones of different noises according to the noise conditions in its territory of jurisdiction, and ~~shall~~ should make periodic review for re-delimitation and re-publication of such zones.

~~9.2.3~~7.2.3 In case that the owner or operator ~~shall~~ intends to~~should~~ install any industrial facility, he ~~must~~ should complete an application form for an installation permit ~~and submit with the following documents~~ to local regulatory authorities containing following information:~~to apply for an installation permit before the install: (This sentence should be reworded)~~

- name, type, specification and quantity of facilities;
- facilities installation location plan which ~~shall~~ should include, within a hundred ~~meters~~ metres from such facilities, the related locations and distance of the subordinate road network and the nearby residential areas;
- the designed sound level and operation condition of facilities; and
- other related documents.

~~9.2.4~~7.2.4 The owner or operator of the facility that has obtained installation permit ~~shall~~ should submit the following documents within six months from the date of the completion of installation to apply for an operation permit from local juridical authorities; and those who have installed such facility ~~shall~~ should submit the following documents to apply for an operation permit from local juridical authorities six months within the proclamation:

- photocopy of the installation permit for new installation;
- photographs and illustrations of the completed installation of the facility;
- photographs and illustrations of noise control measures;
- information about the operation time and condition of the facility;
- noise inspection report; and
- other related documents.

~~9.2.5~~7.2.5 In case that such applications ~~shall~~ should be incomplete or ~~shall~~ should not satisfy the requirements, local juridical authorities ~~shall~~ should inform the applicants to make a remedy at a certain period within fifteen days from the date of acceptance. Such a period for remedy ~~shall~~ should not exceed ninety days. In case that an applicant ~~shall~~ should fail to make a remedy within the specified period, such an application ~~shall~~ should be overruled.

~~9.2.6~~7.2.6 If there is any place in which tranquility is deemed specially necessary by the competent authority concerned, an area within 50 ~~meters~~ metres surrounding the periphery of such place ~~shall~~ should be delimited as a special control area in concerned zone and the highest permissible sound volume in such an area ~~shall~~ should be 5 dB lower than that permitted in the zone. The sound volume at the adjoining border of two or more noise control zones ~~shall~~ should not exceed the noise control criteria set for any of the adjoining zones.

~~9.2.7~~7.2.7 In the case when a compliance cannot be achieved, the owner or operator may apply to the regulatory authority for a temporary permit to operate. The application should provide the following information:

- the name, address and telephone number of the applicant;
- the address of the site;
- the facility permit number (if applicable);
- a description of the source(s) of noise or sound levels;
- the period of time that the temporary permit is desired;
- the applicant’s reason(s) why the temporary permit should be given; and
- a statement of the measures that will be taken to minimize the noise or sound levels.

~~9.3~~7.3 Noise Monitoring

~~9.3.1~~7.3.1 The following provide guidance for the measurement of sound levels from oil and gas operations:

(a) The comprehensive sound level (CSL) ~~must~~ should be measured and compared to the PSL. Modelling of the industrial noise source component can be used as a diagnostic tool to assist in the timely resolution of noise concerns but not to demonstrate compliance.

(b) The CSL for the facility ~~must~~ should not exceed the PSL. The (CSL) is determined by conducting a continuous sound-monitoring survey, which ~~must~~ should encompass a representative portion of the times of day or night on typical days when the noise causing the complaints occurs over a minimum 6-hour to maximum 24-hour period. The maximum survey time may exceed 24 hours where warranted. These exceptional circumstances should be discussed with the regulatory authority before proceeding. If the required survey period straddles the daytime/nighttime periods, then a minimum of three survey hours ~~must~~ should be conducted within each of the daytime and nighttime periods. The measurements are to be conducted 15 m from the complainant's dwelling or place of activity (e.g. trapline) ~~(what about trap lines?)~~ in the direction of the noise source. The 15 m requirement may be altered if it is physically impossible or acoustically illogical.

(c) If there are no occupied building units impacted, sound levels shall be measured at a distance of 8 ~~meters~~ metres or more from the property line radiating the noise.

(d) If a complainant has highlighted specific weather conditions, plant operating conditions, or seasons, the monitoring should take place under these representative conditions. Representative conditions do not constitute absolute worst-case conditions or the exact conditions the complainant has highlighted if those conditions are not easily duplicated. In order to expedite complaint resolution, sound measurements should be conducted at the earliest opportunity when sound propagation towards the impacted dwelling is likely and representative conditions might exist. An extended duration survey (greater than 24 hours) may be considered to ensure representative conditions have been met if they are frequent but difficult to predict.

(e) Short-term measurement shall be made at the time when the noise generated is most representative or at the time designated by the applicant concerned.

(f) Sound level ~~meters~~ metres shall be equipped with wind screens, and readings taken when the wind velocity at the time and place of measurement is not more than 8 km/h.

(g) Sound level measurements shall be taken 1.2 ~~meter~~ metres above ground level and determined by averaging measurements made over fifteen-minute sample duration.

(h) In all sound level measurements, the existing ambient noise level from all other sources in the encompassing environment at the time and place of such sound level measurement ~~shall~~ should be considered to determine the contribution to the sound level by the oil and gas operation(s).

~~9.3.2~~7.3.2 Location of monitoring points should adhere to the following recommendations:

(a) An environmental noise monitoring point ~~shall~~ should be more than 30 ~~meters~~ metres away from the edge of a road with a width of more than 8 ~~meters~~metres, and more than 15 ~~meters~~ metres away from the edge of a road with a width of more than 6 meters but less than 8 meters.

(b) A traffic noise monitoring point ~~shall~~ should be on the road side; and if there are buildings on road side, ~~shall~~ should be located more than 1 ~~meter~~ metre away from the external line of the wall of the buildings.

(c) Monitoring transducers ~~shall~~ should be placed at the height of 1.2 to 1.5 ~~meters~~ metres from the ground surface.

(d) Each monitoring point ~~shall~~ should conduct more than twice 24-hour consecutive monitoring in each quarter.

(e) The location of the monitoring points as designated under the preceding ~~Paragraph~~ section ~~shall~~ should not be changed arbitrarily, and data obtained from monitoring ~~shall~~ should be periodically submitted to the appropriate superior competent authority.

~~9.3.3~~7.3.3 The results of a noise monitoring test should be clearly reported and forwarded to the relevant authority (if requested), or kept on file for reference. It is recommended that they also be made readily accessible to the community.

~~9.3.4~~7.3.4 The following items are to be included in a noise monitoring report:

- the type of monitoring test conducted (that is, the development stage or receiver complaints);
- the development noise limits on the consent/license
- descriptions of the nearest affected receivers or, in the case of receiver complaints, description of the complainant and complaint;
- the monitoring location—this should be at the most affected point at or within the receiver's boundary or, if that is more than 30 m from the receiver's premises, at the most affected point within 30 m of the premises;
- the noise instrumentation used;
- the weather instrumentation used;
- the weather conditions during noise monitoring;
- the time(s) and duration(s) of monitoring, including dates. In the case of receiver complaints, these should coincide with the time of the offence. In the case of development-stage monitoring, these should cover the full cycle of activity;
- the results of noise monitoring at each monitoring location, including a comparison with the development limits;
- a statement outlining the development's compliance or non-compliance with the limit;
- where noise exceedances are found (that is, the monitored noise level is higher than the limit), the reasons for non-compliance should be stated and strategies for management identified and stated; and
- where the noise exceedance is due to excessive noise levels from the development, the strategies to be used to manage the noise exceedance should be identified and stated.

~~9.4~~7.4 Industrial Noise Mitigation

~~9.4.1~~7.4.1 Typical noise sources on upstream oil and gas industrial sites include:

- engines;
- exhausts;
- fans;
- transport of materials, such as on conveyors and trucks;
- pumps and compressors;
- whistles and alarms;
- material dumping and scraping;
- electrical transformers and switching equipment; and
- transportation and service vehicles, especially diesel type.

~~9.4.2~~7.4.2 The choice of noise control measures depends on both the degree of mitigation required and the undesirable characteristics of the noise source that need to be controlled. The actual measures chosen will also depend on site factors, such as the ability of the site to accommodate particular engineering measures relative to other measures and their site costs.

~~9.4.3~~7.4.3 The owner or operator of oil/gas facility ~~shall~~ should select between three main mitigation strategies for noise control:

(a) Controlling noise at the source following Best Management Practice (BMP) and Best Available Technology Economically Achievable (BAT).

(b) Controlling the transmission of noise. There are two approaches: the use of barriers and land-use controls—which attenuate noise by increasing the distance between source and receiver.

(c) Controlling noise at the receiver.

~~9.4.4~~7.4.4 Application of BMP includes the following types of practice:

- scheduling the use of noisy equipment at the least-sensitive time of day;
- placing noisy equipment behind structures that act as barriers, or at the greatest distance from the noise-sensitive area;
- orienting the equipment so that noise emissions are directed away from any sensitive areas, to achieve the maximum attenuation of noise;
- where there are several noisy pieces of equipment, scheduling operations so they are used separately rather than concurrently;
- keeping equipment well maintained;
- employing quiet practices when operating equipment; and
- offering staff education programs on the effects of noise and quiet work practices.

~~9.4.5~~7.4.5 Application of BAT involves incorporation of the most advanced and affordable technology to minimize noise output from equipment, plant and machinery. Examples of uses of BAT are:

- adjusting reversing alarms on heavy equipment to make them ‘smarter’, by limiting acoustic range to the immediate danger area;
- using equipment with efficient muffler design;
- using quieter engines, such as electric instead of internal combustion or gas turbines;

- using efficient enclosures for noise sources; and
- active noise control.

~~9.4.6~~7.4.6 Barriers controls noise in transmission. They are more effective if situated near the source or the receiver. Their effectiveness is also determined by their height, the materials used (absorptive or reflective), and their density. Barriers can take a number of forms—including free-standing walls along the facility generating noise. They are employed when source and receiver control is either impractical or too costly.

~~9.4.7~~7.4.7 Exhaust from all engines, motors, coolers and other mechanized equipment ~~shall~~ should be vented in a direction away from all occupied buildings to the extent practicable.

~~9.4.8~~7.4.8 In high-density areas all facilities within 120 ~~meters~~ metres of occupied buildings with engines or motors, which are not electrically operated, ~~shall~~ should be equipped with quiet design mufflers or equivalent. All mufflers ~~shall~~ should be properly installed and maintained in proper working order.

~~9.4.9~~7.4.9 Road, railway, aviation, and other transportation noises ~~shall~~ should be prevented and controlled through appropriate measures taken by competent authorities in conjunction with appropriate government agencies.

~~9.4.10~~7.4.10 Selecting an appropriate strategy for a proposed development or alterations to an existing development with reference to noise management involves the following steps, summarized in Figure 7.1:

(a) Determining the noise reduction required to achieve the project-specific noise levels.

(b) Identifying the specific characteristics of the industry and the site that would indicate a preference for specified measures.

(c) Examining the mitigation strategy chosen by upstream oil and gas industry on similar sites with similar requirements for noise reduction; and considering that strategy’s appropriateness for the subject development.

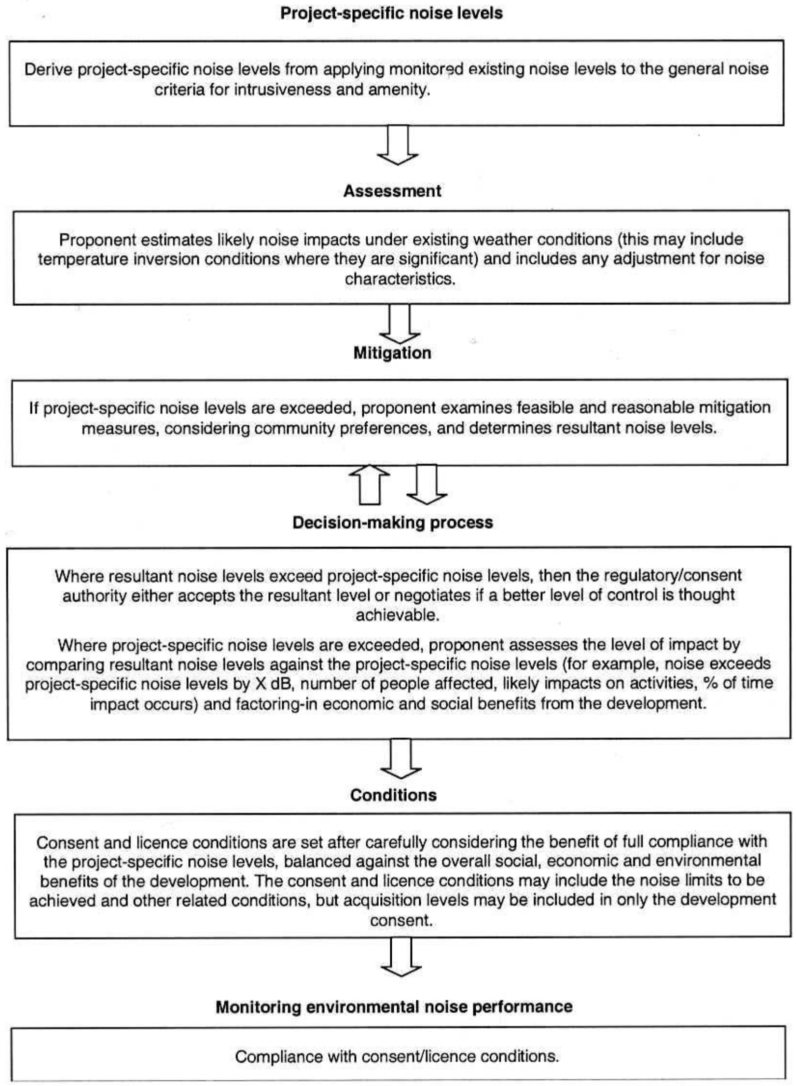
(d) Considering the range of noise-control measures available.

(e) Considering community preferences for particular strategies. This is especially important when the community has particular sensitivities to noise.

~~9.4.11~~7.4.11 The preference ranking (from most preferred to least preferred) for particular strategies is:

(a) Land-use controls—a long-term strategy preferable to other measures when such strategic decisions are possible in planning land use, as it separates noise-producing industries from sensitive areas and avoids more expensive short-term measures.

(b) Control at the source—BMP and BAT— used in conjunction, these strategies are the best after land-use planning, as they serve to reduce the noise output of the source so that the surrounding environment is protected against noise.



Project-specific noise levels

Derive project-specific noise levels from applying monitored existing noise levels to the general noise criteria for intrusiveness and amenity.

Assessment

Proponent estimates likely noise impacts under existing weather conditions (this may include temperature inversion conditions where they are significant) and includes any adjustment for noise characteristics.

Mitigation

If project-specific noise levels are exceeded, proponent examines feasible and reasonable mitigation measures, considering community preferences, and determines resultant noise levels.

Decision-making process

Where resultant noise levels exceed project-specific noise levels, then the regulatory/consent authority either accepts the resultant level or negotiates if a better level of control is thought achievable.

Where project-specific noise levels are exceeded, proponent assesses the level of impact by comparing resultant noise levels against the project-specific noise levels (for example, noise exceeds project-specific noise levels by X dB, number of people affected, likely impacts on activities, % of time impact occurs) and factoring-in economic and social benefits from the development.

Conditions

Consent and licence conditions are set after carefully considering the benefit of full compliance with the project-specific noise levels, balanced against the overall social, economic and environmental benefits of the development. The consent and licence conditions may include the noise limits to be achieved and other related conditions, but acquisition levels may be included in only the development consent.

Monitoring environmental noise performance

Compliance with consent/licence conditions.

Figure 7.1 Overview of sound policy framework.

(c) Control in transmission—the next best strategy to controlling noise at the source—it serves to reduce the noise level at the receiver but not necessarily the environment surrounding the source.

(d) Receiver controls—the least-preferred option, as it protects only the internal environment of the receiver and not the external noise environment.

~~9.4.12~~7.4.12 Proponent should envision the cost-effectiveness of strategies in determining how much noise reduction is affordable. A choice of a particular strategy is likely to have unique features due to the economics of the industry and site specific technical considerations. The steps described in the preceding ~~Paragraph~~ Section and the range of noise control measures can be used as a guide in assessing the strength of the proponent’s mitigation proposals.

~~9.4.13~~7.4.13 Where a proposed mitigation strategy will not achieve the desired noise reduction and leaves a remaining noise impact, the problem needs to be solved by negotiation.

~~7.5Enforcement~~

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~~8.0~~8. MEASUREMENT AND REPORTING

~~10.1~~8.1 Introduction

~~10.1.1~~8.1.1 Under the Environmental Protection Act, the GNWT may require the installation of such monitoring devices as are necessary to measure the concentrations of various air contaminants. Any changes to emission quality or quantity relating to the facilities operation should be approved by the regulatory authority.

~~10.1.2~~8.1.2 Nationally and internationally, the appropriate methods for the monitoring of air contaminants in the upstream oil and gas industry have been specified and standardized to assure that acceptable methods are used and reporting formats and frequencies are followed. The standard contaminants at upstream oil and gas industry includes:

- ~~sulfur~~ sulphur dioxide (SO_2);
- hydrogen sulphide (H_2S);
- Volatile Organic Compounds (VOC);
- Total Hydrocarbons (THC);
- carbon monoxide (CO);
- nitrogen oxides NO_x (as nitrogen monoxide NO and nitrogen dioxide NO_2); and
- particulate matter (PM).

~~10.1.3~~8.1.3 Air quality monitoring can be divided into two main groups: the first group deals with continuous ambient air monitoring in the vicinity of oil/gas production facilities reporting ambient air concentrations; the second covers the monitoring at the point sources such as stacks, flares and vents (continuous or periodic) reporting emission data.

~~10.2~~8.2 Ambient Air Monitoring Stations

~~10.2.1~~8.2.1 The owner or operator of a gas or oil facility may be requested by the regulatory authority to install and operate an ambient air monitoring station or ~~the~~ a network of stations.

~~10.2.2~~8.2.2 Air quality monitoring may be required for one or more of the following purposes:

- to judge compliance with and/or progress made towards meeting ambient air quality standards;
- to activate emergency control procedures that prevent or alleviate air pollution episodes;
- to observe pollution trends throughout the region;
- to provide a data base for research evaluation of effects: urban, land-use, and transportation planning;
- to develop and evaluate abatement strategies;
- to develop and validate diffusion models to determine highest concentrations expected to occur in the area covered by the station or the network;
- to determine the impact on ambient pollution levels of significant sources or source categories; and
- to determine general background concentration levels.

~~10.2.3~~8.2.3 Monitored meteorological and contaminant parameters ~~shall~~ should be determined by the regulatory agency in consultation with the facility owner or operator, depending on type of contaminants released. The meteorological parameters usually include wind speed, wind direction, temperature, atmospheric pressure and wet precipitation. The regulatory authority should be consulted prior to citing of the monitoring station and installation of equipment.

~~10.2.4~~8.2.4 Siting criteria:

(a) Selection of the appropriate location for the ground based air monitoring and meteorological sites is of utmost importance to assure that the data generated is representative of the regime to be investigated. Surface based air monitoring sites may be classified as either regional, urban, or rural. The criteria used to evaluate potential locations for air monitoring site are:

- regional, urban, or suburban representativeness;
- good spatial distribution of sites to assure meaningful area wide trend analysis;
- wildlife;
- vegetation;
- distance from urban areas and point sources;
- availability of electric and telephone service;
- year round accessibility;
- stability of location (land use, ownership, security); and
- availability of site personnel.

(b) In addition to the above, general criteria for each proposed site is evaluated for site specific criteria that may, on a local basis, effect the representativeness of the data collected; local features that may affect either the chemical or meteorological parameters are evaluated to assure a minimum of interference.

~~10.2.5~~8.2.5 Sampling probe criteria:

(a) Probe height ~~shall~~ should be between 3 to 15 ~~meters~~ metres above ground level, preferably 10 m for monitoring both chemical and meteorological parameters.

(b) The probe ~~shall~~ should be located away from obstacles so that the distance to the probe is at least twice the height that the obstacle protrudes above the probe.

(c) The probe ~~shall~~ should have an unrestricted air flow of at least 270º and no obstructions in the primary direction of the emission source.

(d) The probe ~~shall~~ should be located at a minimum distance of 20 ~~meters~~ metres from the drip line of the surrounding trees.

(e) The probe shall be located at a minimum specific distance, based on average daily vehicular traffic numbers, from the nearest roadway; for traffic less than 10,000 vehicles per day the minimum distance is 10 m.

~~10.2.6~~8.2.6 Complete documentation for one or more stations ~~shall~~ should include:

(a) A recent area map showing roadways, railway lines, airports, lakes, rivers, human settlements and other significant landmarks with the station locations clearly indicated.

(b) The area and topographic map showing the station location as well as the location of the plant and all storage tanks and facilities (preferred scale is 1:50,000 with elevation contours at 25 foot intervals).

(c) A wind rose (preferably a ten year average) of the area for existing and new stations (if readily available).

(d) A copy of the completed static station documentation table.

(e) For each continuous monitoring station:
- a copy of the completed site documentation forms;
- current aerial photograph (if it is readily available) covering an approximate area of one square ~~kilometer~~ kilometre with the station at the centre of the photograph;
- a plan view sketch of the immediate surroundings within a 500 ~~meter~~ metre radius showing all topographical features, significant vegetation, buildings and other local disturbances (clearings, pits, towers, etc.) with relevant distances to approximate scale; heights of obstacles should be noted on the sketch;
- a cross-sectional sketch through tall obstacles which gives the relevant heights and elevation angles; and
- obstacles on both sides of the continuous monitoring station within a 500 ~~meter~~ metre radius and also along the line drawn from the plant through the monitoring station.

(f) Colour print(s) showing the details of the sampling inlet(s) or manifold in relation to the station.

(g) A ~~color~~ colour print of the structure housing the instruments from the door side with the direction of the exposure marked on the bottom.

(h) Four prints showing the station environs looking from the shelter to the East, to the South, to the West and to the North with the appropriate direction marked clearly on the bottom.

(i) If the station does not conform to the standard site criteria, additional photographs and sketches illustrating the irregularities.

~~10.2.7~~8.2.7 Monitoring methods used for the measurement of upstream oil and gas industry generated pollutants are summarized in Table 8.1. bIn the case of continuous monitors and met sensors, it would be expected that data logging and communications would be provided to enable the regulatory authority on-line, real-time communication with the station.

~~10.2.8~~8.2.8 Acceptable performance specifications for air monitors are given in Table 8.2 (source: *Air Monitoring Directive (AMD)*, Alberta Environment, 1989).

~~10.2.9~~8.2.9 Quality Assurance / Quality Control (QA/QC) ~~shall~~ should be achieved by implementing the following measures:

- adherence to standard operating procedures, approved by the regulators;
- operating network designed as specified in ~~Paragraphs~~ Section 8.2.3 to 8.2.8 above with final approval by regulators;
- recruitment and training of qualified staff;
- traceability of standards (selection, inventory and regular recertification); and
- calibrations.

Table 8.1 Methods for the Measurement of Ambient Air Pollutants

Pollutant	Principle of Measurement
Sulphur dioxide (SO_2)	Pulses fluorescence
	Coulometric titration
	Flame photometry
Hydrogen sulphide (H_2S)	Fluorescence after thermal oxidation
	Coulometric titration
	Flame photometry
Nitric oxide (NO)	Chemiluminescence
Nitrogen dioxide (NO_2)	Chemiluminescence after conversion to NO
Ozone (O_3)	Chemiluminescence
	Ultraviolet (UV) photometry
Carbon monoxide (CO)	Nondispersive infrared spectroscopy
	Gas-filter correlation
Total hydrocarbons (THC)	Flame ionization
Ammonia (NH_3)	Catalytic thermal oxidation followed by NO measurement
Total suspended particulates (TSP)	High volume air sampling
	Tapered Element Oscillating Microbalance (TEOM)
	Sample collection by dichotomous sampler
VOC	
~~Smoke, haze~~PM10, and PM2.5	~~Light transmission of filter paper soiled by fine suspended particulates (coefficient of haze)~~High volume air sampling
	Low volume air sampling
	Continuous air sampling e.g. TEOM

- zero/span checks;
- control limits and corrective actions;
- preventive and remedial maintenance;
- quality control procedures for air pollution episode monitoring;
- data audit and reporting;
- data quality assessment which includes precision checks and performance audits; and
- reporting of results of precision and accuracy tests to the regualtory authority.

~~10.3~~8.3 Passive Samplers

~~10.3.1~~8.3.1 Passive samplers for monitoring of ~~sulfur~~ sulphur dioxide (SO_2), hydrogen sulphide (H_2S) and nitrogen dioxide (NO_2) may be considered by upstream oil and gas industry for remote locations ~~at~~ in the NWT. They offer some advantages such as:

- generally they are simple in structure and easily used;
- small and portable;
- requiring no power source; and
- cost-effective, and useful for network studies.

~~10.3.2~~8.3.2 The measuring ranges of passive samplers based on an exposure period of one month are:

- 0.1 to 120 ppb for $SO_{2;}$
- 0.02 to 20 ppb for H_2S; and
- 0.1 to 50 ppb for $NO_{2.}$

~~10.3.3~~8.3.3 For credible results, it is recommended that triplicate or at least duplicate passive samplers be used for each monitoring location. To validate results, travel blanks must be included. The number of travel blanks depends on the number of passive samplers used in field studies. Two travel blanks are needed for less than 10 passive samplers.

~~10.3.4~~8.3.4 When passive samplers are ready to be installed in the field, travel blanks should be kept in glass jars with well-sealed metal caps and stored at cool place in order to avoid further contaminations. After exposure, the travel blanks should be removed from the jars and shipped to lab for analyses together with the exposed passive samplers.

~~10.3.5~~8.3.5 The passive samplers are installed in a rain shelter face downward, as shown in Figure 8.1 (source: Maxxam Analytics Inc.).

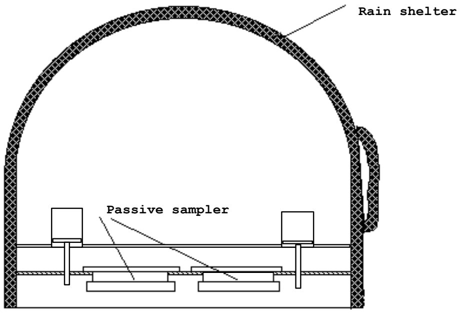

Figure 8.1 Passive sampler arrangement.

Table 8.2 Typical Performance Specifications for Ambient Air Monitors

	POLLUTANT						
PERFORMANCE PARAMETER	Carbon Monoxide	Total Hydrocarbons	Ozone	Oxides of Nitrogen	Sulphur Dioxide	Hydrogen Sulphide	Ammonia
Minimum Detectable Limit	0.1 ppm	0.1 ppm	0.002 ppm	0.005 ppm	0.002 ppm	0.0025 ppm[5]	0.01 ppm
Precision[2]	± 0.1 ppm	± 2% F. S.	± 0.002 ppm	± 0.002 ppm	±0.001 ppm	± 0.001 ppm	± 0.01 ppm
Linearity	1% F. S.	1% F. S.	± 0.001 ppm	1% F. S.	1% F. S.	1% F. S.	1% F. S.
Zero Drift[3]	± 0.2 ppm	± 1% F. S.	<0.5% F. S. per month	± 0.002 ppm	± 0.003 ppm	± 0.003 ppm	± 0.002 ppm
Span Drift[3]	± 1% F. S.	± 1% F. S.	± 1% F. S. per month	± 1% F. S.	± 1% F. S.	± 1% F. S.	± 1% F. S.
Interference Equivalent	200,000:1[4]	<0.01 ppm			<0.012 ppm	<0.012 ppm	
Noise	± 0.05 ppm	±0.5% F. S.	± 0.001 ppm	± 0.002 ppm	± 0.001 ppm	± 0.001 ppm	± 0.002 ppm
Operating Temperature Range	10° - 40°C	10° - 40°C	10° - 40°C	10° - 40°C	10° - 40°C	10° - 40°C	10° - 40°C
Ranges	50 ppm	10 ppm 20 ppm 50 ppm	0.5 ppm 1.0 ppm 2.0 ppm 5.0 ppm 10.0 ppm	0.5 ppm 1.0 ppm 5.0 ppm	0.5 ppm 1.0 ppm 5.0 ppm	0.1 ppm 0.5 ppm 1.0 ppm 5.0 ppm	1.0 ppm 2.0 ppm 5.0 ppm 10.0 ppm

[1] concentration measured at STP (25°C, 750 mm Hg)
[2] F.S. = full scale
[3] per 24 hours unless otherwise specified
[4] rejection ratio for carbon dioxide and water
[5] a minimum detection limit of 0.001 ppm is achievable with some H_2S

~~10.3.6~~8.3.6 The installation height of the rain shelter should follow the standard site criteria such as:

- the rain shelter should be above ground 1 to 3 m;
- election angle should be <30° from the diffusion barrier surface of the passive sampler to the top of any obstacle; and
- the distance from the obstacle should be > 10 times the obstacle height.

~~10.3.7~~8.3.7 In general, the rain shelter ~~must~~ should be installed properly to prevent passive samplers from being reached by animals or human beings, and being interfered by surroundings. If there are several rain shelters in one location, it is recommended to keep them separate in order to avoid air movement interference.

~~10.3.8~~8.3.8 Passive samplers' starting and end times and date should be recorded on a field-sampling sheet. Average temperature, average relative humidity, and average wind speed during the exposure period can be obtained from local weather station or from nearby monitoring stations.

~~10.3.9~~8.3.9 After exposure, the samplers are removed from the rain shelter, sealed in the resealable bags, put back into the protective bottle with the cap sealed using Teflon tape and returned to lab for analysis.

~~10.3.10~~8.3.10 The concentrations of pollutants detected by the passive sampler in the atmosphere are reported as part per billion (ppb).

~~10.3.11~~8.3.11 Unexposed and exposed passive samplers should be kept at 4°C. The shelf life of the passive samplers is 3 months at 4°C and one month at room temperature.

~~10.4~~8.4 Emissions Measurements for Stationary Sources

~~10.4.1~~8.4.1 The owner/operator ~~shall~~ should perform stationary source testing if required by permit, regulation, or bylaw according to the standardized sampling protocols and methods acceptable to the regulatory authority. The protocols also serve as a guideline for stationary emission testing survey reporting for regulatory staff, permittees, and consultants.

~~10.4.2~~8.4.2 For stationary emission monitoring, the regulatory authority requires the use of Environment Canada or United States Environmental Protection Agency (US EPA) Source Testing Codes, unless otherwise superseded by other requirements.

~~10.4.3~~8.4.3 Stack sampling train for particulate and contaminant sampling by impinger method should be arranged as shown in Figure 8.2.

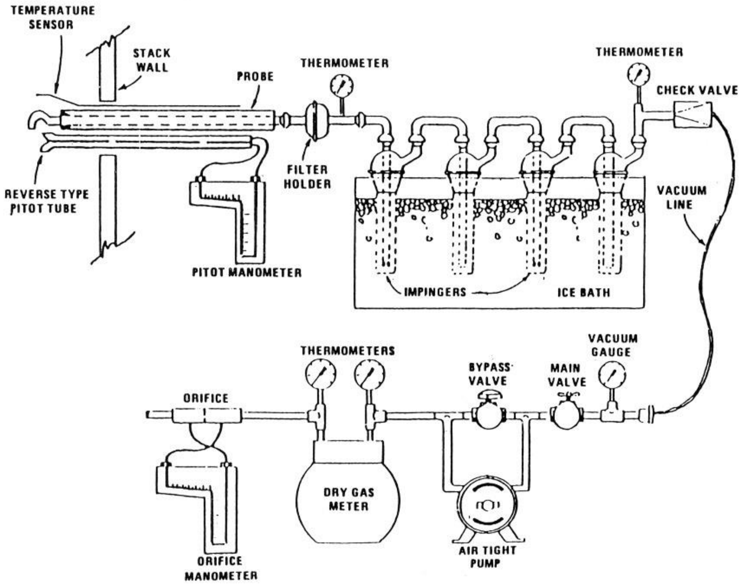

Figure 8.2 Stack sampling train for particulate and gaseous contaminants.

~~10.4.4~~8.4.4 Summary of the EPA Source Testing Codes for Stationary Sources (US EPA), including stacks, flares and vents and Alberta Environment Stack Sampling Code (AEPA) for contaminants discharged by upstream oil and gas industry are as follows.

Measurement	**Traverse Points**
Methods	US EPA and AEPA Method 1.
Principle	To aid in the representative measurement of pollutant emissions and /or total volumetric flow rate from stationary source.
Applicability	This method is applicable flowing of gas streams in ducts, stacks, and flues.

Measurement	**Stack Gas Velocity & Flow Rate**
Methods	US EPA and AEPA Method 2.
Principle	The average gas velocity in a stack is determined from the gas density and from measurement of the average velocity head with a type S Pitot tube.

Applicability	This method is applicable for measurement of the average velocity of gas stream and for quantifying gas flow.
Measurement	**Stack Gas Molecular Weight**
Methods	US EPA and AEPA Method 3.
Principle	This method is applicable for determining carbon dioxide and oxygen concentrations and dry molecular weight of a sample from a gas stream of a fossil-fuel combustion process.
Applicability	Other methods, as well as modifications to the procedure, are also applicable for some or all of the above determinations.
Measurement	**Moisture Content**
Methods	US EPA and AEPA Method 4.
Principle	A gas sample is extracted at a constant rate from the source. Moisture is removed from the sample stream and determined either volumetrically or gravimetrically.
Applicability	The accurate determinations of moisture content as needed to calculate emission data.
Measurement	**Sulphur Dioxide (SO_2)**
Methods	US EPA Method 6 & 8 and AEPA Method 8.
Principle	A gas sample is extracted from a sampling point in the stack, the sulphuric acids mist and the sulphur dioxide are separated. The sulphur dioxide portion is measured by the barium-thorium titration method.
Applicability	This method is applicable for the determination of sulphuric acid mist and sulphur dioxide emissions from stationary sources.
Range and Sensitivity	US EPA Method: The minimum detectable limit is 3.4 mg/m^3 (2.12×10^{-7} lb/ft^3). Although no upper limit has been established, tests have shown that concentrations as high as 80,000 mg/m^3 of SO_2 can be collected efficiently in two midget impingers containing 15 ml of 3% hydrogen peroxide, at a rate of 1.0 lpm for 20 min. AEPA Method: The minimum detectable limit is 1.2 mg/m^3 (0.74×10^{-7} lb/ft^3, 0.46 ppm). No upper limit has been established. Based on theoretical calculations for 200 ml of 3% hydrogen peroxide solution, the upper concentration limit for SO_2 in a $1.0m^3$ ($35.3\ ft^3$) gas sample is about 12,500 mg/m^3 (7.7×10^{-4} lb/ft^3, 4800 ppm).

Apparatus	Leak free diaphragm pump; dry gas volume ~~meter~~metre; vacuum gauge; barometer accuracy ± 2.5 mm Hg (0.1 in Hg); Pitot tube; borosilicate, Teflon or quartz probe liner with a heating system; filter holder; borosilicate glass (not needed for SO_2 determination). Impingers: four, of Greenburg – Smith design. Temperature gauge ± 1ºC. Silica gel: to dry the gas leaving the impingers. Wash bottles, graduated cylinder, and storage bottles.

Measurement	**Hydrogen Sulphide (H_2S)**
Methods	US EPA Method 11.
Principle	Hydrogen sulphide (H_2S) is collected from a source in a series of midget impingers and absorbed in pH 3.0 cadmium sulfate ($CdSO_4$) solution to form cadmium sulphide.
Applicability	The determination of hydrogen sulphide content of fuel gas streams at petroleum refineries, gas plants, flares.
Range and Sensitivity	The lower limit of detention is 8 mg/m^3 (6 ppm). The maximum of the range is 740 mg/m^3 (520 ppm).
Apparatus	Leak free diaphragm pump; volume ~~meter~~metre; dry gas ~~meter~~metre; vacuum gauge; barometer accuracy ± 2.5 mm Hg (0.1 in Hg); Pitot tube; borosilicate, Teflon or quartz liner with a heating system; five midget impingers; temperature gauge accuracy ± 3ºC. Silica gel: to dry the gas leaving the impingers; wash bottles, graduated cylinder, storage bottles. Ice bath: to maintain absorbing solution at low temperature.

Measurement	**Nitrogen Oxides (NO_x)**
Methods	US EPA and AEPA Method 7, 7A & 7C (AEPA) and 7 thru 7D (US EPA), depending on specific requirements.
Principle	A grab sample is collected in an evacuated flask containing a dilute ~~sulfuric~~ sulphuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimetrically using the phenoldisulfonic acid (PDS) procedure.
Applicability	The measurement of nitrogen oxides emitted from stationary sources.
Range and Sensitivity	The range has been determined to be 2 to 400mg NO_x (as NO_2) per dry standard cubic ~~meter~~ metre (std.m^3), without having to dilute the sample.

Apparatus	Pump providing 75 mm Hg (3 in Hg) absolute vacuum; vacuum gauge; barometer accuracy ± 2.5 mm Hg (0.1 in Hg); Borosilicate, Teflon, or stainless steel probe with a heating system if needed. Two-liter borosilicate, round bottom collection flask with short neck. Temperature gauge accuracy ± 1ºC; in-stack or out-stack filter for removal of particulate matter. Volumetric pipette, flask valve, stopcock and Ground joint grease.

Measurement	**Carbon Monoxide (CO)**
Methods	US EPA 10 thru 10B and AEPA Method 10, depending on specifications.
Principle	An integrated or continuous gas sample is extracted from a sampling point and analyzed for carbon monoxide content using a nondispersive infrared analyzer (NDIR) or equivalent.
Applicability	The determination of carbon monoxide emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.
Range and Sensitivity	Detection range from 0 to 1,000 ppm. Minimum detectable concentration is 20 ppm for a 0 to 1000 ppm span.
Apparatus	Leak free diaphragm pump; stainless steel or sheathed Pyrex glass probe equipped with a filter to remove particulate matter; air cooled condenser or equivalent; needle valve or equivalent; rotameter or equivalent rate ~~meter~~ metre to measure a flow range from 0 to 1.0 L/min (0.035 cfm).

Measurement	**Gaseous Organic Compounds (VOC)**
Methods	US EPA and AEPA Method 18.
Principle	The method is based on separating the major components of a gas mixture with a gas chromatograph (GC) and measuring the separated components with a suitable detector.
Applicability	The method applies to approximately 90% of the total gaseous organics emitted from an industrial source. It does not identify and measure trace amounts of organic compounds, such as those found in building air and fugitive emission sources.
Range and Sensitivity	The range of this method is from about 1ppm to the upper limit governed by GC detector saturation or column overloading. The upper limit can be extended by diluting the stack gases with an inert gas or by using smaller gas sampling loops.

Apparatus	Leak free diaphragm pump; stainless steel or sheathed Pyrex glass probe equipped with a filter to remove particulate matter; needle valve or equivalent; rotameter or equivalent rate ~~meter~~ metre to measure a flow range from 0 to 1.0 L/min (0.035 cfm); Tedlar or aluminized Mylar sample bag 5 – 10 L volume; rigid air tight evacuated container “lung” type; S-type Pitot probe; manometer.

Measurement	**Volatile Organic Compounds (Leaks)**
Method	US EPA Method 21
Principle	A portable instrument is used to detect VOC leaks from individual sources. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rates from individual sources.
Applicability	This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include but are not limited to, valves, flanges and other connections, pumps and compressors (including seal system degassing vents), pressure relief devices, process drains, open-end valves, accumulator vessel vents, agitator seals, and access door seals.
Range and Sensitivity	Both linear response range and the measurable range of the instrument for each of the VOC to be measured, and for the VOC calibration gas shall encompass the leak definition concentration specified in the relevant regulation. The response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The calibration precision must be equal to or less than 10% of he calibration gas value.
Apparatus	Monitoring instrument: an acceptable detector type includes catalytic oxidation, flame ionization, infrared absorption, and photoionization. The scale of the instrument ~~meter~~ metre shall be readable to ± 2.5% of the specified leak definition concentration when performing a no detectable emission survey. The instrument shall be equipped with an electrical pump to insure that a sample is provided to the detector at a constant flow rate of 0.10 to 3.0 LPM when the probe is fitted with a filter, and the probe extension for sampling do not exceeds ¼ inch in outside diameter.

~~10.4.5~~8.4.5 The owner/operator ~~shall~~ should assure that the following pre-test conditions are met:

(a) For sources that operate under permit, approval or bylaw, the owner or operator ~~shall~~ should provide the regulatory authority with a minimum of ten working days advance notice before any emission compliance testing is carried out.

(b) The results of all air emission testing performed for regulatory compliance requirements under permit, approval, regulation or bylaw ~~shall~~ should be retained by the facility, for a period of five years, and be made available to the ~~R~~regulatory authority upon request.

(c) A detailed test plan ~~must~~ should be submitted in writing for approval for any nonroutine testing programs 30 days prior to the scheduled sampling.

(d) A minimum of three test runs constitute a valid stack survey, unless the method being used specifically states otherwise; where less than three runs are being used, the Stack Emission Survey Report ~~must~~ should quote the reference that allows exception from the three test run requirement

(e) For a valid stack survey, the individual test runs should be taken on the same day; the duration, over which the three test runs are extracted should not exceed two days.

(f) The results of individual test runs and the average of all test runs constituting a valid stack survey ~~shall~~ should be reported; the arithmetic average of all test runs taken during a valid stack survey shall be used to assess compliance with the limits stated in permits, approvals, regulations or bylaws.

(g) The minimum duration of one complete test run must be 60 minutes.

(h) The sampling nozzle shall be sized to obtain a sample volume of 1 m^3 (as sampled) or greater for particulate testing.

(i) Sample points shall be calculated using the applicable tables or computer programs developed with reference to EPS 1/RM/8 or the US EPA CFR 40 Part 60.

(j) In the recovery procedure for a standard particulate test, acetone and deionized water must be used for washing the interior surfaces of the nozzle, probe, cyclone (if used), and filter holder (the front half of the sampling train).

(k) Leak checks are mandatory and should be carried out as outlined in the Stack Sampling Code.

~~10.4.6~~8.4.6 The owner/operator ~~shall~~ should provide a safe access to the sampling location and a firm sampling platform meeting specifications as detailed in Figure 8.3.

~~10.4.7~~8.4.7 High volume particulate sampling is considered to be non-standard and requires prior written approval from the regulatory authority.

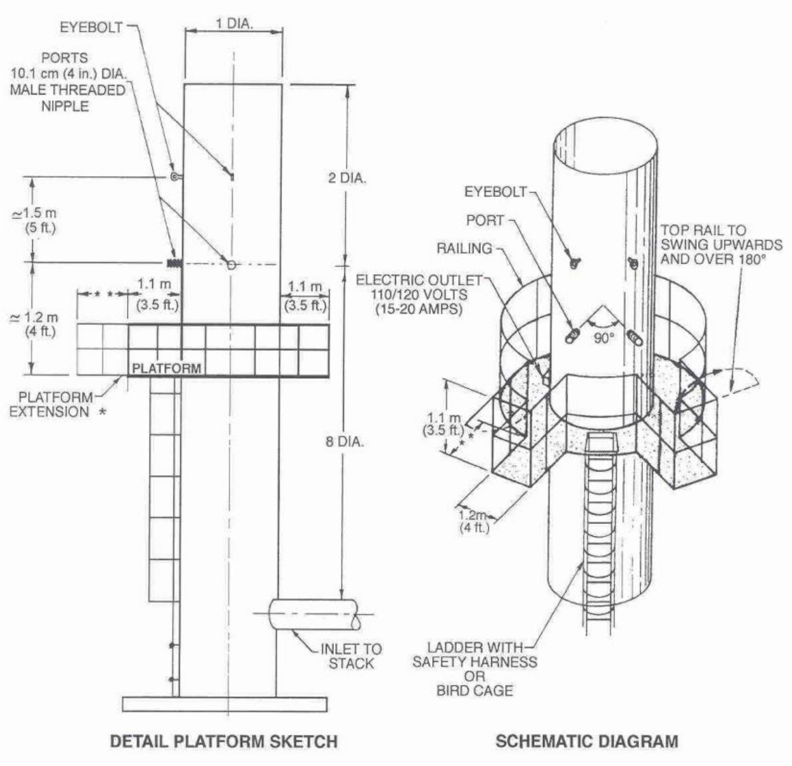

Figure 8.3 Sampling platform specifications.

~~10.5~~8.5 Continuous Emission Monitoring System

~~10.5.1~~8.5.1 A Continuous Emission Monitoring System (CEMS) might be required by the regulatory authority in certain circumstances for either continual compliance determination or determination of exceedances of the standards.

~~10.5.2~~8.5.2 The owner or operator shall implement CEMS in line with standard industrial requirements that are used in other jurisdictions subject to approval by the regulatory authority. This may include the 1992 Canadian Council of Ministry of the Environment (CCME) guidelines for gas turbines if applicable and the 1998 Alberta CEMS Code which is enclosed as Appendix E.

~~10.5.3~~8.5.3 The operator ~~must~~ should perform periodic performance evaluations of the equipment, including daily calibration error tests, daily interference tests for flow monitors, and semi-annual (or annual) relative accuracy test audit (RATA) and bias tests.

~~10.5.4~~8.5.4 The owner or operator ~~must~~ should develop and implement a written quality assurance/quality control plan for each system. The quality control plan ~~must~~ should include complete, step-by-step procedures and operations for calibration checks, calibration adjustments, preventive maintenance, audits, and record-keeping and reporting. The quality assurance plan ~~must~~ should include procedures for conducting periodic performance tests.

~~10.5.5~~8.5.5 The owner or operator of a unit ~~must~~ should conduct certification tests and submit the results to the appropriate regulatory authority which would include:

- a 7-day calibration error test for each monitor;
- linearity check for each pollutant concentration monitor;
- relative accuracy test audit (RATA) for each monitor;
- bias test for each pollutant concentration monitor, flow monitor, and the CEM system;
- cycle time test for each pollutant concentration monitor; and
- daily interference test for flow monitors.

~~10.5.6~~8.5.6 The regulatory authority will issue a notice approving or disapproving the request for certification within 90 days after receiving a complete certification application. If the proposed system is disapproved, the owner or operator ~~must~~ should revise the equipment, procedures, or methods as necessary and resubmit a request for certification.

~~10.5.7~~8.5.7 Reports for continuous emission monitoring surveys ~~shall~~ should include:

- a detailed sampling system description and schematic diagram;
- copies of digital or chart recorder printouts labelled with individual test start and finished time, chart speed, pre- and post calibrations, span, drift determination, parameters sampled, number of sample points, and NO_x converter efficiency if tested; and
- tables for analysis for calibration gases, analyzer calibration data, and system calibration bias and drift test.

~~10.6~~8.6 Additional Information

Additional information concerning measurement and reporting is available at:

(a) Alberta Environment *Alberta Stack Sampling Code.* Publication Ref: 89.

(b) The U.S. Environmental Protection Agency. Title 40, Chapter 1: The Code of Federal Regulations. Part 60 - *Standards of Performance for New Stationary Sources.*

(c) Alberta Environment. *Air Monitoring Directive*: *Monitoring and Reporting Procedures for Industry*. Environmental Protection Services, Standards and Approvals Division, Edmonton, AB. June 1989.

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~~9.0~~9. MODELLING REQUIREMENTS

~~11.1~~9.1 Introduction

~~11.1.1~~9.1.1 Dispersion models are one of the primary tools used in air quality analysis in oil and gas industry. These models estimate the ambient concentrations that will result from proposed source emissions. Models are applied to estimate the ambient concentrations resulting from the combined impacts of proposed and existing sources of air contaminants. The estimated concentrations indicate if ambient air quality objectives are met and if any changes in ambient concentrations of air pollutants would occur. They play a role in determining levels of significance with respect to monitoring requirements in oil and gas industry.

~~11.1.2~~9.1.2 A dispersion model is a series of equations describing the relationships between the concentration of a substance in the atmosphere arising at a chosen location, the release rate, and factors affecting the dispersion and dilution in the atmosphere. The model requires information on the emission characteristics and the local meteorology. Models predict future scenarios, short-term episodes, and long-term trends.

~~11.1.3~~9.1.3 In the event of an upset condition at an upstream oil or gas facility, flaring of large volumes of gas can occur in a short period of time. Designing emergency flare stacks so that Ambient Air Quality Guidelines are met can be difficult since certain parameters, such as duration and flow rates, will vary depending on the nature of the emergency or upset flaring event. In such event, dispersion modelling can assist to account for the likelihood of upset flaring during a period of specific meteorological conditions, including worst-case meteorology.

9.1.4 ~~9.1.4~~ To assist the developer in choosing between available modelling alternatives and to perform and present air quality analyses in a manner preferred by the regulatory authority, this Section has been developed to ensure that the best available tools would be used, consistency in modelling exercise is maintained and the results allow for comparison between different facilities. Soil and vegetation sampling might be required to validate the results of the dispersion modelling.

~~11.1.4~~9.1.5 Baseline or background testing should be conducted before the facility operates.

~~11.2~~9.2 Modelling Requirements

~~11.2.1~~9.2.1 The requirements for modelling vary depending upon the types and amounts of pollutants emitted by the source, and the geographical location of the source within the regions.

~~11.2.2~~9.2.2 Dispersion modelling may be required for the following reasons:

(a) On the request of the regulatory authority as part of the company application for approval to operate a facility which will discharge air contaminants.

(b) On the request of the regulatory authority when the company applies for permit renewal.

(c) Estimating emergency flare stack height which will assure compliance with Ambient Air Quality Objectives.

(d) Estimating significant impact area and obtain distribution of ground level concentrations around emissions source for environmental impact assessment (EIA).

(e) Addressing concerns of the public.

~~11.3~~9.3 Obtaining Models and Resources

~~11.3.1~~9.3.1 Dispersion modelling computer programs can be purchased from commercial suppliers or by downloading them from the US EPA Support Center for Regulatory Air Models site at the Internet site: www.epa.gov/ttn/scram/

~~11.3.2~~9.3.2 Meteorological data required by advanced models can be purchased from Environment Canada, Atmospheric Services.

~~11.3.3~~9.3.3 Following atmospheric dispersion models are recommended:

- the SCREEN3 model for preliminary analysis to determine impact area, or to demonstrate that a source has no significant impacts outside the property boundary;
- the Industrial Source Complex Short Term model ISCST3 for refined assessment;
- the AERMOD model for advanced dispersion modelling in a complex terrain; and
- other models may be used as necessary on a case by case basis.

~~11.3.4~~9.3.4 Detailed model operations guidelines are available at operational manuals which are supplied with a purchased model and at a variety of Internet sites such as

- EPA: www.epa.gov/ttn/scram/;
- Lakes Environmental (commercial supplier): www.lakes-environmental.com; and
- Alberta Environment: www3.gov.ab.ca/env/air/airqual/airmodelling.html.

~~11.4~~9.4 Screening Assessment

~~11.4.1~~9.4.1 A screening assessment ~~shall~~ should be performed with the SCREEN3 air dispersion model. It is designed for analyzing single-source release scenarios in simple or complex terrain. SCREEN3 enables users to prepare an initial screening analysis to establish a conservative or worst-case estimate of short-term air quality impacts from a specific source. The model can analyze the wide variety of scenarios which includes:

- **Sources:** SCREEN3 is designed to model single-source scenarios. Point, area, and volume sources, as well as release from flares, can be analyzed;
- **Terrain:** SCREEN3 can model flat, simple, or complex (above stack height) terrain, or a combination of simple and complex terrain;
- **Receptors:** SCREEN3 allows for both automated receptor arrays and discrete receptors to be used in a model run. Discrete receptors can be entered with a height above ground level (flagpole receptors), except in complex terrain situations; and
- **Meteorological Data:** A matrix of 54 combinations of wind speed and stability class can be analyzed in a single model run to determine which meteorological conditions produce highest downwind concentrations. Discrete wind speed and stability class categories can also be entered directly into SCREEN3. For complex terrain analyses, SCREEN3 uses VALLEY screening conditions (2.5 m/s, F stability class).

~~11.4.2~~9.4.2 In addition to the above scenarios, SCREEN3 has the ability to account for the effects of building downwash and can calculate concentrations in building cavity regions. SCREEN3 is also unique among EPA models because it can incorporate the effects of inversion break-up and shoreline fumigation.

~~11.4.3~~9.4.3 Default options of the model include:

- stack tip downwash;
- final plume rise;
- buoyancy induced dispersion;
- the vertical potential temperature gradient;
- treatment for calms; and
- appropriate wind profile exponents.

~~11.4.4~~9.4.4 The operator ~~shall~~ should provide the following model input data:

(a) For stack modelling
  - pollutant emission rate (g/s);
  - stack height (m);
  - stack internal diameter (m);
  - exhaust exit velocity (m/s) and temperature (K);
  - ambient temperature (K); and
  - receptor height above ground.

(b) For flare modelling
  - pollutant emission rate (g/s);
  - flare stack height (m);
  - total heat release rate (cal/s);
  - receptor height above ground; and
  - the model assumes flare stack temperature of 1273 K and an exit velocity of 20 m/s.

~~11.4.5~~9.4.5 Following modelling options are available:

- source type: stack, flare, area, or volume;
- urban or rural area;
- full meteorology or single stability class;
- building downwash;
- complex, flat or elevated terrain;
- automatic or discrete distances; and
- fumigation (shore line effect).

~~11.4.6~~9.4.6 Model output includes:

- summary of input data;
- tabular and graphical values of concentration vs. distance at 1-hour averaging time;
- terrain height;
- stability class for each point of distance/concentration;
- buoyancy and momentum fluxes; and
- diffusion coefficients in Y and Z directions.

~~11.4.7~~9.4.7 The concentration values (including the addition of background/existing concentrations) shall be compared with Ambient Air Quality Standards (AAQS) which are listed for common pollutants in Table 9.1. If exceedances exist, the model would be run again with individual stability classes (from A to F). Analyzing maximums in each class may indicate that no exceedances occur in all classes except for very unstable class A conditions. This is a very rare stability class so no further modelling would be necessary.

~~11.4.8~~9.4.8 Once the modelling is completed, plots for the flaring scenario of the emission rate versus duration should be created. The amount of plots created may vary depending on the nature of the operation. At a minimum, plots for stabilities (B - unstable), (D - neutral), and (E - stable) should be made for the worst-case flaring event. This will be sufficient to give an operator an indication as to how flaring can be conducted. An example of the plots is shown in Figure 9.1 (source: *Emergency / Process Upset Flaring Management: Modelling Guidance*, Alberta Environment, Pub. No: 0-7785-0685-1, August 1999).

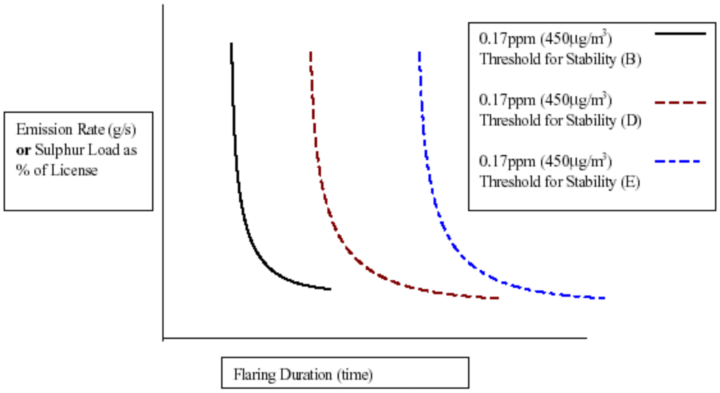

Figure 9.1 **Acid Gas Flaring During Different Stability Conditions.**

~~11.4.9~~9.4.9 When these plots are completed, they should be supplied to the operators, along with a description of stability conditions. The operators will then have the ability to assess the most appropriate way to carry out the flaring, once health, safety and plant integrity considerations are under control.

~~11.4.10~~9.4.10 Another way of lowering maximum concentrations at points of impingement for flares is to run the model with another heating value (achieved by adding lift gas) and determine the results. Repeat modelling runs adjusting the heating value until the guideline is met, or the results are satisfactory within the reasonable bounds of the flaring parameters.

~~11.4.11~~9.4.11 If the modelling results described in ~~Paragraphs~~ Sections 9.4.8 and 9.4.9 are still higher than AAQS, a refined assessment should be performed with less conservative model ISCST3 (see ~~Paragraph~~ Section 9.6). The modelling steps are shown in Figure 9.2 (source: Air Quality Model Guideline, Pub. No. T/564, Alberta Environment, October 2000).

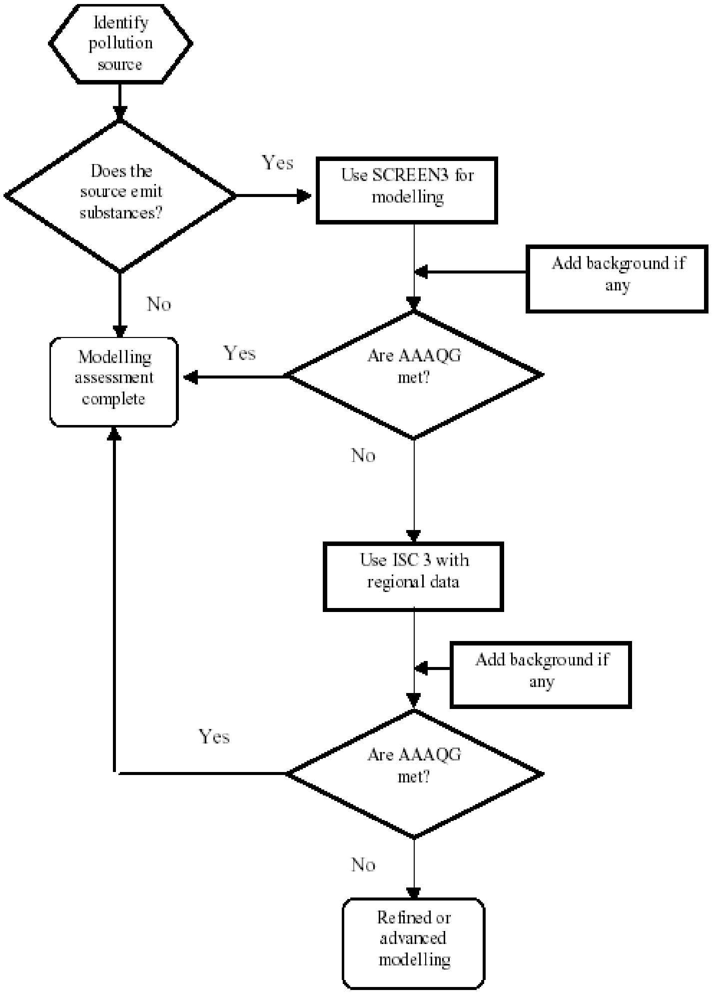

Figure 9.2 Flow chart for screen modelling tier.

~~11.5~~9.5 Adjustment of Predictions to Shorter-Averaging Times

Two methods to convert a 1-hour concentration predicted by the model to a real time emergency or upset flaring event (e.g., less than 1 h) are proposed:

(a) Assume that the total gas release occurs over 10-minutes. The gas rate can be divided by 6, and modelled for the entire hour, and the resulting prediction can be directly compared with a 1 h standard.

(b) Assume that the gas is released over the entire hour and that the resulting concentration is what would actually occur over a 10-minute interval and take zero concentration for the rest of the hour. The resulting prediction from the model must be divided by 6 to obtain the actual 1-hour observed concentration.

~~11.6~~9.6 Refined Assessment

~~11.6.1~~9.6.1 The ISCST3 dispersion model is recommended for a refined assessment. The ISCST3 is a steady-state Gaussian plume model which can be used to assess pollutant concentrations and/or deposition fluxes from a wide variety of sources associated with an industrial source complex. The model was designed to support the EPA's regulatory modelling options, as specified in the US EPA Guidelines on Air Quality Models (Revised). Environment Canada and provincial Departments of the Environment consider this model a supporting tool for the ambient air quality regulations.

~~11.6.2~~9.6.2 Some of the ISCST3 (short term) modelling capabilities are:

- the ISCST3 model may be used to model primary pollutants and continuous releases of toxic and hazardous waste pollutants;
- it can handle multiple sources, including point, volume, area, and open pit source types; line sources may also be modeled as a string of volume sources or as elongated area sources;
- source emission rates can be treated as constant or may be varied by month, season, hour of day, or other optional periods of variation; these variable emission rate factors may be specified for a single source or for a group of sources;
- it can account for the effects of aerodynamic downwash due to nearby buildings on point source emissions;
- contains algorithms for modelling the effects of settling and removal (through dry deposition) of large particulate and for modelling the effects of precipitation scavenging - for gases or particulate;
- receptor locations can be specified as gridded or as discrete receptors in Cartesian or polar coordinates;
- incorporates the COMPLEX1 screening model dispersion algorithms for receptors in complex terrain;
- the model uses real time meteorological data to account for the atmospheric conditions that affects the distribution of air pollution impacts on the modelling area; and
- modelling results can be output for concentration, total deposition flux, dry deposition flux, and/or wet deposition flux.

~~11.6.3~~9.6.3 The operator shall provide the following model input data for each point source:

- pollutant emission rate (g/s);
- stack height (m);

- stack internal diameter (m);
- stack location;
- Universal Transverse Mercator (UTM) coordinates should be used for all ISCST3 modelling, i.e. source locations, receptor locations, property boundaries, etc;
- exhaust exit velocity (m/s) and temperature (K);
- ambient temperature (K); and
- receptor height above ground.

~~11.6.4~~9.6.4 Following modelling options are available:

- source type: point, line, flare, area, open pit, volume;
- urban or rural environment;
- site-specific meteorological conditions;
- building downwash;
- terrain elevations for receptors based on imported digital elevation fields;
- automatic or discrete distances;
- fumigation (shore line effect);
- regulatory default / non-default options;
- results as concentration in air, dry deposition, wet deposition, total deposition; and
- various averaging periods from 1 hour to multiple years.

~~11.6.5~~9.6.5 Five years of site specific meteorological data is preferred, if available. If 5 years of ~~sight~~ site specific data is not available but more than one year is, all available ~~sight~~ site specific data is preferred for the modelling analysis. If less than 1 year of ~~sight~~ site specific data is available, 5 years of meteorological data from Environment Canada, Atmospheric Services, should be used for the modelling analysis and any site specific data available should be included.

~~11.6.6~~9.6.6 Model output will include:

- summary of input data;
- tabular values of concentration vs. distance and graphical concentration isopleths at selected averaging time in 2D or 3D frames;
- stability class for each point of distance/concentration; and
- buoyancy and momentum fluxes.

~~11.6.7~~9.6.7 If the predicted ambient ground level concentrations are greater than the maximum acceptable AAQS listed in Table 9.1, the owner/operator will have to undertake corrective measures that would result in lower ambient concentrations. These measures may include stack height increase, reduction of emission rate, introduction of emission control equipment, dilution with the ambient air, etc. While under certain circumstances, dilution through stack height increase may be an option. RWED would prefer to see the emphasis placed on pollution prevention solutions, best management practices, and/or improved emission controls.

~~11.7~~9.7 Hazardous Air Pollutants (HAPs) and Toxic Chemical Substances (TCS)

The regulations frequently require modelling for HAPs and TCS for which no standards exist. The GNWT might adopt any standards and regulations for HAPS as they are promulgated. If no standard exists for a pollutant for which modelling is required, a reference value of 1/42 of the Threshold Limit Value - Time Weighted Average (TLV-TWA) for a 24 hour averaging time should be used for comparison purposes. TLV-TWA values may be taken from the publication *Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices*.

Table 9.1 Ambient Air Quality Standards

Jurisdiction	Pollutant	Concentration µg/m^3	Averaging Time	Objective
Northwest Territories	TSP	120 60	24 h Annual	Max. acceptable
	PM2.5	30	24 h	Max acceptable
	O_3	130	8 h	Max acceptable
	SO_2	450 150 30	1 h 24 h Annual	Max. acceptable
Canada	NO_2	60	Annual	Max. desirable
		400 200 100	1 h 24 h Annual	Max. acceptable
		1,000 300	1 h 24 h	Max. tolerable
	H_2S	1	1 h	Max. desirable
		15 5	1 h 24 h	Max. acceptable
	CO	15,000 6,000	1 h 8 h	Max. desirable
		35,000 15,000	1 h 8 h	Max. acceptable
		20,000	8 h	Max. tolerable
	O_3	100 30	1 h 24 h	Max. desirable
		160 50 30	1 h 24 h Annual	Max. acceptable
		300	1 h	Max. tolerable
Alberta	Benzene	30	1 h	Max. acceptable
	Ammonia	1,400	1 h	Max. acceptable

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~~11.8~~9.8 Submission of Modelling Results

Upon completion of dispersion modelling an Air Quality Report should be submitted to the regulatory authority. The report should contain the following:

- introduction;
- scope of work;
- model selection criteria;
- short description of the models used;
- model input data and explanation how they were derived or obtained with sample calculations if relevant (e.g. stack testing results, emission calculations with AP42 emission factors, mass balance);
- listing of selected options such as averaging periods, building downwash, terrain data, meteorological data;
- the dispersion modelling results (graphs of isopleths, with background maps, percentile concentrations, concentrations summary tables, models-generated reports);
- a summary of any exceedances identified when compared to the maximum acceptable valued defined by appropriate AAQS; and
- any other information as required by the regulatory authority.

~~11.9~~9.9 Additional Information

Additional information on dispersion modelling is provided in *Air Quality Model Guideline*, Alberta Environment, October 2000, provided in Appendix F.~~ENFORCEMENT~~

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Guide **60**

Upstream Petroleum Industry Flaring Guide

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1 Introduction

Guide 60: Upstream Petroleum Industry Flaring Requirements, introduced by Alberta Energy and Utilities Board (EUB) *Interim Directive* (ID) *99-6*, sets out Alberta requirements and expectations for upstream petroleum industry flaring. It incorporates the recommendations made to the EUB in June 1998 by the multistakeholder Clean Air Strategic Alliance (CASA) on associated or solution gas flaring,[1] as well as additional requirements to address flaring issues not covered by the CASA report.

1.1 What's New?

The following is a summary of the requirements of the management framework introduced by this guide:

- A firm provincial **solution gas** flare volume reduction schedule:
  - 15 per cent reduction from 1996 baseline by 31 December 2000 (reduce flaring to 1445 10^6m^3/year)
  - 25 per cent reduction from 1996 baseline by 31 December 2001 (reduce flaring to 1275 10^6m^3/year)
- New flare performance requirements for **all** flares, including the following compliance deadlines:
  - all new flares by 1 January 2000
  - existing solution gas flares by 31 December 2002
  - flares at other existing permanent facilities by 31 December 2004

Required evaluation of all solution gas flares by 31 December 2002 using a flaring management decision tree, including a streamlined common economic assessment process.

- Commencing 1 January 2000, the reduction of the New Oil Well Production Period (NOWPP) flare limit set out in Informational Letter (IL) 87-9[2] to 300 10^3m^3/month from 500 10^3m^3/month, implementation of a maximum gas oil ratio (GOR) criterion of 3000 m^3/m^3, above which conservation would be required, and tie-in of development wells within one month in pools where gas conservation exists.
- Personal consultation and public notification requirements for new and existing solution gas batteries

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[1] Management of Routine Solution Gas Flaring in Alberta, CASA, June 1998.

[2] *IL 87-9: Revised Procedures for Oil Production Allowable Controls and New Oil Well Production Period*, EUB, 1997.

- Requirements for flaring at normally conserving facilities during planned or emergency flaring, effective 1 January 2000
- Sulphur recovery requirements for facilities outside the scope of EUB *IL 88-13*[3] and the related report ERCB-*AE 88-AA*[4]
- Clarified flaring and venting reporting requirement for all facilities

Other important aspects addressed in the guide include

- Conflict resolution process to address flaring concerns
- Release of flaring and venting (S-2) data to support increased use of otherwise flared gas
- Progress towards minimizing requirements for electricity generators using otherwise flared gas
- Annual EUB reporting of industry performance
- Management framework review in 2001

The following table summarizes some key implementation and compliance dates.

Implementation and Compliance Dates		
Item	**Effective Date**	**Compliance Date**
Solution Gas Reduction Schedule		
15% from 1996 baseline	1 January 2000	31 December 2000
25% from 1996 baseline	1 January 2000	31 December 2001
Reduced NOWPP Flare Limit; GOR Limit; Development Well Tie-in	1 January 2000	1 January 2000
Flaring at Conserving Facilities	1 January 2000	1 January 2000
Evaluation of SG Flares/ Compliance with Flare Performance Requirements		
New Flares	1 January 2000	1 January 2000
Existing Solution Gas Flares	1 January 2000	31 December 2002
Other Existing Flares	1 January 2000	31 December 2004
Consultation and Notification		
New Flares – revise G-56	1 January 2000	1 January 2000
Existing SG Flares – residents within 500 m	1 January 2000	31 December 2000
Review Management Framework	31 March 2001	N/A

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[3] *IL 88-13: Sulphur Recovery Guidelines Gas Processing Operations*, EUB, 1988.

[4] *Report No. ERCB – AE 88-AA: Sulphur Recovery Guidelines for Sour Gas Plants in Alberta*, EUB, 1988.

1.2 Background

Repeated concerns about flaring prompted the EUB in 1990 to support flaring research by the Alberta Research Council (ARC) to evaluate the technology used to flare gas. The ARC research[5] suggested that the destruction efficiency of flare stacks used to dispose of solution gas is not as high as originally thought, and it reported a variety of compounds of concern being emitted as a result of incomplete combustion. In concert with the research, the EUB also initiated a review of its policies respecting solution gas conservation[6] that included provision for several regional multistakeholder consultations.[7]

The Canadian Association of Petroleum Producers (CAPP) proposed that the issue of flaring be reviewed by a multistakeholder team sponsored by CASA. The team chose to focus on routine solution gas flaring, which represents about 70 per cent of the total gas flared in Alberta. The recommendations to CASA were ratified by members of industry for implementation, and the EUB received CASA's recommendations in June 1998. Since then the EUB has worked with CAPP, the Small Explorers and Producers Association of Canada (SEPAC), the Alberta Department of Resource Development (ADRD), and Alberta Environment to build on the framework recommended by CASA to improve the management of all flaring sources.

While this guide is specific to flaring, the EUB recognizes public expectations are to reduce emissions in general. In this regard, the EUB plans to streamline the collection and dissemination of relevant industry emission information in management of these substances.

1.3 Flare Management Framework

CASA recommended a policy objective hierarchy for flaring. The hierarchy can be summarized as eliminate flaring, reduce flaring, and improve the efficiency of flares. The EUB supports the objective hierarchy and believes it provides an appropriate foundation for flare management into the future.

CASA also recommended a flare management framework that strives for eventual elimination of routine solution gas flaring and includes significant short- and long-term targets for flare reductions. It recognized that in some circumstances flaring will be necessary and therefore recommended a suite of flare performance requirements. It is also recommended that the associated regulatory aspects of the recommended framework include public involvement, monitoring, and enforcement. The EUB has adopted the framework to encompass flaring in general. Figure 1 provides an overview of the management framework.

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[5] *Investigations of Flare Gas Emissions in Alberta*, Alberta Research Council, November 1996.

[6] *IL 96-6: Solution Gas Conservation and Emissions Reductions*, EUB, April 1996.

[7] *EUB Report 97-A: Policy Review of Solution Gas Flaring and Conservation*, EUB, June 1997.

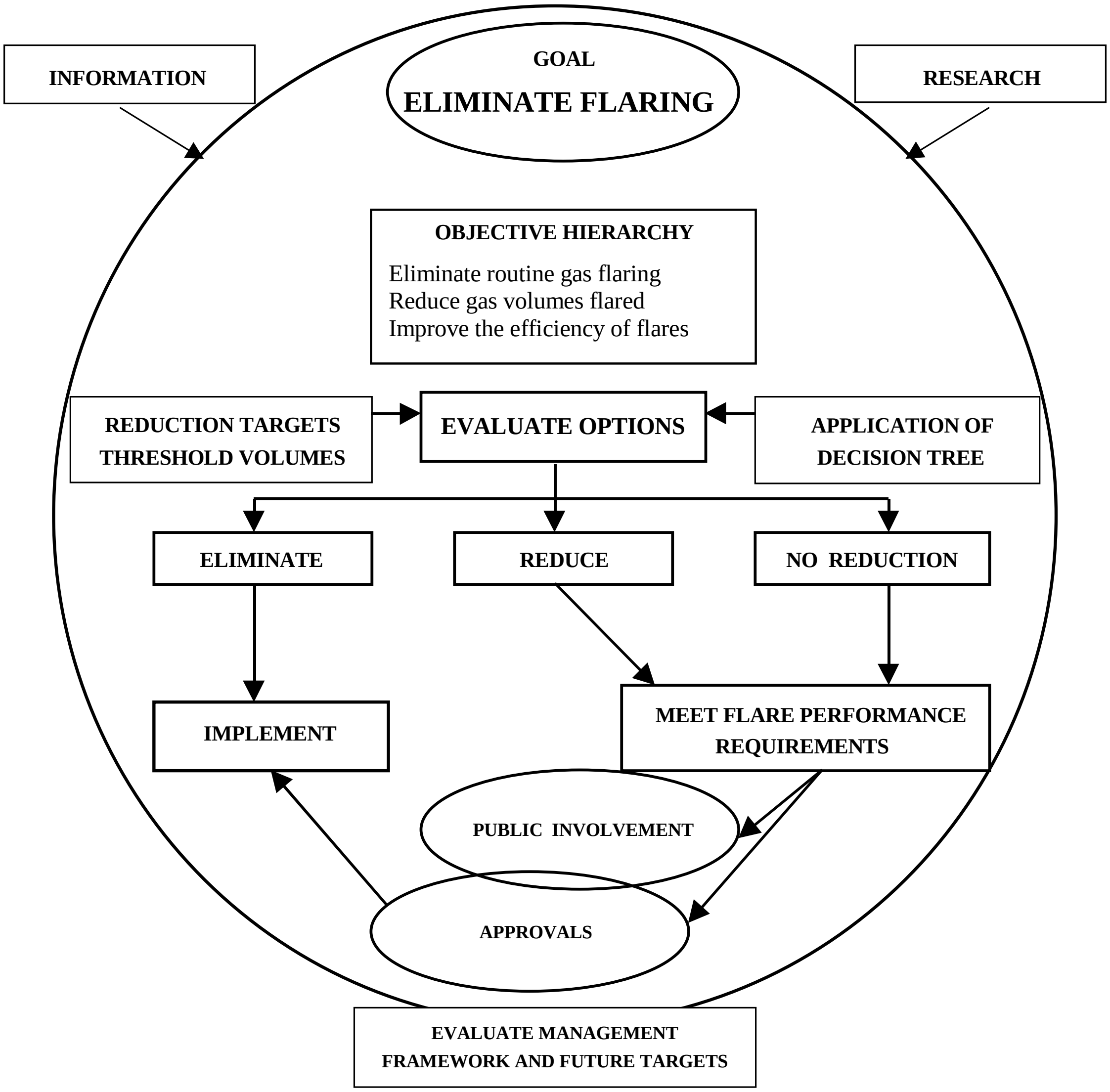

Figure 1. Flaring Management Framework

1.4 Flaring Management in Alberta

Flaring is associated with a wide range of energy activities or operations, including

- oil, oil sands/crude bitumen, and gas well drilling
- initial oil, oil sands/crude bitumen, and gas well completion or servicing clean-up flow-backs
- gas well testing to establish reserves and determine productivity

- disposal of gas associated with oil or oil sands/crude bitumen production while gas conservation is being evaluated and implemented
- non-routine gas gathering, distribution system operations, maintenance pressure relief, reduction
- non-routine processing plant upset or emergency conditions

All emissions are subject to regulatory controls. In Alberta, air quality guidelines[8] are established and set out for all facilities by Alberta Environment. For larger facilities such as sour gas plants, the administration of emission requirements is shared between Alberta Environment and the EUB. The EUB administers requirements for flaring at smaller facilities, including oil batteries.

The guidelines set out acceptable ambient levels of various substances, including hydrogen sulphide (H_2S) and sulphur dioxide (SO_2) contaminants commonly associated with oil and gas production. The limits established in the guidelines are to provide suitable levels of safety and environmental protection. The Alberta Ambient Air Quality Guidelines are listed on Alberta Environment's Web site, www.gov.ab.ca/env.

Notwithstanding the objectives of the existing air quality guidelines, acceptable ambient limits have not been established for many of the compounds measured by the ARC research. Development of ambient air guidelines is a process involving considerable scientific study and extensive consultation among the federal and provincial governments and other stakeholders.

The EUB accepts the framework recommended by CASA to reduce provincial flare emissions, coupled with improved flare performance standards as a practical approach to reduce the overall level of solution gas flaring.

1.5 Ongoing Research

CASA suggested that additional research needs to be undertaken so that Alberta can progress towards the use of practical flare efficiency standards where flaring is necessary.

The EUB notes that some of the necessary research is already under way under the auspices of the Petroleum Technology Alliance of Canada, with several federal and provincial departments participating, along with industry operators and technology suppliers. Some of the multiyear research, at a cost of about $1.4 million, is aimed at the development of an effective combustion efficiency standard for flaring, including practical means to measure combustion efficiency in the field. The development of technologies to improve flaring performance and to identify alternative uses of solution gas is also being investigated.

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[8] Alberta Ambient Air Quality Guidelines, Alberta Environment, www.gov.ab.ca/env

1.6 Regulations Changes

The changes described in this guide will require some revisions to the regulations. The EUB will proceed to make the necessary changes to reflect the requirements for upstream flaring as described in this guide in due course.

IL 91-2: Sour Gas Flaring Requirements and Changes to Regulations **and** ***IL 96-6: Solution Gas Conservation and Emissions Reduction*** **are rescinded.**

1.7 Access to Production and Flaring (S-2) Data

The EUB will make flaring and venting information available to facilitate evaluation of solution gas conservation and clustering opportunities, as described in Section 2.9.2.

1.8 Future Review and Changes

CASA recommended that effectiveness of the new framework be revisited in the second quarter of 2001, particularly the reduction schedule, as well as progressing towards a flare combustion efficiency standard. The EUB supports this concept as a matter of continuous improvement and will initiate the review at that time to assess the new framework, including progress against the firm targets as well as reduction targets for subsequent years.

1.9 Definitions

Appendix 1 defines terms as used in the context of this guide.

As well, in this guide the words **required, shall,** and **must** are to be interpreted to mean that the specified action or item is a minimum regulatory requirement.

2 Solution Gas Management

2.1 Schedule of Reducing Routine Solution Gas Flaring

Through the report of the CASA flaring project team, the oil and gas industry agreed to reduce routine solution gas flaring as measured against the 1996 baseline of 1700 $10^6 m^3$/year as follows:

- a 15 per cent reduction in aggregate annual volumes flared by 31 December 2000 (i.e., reduce solution gas flaring to 1445 $10^6 m^3$/year)

- a 25 per cent reduction in aggregate annual volumes flared by 31 December 2001 (i.e., reduce solution gas flaring to 1275 $10^6 m^3$/year)

If the reductions are not met, the EUB intends to impose the reductions by regulation.

Based on 1996 flare volume information, the reductions would be attained by restricting flare sizes as follows:

- No solution gas flares larger than 2500 x $10^3 m^3$/yr (6.8 $10^3 m^3$/d) would be allowed by 31 December 2000.

- No solution gas flares larger than 1500 x $10^3 m^3$/yr (4.1 $10^3 m^3$ /d) would be allowed by 31 December 2001.

The EUB expects that all operators, in particular those operating facilities with larger solution gas flares, will aggressively pursue other options for the management of their associated solution gas.

The EUB notes that CASA also recommended targets for reductions in solution gas flaring beyond 2001:

- 40-50 per cent reduction in volumes flared by 31 December 2003
- 60-70 per cent reduction in volumes flared by 31 December 2007

The corresponding maximum flare sizes for these reduction targets are

700 x $10^3 m^3$/yr	40 per cent
500 x $10^3 m^3$/yr	50 per cent
350 x $10^3 m^3$/yr	60 per cent
250 x $10^3 m^3$/yr	70 per cent

However, CASA agreed that it would be prudent to review these targets after the initial reductions were accomplished.

The EUB plans to revisit its flaring requirements in the second quarter of 2001.

The EUB agrees that achieving these further reductions will require vigilance and industry cooperation to reduce regional flaring and to successfully introduce alternative technologies, such as electricity generation. It also agrees that further deregulation and restructuring of the electrical industry will assist in attaining these longer-term targets. Sections 2.5.5 and 2.8 discuss these matters further.

2.2 Objective Hierarchy

CASA recommended that the EUB adopt a policy objective hierarchy to guide solution gas flare management in Alberta:

1) eliminate routine solution gas flaring
2) reduce volumes of gas flared
3) meet the flare performance standards

The EUB believes these objectives are consistent with its intent to optimize resource conservation and ensure appropriate levels of environmental protection and accepts CASA's recommendation.

2.3 Evaluation of Solution Gas Flares

As noted above, the objective for solution gas flaring management will be the elimination, reduction, and the improvement of the efficiency of flaring.

In order to accomplish these objectives, the EUB has adopted a decision tree process to be used by operators as a means for implementing the objectives for gas flaring management. The decision tree is shown in Figure 2.

Operators must use the decision tree to assess new flares.

All existing solution gas flares must be evaluated using the decision tree by 31 December 2002.

Flares with residents within 500 metres (m) must be evaluated and brought into compliance with the flare performance requirements by 31 December 2000.

An existing solution gas flare with a demonstrable life expectancy of less than three calendar years would be exempt from the need for compliance with the flare performance requirements detailed in Section 7. Operators subsequently wishing to continue operations at these facilities will be required to cease operations until the facility complies with the requirements of Section 7.

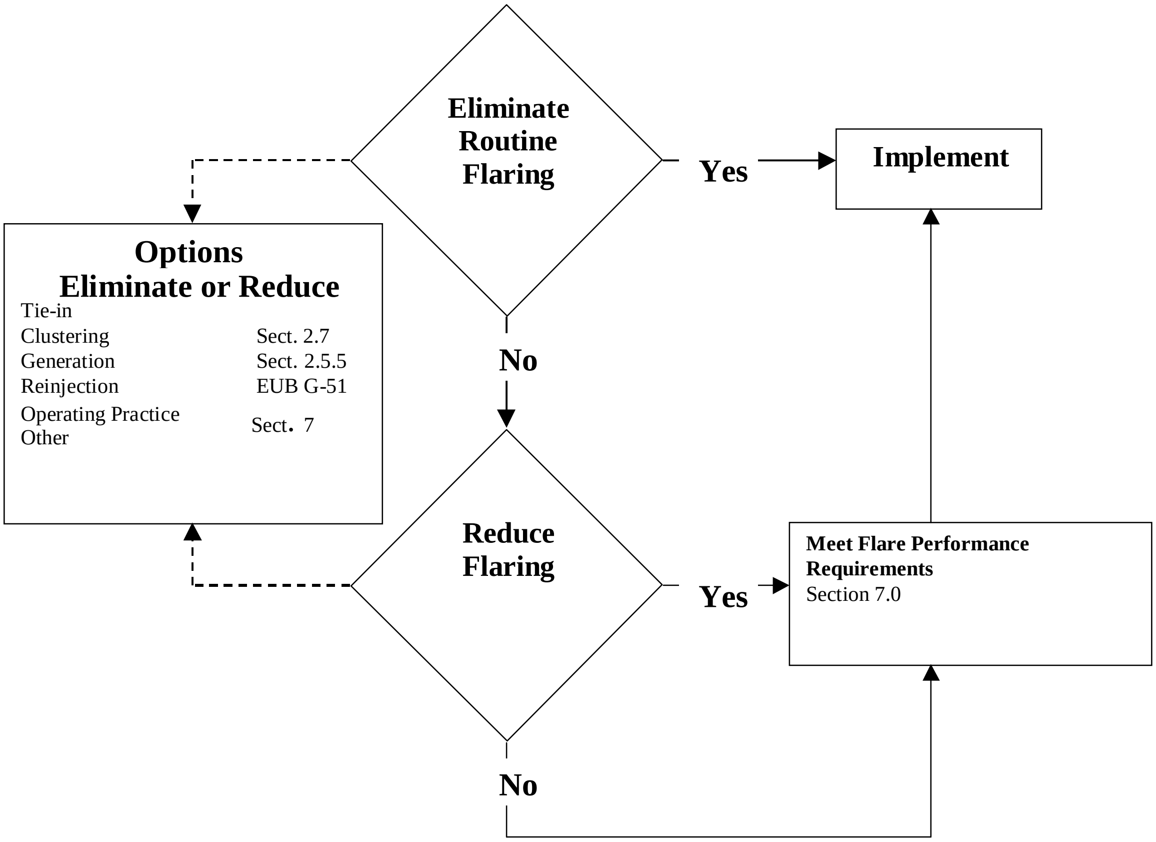

Figure 2. Flaring Management Decision Tree

Using the decision tree, an operator would first assess conservation of solution gas by tie-in to a gathering system, followed by other options such as reinjection and other economic technical options to eliminate flaring. Economic, social, and environmental factors would be considered in this evaluation.

If conservation is determined to be economic by any method using the economic decision process detailed in Section 2.4, the EUB requires that the gas be conserved.

The methods include conventional conservation projects, power generation, or any other alternative method that may become available.

If flaring cannot be eliminated, the operator would then consider alternatives for minimizing the volumes of gas that are flared, such as the generation of electricity.

Remaining flares must meet the flare performance requirements detailed in Section 7.

Venting is not considered an acceptable alternative to flaring.

In all applications and evaluations of the need to flare, the following basic questions would be applied to the assessment:

- Are there residents in proximity?
- Are there directly affected (local) residents with environmental or health concerns?
- Are there economic alternatives to flaring?
- Would clustering of flares create an economic project?
- Are the environmental impacts of eliminating or reducing flaring greater than the environmental benefits?

Section 2.4 details the economic analysis process and criteria required by the decision tree assessment.

Records of the assessments shall be available for audit by the EUB upon request.

2.4 Economic Decision Process

2.4.1 Streamlined Evaluation

In order for the results of the decision tree analysis to be consistent, it is necessary to define the parameters to be used in a streamlined economic evaluation. This will apply to the decision tree analysis of all solution gas conservation projects that may involve existing or new flares. The decision tree analysis is outlined in Section 2.3.

2.4.2 Process

The following assumptions and parameters will be used in the decision tree analysis:

1) The evaluation will be a before-tax analysis.

2) The commodity price forecasts used in evaluations of conventional gas conservation projects (gas gathered, processed, and sold to market) will be the most recently published by Dobson Resource Management. In Dobson’s survey, the average nominal large consulting firms’ Alberta plant gate TCGSL “ blended ” price (C$/MMBTU) for natural gas will be used in evaluations. TCGSL is the Transcanada Gas Services blended price at plant gate. The forecast used for natural gas liquids will be the average nominal large firms’ consulting price FOB Edmonton in C$/BBL. The forecasts are available in Dobson’s publication *Survey of Hydrocarbon Price Forecasts Utilized by Canadian Petroleum Consultants and Canadian Banks*, which is updated semiannually and available at a nominal cost per publication. The publication is also available in the EUB Library.

3) The power price forecast for electrical power generation projects will be the time-weighted average of the previous twelve months paid by the Alberta Power Pool for power generated or the cost of the power displaced at a site. The power price will be

escalated at the annual rate of inflation.

4) The operator will provide information to support the calculation of remaining reserves and to establish the production forecast. This would include planned drilling programs and the implementation of pressure maintenance schemes.

5) The operator will give a detailed breakdown of capital costs, showing equipment, material, installation, and engineering costs. Capital costs will be AFE (approved for expenditure) quality numbers. Capital costs incurred prior to the initiation of the solution gas project (sunk costs) will not be included in the analysis. Only future capital costs related to solution gas conservation will be included.

6) The incremental annual operating costs for the solution gas project will be equal to 10 per cent of the capital cost to initially install the facilities. The 10 per cent includes incremental expenses to operate equipment and gas transportation and gas processing fees.

7) The incremental annual operating costs for power generation projects will be equal to 10 per cent of the capital cost to initially to install the generation facilities. Standby fees would be in addition to the 10 per cent allowance.

8) The long-term inflation rate will be based on the Consumer Price Index forecast, which is available from the same table in the Dobson’s Survey used for natural gas prices. A constant rate of 2.5 per cent will be used for 1999.

9) The discount rate will be equal to the prime lending rate of the Alberta Treasury Branch on loans payable in Canadian dollars plus 3 per cent based on the month preceding the month that the evaluation is conducted. The discount rate will be reviewed periodically by ADRD/EUB and will be revised if the cost of capital for the oil and gas industry changes significantly.

10) Only revenue, minus net royalties, from incremental gas and gas by-products that would otherwise be flared will be included in the economic evaluation.

11) A project will be considered economic if the incremental economics of solution gas conservation generates a net present value (NPV) greater than zero.

When evaluating flares, the economic evaluation must account for any cost savings, such as reduced trucking, equipment rental, and operator costs, resulting from the conservation project.

Should an operator determine that to eliminate flaring either by solution gas conservation or reinjection is uneconomic, a comprehensive report must be available for audit. The report must incorporate the preceding information and provide sufficient detail to allow the results to be verified.

2.5 Approvals

2.5.1 Energy Facility Development Approvals

EUB *Guide 56* details administrative and technical requirements for facilities handling solution gas. CASA recommended several modifications to the facility application process and requirements as noted in the following subsections.

With the issuance of this guide, the EUB is confident that flares will receive additional attention during the facility development approval process. The next version of *Guide 56* will specifically reference flaring requirements. The EUB is satisfied, however, that in view of the specific requirements described in this document, modification of the application form is not necessary at this time.

2.5.2 Personal Consultation and Public Notification

2.5.2.1 New Facilities

For new facilities, the personal consultation and public notification requirements specified in *Guide 56* continue to apply. The minimum personal consultation distance specified in *Guide 56* for sweet single oil wells with flares is increased to 300 m, effective 1 January 2000.

Longer distances may be necessary as a result of emergency planning or public consultation requirements. See *Guide 56*, Volume 2.

In addition to existing information requirements, information specific to flaring, including the material outlined in Section 2.5.2.3, is required for the personal consultation and public notification.

2.5.2.2 Existing Facilities

For existing solution gas flares, operators must notify residents within 500 m of existing flares of the results of the decision tree evaluation conducted for the flare by 31 December 2000.

An information package specific to flaring, including the material outlined in Section 2.5.2.3, is required for the public notification.

2.5.2.3 Information Package

The CAPP publication *Recommended Practices for Flaring of Associated and Solution Gas at Oil Production Facilities* has an information template that may be used as an informational package for this purpose; a company may also develop its own package**. As a minimum, however, all informational packages must include the following key items:**

- Definition of solution gas and information on its conservation and use
- Explanation of the flaring management decision tree process
- Information on general flare performance requirements and reduction targets
- Discussion of options available for managing solution gas and other flaring
- Results of the flaring management decision tree evaluation for the specific flaring at the site in question
- Description of specific actions the company will be taking to eliminate, reduce, or improve the efficiency of the specific flare based on the evaluation
- Description of the EUB's process for facility approvals and *Guide 56*
- Information about individual rights to object and the process for doing so
- List of industry, EUB, and government contacts

2.5.3 Conflict Resolution Process

As outlined in Section 2.3, the operator using the decision tree must evaluate all existing flares. Upon completion of the evaluation of a flare, the operator must give specific notice, including the results of the evaluation to all residents within 500 m of the flare. The notification must give clear statements of what the operator will do with the existing flare as the result of the decision tree evaluation.

In normal circumstances, operator compliance with the flare performance requirements of this guide would satisfy the EUB that health, safety, and environmental impacts have been adequately addressed. However, there may be extenuating circumstances that give rise to landowner concerns with the operation of a flare stack. In this event, if the landowner, resident, or occupant has an objection with respect to the evaluation or the proposed continued operation of the flare, the following process will be used to resolve the objection:

1) The resident will notify the operator and/or the appropriate EUB Field Centre in writing that they have an objection to the flare and the reason for the objection to the flare.

2) The person or persons filing the objection and the operator will try to resolve the matter themselves.

3) If after a reasonable time and after reasonable attempt, the objection is not resolved to the satisfaction of all parties, they may request assistance from the appropriate EUB Field Centre to facilitate further discussions with the objective of resolving the concerns. This would include a review of the evaluation conducted on the flare by the operator (in coordination with EUB Operations Group staff), full documentation of the landowner's

concerns, discussion of solutions utilized in other locations, and clarification of regulatory requirements and procedures as necessary.

4) If this process does not resolve the flare objection to the satisfaction of all parties, EUB staff will refer the objection to the Board for review.

5) The Board will review the matter. The EUB's normal procedures and rules would apply.

6) The Board will issue a decision on its review and direct a resolution.

2.5.4 Reduction to New Oil Well Production Period (NOWPP) Flaring Limits, Early-Time Flaring in Development Wells, and Flaring at High GOR Wells

Production from most new oil pools is initially governed by a maximum rate limitation (MRL). Limits to oil and solution gas production are imposed until the operator and the EUB have agreed on an optimum pool depletion strategy. Solution gas conservation is also required before oil rate limits are removed, unless the operator can show that it is uneconomic. The MRL restrictions are relaxed during the initial few months of a well's production, defined as the new oil well production period (NOWPP). During NOWPP, as described in *IL 87-9*, gas oil ratio (GOR) penalties are not applied, but there is a gas flaring limit of 500 10^3m^3/month/well. Once the optimum depletion strategy for an oil pool has been agreed to and implemented and gas conservation issues have been resolved, an oil pool usually goes on good production practice (GPP). Under GPP, oil rate restrictions and GOR penalties are removed.

In order to reduce early-time solution gas flaring from oil wells, the following policy and regulatory changes will be implemented by the EUB on 1 January 2000:

1) Development wells, completed in pools where gas conservation exists, must be tied in to the gas gathering system within one month. This should allow sufficient time for cleanup and evaluation of the well. It is unlikely that infill wells would require an evaluation period beyond a few days. Step-out wells from existing oil pools may require several more days of evaluation, but this period should not reasonably exceed one month. This requirement applies to all oil wells, whether completed in pools on GPP or in pools subject to an MRL. Operators should ensure that drilling programs in and adjacent to existing conserving pools include measures for implementing gas conservation within the one-month period or be prepared to shut in the well(s) until the gas is tied in.

2) Oil wells with a GOR greater than 3000 m^3/m^3 must be shut in until the gas is conserved. This applies to all oil wells.

3) NOWPP flare gas limits must be reduced from 500 10^3m^3/month/well to 300 10^3m^3/month/well. This applies to wells completed in oil pools subject to an MRL. Note that the above development well and GOR requirements supersede this NOWPP flaring limit. In addition, this new NOWPP flaring limit supersedes the 500 10^3m^3/month/well given in *IL 87-9*.

2.5.5 Electricity Generation Using Otherwise-Flared Gas

One of the ways to eliminate or reduce solution gas flaring is to use waste gas to generate electricity. Although a relatively new technology, micro-turbines are now available to utilize waste natural gas to generate electricity.

A review of the EUB approval process for electrical generation systems that produce less than 2.5 megawatts (MW) is currently under way and will be completed in 1999.

Depending on the generation capacity of the installed engines, approvals issued under the *Environmental Protection and Enhancement Act* (*EPEA*) by Alberta Environment may be required. Power generation facilities with capacity greater than 1.0 MW require an *EPEA* approval.

Companies will be required to report solution gas volumes used to generate electricity to the EUB Utilities Division.

Section 2.8 provides additional information respecting royalty treatment of solution gas to be used to generate electricity.

2.6 Flaring at Conserving Facilities

Non-routine solution gas flaring is any planned or emergency event that results in additional flaring beyond the normal flare volumes at a gas conserving battery. Non-routine flaring may result during upsets or maintenance and repairs at the battery or the downstream pipelines and solution gas plant. The requirements of Sections 2.6.1 and 7 apply to non-routine flaring.

The EUB notes that in certain areas of the province, local emission reduction practices already meet or exceed those detailed in this section. The EUB expects that in those specific instances the current practices would prevail, pending the future review planned for 2001.

2.6.1 General Non-Routine Flaring Requirements

Non-routine solution gas flaring at gas conserving batteries falls under three categories, listed in Table 1: Operational Requirements for Conserving Facility Flaring. The table defines operational requirements for each shutdown type as a function of flaring incident duration.

The requirement for reduction of inlet volumes for planned shutdowns will be effective 1 January 2000.

Table 1. Operational Requirements for Conserving Facility Flaring

Shutdown Category	Duration (hours)	Operational Requirements
Planned	<4	Operators will take all reasonable efforts[1] to reduce battery or solution gas plant inlet gas volumes by 50% of average daily production over the previous 30 days.
	>4	Operators will take all reasonable efforts[1] to reduce battery or solution gas plant inlet gas volumes by 75% of average daily production over the previous 30 days with the following conditions: • Solution gas may not be flared from wells that have an H_2S content greater than 10%. • Production rates will be sufficient to keep equipment operating safely and within minimum design turndown range. • Public, including residents within 500 m, interested individuals, and people sensitive to emissions at the facility, must be notified at least 24 hours before the planned flaring event. • The appropriate EUB Field Centre must be notified prior to the planned shutdown of both the shutdown and any unresolved public complaints. • The appropriate EUB Field Centre must be notified if the event meets reporting requirements identified in *IL 98-01*, Section 4.4.
Emergency[2] or Plant Upset	<4	No reduction in plant inlet is required.[1]
	>4	Operators will take all reasonable efforts[1] to reduce battery or solution gas plant inlet gas volumes by 75% of the average daily production over the previous 30 days with the following conditions: • Solution gas may not be flared from wells that have an H_2S content greater than 10%. • Production rates will be sufficient to keep equipment operating safely and within minimum design turndown range.[1] • Public, including residents within 500 m and people sensitive to flaring at the facility, must be notified as soon as practical during the flaring event. • Interested public must be notified within 24 hours of the flaring event. • The appropriate EUB Field Centre must be notified within 10 days of the flaring event of any unresolved public complaints. • The appropriate EUB Field Centre must be notified if the event meets reporting requirements identified in *IL 98-01*, Section 4.4.
Repeat Non-Routine Flaring[3]		Operators must investigate causes of repeat non-routine flaring and take steps necessary to eliminate or reduce the frequency of such incidents. • Operators must notify the EUB of unresolved public complaints regarding repeat flaring within 10 days of the complaint.

[1] Notwithstanding flare gas reduction requirements listed in Table 1, if a sour or acid gas flare stack is not designed to meet Alberta Ambient Air Quality Guidelines for SO_2 as a one-hour average concentration under high rate flare conditions, then action must be taken immediately to reduce flared gas to rates such that a one-hour exceedance will not occur (see Section 7.3.4).

[2] Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery and causes non-routine flaring at the battery.

[3] **Repeat non-routine flarings are re-occurring events of similar cause at a conserving battery during a 30-day period.**

2.6.2 Planned Shutdown (Turnaround) Considerations

A planned shutdown occurs when the operator proactively schedules maintenance and repairs at the battery or maintenance and repairs, including turnarounds, on the downstream processing facilities; this requires non-routine flaring at the battery.

Alternatives to solution gas flaring available to operators during a gas plant turnaround include

1) delivering the solution gas to a nearby gas plant that is not on turnaround

2) scheduling maintenance at the oil facilities to coincide with the gas plant turnaround

3) injecting the solution gas into the gas cap of an oil pool or into a gas reservoir and producing it back after the gas plant is back on stream — an application is required under Section 26 of the *Oil and Gas Conservation Act* and the information required varies with the proposed scheme; the issue of when royalty is paid must be raised by the operator with ADRD

4) communicating with well, battery, and gas plant operators to ensure non-routine solution gas flaring is minimized

The EUB Field Centres will consider alternatives to Table 1 where the operator can demonstrate that the shutting in of a well or a group of wells may cause permanent damage to well equipment, may cause a significant reduction in well productivity, or is impractical due to the remoteness of facilities. The operator may establish new flaring guidelines for a particular property in consultation with the EUB Field Centre.

2.6.3 Regulatory Response

The conflict resolution process described in Section 2.5.3 will be used to resolve outstanding public complaints before a planned flaring event occurs or within 30 days after the EUB is advised of an unresolved complaint due to an emergency flaring incident.

As part of facility inspections of oil batteries and solution gas plants, EUB staff will check to determine that cutbacks have been within specified guidelines, proper logs are being maintained, and the correct procedures are being used to notify residents and others, as described in Section 2.5.2.

Standard EUB enforcement processes will be utilized if operators are not taking reasonable steps to comply with this guideline.

2.7 Clustering

Clustering, or low-pressure collection, is defined as the practice of bringing several solution gas flares to a common point for conservation. Clustering may enable other technologies, such as generation of electricity, to be viable alternatives to flaring due to improved economics associated with greater volumes of available fuel gas.

2.7.1 Regional Expectations

The EUB has noticed that solution gas is sometimes flared in local areas where it could be conserved if competing operators would combine their efforts to plan a more efficient overall process and take advantage of economies of scale. The most significant impediment to this process is the tendency of operators to have regard only for their own reserves and facilities without considering the activities of others in the same region.

This narrow perspective is unacceptable to the EUB when it impacts on resource conservation or the overall amount of flaring in the area**.**

The EUB expects that if the economics of solution gas conservation can be enhanced by collaboration among companies operating in a particular area, then such cooperation will be forthcoming.

As a rule, the EUB also believes clustering of wells improves the potential for conservation and reduction of flaring. Accordingly, the EUB expects companies to develop facilities that will enhance the ultimate potential to recover the gas or reduce the flaring.

When applying the solution gas decision tree analysis, the EUB expects that operators consider if clustering of flares would create an economic project. Producers are expected to assess their own situation and to complete an area or regional assessment. It will be necessary for producers to exchange production data in order for each company to evaluate the project. The guidelines for an economic evaluation are outlined in Section 2.4.

The EUB recognizes that collaboration may lead to increased use of custom processing arrangements.

In order to facilitate the process, the EUB expects gas plant owners to negotiate reasonable gas processing fees based on the report *Joint Industry Task Force Report on Processing Fees* (JP-95)[9] and its predecessor, JP-90.

In event that commercial agreements cannot be reached, remedial action is available under the legislation upon application by an affected party.

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[9] *JP-95: Joint Industry Task Force Report on Processing Fees*, Petroleum Joint Ventures Association, April 1996.

Operators producing from areas subject to existing gas conservation (GC) orders are also expected to evaluate their developments and meet the requirements of *Guide 60* if more stringent than the flare limits specified in the subject GC order.

2.7.2 Problem Areas

The EUB will be monitoring development in new oil fields and will request gas be conserved when a threshold level of reserves is reached. All operators of existing wells and any new wells drilled within a defined area will be expected to participate.

There may also be areas in the province where the EUB may decide that gas flaring will be reduced because of unique local environmental or land use sensitivities to related emissions. It is recognized that such conditions may warrant the elimination of flaring even though normal economic thresholds are not met. The EUB would expect the same level of cooperation from all producers in evaluating, installing, and fairly distributing the costs of conservation as outlined above. When it is necessary to conserve solution gas for such reasons, cost sharing for sulphur recovery at smaller facilities may be available, as outlined in Section 9.3.

It is expected that the most efficient and cost-effective methods of clustering solution gas will be used. The methods used will be technically sound and meet all pipeline and safety standards.

2.7.3 Regulatory Response

The EUB can request a producer(s) to submit information to indicate that all practical options for gas conservation have been thoroughly evaluated. If a project is economical based on the guidelines in Section 2.4 or conservation is necessary for environmental reasons, operators must conserve the gas.

The EUB may issue or revise a gas conservation (GC) order requiring all producers within a specific geographical area to conserve solution gas.

2.8 Royalty Treatment

The Alberta Government announced a program on 2 December 1998 to encourage the productive use of solution gas currently being flared. The program is summarized as follows:

- Regulatory changes will be made to provide a royalty waiver on solution gas currently being flared because it is uneconomic to conserve the gas.
- The changes are effective 1 January 1999.
- The program covers all methods of conserving or using solution gas. The generation of electricity is one of the potential productive uses for solution gas that would otherwise be flared.

- ADRD will develop criteria to ensure gas that can be economically conserved does not receive a royalty waiver.

- A review of the approval process for small-scale electrical generation installations is under way to ensure the process is simple, clear, and appropriate for the new marketplace. The review will be completed in 1999.

A separate informational letter will be issued by the ADRD to outline the details of the program and the application process.

2.9 Reporting — Data Requirements

2.9.1 S Statements

All flared and vented gas in the province is required to be reported on the S-1 and the S-2 monthly statements, as outlined in *Guide 7,*[10] Appendix 3, and as described here in Section10.1. A battery code must be obtained from the Production and Well Data Services Group of the EUB for new oil wells before any production including flaring can be reported.

The EUB is concerned with the number of oil and crude bitumen batteries that are reporting oil production with zero gas production. If wells are venting gas, this gas must be reported on the S-2 statements.

EUB business rules will be developed to ensure accuracy of flare and vented data submitted for use with existing data quality audit and enforcement protocols.

In some cases where low volumes of gas are being produced and flared, the operator may be exempt from measuring gas production (See *Guide 7,* Appendix 7). However, an operator is not exempt from providing an accurate estimate of gas production and disposition (including flared and vented gas).

2.9.2 Open Market

The CASA project team concluded that if the availability of flared or vented solution gas is made known publicly, the market may identify economic alternatives to flaring without need for government intervention.

Both regulators and individual operators need to cooperate in making available to proponents information necessary to evaluate and implement flare gas conservation or clustering projects, as discussed in Sections 2.9.2.1 and 2.9.2.2. The EUB, however, expects that parties making information requests of operators are technically qualified and have a reasonable expectation of proceeding with relevant gas conservation projects.

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[10] *Guide 7: Production Accounting Handbook*, EUB, December 1998.

Proponents of third-party flare gas conservation or utilization schemes must meet applicable EUB ownership, environmental, and safety regulations, as well as applicable technical standards and codes.

2.9.2.1 Data Required

The EUB will make available select production (S-2) data giving disposition of oil, gas, and water for crude oil and bitumen batteries, except those associated with experimental wells. Confidential information will be respected, using existing confidentiality protocols. Gas disposition information will include gas production, gas receipts, fuel gas, gas flared, gas vented, gas metering difference, and gas deliveries.

2.9.2.2 Data Access

A complete list of information that the EUB intends to release is given in Appendix 2: Monthly Battery (S-2) Information to Be Released. Electronic copies of the selected data will be made available on a monthly basis. Data will be provided for facilities with battery type codes 1-6 (oil batteries) and 12-15 (crude bitumen batteries). There will be a fee for the data, based on cost recovery for the EUB. It will be the responsibility of the interested parties to sort the data for their own needs. It is also the responsibility of the interested party to determine if the S-2 data represent a physical battery, or whether they are for a collection of single wells that are collected on paper into a single S-2 (a paper battery).

Operators of surrounding flares are expected to cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts. Cooperation may include providing non-confidential information such as gas analysis, flared volumes, pressures, and other relevant data on a timely basis to parties studying the clustering of flared or vented gas.

Flaring data will be subject to existing S-form audit and enforcement processes.

3 Well Test Flaring

3.1 Approvals

Depending on the volume and H_2S content of gas to be flared, two separate approvals may be required.

3.1.1 Volume Criteria

Well test volumes exceeding 600 10^3m^3 require an approval from the EUB Resources Division, in accordance with *Oil and Gas Conservation* (*OGC*) *Regulation* 11.135 (1). The purpose of this criterion is to ensure appropriate conservation. The requirements set out in the *Oil and Gas Conservation Regulations* as summarized in Section 3.1.3 below must be met.

EUB *Guide 40* details minimum requirements and recommended practices for well tests to ensure appropriate information is obtained for conservation and pool management purposes. Operators are encouraged to evaluate conservation of well test gas with temporary facilities (see Section 3.3).

3.1.2 H_2S Content Criteria

Section 7.055 of the *OGC Regulations* requires that a permit be obtained to flare gas containing 50 moles of H_2S per kilomole of gas or more or for any well classified as a critical sour well. Section 15.240 summarizes the information to be submitted prior to obtaining a permit. Section 7.060 details other requirements, including required fluid analysis and public and EUB notification.

Flaring of sour gas volumes less than 600 10^3m^3 and containing less than 50 moles of H_2S per kilomole of gas may be conducted without application to or written approval from the EUB, provided the requirements set out in the *OGC Regulations* and summarized here in Section 3.1.3 are met.

See Appendix 3: Flaring Permit Application Process for the flowchart of the flare permit application process.

The requirements for acceptable air dispersion modelling of sour gas flares are listed in Section 7.4. They must be met for all well test flaring to ensure compliance with Alberta Ambient Air Quality Guidelines.

A representative of the EUB may suspend operations if it is found that an operator has not met these requirements.

3.1.3 Well Test Requirements

Flaring of gas containing less than 50 moles of H_2S per kilomole of gas may be conducted without written approval of the Board. However, the following requirements must be adhered to:

1) The technical requirements of Section 7 respecting flare stack design and operation must be met.

2) If a recent gas analysis (taken within a 12-month period) for the well is not available, an on-site H_2S analysis (conducted by Tutweiller or gas chromatography methods) must be conducted upon commencement of flaring. If the H_2S content in the gas is found to exceed 50 moles of H_2S per kilomole of gas, operations must be suspended and a written application to flare the gas must be submitted to the EUB.

3) The total volumes of gas flared, including cleanup volumes, must not exceed 600 10^3m^3 without approval.

4) Notice of flaring or cleanup must be given to the appropriate EUB Field Centre at least 24 hours in advance. Such notice must detail whom to contact in case of complaints or emergencies and provide appropriate telephone numbers.

5) Fluid volumes and fuel consumption must be recorded and reported in the normal manner on S-1, S-2, or S-8 forms.

6) Normal low-stage separation equipment is required where sour liquids are produced.

7) Liquid storage must be designed to eliminate or reduce the escape of vapours to the environment. DACC IRP 4.0[11] provides additional detailed information.

8) Identification and warning signs must be posted on lease in accordance with Section 6.020 of the *OGC Regulations*.

9) The tanks must be diked, unless prior approval has been obtained from the appropriate EUB Field Centre.

10) The equipment spacing must conform to the *OGC Regulations*.

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[11] Drilling and Completion Committee (DACC) Industry Recommended Practices (IRP), Volume 4.0, *Well Testing and Fluid Handling*, Petroleum Industry Training Service (PITS), forthcoming.

11) If any complaint is received during flaring operations, the operator must notify the appropriate EUB Field Centre immediately and then conduct an investigation. If the source and cause of the complaint cannot be determined and rectified immediately, a representative of the EUB may suspend operations.

12) For well tests, the results must be submitted in accordance with the requirements of *Guide 40* and *Guide 52.*[12]

13) For gas wells, all rural residences and administrators of any incorporated centres or hamlets within at least a 3 kilometre radius must be notified prior to the commencement of any flaring operations.

14) For gas wells, drawdowns must be restricted in accordance with the most recent edition of the EUB *Guide 3: Gas Well Testing Theory and Practice of Testing.*

15) For oil wells, if the production test period is to exceed 21 days, an application for a temporary battery must be submitted pursuant to EUB *Guide 56*.

16) For oil wells, all rural residences and the administrators of any incorporated centres or hamlets within at least a 1.5 kilometre radius must be notified prior to the commencement of any flaring operations.

3.2 Well Test Volume Criterion Review

As noted in Section 3.1, a criterion of 600 10^3m^3 is used to define well test volume approval requirements. The EUB plans to examine the continued applicability of the 600 10^3m^3 criterion to explore whether some other value or approach may be utilized to reduce well test flaring without compromising the need for reservoir information necessary for good reserves management. Audit protocols respecting compliance with the criterion will be developed with suitable enforcement actions. EUB *Guide 40* was updated in May 1999 to include emphasis and focus on minimizing flared/vented volumes, clarification of fluid analysis reporting, and well flaring information generally set out in Section 3.1.3.

3.3 Temporary Well Test Facilities

Where gathering and processing infrastructure are in close proximity, the EUB expects operators to recover well test gas as an alternative to flaring. The EUB recognizes that a temporary connection to gathering systems and possibly temporary compression or other facilities will be required to conserve well test gas. To facilitate conservation of new well test gas, the EUB will not require facility approvals for related temporary facilities, including compressors. It is noted that

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[12] EUB *Guide 52: Electronic Capture of Well Test Data*, EUB, 1999.

1) Well test approvals are required, as described in Section 3.1. Applications to the EUB Resources Division for volumes exceeding 600 10^3m^3 must note the operator's intent to install temporary facilities and list the facilities to be used.

2) The temporary equipment must not be operated for more than 21 days in total. Allowance may be made for downtime during the testing period. In general, only one such test period will be approved at each site. An application, as described in EUB *Guide 56,* will be required if extended tests or multiple tests are planned that will require more that 21 days of operation for the temporary facilities.

3) Temporary surface facilities must be removed from the lease within 30 days of completion of the test.

4) Temporary facilities must meet noise control requirements defined in *ID 94-04.*[13]

5) Requirements, including public notification, as defined in Section 3.1.3, must be met.

6) Operators must have appropriate emergency response plans in place for sour wells.

7) Temporary facilities, including pipelines, must meet applicable technical standards and codes and must comply with applicable EUB, environmental, and safety regulations.

8) Notwithstanding (2) above, temporary surface flow lines (jointed or continuous) must be approved prior to operation.

9) Temporary sweetening processes, if used, must be of the zero-sulphur-emissions type. Temporary installation of regenerative sweetening processes with acid gas flaring will require a facility application, as described in EUB *Guide 56*. Under current regulations, all temporary or permanent sweetening facilities, including non-regenerative types, require Alberta Environment gas-processing plant approvals.

Operation of temporary well test compressors and related facilities for longer than 21 days requires an application, as described in EUB *Guide 56*. For further clarity, installation of temporary compressors for reasons other than testing of new wells requires an approval, as described in *Guide 56*, regardless of the duration of expected operation.

3.4 Reporting Gas Well Test Flaring

EUB *Guide 40* and Section 3.1.3 outline the reporting requirements and formats for gas well testing. The licensee/operator of the well is required to submit to the EUB all pressure and deliverability tests conducted, including those not required by *Guide 40*.

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[13] EUB *ID 94-04*: *Noise Control Directive*, EUB, 1994.

All tests must be submitted within three months of completing the fieldwork. Reports must be submitted in an acceptable format, as described in *Guide 52*. Note that this format includes reporting the volume of gas produced to flare, vent, or pipeline. All gas analysis from samples gathered at the wellhead must be submitted to the EUB.

All flaring at a well site (including well tests) must also be reported on the appropriate S forms, as explained in *Guide 7*. Before production including flaring can be reported, a battery code must be obtained from the EUB Well Data Services Group, as outlined in Appendix 3 of *Guide 7*. Any produced volumes, including volumes flared or vented, must be reported on S-1 and S-2 monthly statements, as outlined in *Guide 7*.

Where any flaring or venting occurs at a well site or battery, it must be reported on the S-1 monthly production statement as gas production. Flaring must be reported on the S-2 statement as flared. Venting must be reported on the S-2 statement as vented.

4 Gas Battery Flaring

4.1 Approvals

Applications for new gas facilities must be in accordance with EUB *Guide 56*.

4.2 Flaring Requirements

The requirements of *IL 88-13* for sulphur recovery will apply, as discussed in Section 9.2. Flares at gas production facilities must be in accordance with Section 7.

4.3 Reporting

All flaring at a well site (including well tests) or battery must be reported on the appropriate S statements, as stated in *Guide 7*. Section 10.1 describes requirements for obtaining and using battery codes for reporting.

When any flaring or venting occurs at a well site or battery, it must be reported on the S-1 monthly production statement as gas production. Flaring must also be reported on the S-2 monthly disposition statement as flared. Vented gas must be reported on the S-2 as vented.

Existing data submission compliance and enforcement procedures will be applied.

5 Gas Plant Flaring

5.1 Approvals

Applications for new gas processing facilities must be in accordance with EUB *Guide 56*.

5.2 Flare Performance Requirements

Gas plant flares must be in compliance with the flare performance requirements detailed in Section 7 by 31 December 2004.

Notwithstanding the compliance deadline for compliance with the flare performance requirements detailed in Section 7, gas streams directed to continuous gas plant flares must have a minimum heating value, as defined in Section 7.3.2, effective 1 January 2000.

Short-duration emergency flaring with gas of a heating value of less than 20 MJ/m^3 may occasionally be necessary.

5.3 Gas Plant Flare Volume Limits

The EUB expects operators of gas plants to operate so that a minimum of gaseous hydrocarbons and other gases are flared. Operators must not flare gaseous hydrocarbons in excess of 1.0 per cent of the total volume of raw gas delivered to gas processing plants in the first year of operation and 0.5 per cent in subsequent years. Gas plant flares must be in accordance with Section 7. The EUB intends to review these limits.

The EUB encourages plant operators to use the flare stack that is the most efficient and is capable of providing the best dispersion when flaring solution gas. In many cases this will be the gas plant flare stack. Where operators use the gas plant flare stack, operators will be exempt from the 0.5 per cent for solution gas flared volumes when this is part of a gas plant shutdown lasting more than seven days. These solution gas volumes must be documented and provided to the EUB upon request. Note that the requirements specified in Section 2.6 will still apply.

5.4 Notification and Reporting

An EUB Field Centre is to be notified 24 hours prior to planned or within 24 hours of emergency flaring. Information to be provided includes notification date, time, location, operating company, contact name and telephone number, flaring commencement time, duration, rate, total volume, percentage H_2S, and reason for flaring.

All gas plant flaring volumes must be reported monthly on the EUB's S-20 Monthly Gas Processing Statement. The S-20 is used to record receipts and disposition of gas, including flaring. This information is summarized in the *Alberta Gas Plant Statistics,* EUB reports *ST13-A* (annual report) and *ST 13-B* (monthly report).

Flaring at sour gas plants must also be reported on the S-30 Sulphur Balance Report. When measurement does not occur on all streams, engineering estimates must be used to report any flared gas not measured. The EUB notes that a large number of gas processing plants have reported zero flaring over a calendar year.

The EUB intends to develop suitable business rules for gas plant flaring and venting data submission for use with existing data quality audit and enforcement protocols.

Upon request by EUB staff, all operators must be able to provide a documented system for flare measurement and/or flare estimation, as defined in Section 10.0. Operators must also be able to provide, upon request, information on flaring and related public complaints, as defined in Section 10.3.

The EUB will require operators, on the basis of audit and inspections, to examine flare fuel gas use in cases where it appears that fuel gas use is excessive. Currently, the EUB requires total fuel gas to be measured and reported on the S-20 statement and allows an operator to use an engineering estimate to determine the split between residue fuel gas (processed gas) and overhead fuel gas (gas from plant vessels). Excessive fuel gas use in the flare for flare pilots and purge gas can contribute significantly to fuel use.

6 Pipeline Emissions

6.1 Gas Gathering Systems

Under normal operations, there is little flaring in a gas gathering system. It is estimated that gas gathering systems represent about 2 per cent of the total flared gas in the province. Most flaring is likely to occur at compressor stations or when blowing down gas gathering systems for operational reasons. Currently, all flaring from a gas gathering system must be reported on the S-8 Monthly Gas Gathering Statement, as described in *Guide 7*. Both flared and vented gas should be reported in the flared box on the S-8.

All rural residences and the administrators of any incorporated centres or hamlets within at least a 3 kilometre radius and the EUB Field Centre must be notified at least 24 hours prior to the commencement of flaring.

Flares used at gas gathering systems must be in accordance with Section 7. The requirements of *IL 88-13* for sulphur recovery discussed in Section 9.2 apply for any continuous flaring of sour gas at gas gathering system facilities (e.g., compressor or dehydrator sites).

6.2 Sweet Natural Gas Transmission Systems

Sweet natural gas transmission companies must notify the appropriate EUB Field Centre and discuss measures that will be taken to minimize emissions when venting or flaring of its pipeline is planned.

Operators of sweet natural gas transmission pipelines will be expected to minimize vented or flared volumes of sweet natural gas by adopting practices, procedures, processes, or technologies to minimize emissions wherever feasible and practical.

Each purchaser or transporter of sweet natural gas is required to file with the EUB (*OGC Regulations*, Section 12.051), on a monthly basis, the disposition of gas, including the particulars of the disposition and delivery of all such gas. Where flaring or venting of sweet natural gas occurs, the EUB expects this disposition to be separately reported in volumes at standard conditions.

7 Flare Performance Requirements

7.1 Introduction

The EUB understands the importance and urgency of incorporating suitable flare performance standards and flare stack design requirements in this guide. These topics were discussed at length within the CASA process, and the resulting consensus on the issue of performance and design is a notable achievement. In reaching its conclusions, CASA reviewed legislative requirements and engineering design standards.

This section of the guide addresses technical requirements for flare system design and operation and applies to well test, well site (including flaring associated with cleanup and initial early productivity determination in oil wells), oil and gas battery, and process plant flares. Requirements for flare stack design, liquid separation, and flared gas measurement, as well as limitations on venting of unburned gas, are defined. This section also defines requirements for ambient air quality assessments (e.g., plume dispersion calculations) and cumulative air emissions assessments required for flaring of gas containing H_2S.

The EUB supports the use of alternatives to conventional flare technology where better combustion and dispersion can be obtained. This may include the use of enclosed flares, incinerators, or other alternative technologies.

7.2 Combustion Efficiency Performance Standards

The use of performance standards (e.g., Alberta Ambient Air Quality Guidelines), as opposed to specifying design details or types of equipment, allows greatest flexibility in achieving the desired results in a cost-effective manner. Enforcement is not hampered, since performance can be directly monitored and evaluated. Taking this approach is consistent with the regulatory direction of both the EUB and Alberta Environment. Specifying combustion efficiency or destruction efficiency would be consistent with a performance standard approach.

It is the EUB’s view that achievement of combustion efficiencies of 98 per cent or better on design and operational basis would be the expected result of continuous improvement in flare technology research and flare performance standards. The EUB requires operators to demonstrate that they have assessed and incorporated appropriate flare best-management practices and new technology developments that maximize combustion efficiency in the design of new or modified flare systems.

However, the EUB and Alberta Environment, along with industry stakeholders, have reviewed the status of flare combustion efficiency with research teams investigating gas flaring. The EUB has concluded that specification of mandatory combustion efficiency standards is not practical at this time for the following two reasons:

Practical methodologies are not available for measuring flare combustion efficiency under field conditions. Thus, while it may be possible to specify required combustion efficiency, there is no practical means to monitor compliance at operating facilities.

- The relationship of combustion efficiency with design factors such as flare tip exit velocity, gas composition, crosswind velocity, and air turbulence is not yet sufficiently advanced to prescribe related design standards.

The EUB recognizes the importance of flare combustion efficiency standards to industry and public stakeholders. However, it is the EUB's view that such standards must be technically relevant and/or capable of being practically monitored in the field. Research in Alberta and elsewhere is currently focused on combustion efficiency issues. It is expected that this research will enable development and implementation of flare combustion efficiency requirements no later than the end of 2001, coincidental with the review of the management framework. Based on the direction of current flare research, it is likely that requirements will take the form of prescriptive design standards that will be related to demonstrated levels of combustion efficiency. The EUB will monitor flare research with the intent of updating this document when suitable information is available.

7.3 Flare Stack Design and Operation

Operators are expected to design, operate, and maintain flare systems to safely dispose of gas that must be released to the atmosphere. EUB minimum requirements for the design and operation of flare systems have been established and are included in the following requirements. In addition, the EUB expects that operators will use good engineering practice in the design and operation of flare systems, as outlined in the CAPP *Recommended Practices for Flaring of Associated and Solution Gas at Oil Production Facilities* and in *API Recommended Practice 521*, Section 4, "Selection of Disposal Systems."

Industry must comply with the following requirements for flare systems installed at well testing locations, well sites, oil batteries, gas batteries, and gas processing plants unless otherwise noted.

7.3.1 Ignition

A flame must be present whenever hydrocarbons or acid gases are directed to flares. Acid gas and intermittent sour gas flares are required to have reliable pilot and automatic ignition devices to ensure continuous ignition of any gas discharged to the flare.

Manual flare ignition, subject to adequate safety and forest fire prevention considerations, may be accepted for blowdown stacks or flares installed for maintenance purposes where no continuous gas flow exists or where no automatic relieving systems are connected to the stack.

7.3.2 Flame Stability and Minimum Heating Value of Continuous Acid Gas Flares

Flame stability and combustion efficiency are related to the heating value of the combined flare gas stream and to stack design parameters and features. Existing requirements, including the typically specified minimum heating value[14] for flared acid gas streams of 9 MJ/m^3 and the U.S. EPA minimum guideline for air- or steam-assisted flares of 11.2 MJ/m^3 have been reviewed in light of current research being conducted at the University of Alberta.

Initial results of this research discussed with EUB staff in early 1999 indicated that the crosswind flame stability of gases diluted with CO_2 (i.e., acid gas) was impaired if the heating value was less that 20 MJ/m^3. This initial research information was considered by EUB staff in the preparation of the review draft of this document.

Subsequent to January 1999, the University of Alberta has expanded its research on the effects of CO_2 dilution, stack diameter, exit velocity, and crosswind velocity on flare flame stability. Findings of the new research indicate that flare stability and efficiency are impaired at heating values less that 9 MJ/m^3 for CH_4-CO_2 gas mixtures. At heating values in excess of 20 MJ/m^3, however, the research suggests that most flare conditions would result in acceptable combustion under typical Alberta crosswind conditions. For CH_4-CO_2 mixtures of heating values between 12 and 20 MJ/m^3, efficient combustion can occur provided designs are based on appropriate relationships of heating value, stack diameter, exit velocity, and crosswind velocity.

It was noted that there are continuous acid gas flares operating in the 9-12 MJ/m^3 heating value range that have been stable and appear to meet Alberta Ambient Air Quality Guidelines for H_2S and SO_2 over the long term. It was further noted that an arbitrary increase of fuel make-up requirements to raise acid gas heating values to over 20 MJ/m^3 could significantly increase fuel gas consumption and costs to industry and the province, as well as greenhouse gas emissions.

On the basis of the foregoing, Alberta Environment and the EUB will allow continuous acid gas flares to be operated in the 12-20 MJ/m^3 heating value range on a conditional basis. It is the EUB’s intent, however, to closely monitor research results with respect to the acceptability of approving acid gas flares to operate at less than 20 MJ/m^3 over the next 6-12 months. It is the EUB’s expectation that ongoing industry research and assessment of operating acid gas flare stacks will provide the basis and justification for continuing approval of acid gas flare operation at less than 20 MJ/m^3.

The following requirements are based on current research findings and will be revised as additional research results and stack design/evaluation tools become available. The requirements become effective for all facilities 1 January 2000.

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[14] All heating values refer to the lower, or net, heating value determined on a water-free basis at 15°C and 101.325 kPa.

1) Sufficient fuel gas must be added to continuous or routinely flared sour, acid, or other low-heating-value gas streams to ensure stable and efficient combustion and to ensure compliance with Alberta Ambient Air Quality Guidelines, as well as with specific EUB and/or Alberta Environment approvals.

2) New stacks for continuous flaring of acid gas or other low-heating-value gas streams must be designed by qualified technical staff to ensure flame stability and efficient combustion.

   Stack and operating procedures must be designed so that sufficient fuel gas is added to the low-heating-value stream to ensure efficient and stable combustion.

   a) In the absence of specific engineering evaluations that consider stack diameter, heating value of the combined flare gas stream, stack exit velocity, and local wind velocities, the minimum combined heating value of the flared stream must not be less than 20 MJ/m^3.

   b) Where engineering evaluations are based on stack diameter, heating value of the combined flare gas stream, stack exit velocity, local wind velocities, and other stack design features that promote efficient and stable combustion, combined heating values of not less than 12 MJ/m^3 will be accepted for new stacks. Operators must retain related design evaluations and make them available upon request to Alberta Environment or EUB staff.

3) The review of flare stacks for continuous flaring of acid gas and other low-heating-value streams in operation prior to the implementation date of this guide must include an evaluation of flame stability, odour complaint history, and performance of the stack in meeting Alberta Ambient Air Quality Guidelines. The evaluation must include assessment of the suitable minimum combined heating value for the flare gas exiting the stack.

   a) Flare stacks with an established history of stable operation and compliance with Alberta Ambient Air Quality Guidelines will be permitted to operate with combined flare gas heating values in the 12-20 MJ/m^3 range. Operators will be expected to support claims that existing stacks have operated satisfactorily over time.

   b) Flare stacks with a history of flame failure, odour complaints, and/or Alberta Ambient Air Quality Guidelines exceedances will be required to operate with a combined flare gas heating value of not less than 20 MJ/m^3.

      Operators may be allowed to reduce the combined flare gas heating value to not less than 12 MJ/m^3 following implementation of modifications to increase flame stability and flare performance. Operators must demonstrate to the regulating authority that the engineering design of the modifications is based on evaluations of stack diameter, heating value of the combined flare gas stream, stack exit velocity, local wind velocities, and other stack design features that promote efficient and stable combustion.

4) Flare stacks must have sufficient exit velocity or be provided with suitable features to prevent wind from extinguishing the flame of low or intermittent flows of sour or acid gases (e.g., wind guards).

5) As a guideline, most routine flares will be relatively stable if stack exit velocities are greater than 1-2 m/s and less than 18 m/s. Higher exit velocities, up to 122 m/s, may also be acceptable. The following relationships[15] for flared gas net or lower heating value (H_T in MJ/m^3) provide guidelines for the maximum flare stack exit velocity (V_{max} in m/s):

- Steam and non-assisted flares: $\mathrm{Log}_{10}(V_{max}) = (H_T + 28.8) / 31.7$
- Air assisted flares: $V_{max} = 8.706 + 0.7084(H_T)$

7.3.3 Stack Height

1) Flares stacks must be designed so that the maximum radiant heat intensity at ground level will not exceed 4.73 kW/m^2. Unless otherwise specified, ground-level radiant heat determinations will be based on calculation procedures outlined in API Recommended Practice 521, Section 4.4.2.3, or *GPSA Engineering Data Book* (11th edition), Section 5.

2) Flare stacks located within a distance equivalent to five times the height of neighbouring third-party buildings must have a height of at least 2.5 times the height of the highest building.

3) Flare stacks for acid gas or sour gas containing more than 10 moles of H_2S per kilomole of gas must have a height of at least 12 m above ground level or such greater height as may be required by (1) above or as required to provide adequate plume dispersion to comply with Alberta Ambient Air Quality Guidelines for SO_2 and H_2S (see to Section 7.4).

7.3.4 Emergency Sour and Acid Gas Flaring Procedures

In some instances where volumes and flare rates are very large, it is not practical to design flare stacks with sufficient height and to add sufficient fuel gas to permit continuous emergency flaring in compliance with the Alberta Ambient Air Quality Guidelines at full sour raw or acid gas production rates.

If, based on evaluation procedures described in Section 7.4, a sour or acid gas emergency flare is not of sufficient height to meet the one-hour Alberta Ambient Air Quality Guidelines for SO_2 under high flow rate conditions, then operating procedures and/or automatic shutdowns must be in place to immediately curtail production and control flaring to comply with the one-hour

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[15] Title 40, *U.S. Code of Federal Regulations*, Part 60.18.

guideline. Automated shutdowns are expected to be installed in semi-attended facilities to ensure compliance with this requirement. This requirement takes precedent, as applicable, over flare reduction requirements listed in Section 2.6.1,Table 1.

7.3.5 Liquid Separation

Under no circumstances are flare pits to be used at any facilities constructed after 1 July 1996. For facilities constructed prior to this date, flaring is allowed, provided that there is no potential for produced liquids to enter the pit. Further details on the use of earthen pits are given in *IL 96-04*.[16]

Entrained liquids in flare streams are recognized to reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons, and products of incomplete combustion. To reduce and/or eliminate these effects, the EUB requires the following:

1) If liquid hydrocarbons, water, or other liquids are present in flare gas sources, it is required that adequately designed, operated, and maintained liquids separation equipment be provided in both temporary (well test) and permanent flare systems.

2) Flare system piping and all piping related to the liquids control system must be engineered to prevent retention of liquids by ensuring that piping is sloped to drain to separators and to avoid low-point liquid traps.

3) The flare separator must be designed to provide adequate separation of liquid and large liquid particles entrained in the gas. Liquid hydrocarbons must not be flared.

4) The flare separator or knockout drum must be designed to have sufficient holding capacity for liquids that may accumulate as a result of upstream operations such as hydrocarbon carryover, liquid slugs, and line condensation. The flare separator must be designed such that the ability of the vessel to separate liquids from the gas stream is not impaired at the maximum design liquid level.

5) Design of the flare separator must ensure that no reentrainment of separated liquids will occur at maximum expected flare gas flow rates.

6) Flare separators must be provided with visual level indicators, high-level alarms, or operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level during all operating conditions.

7) A high-level alarm must be installed on flare separators or flare knockout drums where liquid streams are directed to the separator for retention or where free liquids are expected in continuously flared streams. The flare separator high-level alarm must be connected to

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[16] *IL 96-04: EUB Policy Update and Clarification on the Use of Earthen Pits*, EUB, 1996.

facility alarm panels and/or semi-attended facility alarm call-out systems if the facilities are so equipped.

8) The flare system and separator or knockout drum must be designed and operated to ensure that effectiveness will be maintained under all operating scenarios and weather conditions (e.g., freeze protection is required).

9) The flare separator or knockout drum must be designed to the ASME Boiler and Pressure Vessel Code if the maximum pressure due to the flow resistance in the flare system is sufficient to trigger this requirement.

10) Flare separator or knockout drums used for liquids storage must be designed and operated to meet the requirements listed in EUB *Guide 55*[17] for above-ground or below-ground storage tanks, as appropriate.

7.3.6 Spacing Requirements

1) Flare stacks must be located at least 100 m away from an occupied residence.

2) Flares must be located, designed, and operated so that no hazard to public property will be created. Flares must be located at least 100 m away from surface improvements, with the exception of surveyed roadways.

3) Flares must be located at least 50 m away from wells or flammable liquids storage tanks and at least 25 m away from any oil or gas processing equipment.

4) The following requirements are defined in the *Forest and Prairie Protection Regulations* (AR 135/72):

   a) Areas within 30 m of flare pits must be cleared of all combustible debris.

   b) Clear, bare mineral soil surface must be maintained within 8 m of flare pits.

   c) In forest areas, flare stacks must be located at least 2.5 times stack height, or such other distance as prescribed by a forest officer, from combustible debris.

5) Information on fire bans can be obtained from the following sources:

   a) www.gov.ab.ca/env/forest/fpd/ — go to “fire control orders” for fire ban information and regions affected as per Alberta Environment

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[17] EUB *Guide G-55: Storage Requirements for the Upstream Petroleum Industry*, EUB, 1995.

    b) Alberta Environment — (780) 427-fire [3473]

    c) local municipal districts, for their respective fire ban requirements

6) Notwithstanding the above, existing well-site equipment flare-spacing waivers are maintained.

7.3.7 Noise

Flare systems must be designed to operate in compliance with EUB *ID 94-04*. Routine and emergency flare conditions are to be considered in noise impact assessments required by the interim directive.

7.3.8 Visible Emissions

Black smoke from flares must not exceed a 40 per cent opacity average over six consecutive minutes, as specified in EPEA *Substance Release Regulations* or as specified in an EPEA approval, whichever is more stringent.

7.4 Dispersion Modelling Requirements for Sour or Acid Gas Flares

SO_2 and H_2S emissions from flaring, incineration, or combustion of sour or acid gas have potential for adverse effects. Therefore, the design and operation of stacks must consider air quality impacts of sulphur emissions from the stacks, taking into account other sulphur emission sources in the area.

Using dispersion modelling methods accepted by Alberta Environment, operators must demonstrate that SO_2 and H_2S emissions from flaring, incineration, or combustion of sour or acid gas will not result in exceedance of Alberta Ambient Air Quality Guidelines if the gas contains more than or equal to

1) 10 moles of H_2S per kilomole of gas or
2) one tonne per day of sulphur.

Operators flaring gas below the above criteria may wish to consider dispersion modelling as part of their respective environmental due diligence processes. Facilities requiring an EPEA approval may require more detailed evaluation. Alberta Environment should be consulted in these instances.

7.4.1 Definitions

1) **Screening Assessment** – This is the quickest and simplest modelling approach. Screening assessments usually provide a conservative estimate of downwind concentrations. If exceedances of the Ambient Air Quality Guidelines are predicted by a screening assessment, then a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the Alberta

Ambient Air Quality Guidelines.

2) **Refined Assessment –** This is a more complex and data-intensive level of modelling. Refined assessments more closely estimate actual air quality impacts by using actual meteorological data. An appropriate model should be selected, and this choice must be defensible. The applicant must demonstrate that the completed work follows accepted methodologies and standards.

7.4.2 Modelling Assumptions

Ambient air quality modelling will observe the following assumptions for screening assessments:

1) stack-specific terrain extracted from 1:50 000 topographical maps or equivalent

2) full meteorology

3) rural dispersion conditions

4) partial conversion of H_2S to SO_2

   Until such time as combustion efficiency can be reliably estimated based on design conditions, ambient air quality modelling evaluations will assume a 98 per cent molar conversion of H_2S to SO_2 (e.g., 100 moles of H_2S yields 98 moles of SO_2 plus 2 moles of H_2S, and only 98 per cent of the available combustion energy is released as heat). The EUB is closely following the current research in flaring combustion efficiency and will update this section as necessary when research results become available.

7.4.3 Individual Source Modelling Approach

1) Initial modelling can be conducted using a screening assessment. Simple terrain modelling assumptions can be used for situations where terrain elevations are less than the stack height; otherwise complex terrain modelling assumptions must be used. The selected flare design must not result in maximum hourly average ground-level SO_2 or H_2S concentrations in excess of the Alberta Ambient Air Quality Guidelines. A refined assessment can be used if the screening assessment results in an impractical stack height. Modelling should address maximum hourly flow rate conditions.

2) If the predicted maximum hourly average ground-level concentrations using the screening model are less than one-third of any of the related Alberta Ambient Air Quality Guidelines, no further modelling is required.

7.4.4 SO_2 Cumulative Emissions Assessment

If individual source model predictions exceed one-third of the Alberta Ambient Air Quality Guidelines for SO_2, the applicant is required to consider the combined effect of other sources in the area. The following steps should be followed:

1) Repeat the screening dispersion modelling using the flat terrain assumption (if necessary).

2) Identify the farthest downwind location where predictions exceed one-third of the hourly average Alberta Ambient Air Quality Guideline for SO_2 to define the radius of influence.

3) Identify all other sources of the pollutant located within this radius of influence (if there are no other sources of the pollutant within the radius, no further modelling is required).

4) Quantify the emissions of the pollutant from these other sources and obtain all necessary input data, such as stack height and other parameters (the EUB expects that operators share related data on a timely basis). Maximum hourly flare flow rate conditions must be used for all sources in the radius of influence.

5) As a screening approach, perform separate flat terrain screening model runs for each of the sources within the radius of influence.

6) If the sum of the predicted maximum ground-level concentrations for all sources, regardless of location, is less than the Alberta Ambient Air Quality Guideline for SO_2, no further modelling is required.

7) If the sum exceeds the Alberta Ambient Air Quality Guideline, a refined modelling approach will be required to prove that the guideline is not exceeded and to determine the appropriate stack heights required to meet the guideline. All refined modelling must follow the methods outlined in Alberta Environment’s Draft Air Quality Model Guidelines.

Note that the flat terrain assumption is used to simplify the cumulative emissions assessment only. Where complex terrain exists, the final stack height for the source under consideration will be the greater of those determined by single source modelling with complex terrain (Section 7.4.3) and by cumulative emissions assessment (this section).

8 Venting

For companies tracking greenhouse gas emissions, venting leads to higher equivalent CO_2 emissions and for that reason should be discouraged. However, where it is not practical to recover or flare gas, the EUB may accept venting of small volumes of gas. Venting may be considered as an alternative for disposition of small gas volumes from compressor vents, instrument gas systems, pneumatic devices, dehydrators, and storage tanks. For the purposes of this section, vented gas excludes fugitive emissions from piping and equipment leaks.

Venting of gas is governed by the following principles and requirements:

1) If continuous vent volumes are sufficient to support combustion, the gas should generally be burned in a flare.

2) Gas will not be vented if it constitutes an unacceptable fire or explosion hazard on or off the facility lease.

3) Venting of gas containing H_2S to the atmosphere must not result in exceedance of Alberta Ambient Air Quality Guidelines for H_2S or Occupational Exposure Levels for H_2S.

4) As in Section 7.070 of the Alberta *OGC Regulations*, stock tank vapours and other gas emissions from batteries receiving gas or having vapours containing more than 10 moles of H_2S per kilomole of gas must be burned.

5) Continuous venting of gas containing H_2S and other odourous compounds must not result in odours outside the lease boundary.

6) The true vapour pressure of hydrocarbon product stored in atmospheric storage tanks shall not exceed a true vapour pressure of 83 kilopascals where such tanks are vented to the atmosphere.

7) An appropriate flame arrester or equivalent safety device must be used on all vent lines from oil storage tanks connected to flare stacks (see *OGC Regulations* 8.090[7]).

8) Vented gas from gas dehydrators is subject to limitations on benzene emissions, as detailed in *IL 97-04*.[18]

9) If operators have reason to expect that the benzene content of vented gas exceeds 5 moles per kilomole, then **site vent gas** benzene emissions must be assessed and, if necessary, controlled so that total benzene emissions for the facility or lease site will not exceed

    - 3.0 tonnes per year for facilities commissioned prior to 1 January 1999 and located within 0.75 kilometres of a residence, effective 1 January 2001;

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[18] *IL 97-04: Emissions from Glycol Dehydrators*, EUB, 1997.

- 3.0 tonnes per year for facilities commissioned after six months from the issuance of this guide; or

- 5.0 tonnes per year for facilities commissioned prior to the issuance of this guide, effective 1 January 2001.

The EUB plans to review operations involving the venting of gas with the objective of establishing further control criteria as necessary.

9 Sulphur Recovery Requirements

The recovery of sulphur from associated and non-associated gas is important for reasons of conservation, as well as for the protection of the environment.

The current standards for sulphur recovery requirements for new gas plants, stated in *IL 88-13*, are summarized in Table 2.

Table 2. Sulphur Recovery Requirements for Sour Gas Plants

Inlet Sulphur Rate	Sulphur Recovery[1]
1-5 tonnes/day	70%
5-10 tonnes/day	90%
10-50 tonnes/day	96.2%
50–2000 tonnes/day	98.5 - 98.8%[2]
> 2000 tonnes/day	99.8%

[1] Deduct 0.3 per cent for quarterly average requirements.

[2] Recovery = 98.18185 + 0.187259 $\log_{10}$ (inlet sulphur rate).

Acid gas injection is an alternative approach to meeting the sulphur recovery requirements that has an effective recovery of nearly 100 per cent if operated successfully. Excessive flaring of acid gas during injection system upsets and outages could negate the emission reduction advantages of this technology. Sour gas processing plants with acid gas injection schemes must be operated so that at least the percentage of sulphur contained in the inlet raw gas specified in Table 2 is injected or recovered or operated according to conditions within an EPEA approval issued by Alberta Environment.

9.1 Sulphur Recovery at Solution Gas Facilities

IL 88-13 forms the basis for sulphur recovery requirements for the collection (clustering) of sour solution gas from multiple sources, with the flexibility of minor relaxation available in the low inlet sulphur range (1-5 tonnes/day).

The EUB does not want the need for sulphur recovery to deter the collection (clustering) of solution gas if low levels of H_2S are present in the raw gas.

Therefore, each clustering scheme that has a total inlet sulphur of 1-5 tonnes per day will be considered for flexibility by Alberta Environment and the EUB in the application of *IL 88-13* if the scheme is otherwise uneconomic and it is processing strictly solution gas. Site-specific impacts will be part of the EUB's consideration for exemption. The existing processes used for EPEA approvals (sour gas processing plant) and EUB approvals will be used to measure public acceptance of any proposals. If there are no unacceptable impacts and nearby residents agree, meeting the sulphur recovery guidelines may not be required for solution gas facilities. The requirements of *IL 88-13* will apply to all facilities that process any sour non-associated gas. If sulphur recovery is required, some cost sharing with the government may be available, as explained in Section 9.3.

9.2 Sulphur Recovery at Gas Gathering Facilities and Non-associated Gas Batteries

Design of certain types of gas gathering and non-associated gas battery facilities can result in significant sulphur emissions. Among other sources, these emissions may originate from flaring of low-pressure-produced water flash gas and from flaring of glycol dehydrator vent gas. The approval of such facilities falls within the EUB's jurisdiction, and related approvals from Alberta Environment are not currently required.

In approving an acceptable level of continuous sulphur emission (excluding emergency flaring), the EUB will consider the following criteria:

1) It is the EUB's intent to avoid situations where flaring of sour gas at gas batteries and gathering facilities in sour gas production systems (e.g., well through gas plant) results in substantial circumvention of the sulphur recovery levels specified in *IL 88-13*. To encourage industry-sponsored solutions, the EUB will consider cumulative sulphur emissions from gas battery, gas gathering, and gas processing facilities in assessing sulphur recovery requirements for sour gas production projects on a regional basis.

2) As a minimum, IL 88-13 sulphur recovery requirements will apply to sour gas streams continuously flared at gas gathering and gas battery facilities — i.e., if the sulphur content of produced water flash gas, dehydrator vent gas, and other flare gas sources at the site exceeds 1.0 tonne/day, then sulphur recovery in accordance with *IL 88-13* and this document is required for the flared gas.

9.3 Sulphur Emission Control Assistance Program (SECAP)

IL 88-13 normally requires some amount of sulphur recovery at all levels of sulphur inlet at or above one tonne per day. The required sulphur recovery at sulphur inlet levels of 1-5 tonnes per day, which the EUB anticipates to be the level typical for proposed solution gas clustering schemes, is 70 per cent.

A cost-sharing program is available for plants with an approved sulphur inlet of 1-5 tonnes/day that uses royalty credits for 50 per cent of eligible capital and operating costs of the sulphur recovery scheme. This Sulphur Emission Control Assistance Program (SECAP) is administered by ADRD.

SECAP allows for 50 per cent cost sharing on facilities required to recover sulphur and may also include some pipelining costs and the costs of acid gas injection facilities. ADRD will assess the reasonableness of all costs in determining eligible costs. Full descriptions of SECAP and application forms are available from ADRD’s Mineral Revenues Division.

10 Measurement and Reporting

10.1 Measurement of Flared Gas

Operators of oil, bitumen, and natural gas production and processing facilities are required to report gas flared or vented to the nearest 0.1 $10^3 m^3$/month (adjusted to 101.325 kPa and 15°C) on the appropriate EUB S statements. The requirement to report all gas vented or flared includes emissions from routine operations, emergency conditions, and the depressuring of pipeline, compression, and processing systems.

Information and references on EUB measurement and accuracy requirements, as well as requirements for determination of gas properties (e.g., density, composition, and heating value) are provided in *Guide 56* (Volume 2), *Guide 7*, *Guide 49,*[19] and *Guide 54.*[20]

It is preferred that flared or vented gas be metered with equipment suited to the source flow conditions. However, accurate engineering estimates may be accepted where meters are not practical.

10.1.1 Metering Requirements

Measurement accuracy standards defined in ID 94-01[21] apply to flaring at pipeline and gas processing facilities. In general, these accuracy standards (± 5 per cent) are such that meters designed to suit expected flow conditions would be necessary for the flare or vent gas sources listed below:

1) acid gas flared, either continuously by or in emergencies, from gas sweetening systems regardless of volume

2) fuel gas make-up to acid gas flared (where fuel gas must be added to meet minimum acid gas heating value requirements)

3) continuous or routine flare sources in conventional oil and gas production or processing facilities where annual average flared volumes exceed 500 m^3/day

4) solution gas flared from heavy oil or crude bitumen production facilities within designated oil sands areas where annual average flared or vented volumes exceed 2 000 m^3/day, based on general metering requirements specified in *IL 91-09*[22]

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[19] *Guide G-49: Gas Density Measurement Frequency*, EUB, 1993.

[20] *Guide G-54: Gas Inspection Manual*, EUB, 1995.

[21] *ID 94-01: Measurement of Oil, Gas, and Water Production*, EUB, 1994.

[22] *IL 91-09: Exemption from Gas Measurement Crude Oil/Bitumen Wells,* EUB, 1991.

Where operators can demonstrate that such flows can be consistently and accurately estimated from other data, the EUB may accept estimated measurements (see Section 10.1.2 for estimating requirements).

For the purposes of this section, routine flare sources are defined as those sources that by process design are used on a daily basis to dispose of low-pressure or waste gases. The definition excludes flare sources used solely for emergency shutdown or overpressure protection.

Where all solution gas is flared or vented from conventional or heavy oil production facilities, produced gas measurements (minus measured fuel gas use) can be used to report volumes flared or vented. In such situations, specific flare or vent gas meters are not required.

Operators are encouraged to consider measurement of total flare streams in larger oil and gas batteries, pipeline facilities, and gas processing plants where there are multiple connections to the flare system from sources, such as storage tank vents, pressure-relieving valves, manual blowdowns, and emergency vent valves. Several operators have been able to improve profitability by using total flare gas measurement to identify and correct gas losses from such sources.

The EUB may require operators to install total flare gas measurement in instances where there have been repeated failures to provide adequate estimates of flared volumes.

In addition to required measurement of total fuel gas use, operators are also expected to meter or determine fuel gas used for (1) flare pilots or (2) as flare header purge gas. Excessive flare pilot or make-up gas can be a source of significant lost sales. Fuel gas used in flare systems (including fuel gas make-up to acid gas flare) is to be reported as fuel gas on EUB S statements. Fuel gas added to flare systems should not be included in reported flare volumes if total flare gas measurement is used.

Gas measurement technology is continuously evolving. It is not the intent of this document to specify measurement equipment or to impede the application of new measurement techniques. The following guidelines address minimum expectations of flare or vent gas measurement equipment:

1) Measurement of flowing temperature, static pressure, and differential pressure are required where differential meters (e.g., orifice meters, pitot tubes, annubars) are used.

2) Flared gas composition must be determined by analysis or engineering estimate and must be incorporated into meter factor calculations as appropriate.

3) Meters must be suited to the range of flow conditions expected.

4) Measurement equipment, installation, and calculations must be consistent with applicable manufacturer, American Gas Association, and CSA standards and guidelines.

5) High turndown ratio electronic mass flow meters are preferred for measurement in open emergency flare headers.

6) Flare or vent gas measurement systems must comply with EUB requirements as summarized in *Guide 56*, Volume 2, Policy page 6, which lists related interim directives, informational letters, and guides.

10.1.2 Estimating Requirements

Where it is not practical to meter vented or flared gas, accurate estimates of gas may be accepted by the EUB. Operators must be able to demonstrate that a reliable and accurate flare or vented gas estimating and reporting system is in place and consistently used. Flare or vent gas estimating procedures and systems must include the following:

1) Estimating systems must account for all gas flared or vented (expressed to the nearest 0.1 10^3m^3/month) from the facility, including routine, emergency, and maintenance operations and depressuring of vessels, compressors, and pipelines.

2) Estimates must be based on calculations that account for the volume, gas composition, temperature, and initial and final pressures of systems vented or depressurized to flare.

3) Procedures for estimating vented or flared volumes must be developed by a qualified technical person, documented, and available for inspection by EUB staff.

4) A formal system for logging and reporting flaring or venting incidents must be in place and include procedures for reporting the information to staff responsible for preparing EUB S statements (see Section 10.3).

Operators will be expected to produce documented flare estimating procedures, reporting procedures, and logs for review by EUB staff as required. The EUB may require installation of meters in instances where there are repeated failures to demonstrate adequate flare or vent gas estimating and reporting systems.

10.2 Flared Gas Reporting on S Statements

In the CASA report *Management of Solution Gas Flaring in Alberta*, concerns were raised on data collection on solution gas flare and venting reporting.

All flared and vented gas in the province must be reported on the appropriate S statements, as described in EUB *Guide 7*. The EUB expects that industry fully understands the requirements detailed in *Guide 7* and applies them correctly.

Upon review of some industry practices, the EUB is concerned about apparent reporting deficiencies and the potential impacts of incorrect reporting of flared and vented gas. Reporting deficiencies include the incorrect reporting of flared gas as vented, reporting of vented gas as flared, and underreporting of flared and vented gas. To measure industry performance in flare reduction against the 1996 baseline, reporting must be accurate.

To clarify tracking and reporting of solution gas the following changes will be made. The reporting of gas wells as part of an oil battery on the S-1 statement will no longer be allowed. Operators may apply to physically tie a gas well into an oil battery system where they identify a need. These applications will be reviewed and dealt with on an individual basis. If approval is granted, the operator will be expected to submit a separate set of S statements for the gas well(s) showing this facility delivering its gas volume to the oil battery. This will allow for the clear differentiation between solution gas and gas well gas. Operators that have an existing approval to report one or more gas wells on an oil battery S-1 statement are required to obtain a new battery code for the gas wells and report those wells accordingly. Operators with gas wells tied into an oil battery that do not have written approval to do so must apply immediately.

If operators are found to be not complying with these requirements, appropriate enforcement actions will be initiated.

The EUB requires that gas must be reported as flared on the S statement for the facility where the gas is physically flared. That is, gas actually flared at a downstream facility (e.g., a gas processing plant) must not be allocated to an upstream facility (e.g., a battery) and reported on the S statement for that upstream facility.

Before production (including flaring) can be reported, a battery code must be obtained from the Production and Well Data Services Group. To obtain a battery code (*Guide 7*, Appendix 3), the facility type (battery type) must be provided. This battery type is used to identify whether it is a crude oil, gas, or crude bitumen battery. Current errors in the battery type codes are a concern to the EUB. The majority of gas flared in the province comes from solution gas batteries. In order for industry and the EUB to manage and reduce these volumes, it is essential that the volumes be reported under the correct battery code.

The EUB will revise *Guide 7* to clarify the definitions of the various battery type codes. Flaring data will be subject to existing S statements submission audit and enforcement processes.

10.3 Flaring Records

Release reporting requirements are defined in EUB *IL 98-01*[23] and by Alberta Environment's Release Reporting Guideline.

In addition to the requirements of *IL 98-01* and Alberta Environment's Release Reporting Guideline, operators must maintain records on complaints related to flaring.

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[23] *IL 98-01: A Memorandum of Understanding Between Alberta Environment and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*, EUB, 1998.

The EUB requires industry to be vigilant to prevent excessive flaring and be responsive to public complaints about such events. The information must include a description of the operator's response to the complaint, including evaluation of flare incident cause and any remedies implemented by the operator. Additional information related to flaring must be available from flare measurement records, which must include date, time, duration, and volume flared. Where flared gas volumes are estimated, the records must contain any necessary information as required by the operator's estimating and flare gas accounting procedures (see Section 10.1.2).

In the event flaring incidents are reported to the EUB Field Centre for follow-up, the EUB expects such follow-up will entail a review of industry logs in the area. Accordingly, flaring records must be made available for inspection upon request of EUB staff and are required for production (battery), pipeline, and gas processing facilities where flaring occurs. Records for remote or semi-attended facilities may be retained at central locations (e.g., the field centre that would normally receive public complaints related to the facilities).

11 Industry Performance Reporting

A summary of flare and vent emission information compiled will be provided annually and made available on the EUB Web site, www.eub.gov.ab.ca. The information will include

- a pie chart showing the distribution of annual flared volumes for the various types of flaring
- a bar chart showing overall provincial solution gas conservation
- a chart comparing industry performance with the provincial reduction schedule
- tables ranking individual operating company flare reduction (gas conservation) performance by EUB Field Centre area
- a pie chart showing the distribution of gas reported as vented provincially

The above information will be compiled utilizing information submitted by operating companies to the EUB. Companies may be requested or given the opportunity to verify data submitted prior to release of the summary information.

12 Enforcement

The EUB considers the following to be critical aspects of the management framework:

- the review of existing flares,
- completion of the required personal consultation and public notification,
- compliance with the flare performance requirements,
- reducing flaring at conserving facilities, and
- accurate reporting of flare and vent data.

Accordingly, the EUB will focus its audit and enforcement efforts as necessary on these key elements.

In the context of the enforcement process detailed in *IL 99-4*, the critical aspects noted above will be considered “major” non-compliance events. Non-compliance with other requirements set out in this guide will be considered “minor.”

The EUB reserves the right to escalate non-compliance issue(s) to any level should conditions warrant.

If in the opinion of the EUB, a non-compliance causes odours above allowable limits or unacceptable impacts on the public, operations may be suspended if the impacts cannot be resolved.

Appendix 1 Definitions

Acid Gas	Gas that contains hydrogen sulphide (H_2S), total reduced sulphur compounds, and/or carbon dioxide (CO_2) that is separated in the treating of solution or non-associated gas.
Associated Gas	Gas that is produced from an oil or bitumen pool. This may apply to gas produced from a gas cap or in conjunction with oil or bitumen.
Combustion Efficiency	The overall conversion of flared gases to products of complete combustion, such as CO_2, water, and SO_2.
Destruction Efficiency	The destruction of flared gas compounds to products of complete and incomplete combustion. Destruction efficiency does not address complete combustion (see Combustion Efficiency).
Gas Battery	For the purpose of this guide, a gas battery is a system or arrangement of surface equipment that receives primarily gas from one or more wells prior to delivery to a gas gathering system, to market, or to other disposition. Gas batteries may include equipment for measurement and for separating inlet streams into gas, hydrocarbon liquid, and/or water phases. Related production is reported under battery types 7-11, as defined in *Guide* 7*: Production Accounting Handbook.*
Gas Processing Plant	Gas processing plants are defined by Section 1.1 of the *Oil and Gas Conservation Act* as “a plant for the extraction from gas of hydrogen sulphide, helium, ethane, natural gas liquids or other substances but does not include a well head separator, treater, or dehydrator.” Under this definition, any facility that includes an amine or sweetening process is a gas plant and must be approved as such by both Alberta Environment and the EUB. Any sour gas plant that proposes to emit more than 2.8 tonnes/day of sulphur is a Mandatory Activity on Schedule 1 of the EPEA Environmental Assessment (Mandatory and Exempt Activities) Regulation (Alberta Regulation 111/93) and requires an environmental assessment as part of the Alberta Environment approval process. It is EUB practice to exempt from classification as gas processing plants those production facilities that recover less than 2 m^3/day hydrocarbon liquids with refrigeration or remove small amounts of sulphur (less than 0.1 tonnes/day) using non-regenerative scavenging chemicals that have no H_2S or SO_2 air emissions. Consult Alberta Environment as necessary.

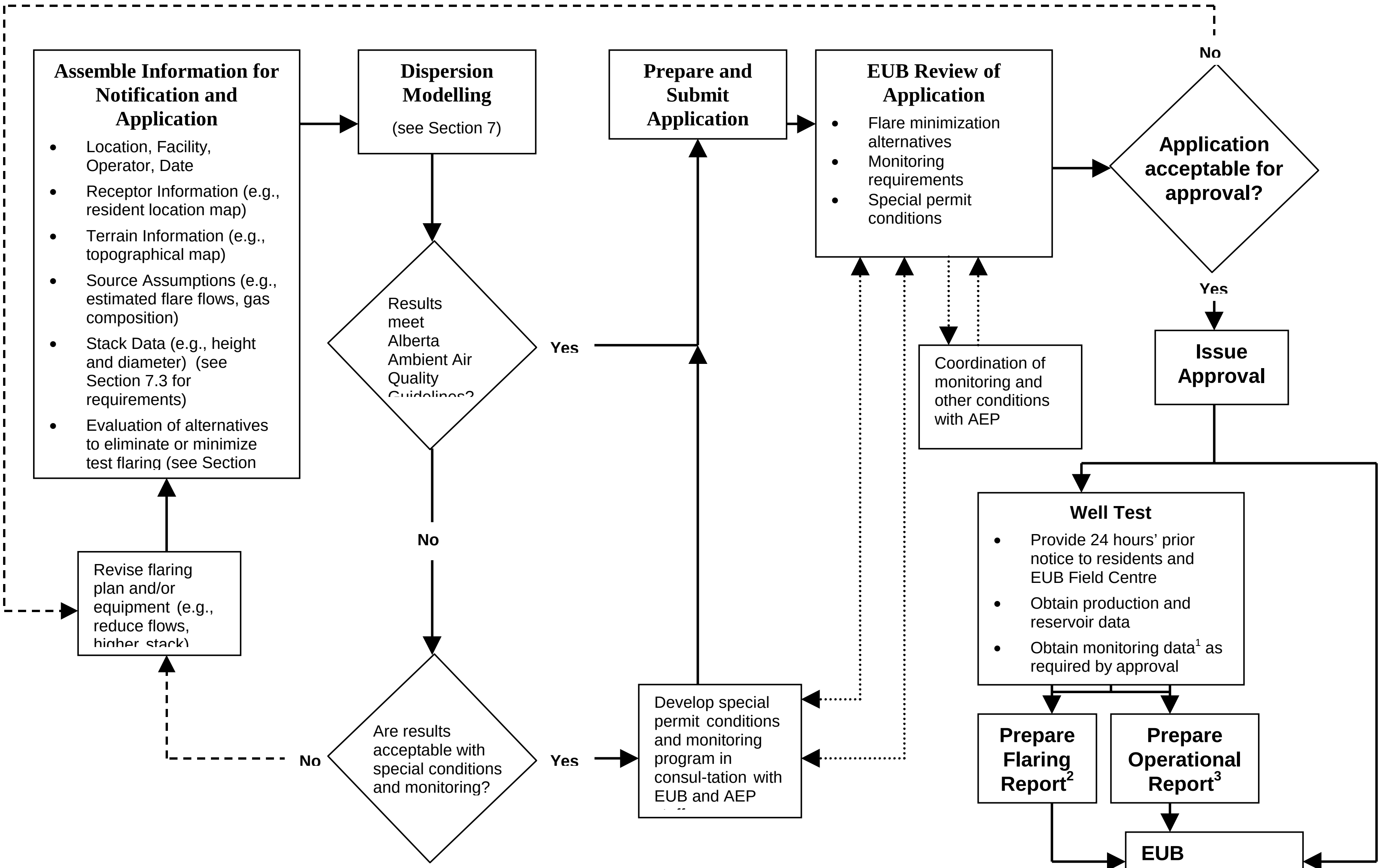
Non-Associated Gas	Gas that is produced from a gas pool (e.g., gas that is not associated with oil or bitumen reservoirs or production).
Oil Battery	For the purposes of this guide, an oil battery is a system or arrangement of tanks or other surface equipment receiving primarily oil or bitumen from one or more wells prior to delivery to market or other disposition. An oil battery may include equipment for measurement and for separating inlet streams into oil, gas, and/or water phases. Related production is reported under battery types 1-6 and 12-15, as defined in *Guide 7*.
Solution Gas	Gas that is in solution with produced oil or bitumen. For the purposes of this guide, solution gas is all gas that is separated from oil or bitumen production.
Sour Gas	Gas that contains H_2S. Unless a concentration is specified in the text, sour gas is defined as gas that contains H_2S in sufficient quantities to pose a public safety hazard if released or to result in unacceptable off-lease odours if vented to the atmosphere.
Sulphur Emissions	For the purposes of this guide, sulphur emissions includes all air emissions of sulphur containing compounds including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.

Appendix 2 Monthly Battery (S-2) Information to Be Released

For battery type codes 1-6 (oil facilities) and 12-15 (crude bitumen facilities) only:

Field Code
Battery Code
Battery Location
Township
Range
Meridian
Operator Code
Operator
Battery Type
Data Date
Run Date
Total Number of Wells
Oil Production
Oil Receipts
Oil Opening Inventory
Oil Closing Inventory
Oil Deliveries
Gas Production
Gas Receipts
Lease Fuel
Gas Flared
Gas Vented
Gas Metering Difference
Gas Deliveries
Water Production
Water Receipts
Water Opening Inventory
Water Closing Inventory
Water Metering Inventory
Water Deliveries

Appendix 3 Flaring Permit Application Process (monitoring information and reports)*



*See next page for footnotes.

Footnotes to Appendix 3

[1] Monitoring Data —— A report of the flaring and monitoring operations must be submitted to the EUB Environment Safety and Technical Services (ESTS) Group within three weeks of the flaring completion date. The report must include

- H_2S and SO_2 concentrations
- wind speed and direction
- dates and times monitoring occurred

[2] Flaring Report — A report outlining the actual volume of gas flared, maximum and average flow rates, actual H_2S content of the flared gas, and the flaring dates must be submitted to ESTS within three weeks of the flaring completion date.

[3] Operational Report (for well tests) — Information submitted in accordance with *Guide 40* and *Guide 52*.

Appendix 4

ID 99-6

29 July 1999

TO: All Oil and Gas Operators

UPSTREAM PETROLEUM INDUSTRY FLARING REQUIREMENTS

Introduction

EUB *Guide-60*: *Upstream Petroleum Industry Flaring Guide* details new Alberta Energy and Utilities Board (EUB) requirements for upstream flaring in Alberta.

Guide 60 is effective 1 January 2000.

Guide 60 represents the end of several multistakeholder processes that examined concerns respecting upstream flaring in Alberta. It incorporates recommendations made to the EUB by the Clean Air Strategic Alliance (CASA), introduces new requirements to address some flaring issues not specifically addressed by CASA, and consolidates other existing EUB flaring requirements into one document.

1.1.1 Management Framework

CASA recommended a goal to "work toward elimination of routine solution gas flaring." CASA also recognized that reaching this goal can not be accomplished easily within a short time frame. As a result, it recommended a flaring management framework which includes significant short- and long-term targets for flare reductions, as well as improved flare performance requirements. It also recommended that the associated regulatory aspects of the recommended framework include public involvement, monitoring, and enforcement.

The Board believes that CASA's recommended goal and management framework, while recommended in the context of solution gas management, are consistent with the EUB's overall intent to optimize resource conservation and ensure appropriate levels of environmental protection. Accordingly, the EUB has adopted them to encompass flaring in general.

A summary of changes introduced by *Guide-60* is attached. Key requirements of the management framework include:

- A firm provincial **solution gas** flare volume reduction schedule:
    - 15 per cent reduction from 1996 baseline by 31 December 2000 (reduce flaring to 1445 $10^6 m^3$/year)
    - 25 per cent reduction from 1996 baseline by 31 December 2001 (reduce flaring to 1275 $10^6 m^3$/year)

- New flare performance requirements for **all** flares, including the following compliance deadlines:
    - all new flares by 1 January 2000
    - all existing solution gas flares by 31 December 2002
    - all flares at other existing permanent facilities by 31 December 2004

- Required evaluation of all solution gas flares by 31 December 2002 using a flaring management decision tree, including a streamlined common economic assessment process

- Commencing 1 January 2000, reduction to the New Oil Well Production Period (NOWPP) flare limit set out in *Informational Letter (IL) 87-9*[1] to 300 $10^3 m^3$/month from 500 $10^3 m^3$/month, implementation of a maximum gas oil ratio (GOR) criterion of 3000 m^3/m^3, above which conservation would be required; and tie in of development wells within one month in pools where gas conservation exists

- Personal consultation and public notification requirements for new and existing solution gas batteries

- Requirements for reduced flaring at normally conserving facilities during planned or emergency flaring

- Sulphur recovery requirements for facilities outside the scope of *IL 88-13*[2] and the related report *ERCB-AE 88-AA*[3]

- Clarified flaring and venting reporting requirements for all facilities

- Annual reporting of regional and overall provincial flaring performance

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[1] *IL 87-9*: *Revised Procedures for Oil Production Allowable Controls and New Oil Well Production Period*, EUB, 1987.

[2] *IL 88-13: Sulphur Recovery Guidelines Gas Processing Operations*, EUB, 1988.

[3] *ERCB – AE 88-AA*: *Sulphur Recovery Guidelines for Sour Gas Plants in Alberta*, EUB, 1988.

Other important aspects addressed in the guide include

- Conflict resolution process to address flaring concerns
- Making available flaring and venting (S-2 statement) data to support increased use of otherwise flared gas

- Progress towards minimizing requirements for electricity generators using otherwise flared gas

- Annual EUB reporting of industry performance

Flare Efficiency Standard

The EUB has concluded that establishing an efficiency standard is not practical at this time, primarily because there are no practical methodologies for measuring either combustion or destruction efficiencies under field conditions. However, it believes that the use of "performance standard" equipment will allow industry the greatest flexibility in achieving the desired environmental protection and safety results in a cost-effective manner.

It is the EUB's view that achievement of combustion efficiencies of 98 per cent or better on both a design and operational basis would be the expected result of focused continuous improvement in flare technology research and flare performance standards. To this end, the EUB anticipates the focused attention of industry and government towards the development of flare equipment certification and field efficiency measurement protocols for consideration during the review of the management framework in 2001.

Notwithstanding the ongoing work towards a practical efficiency-based standard, the EUB expects operators, as they implement the requirements of *Guide 60*, to be able to demonstrate that they have assessed and incorporated appropriate operational practices and new technology developments that maximize combustion efficiency in the design of new or modified flare systems.

Implementation

The EUB requires companies to assess their individual flaring policies and practices as outlined by the management framework detailed in *Guide 60*. Further, it requires companies to exercise diligent operating practices and deliberate development of field facilities to enhance conservation and minimize flaring. EUB personnel will ensure the consistent application of the requirements detailed in *Guide 60* throughout the province.

IL 91-2: S*our Gas Flaring Requirements and Changes to Regulations* and *IL 96-6: Solution Gas Conservation and Emissions Reduction* are rescinded.

Compliance and Enforcement

The EUB considers the following to be critical aspects of the management framework:

- the review of existing flares,
- completion of the required personal consultation and public notification,
- compliance with the flare performance requirements,
- reducing flaring at conserving facilities, and
- accurate reporting of flare and vent data.

Accordingly, it will focus audit and enforcement efforts as necessary to these key elements.

In the context of the enforcement process detailed in *IL 99-4,*[4] the critical aspects noted above will be considered "major" non-compliance events. Non-compliance with other requirements set out in the guide will be considered "minor."

The EUB reserves the right to escalate non-compliance issue(s) to any level should conditions warrant.

If in the opinion of the EUB a non-compliance causes odours above allowable limits or unacceptable impacts on the public, the operations may be suspended if the impacts cannot be resolved.

Where possible, the EUB intends to utilize existing audit and enforcement processes. For example, existing facility application audit protocols will be revised to ensure that personal consultation and public notification specific to flaring takes place.

The following table summarizes some key implementation and compliance dates.

Implementation and Compliance Dates

Item	Effective Date	Compliance Date
Solution Gas Reduction Schedule		
15% from 1996 baseline	1 January 2000	31 December 2000
25% from 1996 baseline	1 January 2000	31 December 2001
Reduced NOWPP Flare Limit; GOR Limit; Development Well Tie-in	1 January 2000	1 January 2000
Flaring at Conserving Facilties	1 January 2000	1 January 2000
Evaluation of Solution Gas Flares/Compliance with Flare Performance Requirements		
New Flares	1 January 2000	1 January 2000
Existing Solution Gas Flares	1 January 2000	31 December 2002
Other Existing Flares	1 January 2000	31 December 2004

(continued)

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[4] *IL 99-4: EUB Enforcement Process, Generic Enforcement Ladder, and Field Surveillance Enforcement Ladder*, EUB, 1999.

Implementation and Compliance Dates (cont'd)

Item	Effective Date	Compliance Date
Consultation and Notification		
New Flares – revise *Guide 56*	1 January 2000	1 January 2000
Existing Solution Gas Flares – residents within 500 m	1 January 2000	31 December 2000
Review Management Framework	31 March 2001	N/A

Other Matters

While *Guide 60* sets out existing requirements for various types of flaring, the feedback received on the review draft suggests further stakeholder discussion is necessary for some matters, including:

- well test volume approval criteria,
- gas plant flare volume limits,
- the development of flare and vent data submission business rules,
- site venting control criteria, and
- minimum heating values required for flame stability.

The EUB will initiate further discussions in due course.

1.1.2 Management Framework Review

The EUB intends to assess all aspects of the overall flare management framework set out in *Guide 60* in 2001. While the EUB anticipates that flares upgraded to meet the flare performance requirements set out in *Guide 60* prior to the 2001 review would not be subject to further revisions, it will consider this matter in light of flaring research available at that time.

Inquiries

Should you have any questions regarding *Guide 60*, please contact the EUB at (403) 297-8311 and ask to be referred to one of the following:

- General Inquiries
- Oil Batteries
- Gas Plants/Gas Batteries
- Well Test Volumes
- Flare Permits
- Flare Performance
- Dispersion Modeling
- Electricity Generation
- S Statements
- Battery Codes

You can also contact any one of the following Field Centres:

Bonnyville	(780) 826-5352
Calgary	(403) 297-8303
Drayton Valley	(780) 542-5182
Grande Prairie	(780) 538-5138
Medicine Hat	(403) 529-3626
Red Deer	(403) 340-5454
St. Albert	(780) 460-3800
Wainwright	(780) 842-7570

Guide 60 is available on the EUB Web site at http//www.eub.gov.ab.ca or through the EUB's Information Services at (403) 297-8190.

F. J. Mink, P.Eng.
Board Member

EUB *Interim Directive (ID) 99-6*: Summary of Changes

Existing	New
Solution Gas Conservation • By application and/or Gas Conservation Order	**Solution Gas Management Framework** • 15% solution gas flare reduction by end 2000 • 25% solution gas flare reduction by end 2001 • Evaluation of new and existing solution gas flares using decision tree, including streamlined common economic assessment process, i.e., discount rate equal to Alberta Treasury Branch prime lending rate plus 3% • Personal consultation and public notification required respecting evaluation results for existing facilities • Evaluation of flares within 500 m of residents with notification of results—compliance by 31 December 2000 • Flare performance requirements: compliance for all existing flares by 31 December 2002 • Reduction to NOWPP flare limit to 300 $10^3 m^3$/month; setting of a maximum GOR limit of 3000 m^3/m^3; and early tie-in requirement – compliance by 1 January 2000
• Facility approvals: per *Guide 56*	• Facility approvals: revise *Guide 56*. • Decision tree must be used for new facilities • Expanded personal consultation and public notification requirements specific to flaring • Electricity generation: streamlined small generator approval process to expedite use of otherwise flared solution gas for electricity generation • Flare reduction requirements for conserving facilities during planned or emergency flaring, including EUB and public notification, effective 1 January 2000 • Log of flare events and complaints • Conflict resolution process to address flare-related concerns
• Reporting: per *Guide 7*	• Reporting: per *Guide 7*; review requirements to improve data quality; data submission enforcement; battery type definitions in *Guide 7*; flare and vent data publicly available • Regional and provincial company benchmarking (ranking) **See *Guide 60*, Section 2**
Well Test Flaring • 600 $10^3 m^3$ volume approval • Flare design requirements >1% H_2S • Flare permit greater than 5% H_2S • Notification: > 1 % H_2S; 3 km, 24 hours • Reporting: per *Guide 40, Guide 7*	**Well Test Flaring** • 600 $10^3 m^3$ volume approval • Volume approval criteria to be reviewed • Flare performance requirements • Flare permit greater than 5% H_2S • Streamlined temporary facility approvals to promote in-line testing • Notification: residents within 3 km, and EUB 24 hours in advance • Reporting: per *Guide 40*, *Guide 7* **See *Guide 60*, Section 3**

EUB *Interim Directive (ID) 99-6*: Summary of Changes (cont'd)

Existing	New
Gas Battery Flaring • Facility approvals: per *Guide 56* • Flare design requirements • Reporting: per *Guide 7*	**Gas Battery Flaring** • Facility approvals: per *Guide 56* • Flare performance requirements • Sulphur recovery requirements • Reporting: per *Guide 7* **See *Guide 60*, Section 4**
Gas Plant Flaring • Facility approvals: per *Guide 56* • Sulphur recovery: per *IL 88-13* • Flare design requirements • 0.5% raw gas inlet /year volume limit • Release reporting: per *IL 98-01* **Reporting: per *Guide 7***	**Gas Plant Flaring** • Facility approvals: per *Guide 56* • Sulphur recovery: per *IL 88-13* • Flare performance requirements: compliance by 1 January 2005; flare stability effective 1 January 2000 • 0.5% raw gas inlet/year volume limit • Flare volume limit to be reviewed • Flare measurement requirements • Notification: EUB 24 hours (advance or after) • Release reporting: per *IL 98-01* • Log of flare events and complaints • Reporting: per *Guide 7*; EUB business rules to improve data quality; data submission enforcement **See *Guide 60*, Section 5**
Pipeline Emissions • Notification: residents within 3 km (GGS flaring) and EUB 24 hours in advance; EUB 24 hours in advance (transmission system venting or flaring) **Reporting: per *Guide 7* (gas gathering systems); Annual Transporter Statements (transmission systems)**	**Pipeline Emissions** • Notification: residents within 3 km (GGS flaring) and EUB 24 hours in advance; EUB 24 hours in advance (transmission system venting or flaring) • Review need for transmission system requirements • Reporting: per *Guide 7* (gas gathering systems); transmission system – report venting and flaring separately **See *Guide 60*, Section 6**
Flare Design Requirements • Scope: > 1% H_2S **Flare Stack Design and Operation** • Ignition: continuous ignition available • Flame stability: 9 MJ/m^3 • Stack height: Ambient Guidelines • Liquid separation: no liquids to flare • Spacing: 100 m from residence • Visible emissions: 40% opacity • Dispersion modelling: single-point source	**Flare Performance Requirements** • Scope: **All** flares, regardless of composition **Flare Stack Design and Operation** • Ignition: flame must be present • Flame stability: 12-20 MJ/m^3. • Exit velocity guidelines • Stack height: Ambient Guidelines • Documented procedures for emergency flares • Liquid separation: No liquids to flare; designed for specific operation; visual liquid level indicators and high-level alarms on knockout drums • Spacing: 100 m from residence • Visible emissions: 40% opacity • Dispersion modelling: cumulative emission assessment if single source exceeds 1/3 of Ambient Air Quality Guideline for SO_2 **See *Guide 60*, Section 7**

EUB *Interim Directive (ID) 99-6*: Summary of Changes (cont'd)

Existing	New
Venting Limits • Significant volumes to be burned • Ambient Air Quality Guidelines	**Venting Limits** • Significant continuous volumes to be burned; no continuous off-site odours • Site venting control criteria to be reviewed • Benzene emission requirements of *IL 97-04* • Ambient Air Quality Guidelines **See *Guide 60*, Section 8**
Sulphur Recovery Guidelines • Gas plants	**Sulphur Recovery Guidelines** • Facilities emitting more than 1 tonne/day • Review of facilities emitting 1-5 tonne/day **See *Guide 60*, Section 9**
Industry Performance Reporting • Annual solution gas conservation	**Industry Performance Reporting** • Reduction schedule progress (line chart) • Annual flaring by type (pie chart) • Annual solution gas conservation (bar chart) • Regional and provincial company solution gas flare benchmarking (ranking) • Annual venting by type (pie chart) **See *Guide 60*, Section 11**
Enforcement • New facility consultation and notification • Flare design requirements • Individual facility focus	**Enforcement** • New facility consultation and notification • Evaluation process including consultation and notification respecting existing flares • Flare performance requirements • Flaring at conserving facilities • Corporate focus • Reference *IL 99-4* ***See Guide 60*, Section 12**

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

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Air

EPA

Protocol for Equipment Leak Emission Estimates

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1995 Protocol for Equipment Leak Emission Estimates

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
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FOREWORD

The EPA's protocol for estimating equipment leak emissions is the result of detailed information gathering and data analysis. The protocol was written to provide a thorough understanding of acceptable approaches to generating process unit-specific emission estimates. In preparing this document, the EPA has encouraged knowledgeable individuals in industry and the regulatory community to provide comments.

The EPA has put forth considerable effort to make this document as comprehensive as possible. However, it should be understood that not all details and topics pertaining to equipment leaks could feasibly be included in this document. Additionally, it should be understood that the procedures presented in this document are not necessarily suitable for all applications. There will be cases where it will be necessary for the user of the document to make a professional judgement as to the appropriate technical approach for collecting and analyzing data used to estimate equipment leak emissions.

Additional data on equipment leak emissions continues to be collected. It is the intent of the EPA to periodically update this document after analysis of the data warrants such an update. For example, data recently collected in the petroleum industry has been used to revise the existing refinery correlations, which are based on data collected in the late 1970s. Furthermore, as new techniques for collecting and analyzing data are developed, they will be included in updated versions of this document.

Mention of any manufacturer or company name within this document does not represent endorsement by the EPA.

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1.0 INTRODUCTION

This document is an update to the EPA equipment leaks protocol document ("Protocol for Equipment Leak Emission Estimates," EPA-453/R-93-026, June 1993). The purpose of this document is the same as the original protocol document and subsequent revisions- to present standard procedures for estimating mass emissions from equipment leaks. However, this document publishes the results of additional data collection and analysis that has occurred since the original protocol and subsequent revisions were published, and also expands on some of the topics that were covered in the original protocol.

Some of the new features of the updated protocol are:

(1) New correlation equations, default zero emission rates, and pegged emission rates for the petroleum industry that replace the refinery correlations previously published are presented. The correlations relate screening values obtained using a portable monitoring instrument to mass emissions.

(2) The document has been expanded to include emission factors for marketing terminals and for oil and gas production operations. The refinery emission factors were not revised due to an unavailability of new data.

(3) Pegged emission rates for pegged readings at 10,000 ppmv have been added for SOCMI process units.

(4) Several of the equations in this version of the protocol have been revised by simplifying the symbols to more clearly communicate the concept being conveyed.

(5) An adjustment has been added to the blow-through method of calculating mass emissions. This adjustment more accurately accounts for the total flow through the bag.

As with the original protocol document, this document presents standard procedures for general use in generating unit-specific emission estimates for permitting and inventories. The document describes methodologies the EPA considers appropriate for development of equipment leak emission estimates. These methodologies are intended to assist States and industry in their efforts to estimate equipment leak emissions.

The updated protocol is divided into five chapters and several appendices. Chapter 2.0 describes how to estimate equipment leak emissions. Chapter 3.0 describes collecting screening data that can be used in the emission estimates. Chapter 4.0 describes collecting unit-specific equipment leak mass emissions data. Chapter 5.0 describes how to estimate the control efficiencies of equipment leak control techniques. The appendices support information contained in the chapters. Each of these chapters and the appendices are briefly described below.

Chapter 2.0 presents the four approaches for estimating total organic emissions from equipment leaks. These approaches are:

- Average Emission Factor Approach;
- Screening Ranges Approach;
- EPA Correlation Approach; and
- Unit-Specific Correlation Approach.

Additionally, several topics that are relevant to estimating equipment leak emissions are addressed. These topics include speciating equipment leak emissions of individual compounds from an equipment piece containing a mixture, using response factors, estimating emissions of volatile organic compounds, estimating emissions of inorganic compounds, and other topics not specifically related to any one of the four approaches.

Chapter 3.0 explains how to perform a screening survey at a process unit. Requirements for the use of a portable monitoring instrument are described. These requirements are based on the EPA Reference Method 21. Additionally, in chapter 3.0, guidance is provided on how to set up a screening program and how to screen different types of equipment.

Chapter 4.0, explains how to collect equipment leak rate data (bagging data) by enclosing individual equipment in a "bag" and measuring mass emissions. These data can be used to develop unit-specific leak rate/screening value correlations. Chapter 4.0 details the rigorous steps that need to be followed when collecting the bagging data to generate unit-specific correlations. These steps are intended to ensure that the data are of high quality.

Chapter 5.0, explains how to estimate the control efficiency of equipment leak emission control techniques. The two primary control techniques for reducing equipment leak emissions are (1) equipment modifications (such as replacing a standard valve with a sealless type) and (2) implementing a leak detection and repair (LDAR) program. Control efficiencies for different equipment leak modifications are summarized, and an approach for estimating the control efficiency of any LDAR program is provided.

Appendices A through G provide additional information supporting the material in the chapters. Appendix A contains detailed example calculations using the approaches described in chapter 2.0. Appendix B documents how the SOCMI correlations and emission factors were revised. Appendix B also serves as a demonstration of how data can be analyzed to develop unit-specific correlations. Appendix C presents the rationale for the development of the petroleum industry correlations, as well as the background for the development of marketing terminal and oil and gas production operations emission factors. Appendix D summarizes available data on response factors. Appendix E provides guidance on how to collect representative screening data for connectors. Appendix F contains a copy of the EPA Reference Method 21. Finally, appendix G demonstrates how LDAR control efficiencies presented in chapter 5.0 were calculated.

2.0. DEVELOPMENT OF EQUIPMENT LEAK EMISSION ESTIMATES

2.1 INTRODUCTION

The purpose of this chapter is to describe the methods for estimating mass emissions from equipment leaks in a chemical processing unit. Four approaches for estimating equipment leak emissions are presented:

Approach 1: Average Emission Factor Approach;
Approach 2: Screening Ranges Approach;
Approach 3: EPA Correlation Approach; and
Approach 4: Unit-Specific Correlation Approach.

General information on these approaches is presented in section 2.2, and detailed information on applying each of the approaches is presented in section 2.3. Included in section 2.3 are emission factors and leak rate/screening value correlations for use in estimating emissions from equipment leaks in the petroleum industry and the synthetic organic chemical manufacturing industry (SOCMI). The SOCMI emission factors and correlations were revised and introduced in the 1993 update of this document. The refinery correlations that have been revised and expanded to include the entire petroleum industry are introduced in this document. Additionally, emission factors for marketing terminals are introduced in this document. Emission factors for gas plants that have been updated and expanded to included oil and gas production operations are also introduced in this document. The procedures in this document estimate emissions of total organic compounds (TOC’s). However, special procedures are also described for the purpose of estimating volatile organic compounds (VOC’s). As defined by the EPA, VOC’s include all organic compounds except those specifically excluded by the EPA due to negligible photochemical activity.

After the four approaches have been discussed, topics that are not specifically related to any particular approach, but are relevant to how equipment leak emissions are estimated, are addressed in section 2.4. These topics include:

- Estimating emissions of individual compounds within a mixture;
- Using response factors when estimating emissions;
- Considerations regarding the monitoring instrument used;
- Estimating emissions of equipment not screened when other equipment have been screened;
- Using screening data collected at different times;
- Estimating VOC emissions from equipment containing organic compounds excluded from the EPA's classification of TOC's; and
- Estimating emissions from equipment containing inorganic compounds.

Appendices A through E contain supporting documentation for the material presented in this chapter. Appendix A contains detailed example calculations that demonstrate the four approaches for estimating equipment leak emissions, as well as the topics discussed in section 2.4. Appendix B presents details on how unit-specific correlations can be developed, and also presents background information on the revision of the SOCMI correlations and emission factors. Appendix C presents background information on the development of average emission factors and correlation equations for the petroleum industry. Appendix D offers a detailed listing of available response factors. Appendix E contains information on the minimum number of connectors in a process unit that must be screened in order to obtain a representative sample.

2.2 GENERAL INFORMATION ON THE APPROACHES FOR ESTIMATING EQUIPMENT LEAK EMISSIONS

This section presents general information on the four approaches for estimating equipment leak emissions. Each approach is briefly described, and data requirements for each are summarized. Additionally, background information is presented to provide an historical overview of data collection and analysis on emissions of VOC's from equipment leaks.

2.2.1 Equipment Leak Emission Estimation Approaches

The four approaches described here can be used by any chemical-handling facility to develop an inventory of TOC or VOC emissions from equipment leaks. The approaches, in order of increasing refinement, are: Average Emission Factor Approach, Screening Ranges Approach, EPA Correlation Approach, and Unit-Specific Correlation Approach.

In general, the more refined approaches require more data and provide more accurate emission estimates for a process unit. In the Average Emission Factor Approach and the Screening Ranges Approach, emission factors are combined with equipment counts to estimate emissions. To estimate emissions with the EPA Correlation Approach, measured concentrations (screening values) for all equipment are individually entered into general correlations developed by the EPA. In the Unit-Specific Correlation Approach, screening and leak rate data are measured for a select set of individual equipment components and then used to develop unit-specific correlations. Screening values for all components are then entered into these unit-specific correlations to estimate emissions.

Figure 2-1 is an overview of the data collection and analysis required to apply each of the approaches. As can be seen from this figure, all of the approaches require an accurate count of equipment components by type of equipment (i.e., valves, pumps, connectors, etc.). Additionally, for some of the equipment types, the count must be further described by service (i.e., heavy liquid, light liquid, and gas).

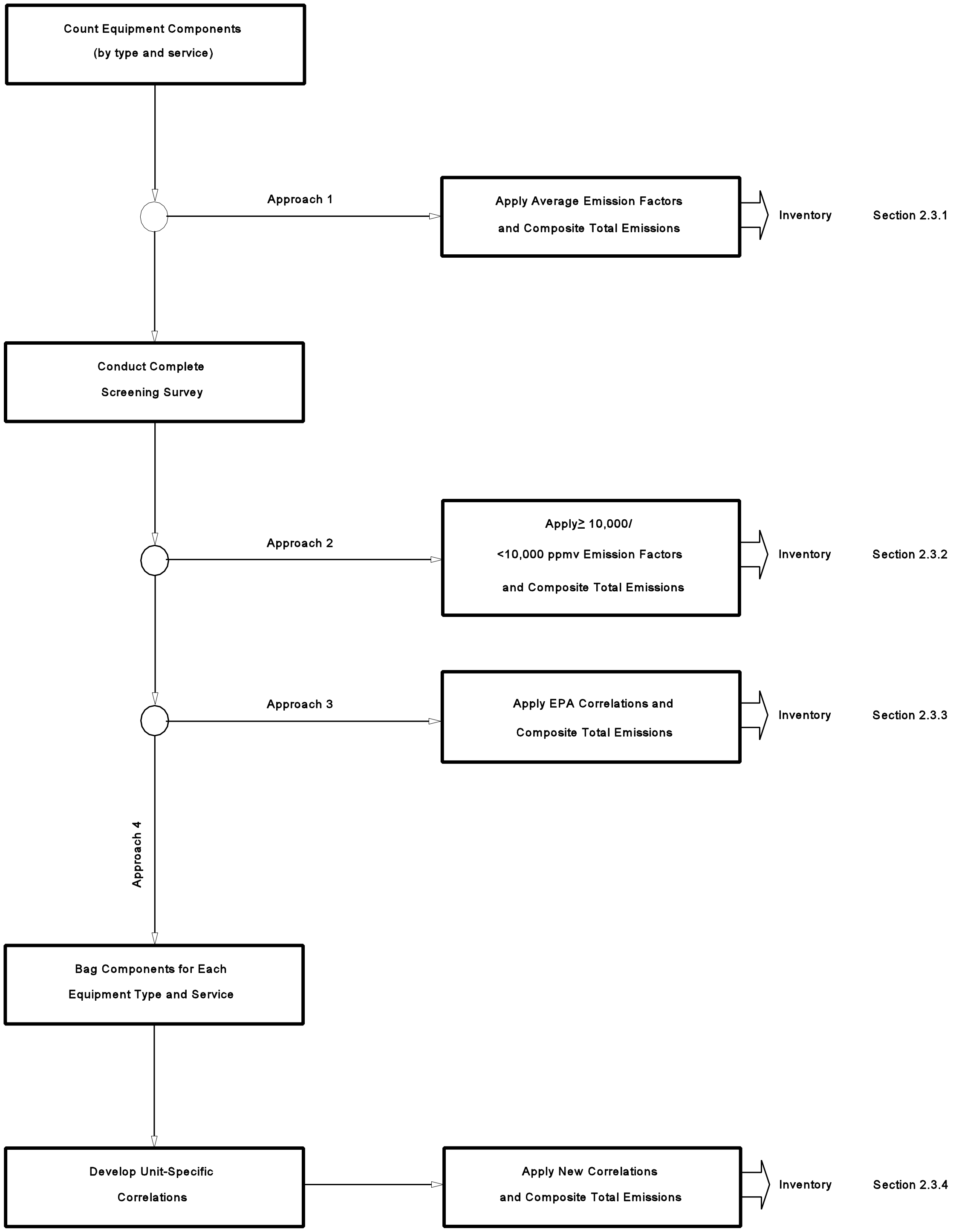

Figure 2-1. Overview of Data Collection and Analysis Approaches for Developing Equipment Leak Emissions Inventory

Except for the Average Emission Factor Approach, all of the approaches require screening data. Screening data are collected by using a portable monitoring instrument to sample air from potential leak interfaces on individual pieces of equipment. A screening value is a measure of the concentration of leaking compounds in the ambient air that provides an indication of the leak rate from an equipment piece, and is measured in units of parts per million by volume (ppmv). The procedures for collecting screening data are presented in chapter 3.0.

In addition to equipment counts and screening data, the Unit-Specific Correlation Approach requires bagging data. Bagging data consist of screening values and their associated measured leak rates. A leak rate is measured by enclosing an equipment piece in a bag to determine the actual mass emission rate of the leak. The screening values and measured leak rates from several pieces of equipment are used to develop a unit-specific correlation. The resulting leak rate/screening value correlation predicts the mass emission rate as a function of the screening value. Procedures for collecting bagging data are described in detail in chapter 4.0.

Each of the approaches are applicable to any chemical-handling facility. However, the EPA has developed more than one set of emission factors and correlations, and the type of process unit being considered governs which set must be used to estimate emissions. Historical data collection on emissions from equipment leaks in SOCMI, refineries, marketing terminals and oils and gas production operations have yielded emission factors and correlations for these source categories. Emission factors and correlations for other source categories have not been developed.

For process units in source categories for which emission factors and/or correlations have not been developed, the factors and/or correlations already developed can be utilized. However, appropriate evidence should indicate that the existing emission factors and correlations are applicable to the source category in question. Criteria for determining the appropriateness of applying existing emission factors and correlations to another source category may include one or more of the following: (1) process design, (2) process operation parameters (i.e., pressure and temperature), (3) types of equipment used, and (4) types of material handled. For example, in most cases, SOCMI emission factors and correlations are applicable for estimating equipment leak emissions from the polymer and resin manufacturing industry. This is because, in general, these two industries have comparable process design and comparable process operation, they use the same types of equipment, and they tend to use similar feedstock.

2.2.2 Overview of Equipment Leak Data Collection

Data on equipment leak emissions of organic compounds have been collected from refineries, marketing terminals, oil and gas production operations, and SOCMI process units. Emission factors and correlations have been developed for the following equipment types: valves, pumps, compressors, pressure relief valves, connectors, flanges, and open-ended lines. An "others" category has also been developed for the petroleum industry. For sampling connections, an average emission factor has been developed that estimates the typical amount of material purged when a sample is collected. A brief history of the development of these factors and correlations is presented below.

2.2.2.1 Refinery Assessment Study.[1,2] In the late 1970s, the EPA initiated the Petroleum Refinery Assessment Study, and equipment leak data from 13 refineries were collected. In this study, equipment was screened and the majority of sources that had screening values over 200 ppmv were bagged. Bagged equipment emission rates were reported as non-methane organic compound emission rates. Average emission factors and correlations for each equipment type were developed based on the screening and bagging data collected in this study.

The Refinery Assessment Study included an investigation of possible correlations between equipment leaks and process variables. The only process variables found to correlate with mass emission rates in a statistically significant manner were

(1) the phase of the process stream (service), and (2) the relative volatility of liquid streams. This finding led to the separation of data for valves, pumps, and pressure relief valves by type of service. Three service categories were defined:

- Gas/vapor - material in a gaseous state at operating conditions;
- Light liquid - material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kilopascals (kPa) at 20 ^{O}C is greater than or equal to 20 weight percent; and
- Heavy liquid - not in gas/vapor service or light liquid service.

2.2.2.2 Gas Plant Studies.[3] A total of six gas plants were screened in two studies: Four were screened by the EPA and two by the American Petroleum Institute. Average emission factors were developed, and information on the percentage of equipment with screening values equal to or greater than 10,000 ppmv was presented. The average factors include emissions of ethane and methane, which are hydrocarbons but are not classified as VOC’s.

2.2.2.3 Revised Petroleum Industry Correlations and Emission Factors. During the early-1990’s, new petroleum industry equipment leak bagging data were collected and analyzed. The Western States Petroleum Association (WSPA) and the American Petroleum Institute (API) jointly commissioned the 1994 refinery equipment leak report[4] to evaluate fugitive emissions collected from five petroleum refineries. The API also commissioned the 1993 marketing terminal equipment leak report,[5] which included bagging data from three marketing terminals, and, along with the Gas Research Institute (GRI), jointly commissioned the 1993 and 1995 oil and gas production operations reports, which included bagging data from 24 facilities.[6,7] In addition to the bagging data, screening data were also collected from 17 marketing terminals[8] and 24 oil and gas production facilities.[6,7] Data from gas/vapor, light liquid, and/or heavy liquid streams were collected for these studies from non-flanged connectors, flanges, open-ended lines, pumps, values, instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters, and polished rods.

A specific goal of the above studies was to collect high quality data to enhance or replace the previously published refinery correlations. As a result of the analyses discussed in appendix C, the bagging data collected from refineries, marketing terminals, and oil and gas production facilities during the early-1990's were combined to replace the previously published refinery correlations with correlations applicable to the entire petroleum industry. In addition, the new correlations apply across all services for a given equipment type. The previously published refinery correlations were specific to service and equipment.

The screening data were used to develop average emission factors for marketing terminals and for oil and gas production operations. The average emission factors for oil and gas production operations replace the gas plant factors published in previous versions of this document and apply to light crude, heavy crude, gas plant, gas production and off shore facilities. No new screening data were available for refineries, therefore the previously published refinery average emission factors remain unchanged in this version of the protocol. Appendix C contains more detailed information on how the new petroleum industry correlations, marketing terminal emission factors, and oil and gas production operations emission factors were developed.

2.2.2.4 Original SOCMI Average Emission Factors and Correlations. In 1980, two studies were coordinated by the EPA to collect data from SOCMI process units. These studies were the 24-Unit Study,[9] and the Six-Unit Maintenance Study.[10] In the 24-Unit Study, screening data were obtained from equipment containing organic compounds at 24 individual chemical process units representing a cross-section of the SOCMI. In the Six-Unit Maintenance Study, bagging data were collected from six of the process units within the 24-Unit Study to determine the effect of maintenance on equipment leak emissions. Most of the bagging data were collected from equipment with screening values above 1,000 ppmv. As part of the Six-Unit Maintenance Study, correlations were developed for light liquid pumps, gas valves, and light liquid valves.

The original SOCMI average emission factors were first presented in the document "Fugitive Emission Sources of Organic Compounds--Additional Information on Emissions, Emission Reductions, and Costs."[6] This document is referred to as the Fugitive Emissions Additional Information Document (AID). In the Fugitive Emissions AID, the data from the Refinery Assessment Study were further analyzed to develop "leak/no leak" emission factors. (A "leak" was defined as a screening value greater than or equal to 10,000 ppmv.) With the exception of the factor for gas valves, the original SOCMI average emission factors were developed using (1) the leak/no-leak emission factors developed from the Refinery Assessment Study data, and (2) the leak frequencies from the SOCMI 24-Unit Study screening value data set. This approach was based on statistical comparisons that indicated that the most significant characteristic that distinguished equipment in SOCMI facilities from that in refineries was not the leak rate for a given screening value, but rather the fraction of equipment that had screening values greater than or equal to 10,000 ppmv.

Thus, the following equation was used to calculate the original SOCMI average emission factors:

$$\text{SOCMI Average Factor} = (F \times RLF) + (1 - F) \times RNLF$$

where:

F = Fraction of sources from the 24-Unit Study that screened greater than or equal to 10,000 ppmv;

RLF = Refinery leaking emission factor; and

RNLF = Refinery non-leaking emission factor.

For gas valves, the previously collected data suggested that for a given screening value the leak rate at a SOCMI facility was not statistically equivalent to the leak rate at a refinery. Therefore, data from the Six-Unit Maintenance Study were used to develop the gas valve average emission factor.

2.2.2.5 Revised SOCMI Emission Factors and Correlations. In 1987 and 1988, screening data were obtained from 19 ethylene oxide and butadiene producers, and, in 1990, bagging data were collected from 16 of these process units. Screening and bagging data were collected from light liquid pumps, gas valves, light liquid valves, and connectors. A specific goal of the program was to bag equipment that had screening values less than 1,000 ppmv. The bagging data were combined with bagging data previously collected in the Six-Unit Maintenance Study, and this combined bagging data set was used to revise the SOCMI correlations. Likewise, the new screening data were combined with screening data previously collected in the 24-Unit Study, and this combined screening data set was used with the revised correlations to generate new SOCMI emission factors. Appendix B.2 contains more detailed information on how the revised SOCMI correlations and emission factors were developed.

2.3 APPROACHES FOR ESTIMATING EQUIPMENT LEAK EMISSIONS

In this section, each of the approaches for estimating equipment leak emissions are discussed. The description of each approach focuses on the basic method for estimating TOC emissions. Each of the approaches are demonstrated in example calculations contained in appendix A. Special topics at the end of the chapter have been included to address how to estimate VOC emissions when some of the organic compounds in the stream are not classified as VOC’s and also how to speciate emissions for individual chemicals from equipment containing a mixture.

2.3.1 Average Emission Factor Approach

One accepted approach for estimating emissions allows use of average emission factors developed by the EPA in combination with unit-specific data that are relatively simple to obtain. These data include: (1) the number of each type of component in a unit (valve, connector, etc.), (2) the service each component is in (gas, light liquid, or heavy liquid), (3) the TOC concentration of the stream (and VOC or HAP concentrations if speciation is to be performed), and (4) the time period each component was in that service. The average emission factors for SOCMI process units, refineries, marketing terminals, and oil and gas production operations are presented in tables 2-1, 2-2, 2-3, and 2-4 respectively. The SOCMI, marketing terminal, and oil and gas production operations average emission factors predict total organic compound emission rates, whereas the refinery average factors predict non-methane organic compound emission rates. Note that limited data has been collected on the leak rate of agitators, and, until additional data are collected for emissions from agitator seals, the average factor for light liquid pump seals can be used to estimate emissions from agitators.

Although the average emission factors are in units of kilogram per hour per individual source, it is important to note that these factors are most valid for estimating emissions from a population of equipment. The average factors are not intended to be used for estimating emissions from an individual piece of equipment over a short time period (i.e., 1 hour).

To estimate emissions using the Average Emission Factor Approach, the concentration of TOC in weight fraction within the equipment is needed because equipment with higher TOC concentrations tend to have higher TOC leak rates. When using the Average Emission Factor Approach, equipment should be grouped into "streams" where all the equipment within the stream have approximately the same TOC weight fraction.

To apply the average emission factors, use the following equation to estimate TOC mass emissions from all of the equipment in a stream of a given equipment type:

$$E_{TOC} = F_A \times WF_{TOC} \times N$$

where:

E_{TOC} = Emission rate of TOC from all equipment in the stream of a given equipment type (kg/hr);

TABLE 2-1. SOCMI AVERAGE EMISSION FACTORS

Equipment type	Service	Emission factor[a] (kg/hr/source)
Valves	Gas	0.00597
	Light liquid	0.00403
	Heavy liquid	0.00023
Pump seals[b]	Light liquid	0.0199
	Heavy liquid	0.00862
Compressor seals	Gas	0.228
Pressure relief valves	Gas	0.104
Connectors	All	0.00183
Open-ended lines	All	0.0017
Sampling connections	All	0.0150

[a] These factors are for total organic compound emission rates.

[b] The light liquid pump seal factor can be used to estimate the leak rate from agitator seals.

TABLE 2-2. REFINERY AVERAGE EMISSION FACTORS[a]

Equipment type	Service	Emission factor (kg/hr/source)[b]
Valves	Gas	0.0268
	Light liquid	0.0109
	Heavy liquid	0.00023
Pump seals[c]	Light liquid	0.114
	Heavy liquid	0.021
Compressor seals	Gas	0.636
Pressure relief valves	Gas	0.16
Connectors	All	0.00025
Open-ended lines	All	0.0023
Sampling connections	All	0.0150

[a] Source: Reference 2.

[b] These factors are for non-methane organic compound emission rates.

[c] The light liquid pump seal factor can be used to estimate the leak rate from agitator seals.

TABLE 2-3. MARKETING TERMINAL AVERAGE EMISSION FACTORS

Equipment type	Service	Emission factor (kg/hr/source)[a]
Valves	Gas	1.3E-05
	Light Liquid	4.3E-05
Pump seals	Gas	6.5E-05
	Light Liquid	5.4E-04
Others (compressors and others)[b]	Gas	1.2E-04
	Light Liquid	1.3E-04
Fittings (connectors and flanges)[c]	Gas	4.2E-05
	Light Liquid	8.0E-06

[a] These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane).

[b] The "other" equipment type should be applied for any equipment type other than fittings, pumps, or valves.

[c] "Fittings" were not identified as flanges or non-flanged connectors; therefore, the fitting emissions were estimated by averaging the estimates from the connector and the flange correlation equations.

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

[a] Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

[b] These factors are for total organic compound emission rates (including non-VOC’s such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and off shore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.

[c] The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

F_A = Applicable average emission factor for the equipment type (kg/hr/source);

FOR REFINERIES ONLY: The emission factor "F_A" must be adjusted to account for all organic compounds in the stream because the refinery factors are only valid for non-methane organic compounds (percents up to a maximum of 10 percent by weight methane are permitted):

$$F_A = F_A \times \frac{WF_{TOC}}{WF_{TOC} - WF_{methane}} ;$$

WF_{TOC} = Average weight fraction of TOC in the stream;

$WF_{methane}$ = Average weight fraction of methane in the stream; and

N = Number of pieces of equipment of the applicable equipment type in the stream.

Note that the emission factor "F_A" is defined differently for refineries than for SOCMI, marketing terminals, or oil and gas production operations when calculating TOC mass emissions. It is necessary to adjust the "F_A" term when applied to refineries, because when the refinery factors were developed, the methane was subtracted out of the organic total. Adjusting the "F_A" term for refineries is a way to correct for this. Two guidelines when correcting the "F_A" term when applied to refineries are as follows:

- The correction should only be applied to equipment containing a mixture of organics and methane; and
- The maximum correction for the methane weight fraction should not exceed 0.10, even if the equipment contains greater than 10 weight percent methane. (This reflects that equipment in the Refinery Assessment Study[1,2] typically contained 10 weight percent or less methane).

Thus, at a SOCMI process unit, if there were 100 gas valves in a stream containing, on average, 90 weight percent TOC and 10 weight percent water vapor, emissions would be calculated as follows:

$$E_{TOC} = F_A \times WF_{TOC} \times N$$

= 0.00597 kg/hr/gas valve × 0.9 × 100 gas valves

= 0.54 kg/hr of VOC from gas valves in the stream

At a refinery, if there were 100 gas valves in a stream that, on average, contained 80 weight percent non-methane TOC, 10 weight percent water vapor, and 10 weight percent methane (thus, the TOC weight percent would be 90), emissions would be calculated using the above equation as follows:

$$E_{TOC} = F_A \times \frac{WF_{TOC}}{WF_{TOC} - WF_{methane}} \times WF_{TOC} \times N$$

= 0.0268 kg/hr/gas valve × (0.9/0.9-0.1) × 0.9 × 100 gas valves

= 2.71 kg/hr of VOC from gas valves in the stream

If there are several streams at a process unit, the total TOC emission rate for an equipment type is the sum of emissions from each of the streams. The total emission rates for all of the equipment types are summed to generate the process unit total TOC emission rate from leaking equipment.

Assuming all of the organic compounds in the stream are classified as VOC’s, the total VOC emission for each stream is calculated as the sum of TOC emissions associated with each specific equipment type in the stream. Section 2.4.6 discusses an adjustment that can be made to predict the VOC emission rate if some of the organic compounds in the stream are not classified as VOC’s (such as methane and ethane).

As mentioned earlier, the average emission factors are not intended to provide an accurate estimate of the emission rate from a single piece of equipment. Rather, the average factors are more appropriately applied to the estimation of emissions from populations of equipment. Data indicate that the range of possible leak rates from individual pieces of equipment spans several orders of magnitude. As a result, the majority of total emissions from a population of equipment at any given time will normally occur from a small percentage of the total equipment. The average emission factors account for the span of possible leak rates, but, as a result, they are not necessarily an accurate indication of the mass emission rate from an individual piece of equipment.

Furthermore, the average emission factors do not reflect different site-specific conditions among process units within a source category. Site-specific factors can have considerable influence on leak rates from equipment. Nevertheless, in the absence of screening data, the average emission factors do provide an indication of equipment leak emission rates from equipment in a process unit.

2.3.2 Screening Ranges Approach

The Screening Ranges Approach (formerly known as the leak/no-leak approach) offers some refinement over the Average Emission Factor Approach, thereby allowing some adjustment for individual unit conditions and operation. This approach is included in this section primarily to aid in the analysis of old datasets which were collected for older regulations that used 10,000 ppmv as the leak definition. This approach and the other two remaining approaches require that screening data be collected for the equipment in the process unit. The screening data are an indication of leak rates. When applying this approach, it is assumed that components having screening values greater than 10,000 ppmv have a different average emission rate than components with screening values less than 10,000 ppmv.

This approach may be applied when screening data are available as either "greater than or equal to 10,000 ppmv" or as "less than 10,000 ppmv." Emission factors for SOCMI, refineries, marketing terminals, and oil and gas production operations for these two ranges of screening values are presented in tables 2-5, 2-6, and 2-7, and 2-8, respectively. As with the average factors, the SOCMI, marketing terminal, and oil and gas production operations screening range factors predict total

TABLE 2-5. SOCMI SCREENING RANGES EMISSION FACTORS

Equipment type	Service	≥10,000 ppmv Emission factor (kg/hr/source)[a]	<10,000 ppmv Emission factor (kg/hr/source)[a]
Valves	Gas	0.0782	0.000131
	Light liquid	0.0892	0.000165
	Heavy liquid	0.00023	0.00023
Pump seals[b]	Light liquid	0.243	0.00187
	Heavy liquid	0.216	0.00210
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

[a] These factors are for total organic compound emission rates.

[b] The light liquid pump seal factors can be applied to estimate the leak rate from agitator seals.

TABLE 2-6. REFINERY SCREENING RANGES EMISSION FACTORS[a]

Equipment type	Service	≥10,000 ppmv Emission factor (kg/hr/source)[b]	<10,000 ppmv Emission factor (kg/hr/source)[b]
Valves	Gas	0.2626	0.0006
	Light liquid	0.0852	0.0017
	Heavy liquid	0.00023	0.00023
Pump seals[c]	Light liquid	0.437	0.0120
	Heavy liquid	0.3885	0.0135
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.0375	0.00006
Open-ended lines	All	0.01195	0.00150

[a] Source: Reference 6.

[b] These factors are for non-methane organic compound emission rates.

[c] The light liquid pump seal factors can be applied to estimate the leak rate from agitator seals.

TABLE 2-7. MARKETING TERMINAL SCREENING RANGES EMISSION FACTORS

Equipment type	Service	≥10,000 ppmv Emission factor (kg/hr/source)[a]	<10,000 ppmv Emission factor (kg/hr/source)[a]
Valves	Gas	NA	1.3E-05
	Light Liquid	2.3E-02	1.5E-05
Pump seals	Light liquid	7.7E-02	2.4E-04
Other (compressors and others)[b]	Gas	NA	1.2E-04
	Light liquid	3.4E-02	2.4E-05
Fittings (connectors and flanges)[c]	Gas	3.4E-02	5.9E-06
	Light liquid	6.5E-03	7.2E-06

[a] These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane). "NA" indicates that not enough data were available to develop the indicated emission factor.

[b] The "other" equipment type should be applied for any equipment type other than fittings, pumps, or valves.

[c] "Fittings" were not identified as flanges or connectors; therefore, the fitting emissions were estimated by averaging the estimates from the connector and the flange correlation equations.

TABLE 2-8. OIL AND GAS PRODUCTION OPERATIONS SCREENING RANGES EMISSION FACTORS

Equipment type	Service[b]	≥10,000 ppmv Emission factor (kg/hr/source)[a]	<10,000 ppmv Emission factor (kg/hr/source)[a]
Valves	Gas	9.8E-02	2.5E-05
	Heavy Oil	NA	8.4E-06
	Light Oil	8.7E-02	1.9E-05
	Water/Oil	6.4E-02	9.7E-06
Pump seals	Gas	7.4E-02	3.5E-04
	Heavy Oil	NA	NA
	Light Oil	1.0E-01	5.1E-04
	Water/Oil	NA	2.4E-05
Others[c]	Gas	8.9E-02	1.2E-04
	Heavy Oil	NA	3.2E-05
	Light Oil	8.3E-02	1.1E-04
	Water/Oil	6.9E-02	5.9E-05
Connectors	Gas	2.6E-02	1.0E-05
	Heavy Oil	NA	7.5E-06
	Light Oil	2.6E-02	9.7E-06
	Water/Oil	2.8E-02	1.0E-05
Flanges	Gas	8.2E-02	5.7E-06
	Heavy Oil	NA	3.9E-07
	Light Oil	7.3E-02	2.4E-06
	Water/Oil	NA	2.9E-06
Open-ended lines	Gas	5.5E-02	1.5E-05
	Heavy Oil	3.0E-02	7.2E-06
	Light Oil	4.4E-02	1.4E-05
	Water/Oil	3.0E-02	3.5E-06

[a] These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and offshore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.

[b] Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

[c] The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

organic compound emissions, whereas the refinery screening range factors predict non-methane organic compound emissions. Note that there are not screening range factors for sampling connections because emissions from sampling connections occur when the line is purged, and, thus, are independent of any screening value. Also, as with the average factors, the screening range factors for light liquid pumps can be applied to agitators.

The Screening Ranges Approach is applied in a similar manner as the Average Emission Factor Approach in that equipment counts are multiplied by the applicable emission factor. Also, for refineries, the screening range emission factors must be adjusted for methane in the equipment because when the refinery factors were developed, the methane was subtracted out of the organic total.

To calculate TOC emissions using the Screening Ranges Approach, the following equation is used:

$$E_{TOC} = (F_G \times N_G) + (F_L \times N_L)$$

where:

E_{TOC} = TOC emission rate for an equipment type (kg/hr);

F_G = Applicable emission factor for sources with screening values greater than or equal to 10,000 ppmv (kg/hr/source);

FOR REFINERIES ONLY: The emission factor "F_G" must be adjusted to account for all organic compounds in the stream because the refinery factors are only valid for non-methane organic compounds (percents up to a maximum of 10 percent by weight methane are permitted):

$$F_G = F_G \times \frac{WP_{TOC}}{WP_{TOC} - WP_{methane}};$$

WP_{TOC} = Average weight percent of TOC in the stream;

$WP_{methane}$ = Average weight percent of methane in the stream;

N_G = Equipment count (specific equipment type) for sources with screening values greater than or equal to 10,000 ppmv;

F_L = Applicable emission factor for sources with screening values less than 10,000 ppmv (kg/hr/source)

FOR REFINERIES ONLY: The emission factor "F_L" must be adjusted to account for all organic compounds in the stream because the refinery factors are only valid for non-methane organic compounds (percents up to a maximum of 10 percent by weight methane are permitted):

$$F_L = F_L \times \frac{WP_{TOC}}{WP_{TOC} - WP_{methane}} \text{; and}$$

N_L = Equipment count (specific equipment type) for sources with screening values less than 10,000 ppmv.

Assuming all of the organic compounds in the stream are classified as VOC's, the total VOC emission for each stream is calculated as the sum of TOC emissions associated with each specific equipment type in the stream. Section 2.4.6 discusses an adjustment that can be made to predict the VOC emission rate if some of the organic compounds in the stream are not classified as VOC's (such as methane and ethane).

The screening range emission factors are a better indication of the actual leak rate from individual equipment than the average emission factors. Nevertheless, available data indicate that measured mass emission rates can vary considerably from the rates predicted by use of these factors.

2.3.3 EPA Correlation Approach

This approach offers an additional refinement to estimating emissions from equipment leaks by providing an equation to predict mass emission rate as a function of screening value for a particular equipment type. Correlations developed by the EPA relating screening values to mass emission rates for SOCMI process units and for petroleum industry process units are presented in tables 2-9 and 2-10, respectively. Correlations for the petroleum industry apply to refineries, marketing terminals and oil and gas production operations. Figures 2-2 through 2-5 plot the correlations. Both the SOCMI and petroleum industry correlations predict total organic compound emission rates. Appendix B.1 contains additional information on the general development of correlation equations. Additionally, appendix B.2 contains information about the development of the SOCMI correlations and appendix C contains information about the development of the petroleum industry correlations.

The EPA Correlation Approach is preferred when actual screening values are available. Correlations can be used to estimate emissions for the entire range of non-zero screening values, from the highest potential screening value to the screening value that represents the minimum detection limit of the monitoring device. This approach involves entering the non-zero, non-pegged screening value into the correlation equation, which predicts the TOC mass emission rate based on the screening value. Default zero emission rates are used for screening values of zero ppmv and pegged emission rates are used for "pegged" screening values (the screening value is beyond the upper limit measured by the portable screening device).

Correlations for SOCMI are available for (1) gas valves; (2) light liquid valves; (3) connectors; and (4) light liquid pump seals. Correlations for the petroleum industry are available for (1) valves; (2) connectors; (3) pumps; (4) flanges; (5) open-ended lines; and (6) "others" (derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents).

Limited bagging data for compressors and pressure relief devices have been obtained at SOCMI plants. However, because statistical tests performed as part of the Refinery Assessment Study[2] indicated that emissions from light liquid pumps, compressors, and pressure relief valves could be expressed with a single correlation, until additional data are collected, the SOCMI equation for light liquid pump seals can be applied to

TABLE 2-9. SOCMI LEAK RATE/SCREENING VALUE CORRELATIONS

Equipment type	Correlation[a,b]
Gas valves	Leak rate (kg/hr) = 1.87E-06 × $(SV)^{0.873}$
Light liquid valves	Leak rate (kg/hr) = 6.41E-06 × $(SV)^{0.797}$
Light liquid pumps[c]	Leak rate (kg/hr) = 1.90E-05 × $(SV)^{0.824}$
Connectors	Leak rate (kg/hr) = 3.05E-06 × $(SV)^{0.885}$

[a] SV = Screening value in ppmv.

[b] These correlations predict total organic compound emission rates.

[c] The correlation for light liquid pumps can be applied to compressor seals, pressure relief valves, agitator seals, and heavy liquid pumps.

TABLE 2-10. PETROLEUM INDUSTRY LEAK RATE/SCREENING VALUE CORRELATIONS[a]

Equipment type/service	Correlation[b,c]
Valves/all	Leak rate (kg/hr) = 2.29E-06 × $(SV)^{0.746}$
Pump seals/all	Leak rate (kg/hr) = 5.03E-05 × $(SV)^{0.610}$
Others[d]	Leak rate (kg/hr) = 1.36E-05 × $(SV)^{0.589}$
Connectors/all	Leak rate (kg/hr) = 1.53E-06 × $(SV)^{0.735}$
Flanges/all	Leak rate (kg/hr) = 4.61E-06 × $(SV)^{0.703}$
Open-ended lines/all	Leak rate (kg/hr) = 2.20E-06 × $(SV)^{0.704}$

[a] The correlations presented in this table are revised petroleum industry correlations.

[b] SV = Screening value in ppmv.

[c] These correlations predict total organic compound emission rates (including non-VOC’s such as methane and ethane).

[d] The "other" equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

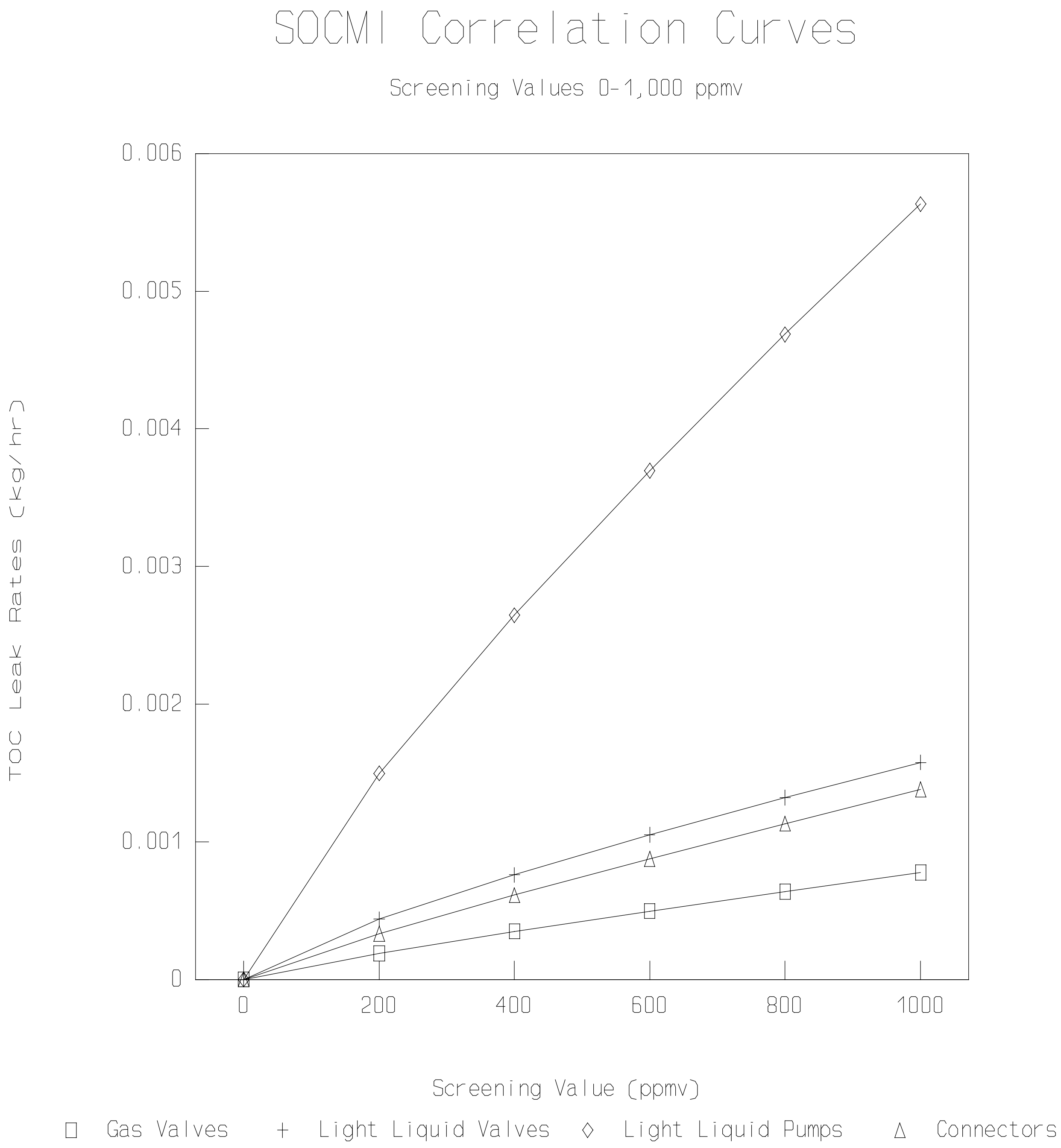

Figure 2-2. SOCMI Correlations relating total organic compound (TOC) leak rate to screening value: 0 - 1,000 ppmv

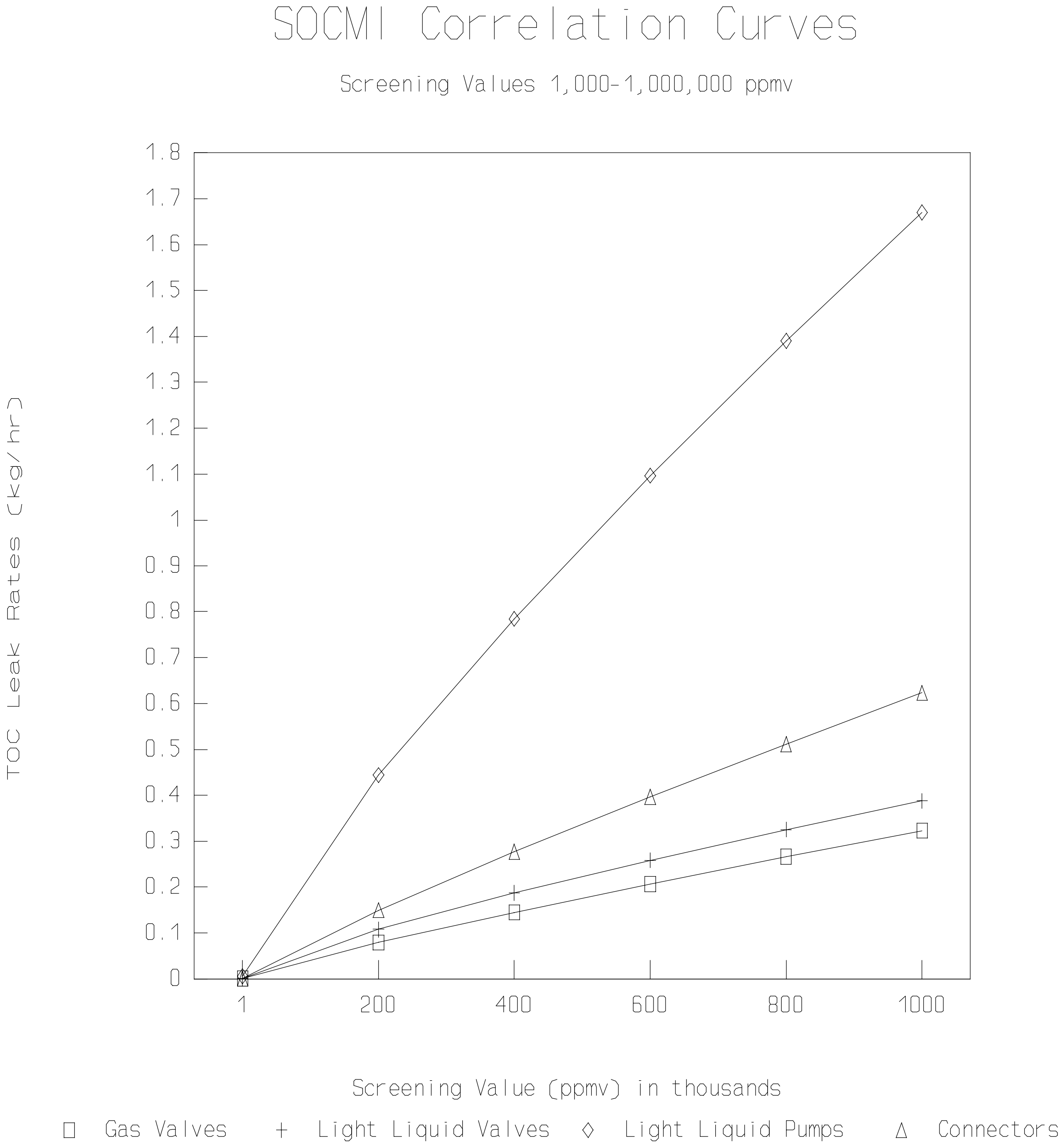

Figure 2-3. SOCMI Correlations relating total organic compound (TOC) leak rate to screening value: 1,000 - 1,000,000 ppmv

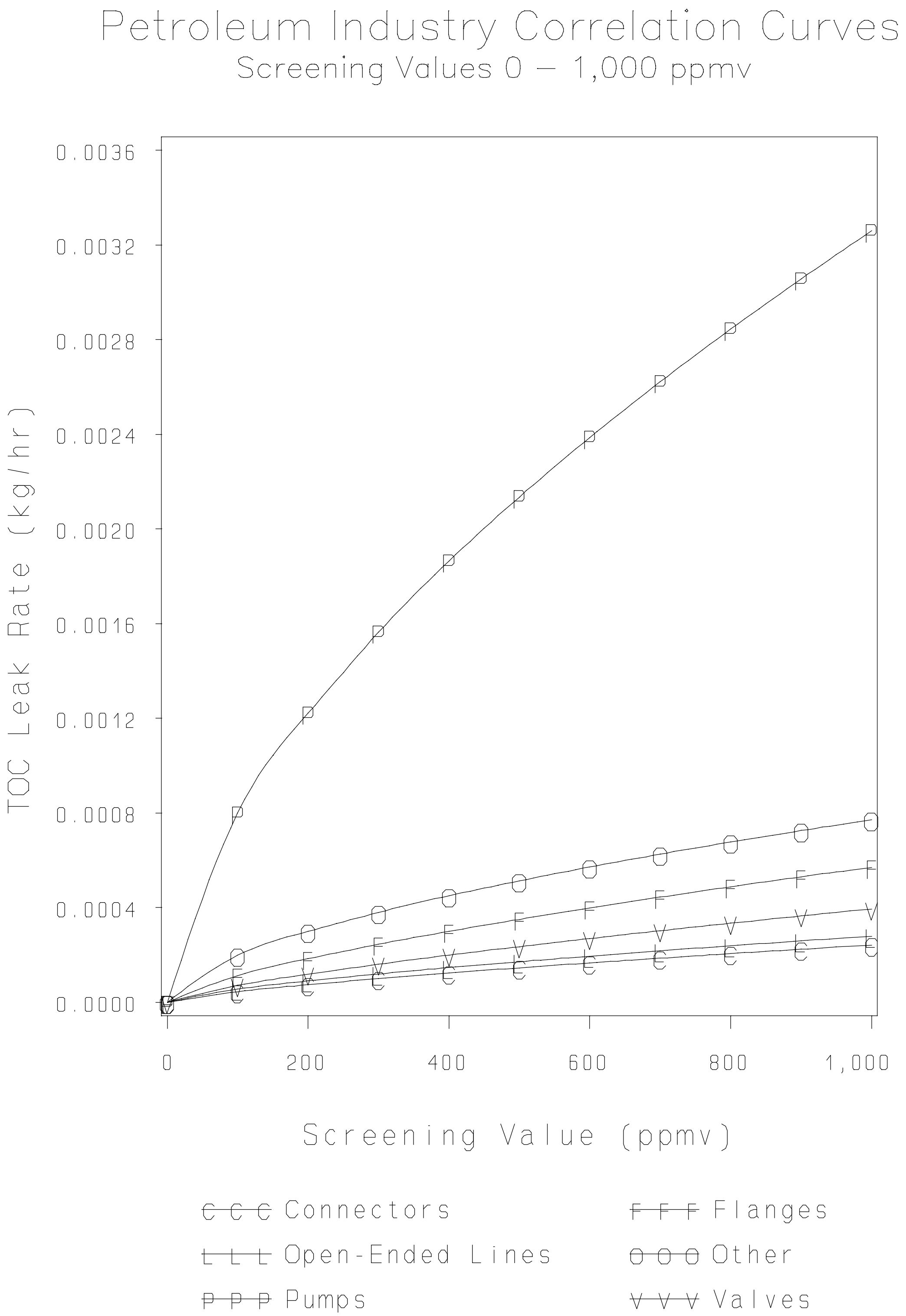

Figure 2-4. Petroleum Industry Correlations relating total organic compound (TOC) leak rate to screening value: 1,000 - 1,000,000 ppmv

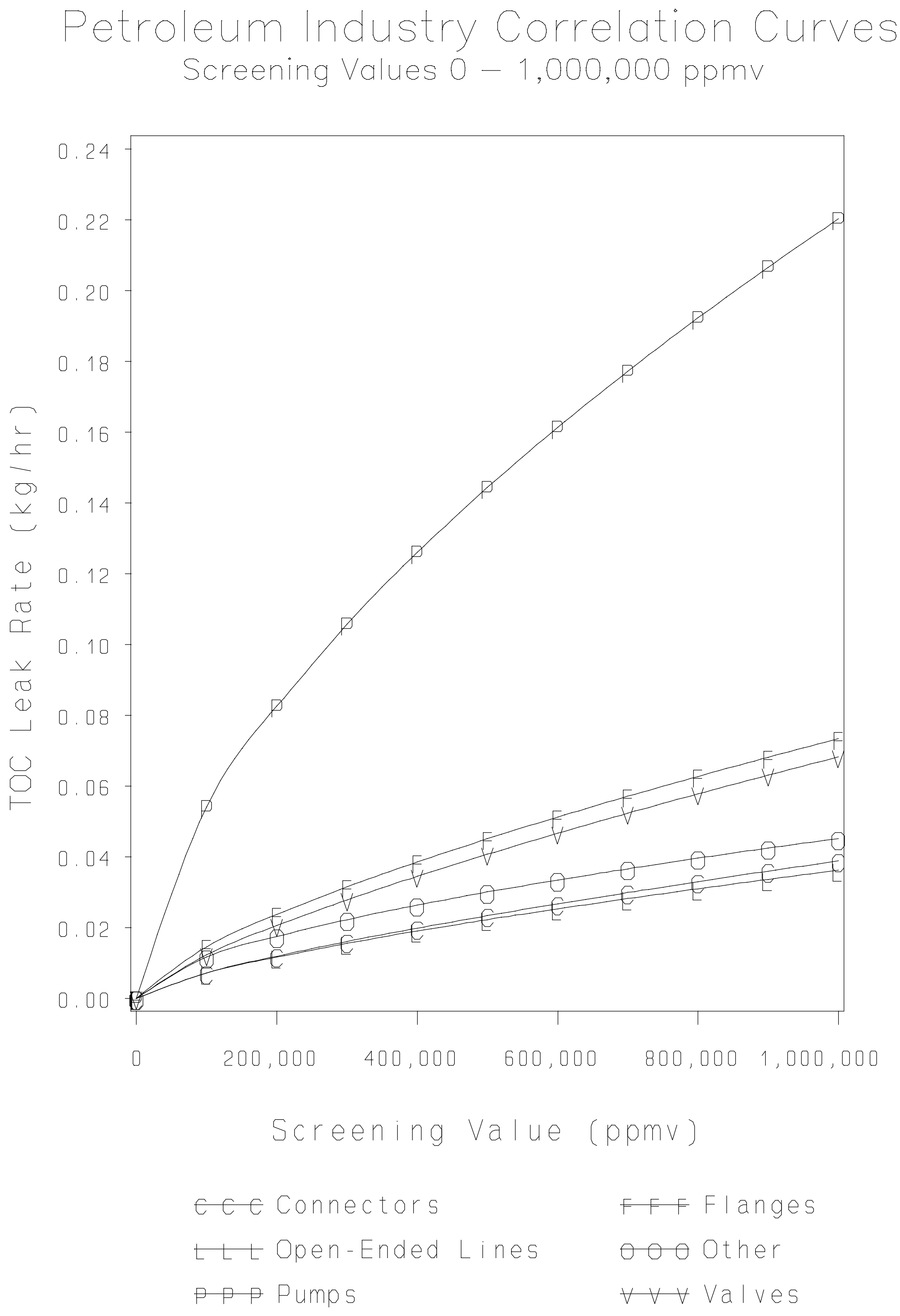

Figure 2-5. Petroleum Industry Correlations relating total organic compound (TOC)leak rate to screening value: 1,000 - 1,000,000 ppmv

estimate emissions for compressor seals and pressure relief valves in SOCMI process units. Because bagging data were limited and the frequency of occurrence of some equipment types was small, a correlation for an "other" equipment type was developed for the petroleum industry correlations to apply to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Bagging data for agitator seals at petroleum industry and SOCMI process units are unavailable at this time. Compared to those equipment types that have correlations, agitators most closely resemble light liquid pumps, and, for this reason, the applicable light liquid pump correlation can be used to estimate agitator emissions. Similarly, the SOCMI light liquid pump correlation can be used to estimate emissions from SOCMI heavy liquid pumps.

The "default-zero" leak rate is the mass emission rate associated with a screening value of zero. (Note that any screening value that is less than or equal to ambient [background] concentration is considered a screening value of zero.) The correlations mathematically predict zero emissions for zero screening values. However, data collected by the EPA show this prediction to be incorrect. Mass emissions have been measured from equipment having a screening value of zero.
A specific goal when revising the SOCMI and petroleum industry correlations was to collect mass emissions data from equipment that had a screening value of zero. These data were used to determine a default-zero leak rate associated with equipment with zero screening values.

Table 2-11 lists the SOCMI default-zero leak rates and table 2-12 presents the petroleum industry default-zero leak rates for each of the equipment types with correlation equations. These default-zero leak rates are applicable only when the minimum detection limit of the portable monitoring instrument is 1 ppmv or less above background.

The portable monitoring device used to collect the default-zero data was sufficiently sensitive to indicate a

TABLE 2-11. DEFAULT-ZERO VALUES: SOCMI PROCESS UNITS

Equipment type	Default-zero emission rate (kg/hr/source)[a]
Gas valve	6.6E-07
Light liquid valve	4.9E-07
Light liquid pump[b]	7.5E-06
Connectors	6.1E-07

[a] The default zero emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

[b] The light liquid pump default zero value can be applied to compressors, pressure relief valves, agitators, and heavy liquid pumps.

TABLE 2-12. DEFAULT-ZERO VALUES: PETROLEUM INDUSTRY

Equipment type/service	Default-zero emission rates[a,b] (kg/hr/source)
Valves/all	7.8E-06
Pump seals/all	2.4E-05
Others[c]/all	4.0E-06
Connectors/all	7.5E-06
Flanges/all	3.1E-07
Open-ended lines/all	2.0E-06

[a] Default zero emission rates were based on the combined 1993 refinery and marketing terminal data only (default zero data were not collected from oil and gas production facilities).

[b] These default zero emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

[c] The "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

screening value of 1 ppmv or less. In cases where a monitoring instrument has a minimum detection limit greater than 1 ppmv, the default-zero leak rates presented in tables 2-11 and 2-12 are not applicable. For these cases, an alternative approach for determining a default-zero leak rate is to (1) determine one-half the minimum screening value of the monitoring instrument, and (2) enter this screening value into the applicable correlation to determine the associated default-zero leak rate.

The "pegged" emission rate is the mass emission rate associated with a screening value that has "pegged" the meter on the portable screening device (i.e. the screening value is beyond the upper limit measured by the portable screening device). In the case of a screening value pegged at 10,000 ppmv, a dilution probe should be used to extend the upper limit of the portable screening device to 100,000 ppmv. Thus, screening values can be reported up to 100,000 ppmv before pegging the instrument and the correlation equation can be used to estimate the mass emissions. However, in the case of previously-collected data or in the absence of a dilution probe, pegged readings of 10,000 ppmv are sometimes reported. In such cases, the 10,000 ppmv pegged emission rates can be used to estimate the mass emissions.

Table 2-13 presents the 10,000 ppmv and 100,000 ppmv pegged emission rates for SOCMI process units and table 2-14 presents the 10,000 ppmv and 100,000 ppmv pegged emission rates for petroleum industry process units. These pegged emission rates are to be used to estimate emissions when instrument readings are pegged and a dilution probe is not used.

Assuming all of the organic compounds in the equipment are classified as VOC's, total VOC emissions for each equipment type are calculated as the sum of emissions associated with each of the screening values. Section 2.4.6 discusses a correction that can be made to the predicted VOC emissions rate if some of the organic compounds in the equipment are not classified as VOC's (such as methane and ethane).

To summarize the correlation approach, each equipment piece with a screening value of zero is assigned the default-zero leak

TABLE 2-13. 10,000 PPMV AND 100,000 PPMV SCREENING VALUE PEGGED EMISSION RATES FOR SOCMI PROCESS UNITS

Equipment type	10,000 ppmv pegged emission rate (kg/hr/source)[a,b]	100,000 ppmv pegged emission rate (kg/hr/source)[a]
Gas valves	0.024	0.11
Light liquid valves	0.036	0.15
Light liquid pump seals[b]	0.14	0.62
Connectors	0.044	0.22

[a] The SOCMI pegged emission rates are for total organic compounds.

[b] The 10,000 ppmv pegged emission rate applies only when a dilution probe cannot be used or in the case of previously-collected data that contained screening values reported pegged at 10,000 ppmv.

[c] The light liquid pump seal pegged emission rates can be applied to compressors, pressure relief valves, and agitators.

TABLE 2-14. 10,000 ppmv and 100,000 PPMV SCREENING VALUE PEGGED EMISSION RATES FOR THE PETROLEUM INDUSTRY

Equipment type/service	10,000 ppmv pegged emission rate (kg/hr/source)[a,b]	100,000 ppmv pegged emission rate (kg/hr/source)[a]
Valves/all	0.064	0.140
Pump seals/all	0.074	0.160[c]
Others[d]/all	0.073	0.110
Connectors/all	0.028	0.030
Flanges/all	0.085	0.084
Open-ended lines/all	0.030	0.079

[a] The petroleum industry pegged emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

[b] The 10,000 ppmv pegged emission rate applies only when a dilution probe cannot be used or in the case of previously-collected data that contained screening values reported pegged at 10,000 ppmv. The 10,000 ppmv pegged emission rate was based on components screened at greater than or equal to 10,000 ppmv; however, in some cases, most of the data could have come from components screened at greater than 100,000 ppmv, thereby resulting in similar pegged emission rates for both the 10,000 and 100,000 pegged levels (e.g., connector and flanges).

[c] Only 2 data points were available for the pump seal 100,000 pegged emission rate; therefore the ratio of the pump seal 10,000 pegged emission rate to the overall 10,000 ppmv pegged emission rate was multiplied by the overall 10,000 ppmv pegged emission rate to approximate the pump 100,000 ppmv pegged emission rate.

[d] The "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters, and polished rods. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, and valves.

rate. For all equipment with a non-zero screening value, the screening value associated with each individual equipment piece is entered into the applicable correlation to predict emissions. *It should be noted that each individual screening value must be entered into the correlation to predict emissions for an equipment piece. Do not average screening values and then enter the average value into the correlation to estimate emissions.* Finally, each equipment piece with a screening value reported as pegged is assigned the appropriate pegged emission rate.

2.3.4 Unit-Specific Correlation Approach

To develop unit-specific correlations screening value and corresponding mass emissions data (i.e., bagging data) must be collected from process unit equipment. (See chapter 4.0 for a detailed discussion on the procedures for bagging equipment.) The equipment selected for bagging should be screened at the time of bagging. The mass emissions rate determined by bagging, and the associated screening value, can then be used to develop a leak rate/screening value relationship (i.e., correlation) for that specific equipment type in that process unit. The correlations must be developed on a process unit basis to minimize the error associated with differing leak rate characteristics between units.

If a unit-specific correlation is developed, as long as the procedures for bagging discussed in chapter 4.0 are followed, it is not necessary to demonstrate that the correlation is statistically different from the EPA correlation for it to be applied. However, before developing unit-specific correlations, it may be desirable to evaluate the validity of the EPA correlations to a particular process unit. As few as four leak rate measurements of a particular equipment type in a particular service can be adequate for this purpose. The measured emission rates can be compared with the rates that would be predicted by the EPA correlations to evaluate whether or not the EPA correlations provide reasonable mass emission estimates. A simple method of comparison is to determine if measured emission rates are consistently less than or greater than what would be predicted by the EPA correlation. If there is a consistent trend, such as all of the measured leak rates being lower than the rate predicted by the EPA correlation, the EPA correlation may not provide reasonable emission estimates for the process unit.

A more formal comparison is the Wilcoxon signed-rank test. This test can be performed by comparing the logarithm of the measured mass emission rates to the logarithm of the corresponding rates predicted by the EPA correlation. The absolute magnitude of the differences are then ranked (e.g., the pair with the smallest difference is assigned a rank of 1, the pair with the next smallest difference a rank of 2, etc.), and the sum of the ranks associated with positive differences is computed. For example, if four bags were measured and they each predicted higher mass emission rates than the EPA correlation, the value of the sum of the ranks associated with those pairs with positive differences would equal:

$$1 + 2 + 3 + 4 = 10$$

On the other hand, if four bags were measured and three predicted higher mass emission rates than the EPA correlation, but the one with the greatest absolute difference predicted a lower rate than the EPA correlation, then the sum of the positive ranks would equal:

> $1 + 2 + 3 = 6$. *(Note: The sum of the negative ranks would equal 4).*

The value of the sum of the positive ranks can be compared to given values on statistical tables to evaluate if there are statistically significant differences between the measured rates and the rates predicted by the EPA correlation.

However the comparison is performed, in cases where the EPA correlations provide an adequate estimate of emissions, then the potential increase in accuracy obtained by developing unit-specific correlations may not be worth the effort. Consideration should also be given to the typical screening value measured at a process unit. If a process unit normally has very low screening values, then the difference between the sum of unit equipment leak emissions predicted by a unit-specific correlation and the EPA correlation will likely be relatively small.

In developing new correlations, a minimum number of leak rate measurements and screening value pairs must be obtained according to the following methodology. First, equipment at the process unit is screened so that the distribution of screening values at the unit is known. Then, mass emissions data must be collected from individual sources that have screening values distributed over the entire range. The criteria for choosing these sources is as follows. For each equipment type (i.e., valves, pumps, etc.) and service (i.e., gas, light liquid, etc.), a random sample of a minimum of six components should be chosen for bagging from each of the following screening value ranges:

Screening Value Range (ppmv)
1 - 100
101 - 1,000
1,001 - 10,000
10,001 - 100,000
> 100,000

The requirement of six bags per screening value range is based on the EPA experience with bagging components. There are two primary reasons for the above requirement: (1) to be confident in the representativeness of the data, and (2) to accurately reflect the range of possible mass emission rates associated with a given screening value. The importance of the first reason is self-evident: The more data collected the better the representativeness. The importance of the second reason is that a given screening value does not necessarily have a "true" emissions rate. For a single screening value, the mass emissions may range over several orders of magnitude depending upon several factors, including the equipment type (i.e., gate valve versus ball valve versus plug valve, etc.) and operating parameters (i.e., chemical handled, temperature, pressure, etc.). This range of possible mass emission rates is accounted for when the correlation is developed (see discussion on the scale bias correction factor), and it is important to obtain enough data to accurately reflect the range. If six sources are not available in a particular screening value range, additional sources from the nearest range should be tested so that a minimum of 30 emission rate/screening value pairs are obtained for each source type. If 30 or more bags are collected, the process unit-specific correlation can be used to estimate emissions across the entire range of screening values (1 to 1,000,000 ppmv).

In some cases, it may be desirable to develop a correlation with fewer than 30 bags. This can be accomplished by developing a correlation that is not valid across the entire range of screening values. Two alternatives are available: (1) to develop a correlation valid for screening values ranging from 1 to 100,000 ppmv, or (2) to develop a correlation valid for screening values ranging from 1 to 10,000 ppmv. These alternatives may be preferable for process units with equipment that do not normally have high screening values. An example of this type of process unit is one that already has a leak detection and repair program in place to prevent the release of odor-causing chemicals. At this type of process unit, leaks may be quickly detected and repaired.

For the first alternative, a minimum of 24 bags are required, rather than 30, because sources with screening values greater than 100,000 ppmv do not need to be bagged. Thus, a minimum of six sources each should be chosen for bagging from each of the screening ranges presented above except for the greater than 100,000 ppmv range. In the event that a source screens at 100,000 ppmv or greater, emissions can be estimated using "pegged" emission rates shown in table 2-13 for SOCMI process units, and in table 2-14 for petroleum industry process units.

For the second alternative, a minimum of 18 bags are required, because sources screening greater than 10,000 ppmv do not need to be bagged. Thus, a minimum of six sources should be chosen for bagging from the 1 to 100 ppmv range, the 100 to 1000 ppmv range, and the 1,000 to 10,000 ppmv range. In the event that a source screens at 10,000 ppmv or greater, emissions can be estimated using the applicable greater than or equal to 10,000 ppmv pegged emission rate presented in table 2-13 for SOCMI process units, or table 2-14 for petroleum industry process units. An advantage of using the greater than or equal to 10,000 ppmv pegged emission rates is that several of the available portable monitoring instruments have a maximum readout of 10,000 ppmv, and to obtain a screening value from a source screening at 10,000 ppmv, it is necessary to install a dilution probe. However, if the greater than or equal to 10,000 ppmv factor is used, installing a dilution probe is not necessary for this alternative.

The above groupings and recommended number of sources are given as guidelines. They are based on experience in measuring leak rates and developing leak rate/screening value correlations. Other source selection strategies can be used if an appropriate rationale is given.

With mass emissions data and screening values, leak rate/screening value correlations can be generated using the following methodology. Least-squares regression analyses are completed for each equipment type/service, regressing the log of the leak rate on the log of the screening concentration, according to:

$$\text{Log}_{10}\ (\text{leak rate [in kg/hr]}) = \beta_0 + \beta_1 \times \text{Log}_{10}\ (\text{SV})$$

where:

β_0, β_1 = Regression constants; and

SV = Screening value.

Note that the results are the same whether the base 10 or natural logarithm are used (see appendix B). The equations presented here are written assuming the base 10 logarithm is used. All analyses should be conducted using logarithms of both the leak rate and screening value because this type of data has been shown to be log-normally distributed. A scale bias correction factor (SBCF) is required in transforming the equation in the log-scale back to the original units. The transformed equation is the unit-specific correlation, and is expressed as:

$$\text{Leak rate} = \text{SBCF} \times 10^{\beta_0} \times \text{SV}^{\beta_1}$$

where:

Leak rate = Emission rate of TOC’s from the individual equipment piece (kg/hr);

SBCF = Scale bias correction factor;

β_0, β_1 = Regression constants; and

SV = Screening value.

The SBCF is a function of the mean square error of the correlation in log space. The greater the range of possible emission rates for a given screening value, the greater the SBCF will be. The purpose of the SBCF is to reflect this range when transforming the correlation out of log space. When regressed in log space, in general, approximately half of the data points will lie above the correlation line and half will lie below it, and, for a given screening value, the correlation will pass through the mean log leak rate (i.e., the geometric mean). Thus, one way of thinking of the correlation in log space is that it predicts the geometric mean emissions rate across the range of screening values. However, the geometric mean always underestimates the arithmetic mean.

A simplified hypothetical example will help demonstrate this point: For a screening value of 500,000 ppmv, three bagging data points were obtained with mass emission rates of 0.1 kg/hr, 1 kg/hr, and 10 kg/hr. In log space, these emission rates correspond to $\log_{10}(0.1) = -1$, $\log_{10}(1) = 0$, and $\log_{10}(10) = 1$, respectively. Thus, the geometric mean of these three points is $(-1 + 0 + 1)/3 = 0$. Directly transforming this geometric mean to normal space predicts an emission rate for a screening value of 500,000 ppmv of $10^0 = 1$ kg/hr, whereas the arithmetic mean of the emission rates is $(0.1 + 1 + 10)/3 = 3.7$ kg/hr. From this example, it can be seen that the geometric mean underestimates the arithmetic mean.

Thus, if the correlation was directly transformed, it would underestimate the true average emission rate associated with a given screening value, and, for this reason, the SBCF is necessary to transform the correlation out of log space.

In appendix B, additional details on developing a process-unit specific correlation are presented. Appendix B also contains information on development of the revised SOCMI correlations.

2.4 SPECIAL TOPICS

There are several special topics relevant to estimating equipment leak emissions that are not specific to any one of the four approaches that have been described. These special topics are discussed in this section:

- Speciating emissions;
- Using response factors;
- Monitoring instrument type and calibration gas;
- Estimating emissions for equipment not screened (when other screening data are available);
- Using screening data collected at several different times;
- Estimating VOC emission rates from equipment containing organic compounds not classified as VOC's (such as methane and ethane); and
- Estimating equipment leak emissions of inorganic compounds.

Each of these topics above are addressed in the following sections.

2.4.1 Speciating Emissions

For each of the four approaches for estimating equipment leak emissions, the equations presented are used to estimate TOC emissions for estimating equipment leak emissions. Often, in a chemical-handling facility, material in equipment is a mixture of several chemicals, and, in some cases, it may be necessary to estimate emissions of a specific VOC in the mixture. The following equation is used to speciate emissions from a single equipment piece:

$$E_X = E_{TOC} \times (WP_X/WP_{TOC})$$

where:

E_X = The mass emissions of organic chemical "x" from the equipment (kg/hr);

E_{TOC} = The TOC mass emissions from the equipment (kg/hr) calculated from either the Average Emission Factor, Screening Ranges, Correlation, or Unit-Specific Correlation approaches;

WP_X = The concentration of organic chemical "x" in the equipment in weight percent; and

WP_{TOC} = The TOC concentration in the equipment in weight percent.

An assumption in the above equation is that the weight percent of the chemicals in the mixture contained in the equipment will equal the weight percent of the chemicals in the leaking material. In general, this assumption should be accurate for single-phase streams containing (1) any gas/vapor material, or (2) liquid mixtures containing constituents of similar volatilities.

If the material in the equipment piece is a liquid mixture of constituents with varying volatilities, in certain cases this assumption may not be correct. Whether or not the assumption is valid for a liquid mixture of varying volatilities depends on the physical mechanism of how the leakage occurs from the equipment.

If the physical mechanism is one in which the liquid "flashes" before it leaks from the equipment, the leaking vapor may contain a higher concentration of the more volatile constituents than is contained in the liquid mixture. On the other hand, if the mechanism is one in which the liquid material leaks from the equipment and then evaporates, the assumption that the weight percent of each constituent in the liquid will equal the weight percent of each constituent in the vapor is valid. There are no clear guidelines to determine what mechanism is taking place for any given piece of equipment; for this reason, unless there is information to suggest otherwise, it should be assumed that the leaking vapor has the same concentrations as the liquid.

For those cases where it is suspected the leaking vapor will have different concentrations than the liquid, engineering judgement should be used to estimate emissions of individual chemical species. An example might be equipment containing material in two phases. Another hypothetical example is a case where equipment contain a liquid mixture of two constituents with one of the constituents having a very low vapor pressure and the other a much higher vapor pressure. Leaks may occur from the equipment such that the constituent with higher vapor pressure volatilizes to the atmosphere, but the constituent with lower vapor pressure is washed to the waste water treatment system prior to volatilization.

2.4.2 Using Response Factors

A correction factor that can be applied to a screening value is a response factor (RF) that relates the actual concentration to the measured concentration of a given compound, using a specific reference gas. As stated earlier, screening values are obtained by using a portable monitoring instrument to detect VOC’s at an equipment piece leak interface. An "ideal" screening RF value is one that is equal to the actual concentration of VOC’s at the leak interface. However, portable monitoring instruments used to detect TOC concentration do not respond to different TOC’s equally. (This is discussed in more detail in chapter 3.0). To demonstrate this point, consider a monitoring instrument calibrated using a reference gas. If the instrument is calibrated correctly and is used to measure the concentration of the gas with which it has been calibrated, it will indicate the actual concentration. However, when used to measure other gases for which the monitoring instrument is more or less sensitive than the calibration gas, it will not indicate the actual concentration. To correct for this, RF's have been developed. The RF is calculated using the equation:

$$RF = AC/SV$$

where:

RF = Response factor;

AC = Actual concentration of the organic compound (ppmv); and

SV = Screening value (ppmv).

The value of the RF is a function of several parameters. These parameters include the monitoring instrument, the calibration gas used to calibrate the instrument, the compound(s) being screened, and the screening value.

The correlations presented in this chapter have been developed primarily from screening value/mass emission data pairs collected from equipment containing compounds that had RF's less than three. Thus, for cases in which a calibrated instrument is used to measure concentrations of a compound for which that instrument has an RF of three or less, reasonably accurate emission estimates can be obtained directly without adjusting the screening value. However, for a case in which a compound has an RF greater than three for the calibrated instrument, the emissions estimated using the unadjusted screening value will generally underestimate the actual emissions. The EPA recommends that if a compound (or mixture) has an RF greater than three, then the RF should be used to adjust the screening value before it is used in estimating emissions.

A detailed listing of published RF’s is contained in appendix D. These RF’s were developed by injecting a known concentration of a pure compound into a monitoring instrument and comparing that actual concentration to the instrument readout (i.e., screening value).

As an example of applying a RF, consider chloroform. From table D-2 in appendix D, it can be seen that the RF for chloroform at an actual concentration of 10,000 ppmv is equal to 4.48 for a Foxboro OVA-108 monitoring instrument calibrated with methane. Thus, when the actual concentration of chloroform is 10,000 ppmv, the instrument will read 10,000 ppmv divided by 4.48, which equals 2,230 ppmv. If the measured value for chloroform was directly entered into the correlation, it would tend to underestimate emissions. (Note that when the RF is less than 1 the unadjusted screening value will tend to overestimate actual emissions.)

The RF’s in appendix D are for pure compounds. Those RF’s can be used to estimate the RF for a mixture using the equation:

$$RF_m = \frac{1}{\sum_{i=1}^{n} (x_i/RF_i)}$$

where:

RF_m = Response factor of the mixture;
n = Number of components in the mixture;
x_i = Mole fraction of constituent i in the mixture; and
RF_i = Response factor of constituent i in the mixture.

This equation is derived in appendix A.

An alternative approach for determining the RF of a pure compound or a mixture is to perform analysis in a laboratory to generate the data used to calculate a RF. The approach for generating these data in the laboratory is described in chapter 3.0. The approach involves injecting samples of a known concentration of the material of interest into the actual portable monitoring instrument used to obtain the screening values and calculating the RF based on the instrument readout.

In general, calculating the RF by performing analysis on site will give the most accurate RF information, since, among other factors, RF's have been shown to be a function of the individual monitoring instrument.

Ideally, when using screening values to estimate equipment leak emissions, the RF would be equal to 1, and, in this way, the screening value would be the actual concentration. However, because RF's are a function of several parameters, this cannot normally be achieved. Response factors can be used to correct all screening values, if so desired. To evaluate whether a RF correction to a screening value should be made, the following three steps can be carried out.

(1) For the combination of monitoring instrument and calibration gas used, determine the RF's of a given material at an actual concentration of 500 ppmv and 10,000 ppmv. (See appendix D; in some cases, it may not be possible to achieve an actual concentration of 10,000 ppmv for a given material. In these cases, the RF at the highest concentration that can be safely achieved should be determined.)

(2) If the RF's at both actual concentrations are below 3, it is not necessary to adjust the screening values.

(3) If either of the RF's are greater than 3, then the EPA recommends an RF be applied for those screening values for which the RF exceeds 3.

One of the following two approaches can be applied to correct screening values:

(1) Use the higher of either the 500 ppmv RF or the 10,000 ppmv RF to adjust all screening values.

(2) Generate a response factor curve to adjust the screening values.

A RF curve can be generated in one of two ways. The simplest way is to assume that the RF value is a linear function of the screening value. The first step to generate a line relating screening value to RF is to convert the RF at the actual concentration to the RF at the associated screening value. This is done by dividing the RF by the actual concentration to get the associated screening value. Thus, if, at an actual concentration of 10,000 ppmv, an instrument has a RF of 5, this corresponds to a screening value of 2,000 ppmv (i.e., 10,000 ppmv divided by 5). This procedure is implemented at both actual concentrations of 10,000 ppmv and 500 ppmv, and a line is drawn between the RF's at each associated screening value. This line can then be used to estimate the RF at any given screening value. (See appendix A for a demonstration of this procedure.) The line should not be extrapolated for screening values beyond the endpoints. For these screening values, the endpoint RF should be applied.

For some materials, the RF is nonlinear as the screening value increases. For these materials, RF's at several screening values can be estimated by collecting data in a laboratory, as mentioned earlier. The RF/screening value relationship can then be generated by fitting a curve through the data pairs.

When an RF is used, the screening value is multiplied by the RF before mass emissions are estimated. Thus, if a screening value is 3,000 ppmv and the associated RF is 4, then the screening value must be adjusted to 12,000 ppmv (i.e., 3,000 multiplied by 4) before mass emissions are predicted.

It should be noted that if it is possible to calibrate the monitoring instrument with the material contained in the equipment that is being screened, the RF should equal 1. Thus, theoretically, the screening values will equal the actual concentration, and no RF adjustment will be necessary. If it is necessary to apply RF's, site personnel should use engineering judgement to group process equipment into streams containing similar compounds. All components associated with a given stream can then be assigned the same RF, as opposed to calculating an RF for each individual equipment piece.

2.4.3 Monitoring Instrument Type and Calibration Gas

When the correlations presented in section 2.3 were developed, in general, for each of the source categories, the data were collected using a specific type of monitoring instrument calibrated with a specific calibration gas. The correlations are intended to relate actual concentration to mass emissions. For this reason, screening values obtained from any combination of monitoring instrument and calibration gas can be entered directly into the correlations as long as the screening values are an indication of actual concentration. If the screening values are not an indication of the actual concentration, the guidelines set forth in the previous section on RF’s can be applied to correct the screening values (i.e., screening values should be adjusted if the RF is greater than 3). Otherwise, it is not necessary to correct screening values to account for the instrument type and calibration gas that were used to develop the correlation curves developed by the EPA.

2.4.4 Estimating Emissions for Equipment Not Screened

Often, screening data cannot be collected for all of the equipment pieces in a process unit. In some cases, equipment are difficult or unsafe to screen. Difficult or unsafe to screen equipment must be included in the equipment counts. For these equipment pieces, the average emission factors must be used to estimate emissions.

In other cases, it is not possible to screen every equipment piece due to cost considerations. This is particularly true for connectors. Appendix E provides criteria for determining how many connectors must be screened to constitute a large enough sample size to identify the screening value distribution for connectors. If the criteria in appendix E are met, the average emission rate for connectors that were screened can be applied to connectors that were not screened. It should be noted that if connectors must be included in a leak detection and repair program as part of an equipment leaks standard, then all connectors must be screened. For equipment types other than connectors, if they are not monitored, the Average Emission Factor approach should be used to estimate emissions.

2.4.5 Using Screening Data Collected at Several Different Times

When screening data is collected and used to estimate emissions, the emissions estimate represents a "snapshot" of emissions at the time the screening data were obtained. Over time, it is possible that more screening data will be collected, and that for individual equipment pieces, several screening values will have been obtained at different time periods. For example, if quarterly monitoring is performed on a valve, in an annual period four screening values will be obtained from the valve. The annual emissions from the valve should be calculated by determining the emissions for each quarter based on the operational hours for the quarter, and summing the quarterly emissions together to arrive at emissions for the entire year. See appendix A for an example of estimating emissions from an equipment piece for which more than one screening value has been obtained.

2.4.6 Estimating VOC Emission Rates from Equipment Containing Non-VOC's

Some organic compounds not classified as VOC's can be detected by the screening instrument. Because the compounds are detected, the emissions associated with the screening value will include emissions of the "non-VOC's." The two key organic compounds not classified as VOC's are methane and ethane, but other organic compounds not classified as VOC's include methylene chloride, 1,1,1-trichloroethane, and several chlorofluorocarbons. An approach very similar to that outlined in section 2.4.1 (Speciating Emissions) is used to estimate VOC emissions from equipment containing these non-VOC's mixed with VOC's.

Once TOC emissions have been estimated by using either the Average Emission Factor, the Screening Ranges, the Correlation, or the Unit-Specific Correlation approaches, the VOC emissions from a group of equipment containing similar composition can be calculated using the equation:

$$E_{VOC} = E_{TOC} \times (WP_{VOC}/WP_{TOC})$$

where:

E_{VOC} = The VOC mass emissions from the equipment (kg/hr);

E_{TOC} = The TOC mass emissions from the equipment (kg/hr) calculated form either the Average

Emission Factor, Screening Ranges, Correlation, or Unit-Specific Correlation approaches;

WP_{VOC} = The concentration of VOC in the equipment in weight percent;

WP_{TOC} = The TOC concentration in the equipment in weight percent.

2.4.7 Estimating Equipment Leak Emissions of Inorganic Compounds

The majority of data collected for estimating equipment leak emissions has been for TOC's or VOC's and not for inorganic compounds. Accordingly, the emission factors and correlations presented in section 2.3 are not intended to be applied for the used of estimating emissions of inorganic compounds. However, in some cases, there may be a need to estimate equipment leak emissions of inorganic compounds--particularly for those that exist as a gas/vapor or for those that are volatile. Some examples of inorganic compounds include sulfur dioxide, ammonia, and hydrochloric acid.

The best way to estimate equipment leak emissions of inorganic compounds would be to develop unit-specific correlations as described in section 2.3.4. To do this, it would be necessary to obtain a portable monitoring instrument that could detect the inorganic compounds. If it is not possible to develop a unit-specific correlation, but a portable monitoring instrument (or some other approach) can be used to indicate the actual concentration of the inorganic compound at the equipment leak interface, then the "screening values" obtained with this instrument can be entered into the applicable correlations presented in section 2.3.3 to estimate emissions. Alternatively, the equal to or greater than 10,000 ppmv, or the less than 10,000 ppmv emission factors could be applied. In the event that there is no approach that can be used to estimate the concentration of the inorganic compound at the leak interface, then in the absence of any other data, the average emission factors can be used.

2.5 REFERENCES

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3.0 SOURCE SCREENING

3.1 INTRODUCTION

This chapter presents procedures for screening equipment components with a portable volatile organic compound (VOC) analyzer. When performing source screening, the portable analyzer probe opening is placed at the leak interface of the equipment component to obtain a "screening" value. The screening value is an indication of the concentration level of any leaking material at the leak interface. A screening value is not a direct measure of mass emissions rate, but, as discussed in chapter 2.0, can be entered into a mass emissions/screening value correlation equation to estimate mass emissions.

This chapter is divided into two sections. The first section provides a description of the portable analyzers that can be used when conducting screening surveys. Operating principles of the analyzers and performance criteria and specifications in the EPA Reference Method 21 (the method describing the use of portable VOC analyzers)[1] are described, and the use of monitoring devices that do not meet the EPA Reference Method 21 requirements is discussed. The second section presents the protocol for successfully conducting a screening program. This section includes methods to identify components to be included in the screening program, a discussion on the development of a systematic approach for performing the screening survey, the protocol for screening each of the equipment types, and recommendations for collecting and handling data.

3.2 MONITORING INSTRUMENTS

A number of portable VOC detection devices have the potential to measure the concentration level at the leak interface of equipment. Any analyzer can be used, provided it meets the specifications and performance criteria set forth in the EPA Reference Method 21, section 3.0.[1]. Reference Method 21 is included in this document as appendix F.

In general, portable VOC monitoring instruments are equipped with a probe that is placed at the leak interface of a piece of equipment. A pump within the instrument draws a continuous sample of gas from the leak interface area to the instrument detector. The instrument response is a screening value--that is, a relative measure of concentration level. The screening value is in units of parts per million by volume (ppmv). However, the screening value does not necessarily indicate the actual total concentration at the leak interface of the compound(s) being detected because the sensitivity of instruments vary for different compounds. As discussed in section 2.4.2, response factors (RF’s) relate actual concentration of a compound to the observed concentration from the detector. Before a monitoring instrument is used, it must first be calibrated using a reference gas containing a known compound at a known concentration. Methane and isobutylene are frequently used reference compounds.

3.2.1 Operating Principles and Limitations of Portable VOC Detection Devices

Monitoring instruments operate on a variety of detection principles, with the three most common being ionization, infrared absorption, and combustion. Ionization detectors operate by ionizing the sample and then measuring the charge (i.e., number of ions) produced. Two methods of ionization currently used are flame ionization and photoionization. Each of these detector types are briefly described below.

A standard flame ionization detector (FID) theoretically measures the total carbon content of the organic vapor sampled, but many other factors influence the FID readout. Although carbon monoxide and carbon dioxide (CO_2) do not produce interferences, FID’s react to water vapor at a low sensitivity. Furthermore, erratic readings may result if water condenses in the sample tube. A filter is used to remove particulate matter from the sample. Certain portable FID instruments are equipped with gas chromatograph (GC) options making them capable of measuring total gaseous non-methane organics or individual organic components. Certain organic compounds containing nitrogen, oxygen, or halogen atoms give a reduced response when sampled with an FID, and the FID may not respond to some organic compounds.

Photoionization detectors use ultraviolet light (instead of a flame) to ionize organic vapors. As with FID’s, the detector response varies with the functional group in the organic compounds. Photoionization detectors have been used to detect equipment leaks in process units in the SOCMI, especially for certain compounds, such as formaldehyde, aldehydes, and other oxygenated compounds, which will not give a satisfactory response on a FID or combustion-type detector.

Nondispersive infrared (NDIR) instruments operate on the principle of light absorption characteristics of certain gases. These instruments are usually subject to interference because other gases, such as water vapor and CO_2, may also absorb light at the same wavelength as the compound of interest. These detectors are generally used only for the detection and measurement of single components. For this type of detection, the wavelength at which a certain compound absorbs infrared radiation is predetermined and the device is preset for that specific wavelength through the use of optical filters. For example, if set to a wavelength of 3.4 micrometers, infrared devices can detect and measure petroleum fractions, including gasoline and naphtha.

Combustion analyzers are designed either to measure the thermal conductivity of a gas or to measure the heat produced by combustion of the gas. The most common method in which portable VOC detection devices are used involves the measurement of the heat of combustion. These detection devices are referred to as hot wire detectors or catalytic oxidizers. Combustion analyzers, like most other detectors, are nonspecific for gas mixtures. In addition, combustion analyzers exhibit reduced response (and, in some cases, no response) to gases that are not readily combusted, such as formaldehyde and carbon tetrachloride.

3.2.2 Specifications and Performance Criteria of Portable VOC Detection Devices

As previously stated, any portable analyzer may be used as a screening device, provided it meets the specifications and the performance criteria called for in the EPA Reference Method 21. (See appendix F.) Reference Method 21 specifies the requirements that must be met when a facility is collecting screening data to comply with a regulation. The requirements of the EPA Reference Method 21 are also applicable when screening data are collected for the sole purpose of estimating emissions. When the requirements of Reference Method 21 refer to a "leak definition," this is the screening value indicating that a piece of equipment is leaking as defined in the applicable regulation. If screening data are collected for the sole purpose of estimating emissions, the equivalent to the "leak definition" concentration in the text that follows is the highest screening value (i.e., 10,000 ppmv) that the monitoring instrument can readout.

Reference Method 21 requires that the analyzer meet the following specifications:[1]

- The VOC detector should respond to those organic compounds being processed (determined by the RF);
- Both the linear response range and the measurable range of the instrument for the VOC to be measured and the calibration gas must encompass the leak definition concentration specified in the regulation;
- The scale of the analyzer meter must be readable to ± 2.5 percent of the specified leak definition concentration;
- The analyzer must be equipped with an electrically driven pump so that a continuous sample is provided at a nominal flow rate of between 0.1 and 3.0 liters per minute;

- The analyzer must be intrinsically safe for operation in explosive atmospheres; and
- The analyzer must be equipped with a probe or probe extension for sampling not to exceed .25 inch in outside diameter, with a single end opening for admission of sample.

Note that the suction flow rate span allowed by Reference Method 21 is intended to accommodate a wide variety of instruments, and manufacturers guidelines for appropriate suction flow rate should be followed.

In addition to the above specifications, criteria for the calibration gases to be used are specified. A minimum of two calibration gases are required for analyzer performance evaluation. One is a "zero" gas, which is defined as air with less than 10 ppmv VOC; the other calibration gas, or reference gas, uses a specified reference compound in an air mixture. The concentration of the reference compound must approximately equal the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within ± 2 percent accuracy. The shelf life must also be specified. Calibration gases can also be prepared by the user as long as they are accurate to within ± 2 percent.

The instrument performance criteria that each analyzer must meet are presented in table 3-1 and discussed in greater detail in the following sections.

3.2.2.1 <u>Response Factor</u>. The sensitivity of an analyzer varies, depending on the composition of the sample and concentration of VOC detected. The RF quantifies the sensitivity of the analyzer to each compound. The RF is defined by:

$$RF = \frac{\text{Actual Concentration of Compound}}{\text{Observed Concentration from Detector}}$$

An RF must be determined for each compound that is to be measured. Response factors may be determined either by testing or from referenced sources. (The RF’s for many commonly screened compounds are presented in appendix D.) The RF tests are

TABLE 3-1. PERFORMANCE CRITERIA FOR PORTABLE VOC DETECTORS[a]

Criteria	Requirement	Time interval
Instrument response factor	Must be <10 unless correction curve is used	One time, before detector is put in service.
Instrument response time	Must be ≤30 seconds	One time, before detector is put in service. If modification to sample pumping or flow configuration is made, a new test is required.
Calibration precision	Must be ≤10 percent of calibration gas value	Before detector is put in service and at 3-month intervals or next use, whichever is later.

[a] Source: Reference 1.

required before placing the analyzer into service, but do not need to be repeated. The RF for each compound to be measured must be less than 10 for an analyzer to be acceptable for use in a screening program. According to Reference Method 21, the RF can either be measured in the laboratory using a prepared gas concentration at 80 percent of the applicable leak definition, or it can be taken from values published in the literature. When no instrument is available that meets this criteria when calibrated with the reference compound specified in the applicable regulation, the available instrument may be calibrated with one of the VOC's to be measured. However, the analyzer RF must still be less than 10 for each VOC to be measured.

As discussed in section 2.4.2, RF's depend on several parameters, including the compound, the screening value, the monitoring instrument, and the calibration gas. In chapter 2.0, guidance was provided on when and how to apply RF's for estimating emissions. Methods were presented on calculating an RF for a given chemical at a screening value other than one for which data were published. Methods were also presented for calculating RF's for mixtures.

In this chapter, several additional issues pertaining to RF's are discussed. These issues are (1) the consideration of RF's when selecting a monitoring instrument, (2) how laboratory analysis can be performed to generate data to determine an RF for a given compound, and (3) when laboratory analysis is recommended.

Response factors contained in appendix D can be used as a guide for selecting an appropriate monitoring device. If at the applicable leak definition, the RF of an instrument is greater than 10, that instrument does not meet Reference Method 21 requirements unless a substitute reference gas is used to calibrate the instrument. For example, at a concentration of 10,000 ppmv, it can be seen that when screening equipment in a process unit that contains cumene, an FID can be used (RF = 1.92 at an actual concentration of 10,000 ppmv), while the catalytic oxidation detector cannot (RF = 12.49). Similarly, at a concentration of 10,000 ppmv, neither of these devices respond to carbon tetrachloride and, therefore, cannot be used unless calibrated with a substitute VOC such that an RF of under 10 can be calculated for this compound.

Response factors can be determined by laboratory analysis using the following method. First, the analyzer is calibrated using the reference gas. Then, for each organic species that is to be measured, a known standard in air is obtained or prepared. The concentration of the organic species should be at approximately the leak definition value. This mixture is then injected into the analyzer and the observed meter reading is recorded. The analyzer is then "zeroed" by injecting zero air until a stable reading is obtained. The procedure is repeated by alternating between the mixture and zero air until a total of three measurements are obtained. An RF is calculated for each repetition and then averaged over the three measurements. This procedure can be repeated at several different concentration values. The data can then be used to generate a curve that relates RF to screening value. (See appendix A.)

The most accurate method for estimating RF’s is to perform laboratory analysis. This is particularly true because RF’s vary, not just for the detector type, but also for each individual instrument. However, in some cases, time and resource constraints may require the use of published RF data. Nevertheless, a limitation of the published data is that it is typically specific to a pure compound for a single actual concentration value, detector type, and calibration gas. Additionally, although an RF for mixtures can be calculated as described in section 2.4.2 (i.e., if an RF is known for each individual compound), the most accurate RF for a mixture is calculated by preparing known standards of air for the mixture and injecting the standard into the analyzer as described earlier.

3.2.2.2 Response Time. The response time of an analyzer is defined as the time interval from a step change in VOC concentration at the input of a sampling system, to the time at which the corresponding concentration value is reached as displayed on the analyzer readout meter. Response time is determined by introducing zero air into the instrument sample probe. When the meter reading has stabilized, the specified calibration gas is injected. The response time is measured as the time lapsed between switching to the calibration gas and the time when 90 percent of the final stable reading is obtained. This test is performed three times and the response time is calculated as the average of the three tests. The response time must be equal to or less than 30 seconds for the analyzer to be acceptable for screening purposes.

The response time test is required before placing an analyzer in service. The response time must be determined for the analyzer configuration that will be used during testing. If a modification to the sample pumping system or flow configuration is made that would change the response time (e.g., change in analyzer probe or probe filter, or the instrument pump), a new test is required before the screening survey is conducted.

3.2.2.3 Calibration Precision. Calibration precision is the degree of agreement between measurements of the same known value. To ensure that the readings obtained are repeatable, a calibration precision test must be completed before placing the analyzer in service, and at 3-month intervals, or at the next use, whichever is later. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

To perform the calibration precision test, three measurements are required for each non-zero concentration. Measurements are made by first introducing zero gas and adjusting the analyzer to zero. The specified calibration gas (reference) is then introduced and the meter reading is recorded. This procedure must be performed three times. The average algebraic difference between the meter readings and the known value of the calibration gas is then computed. This average difference is then divided by the known calibration value and multiplied by 100 to express the resulting calibration precision as percent. The calibration precision of the analyzer must be equal to or less than 10 percent of the calibration gas value.

3.2.2.4 Safety. Portable instruments to detect VOC emissions from equipment leak sources are required to be used in potentially hazardous locations such as petroleum refineries and bulk gasoline terminals. The National Electrical Code requires that instruments to be used in hazardous locations be certified to be explosion-proof, intrinsically safe, or purged.

Hazardous locations are divided into three classes: Class I, Class II, and Class III. Each class is divided into two divisions (division 1 or 2) according to the probability that a hazardous atmosphere will be present and also into seven groups, depending on the type of hazardous material exposure: Groups A through D are flammable gases or vapors, and groups E, F, and G apply to combustible or conductive gases. Class I, division 1, groups A, B, C, and D locations are those in which hazardous concentrations of flammable gases or vapors may exist under normal operating conditions. Class I, division 2, groups A, B, C, and D locations are those in which hazardous concentrations of flammable gases may exist only under unlikely conditions of operation.

Any instrument considered for use in potentially hazardous environments must be classified as intrinsically safe for Class I, division 1 and class II, division 1 conditions at a minimum. The instrument must not be operated with any safety device, such as an exhaust flame arrestor, removed.

Table 3-2 lists several portable VOC detection instruments. table 3-2 includes manufacturer, model number, pollutants detected, principle of operation, and range. Note that additional instruments, not listed here, may be available.

3.2.3 Use of Monitoring Devices That Do Not Meet EPA Reference Method 21 Requirements

In some cases, a monitoring device may not be available that meets all of the performance specifications of the EPA Reference

TABLE 3-2. PORTABLE VOC DETECTION INSTRUMENTS

Manufacturer	Model no.	Pollutant(s) detected	Principle of operation	Range (ppm)
Bacharach Instrument Co., Santa Clara, California	L	Combustible gases	Catalytic combustion	0-100% LEL[a]
	TLV Sniffer	Combustible gases	Catalytic combustion	0-1,000 and 0-10,000
Foxboro, S. Norwalk, Connecticut	OVA-128	Most organic compounds	FID/GC	0-1,000
	OVA-108	Most organic compounds	FID/GC	0-10,000
	Miran IBX	Compounds that absorb infrared radiation	NDIR	Compound specific
Health Consultants	Detecto - PAK III	Most organic compounds	FID/GC	0-10,000
HNU Systems, Inc. Newton Upper Falls, Massachusetts	HW-101	Chlorinated hydrocarbons, aromatics, aldehydes, ketones, any substance that UV light ionizes	Photoionization	0-20, 0-200, 0-2,000
Mine Safety Appliances Co., Pittsburgh, Pennsylvania	40	Combustible gases	Catalytic combustion	0-10% and 0-100% LEL[a]
Survey and Analysis, Inc., Northboro, Massachusetts	On Mark Model 5	Combustible gases	Thermal conductivity	0-5 and 0-100% LEL[a]

[a] LEL = Lower explosive limit.

Method 21. For example, there are several cases (e.g., phosgene) where the RF at 10,000 ppmv is greater than 10. An instrument may meet all other requirements, but fail as a Reference Method 21 instrument because it cannot meet the RF requirement. If an instrument fails to meet Reference Method 21 requirements, it can still be used for the purpose of estimating emissions if its reliability can be documented.

Two primary steps must be taken to document the reliability of an analyzer that fails to meet the Reference Method 21 requirements. First, a laboratory program must be undertaken to demonstrate the response of the monitoring instrument to the compounds being measured; that is, an instrument response curve must be developed for the entire screening value range and documented so that screening values taken in the field can be adjusted to actual concentrations if necessary. Second, the testing program must be sufficiently well-documented to demonstrate how the instrument will be used when screening equipment. For example, if the response time of the candidate instrument exceeds the Reference Method 21 performance specification, the test plan should reflect added screening time at each potential leak point. Once this laboratory demonstration has been completed and the screening value correction curve has been established, the instrument may be used in a screening program.

3.3 THE SCREENING PROGRAM

The goal of the screening program is to measure VOC concentrations at seals, shafts, and other potential leak points. All equipment to be included in the screening survey needs to be identified before the screening program starts. A list of equipment types that are potential sources of fugitive emissions is provided in table 3-3.

3.3.1 Identification of Equipment to be Screened

The first step in the screening survey is to precisely define the process unit boundaries. This is usually straightforward, but occasionally multiple units may be built on the same pad and share some common facilities. A process unit can be defined as

TABLE 3-3. EQUIPMENT LEAK EMISSION SOURCES

Equipment types
Agitator seals
Compressor seals
Connectors
Diaphrams
Drains
Dump lever arms
Flanges
Hatches
Instruments
Loading arms
Meters
Open-ended lines
Polished rods
Pressure relief devices
Pump seals
Stuffing boxes
Valves
Vents
Service
Gas/vapor
Light liquid
Heavy liquid

the smallest set of process equipment that can operate independently and includes all operations necessary to achieve its process objective. The exact basis for the unit definition should be documented. A plot plan of the unit should be obtained and marked with the appropriate boundaries.

The next step is to obtain a simplified flow diagram of the process and note the process streams. The actual screening and data collection can be done efficiently by systematically following each stream. For example, a logical starting point would be where one of the feed lines enters the process boundary. The screening team would follow that line, screening all sources, until the line terminates at the connectors of a reactor or separation step. This approach offers the advantage of screening groups of equipment with roughly the same composition of material in the line. Screening would then continue on the outlet side of the reactor or separation equipment. Minor loops, such as a bypass around a control valve, pump, or heat exchanger, should be screened on the initial pass. Larger loops of process equipment, such as parallel passes and processing alternatives, are more effectively treated as separate streams.

Each source should be uniquely identified to indicate that it has been screened. For example, sources can be tagged. Tags can consist of any form of weatherproof and readily visible identification. Alternatively, a process unit can be considered appropriately tagged if the unit has a system of identifying markings with an associated diagram allowing easy location of marked sources. Once all the equipment along the major streams has been screened, the unit should be divided into a grid to search for fittings missed on the initial survey. Consistent with equipment leaks standards, equipment that is unsafe to monitor or very difficult to access does not need to be included in the survey. Documentation must be provided, however, to substantiate the unsafe or confined nature of such equipment.

3.3.2 Procedure for Screening

Once the equipment to be screened has been identified, the procedures outlined in the EPA Reference Method 21 to screen each equipment type are followed.[1] The probe inlet is placed at the surface of the potential leak interface where leakage could occur. (The potential leak interface is the boundary between the process fluid and the atmosphere.) For equipment with no moving parts at the leak interface, the probe should be placed directly on the leak interface; for equipment with moving parts (e.g., pumps, compressors, and agitators), the probe should be placed approximately 1 centimeter off from the leak interface. Care must be taken to ensure that the probe is held perpendicular, not tangential, to the leak potential interface; otherwise, inaccurate readings will result. The probe must then be moved along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly move the probe along the interface where concentrations register until the maximum meter reading is obtained. The probe inlet should be left at this maximum reading location for approximately two times the instrument response time. The maximum reading is recorded as the screening value.

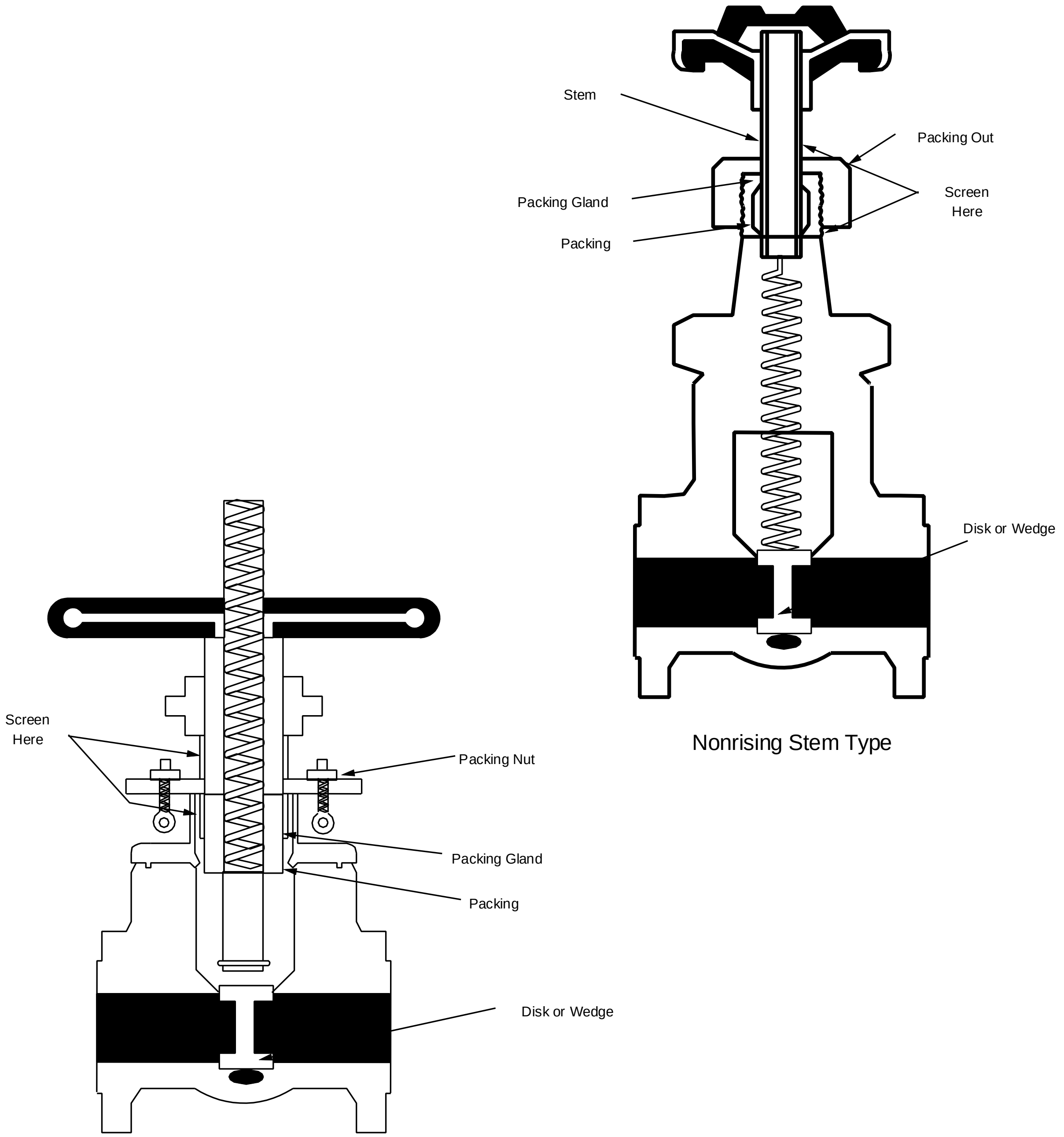
The instrument measurement may exceed the scale of the instrument. This is referred to as a "pegged" readout. For example, for several instruments, the highest readout on the scale is 10,000 ppmv. For the purposes of generating an emissions estimate, a dilution probe should be employed to measure concentrations greater than the instrument’s normal range unless average emission factors for greater than or equal to the "pegged" readout are applied. It is important to note that extending the measurement range necessitates the calibration of the instrument to the higher concentrations.

Care should be taken to avoid fouling the probe with grease, dust, or liquids. A short piece of Teflon® tubing can be used as a probe tip extender and then can be snipped off as the tip fouls. In areas with a noticeable particulate loading, this tubing can be packed loosely with untreated fiberglass, which acts as a filter. (Note that the instrument must also be calibrated with this filter in place.) If a surface to be screened is obviously dirty, hold the probe tip just over the surface to avoid scooping up contaminants. Some fouling is unavoidable, so it is recommended that the probe tip filter be cleaned at least daily and any other filters on a weekly basis. Normally, these filters can be cleaned by just tapping them lightly on a table top, but if the deposits are wet and caked on, they should be washed with an aqueous solution of soap and alcohol. This solution also can be used to wash the probe and transfer line periodically. Care should be taken to blow the equipment dry before reuse.

This general procedure can be used to screen equipment such as valves, connectors and flanges, pumps and compressors, open-ended lines, and other potential sources of VOC leakage, such as pressure relief devices, loading arms, stuffing boxes, instruments, vents, dump lever arms, drains, diaphrams, hatches, notes, or polished rods. The following sections describe the location on each type of equipment where screening efforts should be concentrated.

3.3.2.1 Valves. For valves, the most common source of leaks is at the seal between the stem and housing. To screen this source, the probe opening is placed where the stem exits the packing gland and is moved around the stem circumference. The maximum reading is recorded as the screening valve. Also, the probe opening is placed at the packing gland take-up connector seat, and the probe is moved along the periphery. In addition, valve housings of multipart assemblies should be screened at the surface of all points where leaks could occur. Figures 3-1 through 3-5 illustrate screening points for several different types of valves.

3.3.2.2 Connectors and Flanges. For connectors, the probe opening is placed at the outer edge of the connector - gasket interface and the circumference of the connector is sampled. For screwed connectors, the threaded connection interface must also be screened. Other types of nonpermanent joints, such as

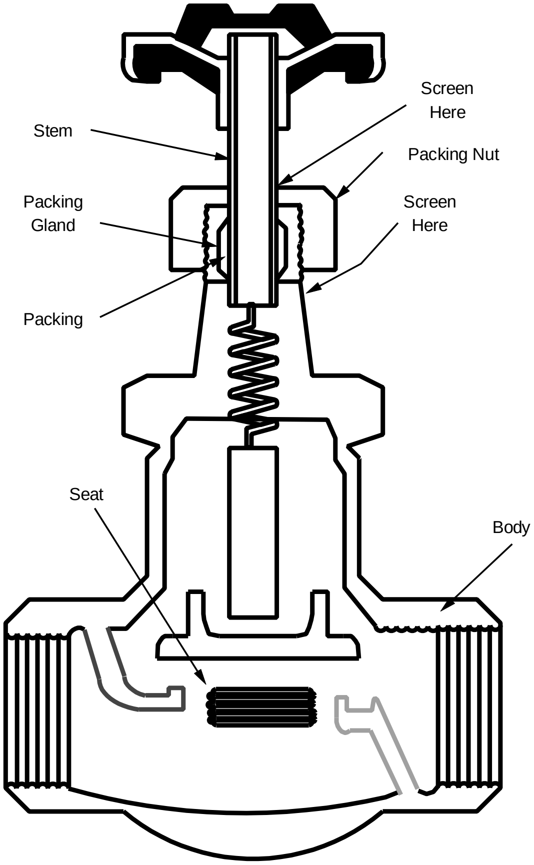


Nonrising Stem Type

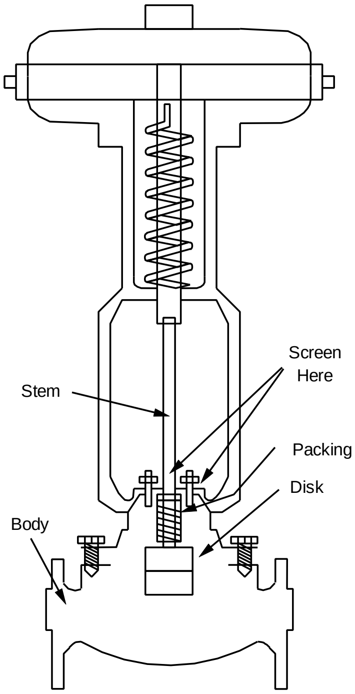
Rising Stem Type

Figure 3-1. Gate Valves

through



Manual Globe Valve



Globe Type Control Valve

Figure 3-2. Globe Valves

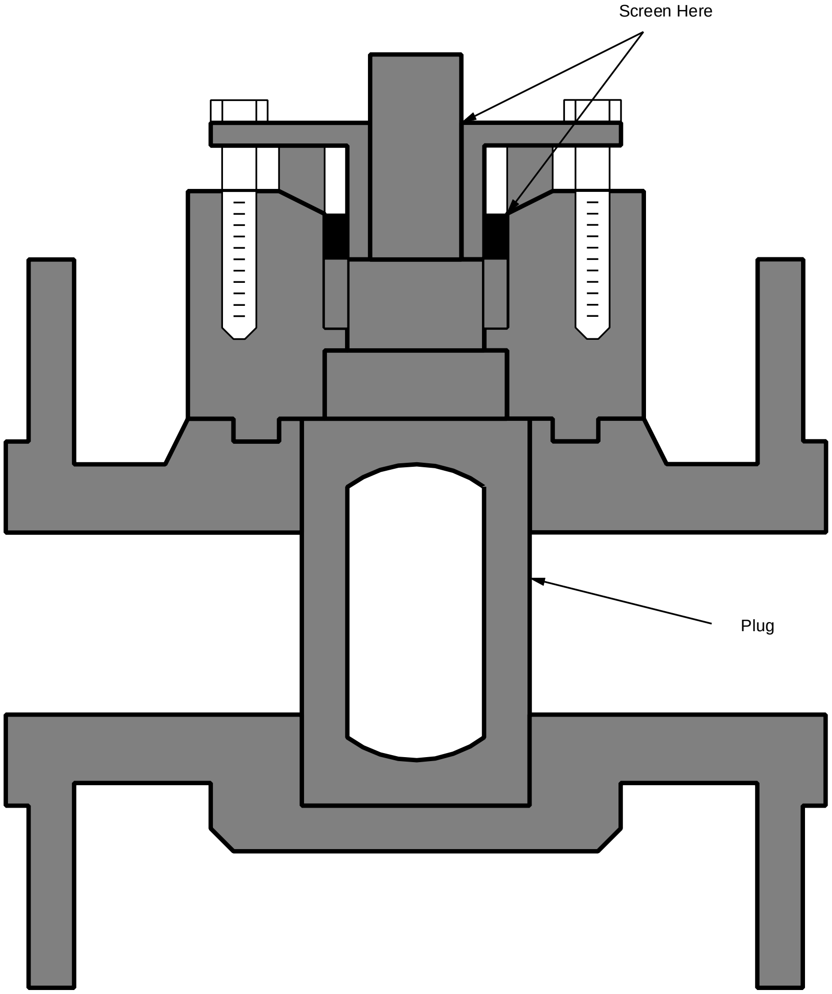
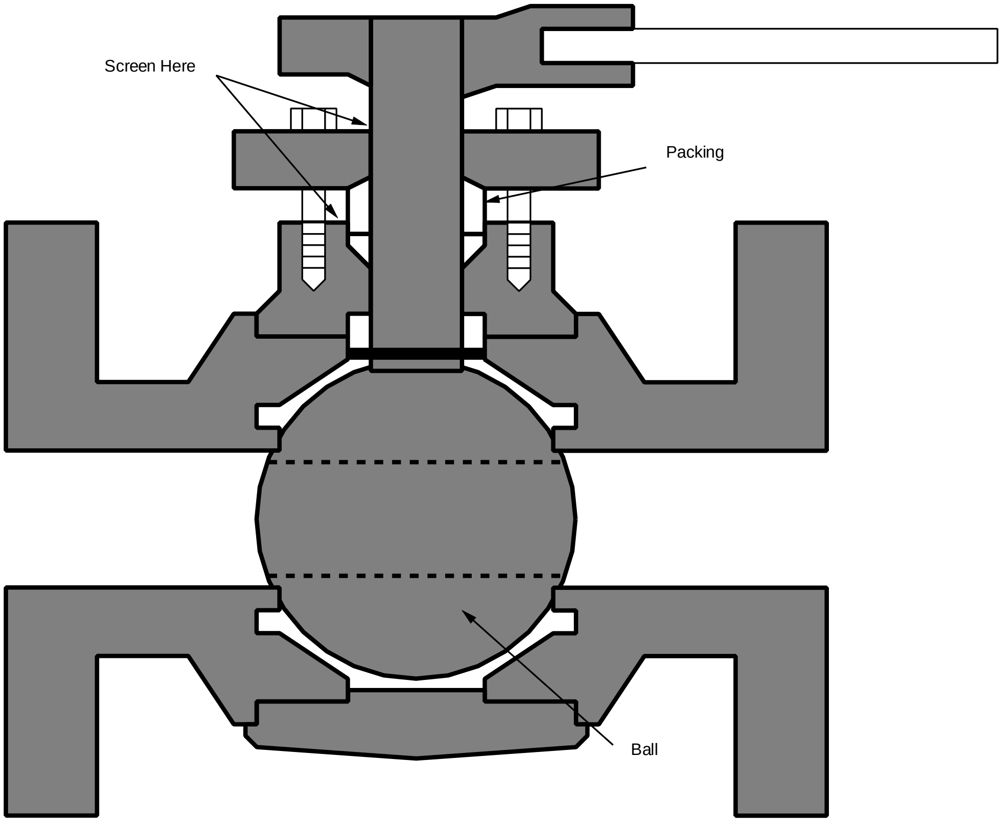
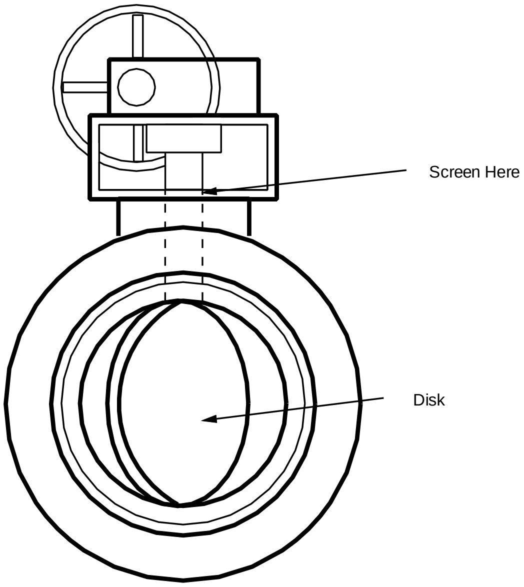


Figure 3-3. Lubricated Plug Valve

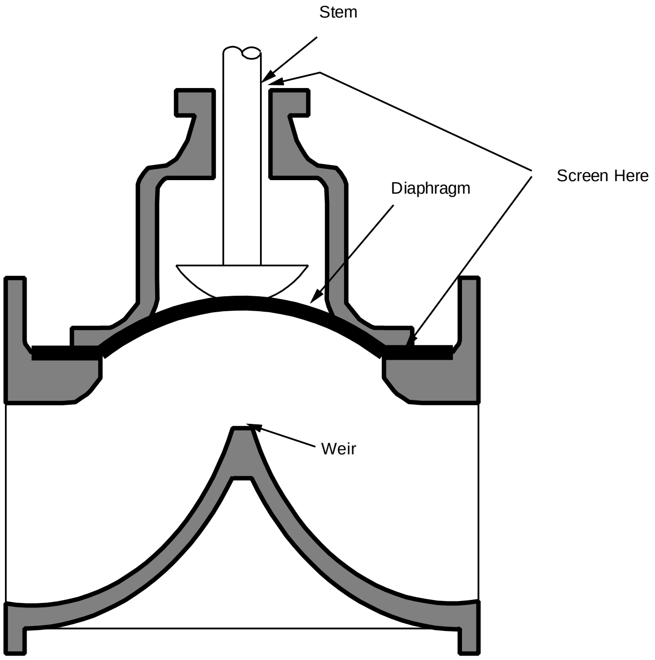


Ball Valve

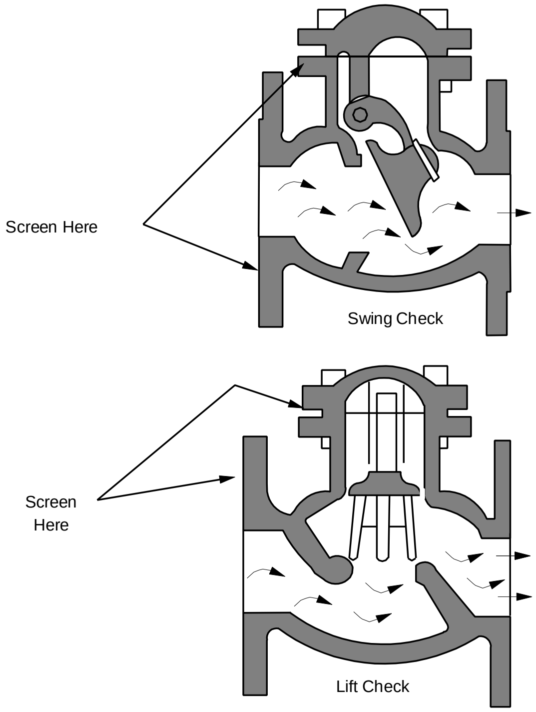


Butterfly Valve

Figure 3-4. Ball Valve and Butterfly Valve



Weir-Type Diaphragm Valve



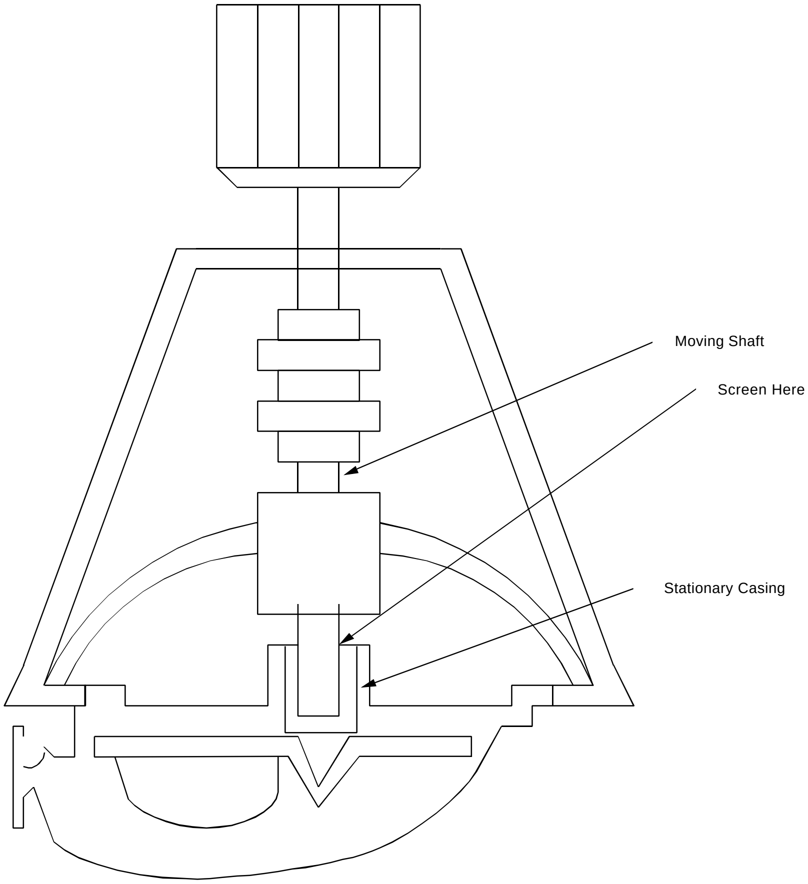
Check Valves

Figure 3-5. Weir-Type Diaphragm Valve and Check Valves threaded connections, are sampled with a similar traverse.

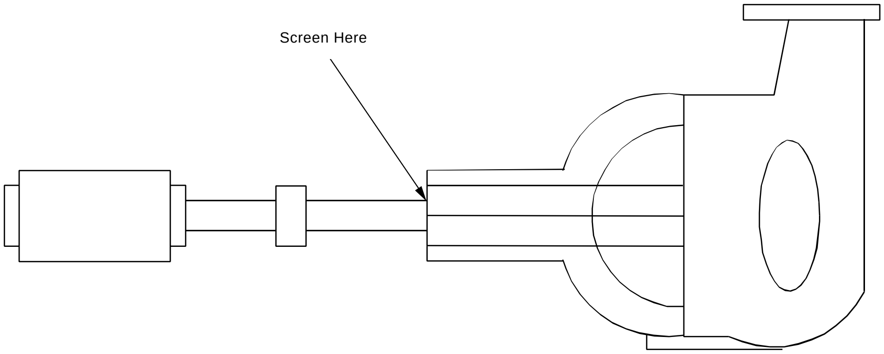
3.3.2.3 Pumps, Compressors, and Agitators. Pumps, compressors, and agitators are screened with a circumferential traverse at the outer surface shaft and seal interface where the shaft exits the housing. If the source is a rotating shaft, the probe inlet is positioned within 1 centimeter of the shaft - seal interface. If the housing configuration prevents a complete traverse of the shaft periphery, all accessible portions must be sampled. All other joints on the pump or compressor housing where leakage could occur should also be sampled. Figure 3-6 illustrates screening points for two types of centrifugal pumps.

3.3.2.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat. Because of their design and function, pressure relief devices must be approached with extreme caution. These devices should not be approached during periods of process upsets, or other times when the device is likely to activate. Similarly, care must be used in screening pressure relief devices to avoid interfering with the working parts of the device (e.g., the seal disk, the spring, etc.) For those devices equipped with an enclosed extension, or horn, the probe inlet is placed at approximately the center of the exhaust area to the atmosphere. It should be noted that personnel conducting the screening should be careful not to place hands, arms, or any parts of the body in the horn. Figure 3-7 illustrates the screening points for a spring-loaded relief valve.

3.3.2.5 Open-Ended Lines. Fugitive leaks from open-ended lines are emitted through a regularly shaped opening. If that opening is very small (as in sampling lines of less than 1 inch in diameter), a single reading in the center is sufficient. For larger openings it is necessary to traverse the perimeter of the opening. The concentration at the center must also be read.



Vertical Centrifugal Pump



Horizontal Centrifugal Pump

Figure 3-6. Centrifugal Pumps

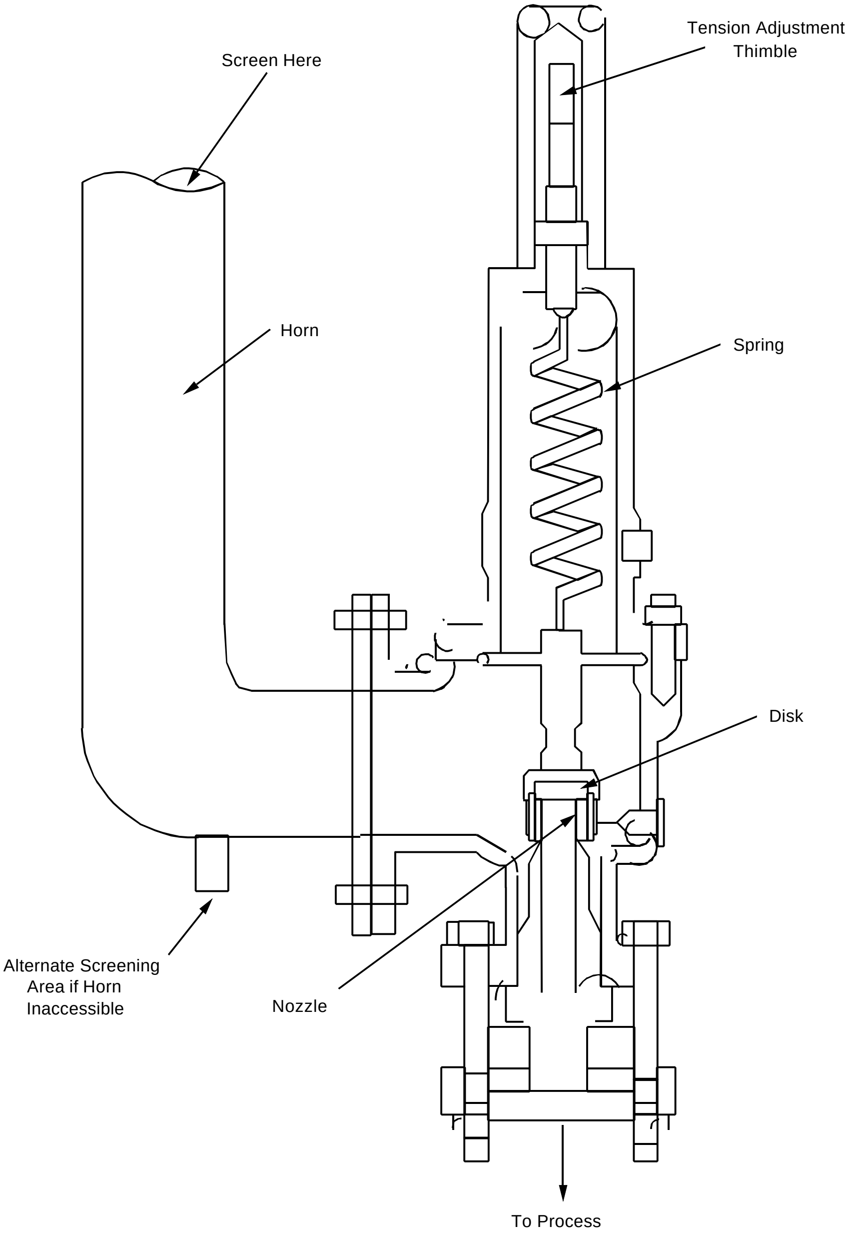


Figure 3-7. Spring-Loaded Relief Valve

3.3.3 Data Handling

To ensure that data quality is maintained, it is recommended that data be recorded on prepared data sheets. The data collected should include the following:

1. Monitoring instrument type and model number.
2. Operator’s name.
3. Date.
4. Component identification number (ID number). (If permanent ID’s are not in place, assign ID’s as each source is screened.)
5. Component type (i.e., valve, connector, open-ended line, etc.)
6. Location/stream. (Provide brief description of where the screened component is located and the composition of material in the equipment.)
7. Service (i.e., gas, light liquid, or heavy liquid).
8. Number of hours per year the component is in service.
9. Screening value (ppmv).
10. Background concentration (ppmv).
11. Comments. If any explanation is required, it should be noted in a "comments" section.

In some cases, it may be necessary or desirable to adjust the screening values for RF. In these cases, the data sheet should be designed to accommodate extra columns for RF and corrected screening values. Table 3-4 provides an example data sheet that may be used to log measurements taken during a screening program.

TABLE 3-4. EXAMPLE FIELD SHEETS FOR EQUIPMENT SCREENING DATA

Detector model no. ______________________

Operator name ______________________

Date ______________________

Component ID	Component Type	Location/ Stream	Service	Operating hrs/yr	Screening value (ppmv)	Background (ppmv)	Comments

3.4 REFERENCES

1. Code of Federal Regulations, Title 40, Part 60, Appendix A. Reference Method 21, Determination of Volatile Organic Compound Leaks. Washington, DC. U.S. Government Printing Office. Revised June 22, 1990.

4.0 MASS EMISSION SAMPLING

4.1 INTRODUCTION

This chapter describes the procedures for "bagging" equipment to measure mass emissions of organic compounds. An equipment component is bagged by enclosing the component to collect leaking vapors. Measured emission rates from bagged equipment coupled with screening values can be used to develop unit-specific screening value/mass emission rate correlation equations. Unit-specific correlations can provide precise estimates of mass emissions from equipment leaks at the process unit. However, it is recommended that unit-specific correlations are only developed in cases where the existing EPA correlations do not give reasonable mass emission estimates for the process unit. The focus of the chapter is on bagging equipment containing organic compounds, but similar procedures can be applied to bag equipment containing inorganic compounds as long as there are comparable analytical techniques for measuring the concentration of the inorganic compound.

This chapter is divided into four sections. In section 4.2, the methods for bagging equipment are discussed. Considerations for bagging each equipment type are discussed in section 4.3. In section 4.4, techniques used in the laboratory analysis of bagged samples are discussed. Section 4.4 also includes a description of a rigorous calibration procedure for the portable monitoring device that must be followed. Finally, in section 4.5, quality assurance and quality control (QA/QC) guidelines are provided.

4.2 SAMPLING METHODS

The emission rate from an equipment component is measured by bagging the component--that is, isolating the component from ambient air to collect any leaking compound(s). A tent (i.e., bag) made of material impermeable to the compound(s) of interest is constructed around the leak interface of the piece of equipment. A known rate of carrier gas is induced through the bag and a sample of the gas from the bag is collected and analyzed to determine the concentration (in parts per million by volume [ppmv]) of leaking material. The concentration is measured using laboratory instrumentation and procedures. Mass emissions are calculated based on the measured concentration and the flow rate of carrier gas through the bag.

In some cases, it may be necessary to collect liquid leaking from a bagged equipment piece. Liquid can either be dripping from the equipment piece prior to bagging, and/or be formed as condensate within the bag. If liquid accumulates in the bag, then the bag should be configured so that there is a low point to collect the liquid. The time in which the liquid accumulates should be recorded. The accumulated liquid should then be taken to the laboratory and transferred to a graduated cylinder to measure the volume of organic material. Based on the volume of organic material in the cylinder (with the volume of water or nonorganic material subtracted out), the density of the organic material, and the time in which the liquid accumulated, the organic liquid leak rate can be calculated. Note that the density can be assumed to be equivalent to the density of organic material in the equipment piece, or, if sufficient volume is collected, can be measured using a hydrometer. It should be noted that in some cases condensate may form a light coating on the inside surface of the bag, but will not accumulate. In these cases, it can be assumed that an equilibrium between condensation and evaporation has been reached and that the vapor emissions are equivalent to total emissions from the source.

When bagging an equipment piece, the enclosure should be kept as small as practical. This has several beneficial effects:

- The time required to reach equilibrium is kept to a minimum;
- The time required to construct the enclosure is minimized;
- A more effective seal results from the reduced seal area; and
- Condensation of heavy organic compounds inside the enclosure is minimized or prevented due to reduced residence time and decreased surface area available for heat transfer.

Two methods are generally employed in sampling source enclosures: the vacuum method and the blow-through method. Both methods involve enclosing individual equipment pieces with a bag and setting up a sampling train to collect two samples of leaking vapors to be taken to the laboratory for analysis. Both methods require that a screening value be obtained from the equipment piece prior to and after the equipment piece is enclosed. The methods differ in the ways in which the carrier gas is conveyed through the bag. In the vacuum method, a vacuum pump is used to pull air through the bag. In the blow-through method, a carrier gas such as nitrogen (or other inert gas) is blown into the bag.

In general, the blow-through method has advantages over the vacuum method. These advantages are as follows.

(1) The blow-through method is more conducive to better mixing in the bag.

(2) The blow-through method minimizes ambient air in the bag and thus reduces potential error associated with background organic compound concentrations. (For this reason the blow-through method is especially preferable when measuring the leak rate from components with zero or very low screening values.)

(3) The blow-through method minimizes oxygen concentration in the bag (assuming air is not used as the carrier gas) and the risk of creating an explosive environment.

(4) In general, less equipment is required to set up the blow-through method sampling train.

However, the blow-through method does require a carrier gas source, and preferably the carrier gas should be inert and free of any organic compounds and moisture. The vacuum method does not require a special carrier gas.

Details of the sampling train of each of these bagging methods are discussed in sections 4.2.1 and 4.2.2, respectively. These sections also contain summaries of the steps of the sampling procedure for each method. For both methods, the approach described above for collecting and measuring liquid leak rates can be utilized. In addition to the sampling descriptions presented in the following sections, the quality control and assurance guidelines presented in section 4.5 must also be followed when bagging equipment.

4.2.1 Vacuum Method

The sampling train used in the vacuum method is depicted in figure 4-1. The train can be mounted on a portable cart, which can be moved around the process unit from component to component. The major equipment items in the sampling train are the vacuum pump used to draw air through the system, and the dry gas meter used to measure the flow rate of gas through the train. In previous studies that the EPA conducted, a 4.8-cubic feet per minute Teflon® ring piston-type vacuum pump equipped with a 3/4-horsepower, air-driven motor was used. Other equipment that may be used in the train includes valves, copper and stainless steel tubing, Teflon® tubing and tape, thermometer, pressure-reading device, liquid collection device, and air-driven diaphragm sampling pumps. It also may be necessary to use desiccant preceding the dry gas meter to remove any moisture.

The bag is connected by means of a bulkhead fitting and Teflon® tubing to the sampling train. A separate line is connected from the bag to a pressure-reading device to allow continuous monitoring of the pressure inside the bag. If a significant vacuum exists inside the bag when air is being pulled through, a hole is made in the opposite side of the bag from the outlet to the sampling train. This allows air to enter the bag more easily and, thus, reduces the vacuum in the enclosure. However, it is important to maintain a vacuum in the bag, since VOC could be lost through the hole if the bag became pressurized.

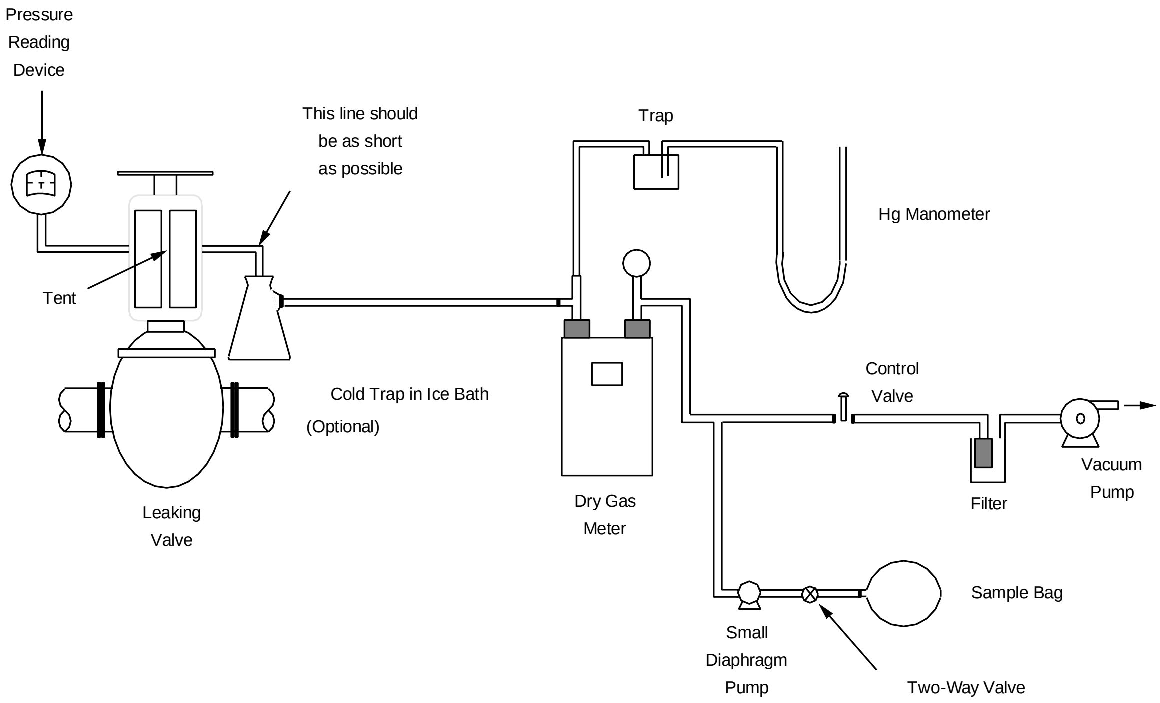


Figure 4-1. Sampling train for bagging a source using the vacuum method.

In practice, it has been found that only a very slight vacuum (0.1 inches of water) is present in the bag during most of the sampling, even in the absence of a hole through the bag wall. Sufficient air enters around the seals to prevent the development of a significant vacuum in the bag. A small diaphragm sampling pump can be used to collect two samples into sample bags or canisters, which are then transported to the laboratory for analysis.

The diaphragm pump can also be used to collect a background sample of the ambient air near the bagged component. The concentration in the background bag is subtracted from the average concentration in the sample bags when calculating the leak rate. Often this correction is insignificant (particularly for components with high leak rates or in cases where there is no detectable volatile organic compound (VOC) concentration measured by the portable monitoring device), and collection of a background bag is optional. However, in some cases collection of a background bag is important so that emission rates are not biased high.

Any liquid that accumulates in the bag should be collected using the approach described in section 4.2. Note that if there is a concern that condensation will occur in equipment downstream from the bag outlet, a cold trap can be placed as close to the bag outlet as possible to remove water or heavy organic compounds that may condense downstream. Any organic condensate that collects in the cold trap must be measured to calculate the total leak rate.

The flow rate through the system can be varied by throttling the flow with a control valve immediately upstream of the vacuum pump. Typical flow rates are approximately 60 liters per minute (ℓ/min) or less. A good flow rate to use is one in which a balance can be found between reaching equilibrium conditions and having a high enough concentration of organic compounds in the bag outlet to accurately measure the concentration in the laboratory. As the flow rate is decreased, the concentration of organic compounds increases in the gas flowing through the sampling system. The flow rate should be adjusted to avoid any operations with an explosive mixture of organic compounds in air. It may also be possible to increase the flow rate in order to minimize liquid condensation in the bag.

The flow rate should be set to a constant rate and kept at that rate long enough for the system to reach equilibrium. To determine if equilibrium conditions have been reached, a portable monitoring device can be used to indicate if the outlet concentration has stabilized.

It is not recommended that the vacuum method be used to measure the leak rate from equipment that have low screening values (approximately 10 ppmv or less), because considerable error can be introduced due to the background organic concentration in the ambient air that is pulled through the bag.

In summary, the vacuum sampling procedure consists of the following steps.

(1) Determine the composition of material in the designated equipment component, and the operating conditions of the component.

(2) Obtain and record a screening value with the portable monitoring instrument.

(3) Cut a bag from appropriate material (see section 4.3) that will easily fit over the equipment component.

(4) Connect the bag to the sampling train.

(5) If a cold trap is used, immerse the trap in an ice bath.

(6) Note the initial reading of the dry gas meter.

(7) Start the vacuum pump and a stopwatch simultaneously. Make sure a vacuum exists within the bag.

(8) Record the temperature and pressure at the dry gas meter.

(9) Observe the VOC concentration at the vacuum pump exhaust with the monitoring instrument. Make sure concentration stays below the lower explosive limit.

(10) Record the temperature, pressure, dry gas meter reading, outlet VOC concentration and elapsed time every 2 to 5 minutes (min).

(11) Collect 2 gas samples from the discharge of the diaphragm sampling pump when the outlet concentration stabilizes (i.e., the system is at equilibrium).

(12) Collect a background bag (optional).

(13) Collect any liquid that accumulated in the bag as well as in the cold trap (if used) in a sealed container.

(14) Take a final set of readings and stop the vacuum pump.

(15) Transport all samples to the laboratory, along with the data sheet.

(16) Remove the bag.

(17) Rescreen the source with the portable monitoring instrument and record.

Based on the data collected in the steps described above, mass emissions are calculated using the equation presented in table 4-1.

4.2.2 Blow-Through Method

The sampling train for the blow-through method is presented in figure 4-2. The temperature and oxygen concentrations are measured inside the bag with a thermocouple (or thermometer) and an oxygen/combustible gas monitor. The carrier gas is metered into the bag through one or two tubes (two tubes provide for better mixing) at a steady rate throughout the sampling period. The flow rate of the carrier gas is monitored in a gas rotameter calibrated to the gas. Typical flow rates are approximately 60 ℓ/min or less. It is preferable to use an inert gas such as nitrogen for the blow-through method so as to minimize the risk of creating an explosive environment inside the bag. Also, the carrier gas should be free of any organic compounds and moisture. The pressure in the bag should never exceed 1 pound per square inch gauge (psig).

The flow rate through the bag can be varied by adjusting the carrier gas regulator. As mentioned in section 4.2.1, a good flow rate to use is one in which a balance can be found between reaching equilibrium conditions and having a high enough

TABLE 4-1. CALCULATION PROCEDURES FOR LEAK RATE WHEN USING THE VACUUM METHOD

$$\underset{\text{(kg/hr)}}{\text{Leak Rate}} = \frac{9.63 \times 10^{-10}\,(Q)(MW)(GC)(P)}{T + 273.15} + \frac{(\rho)(V_L)}{16.67(t)}$$

where:

9.63×10^{-10} = A conversion factor using the gas constant:

$$\frac{°K \times 10^{6} \times \text{kg-mol} \times \text{min}}{\ell \times \text{hour} \times \text{mmHg}} ;$$

Q = Flow rate out of bag (ℓ/min);

MW^{a} = Molecular weight of organic compound(s) in the sample bag[c] or alternatively in the process stream contained within the equipment piece being bagged (kg/kg-mol);

GC^{b} = Sample bag organic compound concentration (ppmv) minus background bag organic compound concentration[c] (ppmv);

P = Absolute pressure at the dry gas meter (mmHg);

T = Temperature at the dry gas meter (°C);

ρ = Density of organic liquid collected (g/mℓ);

V_L = Volume of liquid collected (mℓ);

16.67 = A conversion factor to adjust term to units of kilograms per hour (g × hr)/(kg × min)

t = Time in which liquid is collected (min); and

---

[a] For mixtures calculate MW as:

$$= \sum_{i=1}^{n} MW_i \, X_i \; / \; \sum_{i=1}^{n} X_i$$

where:

MW_i = Molecular weight of organic compound i;
X_i = Mole fraction of organic compound i; and
n = Number of organic compounds in mixture.

[b] For mixtures, the value of GC is the total concentration of all the organic compounds in the mixture.

[c] Collection of a background bag is optional. If a background bag is not collected, assume the background concentration is zero.

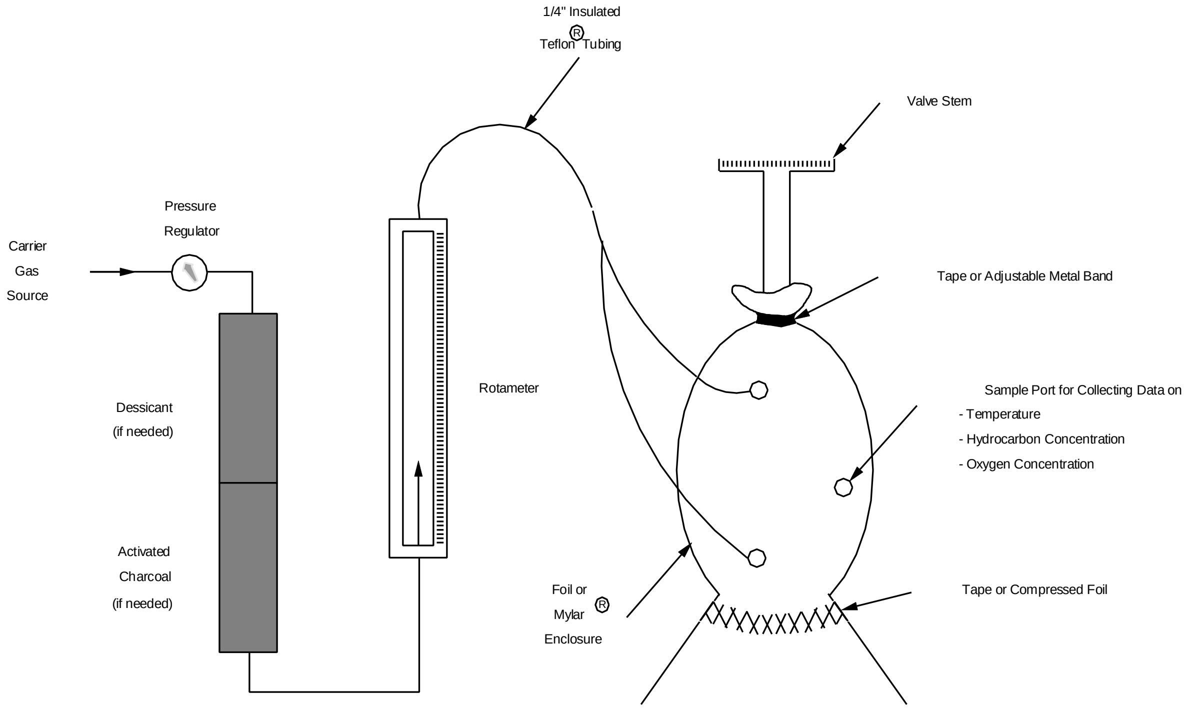


Figure 4-2. Equipment Required for the Blow-Through Sampling Technique

concentration of organic compounds in the bag outlet to accurately measure the concentration in the laboratory. Adjustments to the flow rate may also help minimize liquid condensation in the bag. Any liquid that does accumulate in the bag should be collected using the approach described in section 4.2.

The carrier gas flow rate should be set to a constant rate and kept at that rate long enough for the system to reach equilibrium. In addition to the carrier gas flow through the bag, some ambient air may enter the bag if it is not airtight. The oxygen measurements are used to determine the flow of ambient air through the bag. The oxygen measurements are also an indication of the quality of the bagging procedure (the lower the oxygen concentration the better). Once oxygen concentration falls below 5 percent, the portable monitoring instrument is used to check organic compound concentrations at several locations within the bag to ensure that the bag contents are at steady state.

Once the bag contents are at steady state, two gas samples are drawn out of the bag for laboratory analysis using a portable sampling pump. It may also be necessary to collect a background bag sample, particularly if the source had screened at zero and if there is still a detectable level of oxygen in the bag. However, collection of a background bag is optional.

In summary, the blow-through method consists of the following steps, which assume nitrogen is used as the carrier gas.

(1) Determine the composition of the material in the designated equipment component, and the operating conditions of the component.

(2) Screen the component using the portable monitoring instrument.

(3) Cut a bag that will easily fit over the equipment component.

(4) Connect tubing from the nearest nitrogen source to a rotameter stand.

(5) Run tubing from the rotameter outlet to a "Y" that splits the nitrogen flow into two pieces of tubing and insert the tubes into openings located on either side of the bag.

(6) Turn on the nitrogen flow and regulate it at the rotameter to a constant rate and record the time.

(7) After the nitrogen is flowing, wrap aluminum foil around those parts of the component where air could enter the bag-enclosed volume.

(8) Use duct tape, wire, and/or rope to secure the bag to the component.

(9) Put a third hole in the bag roughly equidistant from the two carrier gas-fed holes.

(10) Measure the oxygen concentration in the bag by inserting the lead from an oxygen meter into the third hole. Adjust the bag (i.e., modify the seals at potential leak points) until the oxygen concentration is less than 5 percent.

(11) Measure the temperature in the bag.

(12) Check the organic compound concentration at several points in the bag with the portable monitoring instrument to ensure that carrier gas and VOC are well mixed throughout the bag.

(13) Collect samples in sample bags or canisters by drawing a sample out of the bag with a portable sampling pump.

(14) Collect a background bag (optional).

(15) Remove the bag and collect any liquid that accumulated in the bag in a sealed container. Note the time over which the liquid accumulated.

(16) Rescreen the source.

Table 4-2 gives equations used to calculate mass emission rates when using the blow-through method. An adjustment is provided for the leak rate equation in table 4-2 to account for the total flow through the bag. This adjustment is recommended and represents an improvement over previous versions

TABLE 4-2. CALCULATION PROCEDURES FOR LEAK RATE WHEN USING THE BLOW-THROUGH METHOD

$$\text{Leak Rate (kg/hr)} = \left(\frac{1.219 \times 10^{-5}\,(Q)\,(MW)\,(GC)}{T + 273.15} + \frac{(\rho)\,(V_L)}{16.67\,(t)} \right) \times \left(\frac{10^6\text{ppmv}}{10^6\text{ppmv} - GC} \right)$$

where:

1.219×10^{-5} = A conversion factor taking into account the gas constant and assuming a pressure in the tent of 1 atmosphere:

$$\frac{{}^{o}K \times 10^{6} \times \text{kg-mol}}{m^{3}}\;;$$

Q = flow rate out of tent (m^3/hr);

$$= \frac{N_2 \text{ Flow Rate } (\ell/\text{min})}{1 - [\text{Tent Oxygen Conc. (volume \%)}/21]} \times \frac{[0.06\ (m^3/\text{min})]}{(\ell/\text{hr})}$$

MW^a = Molecular weight of organic compounds in the sample bag or alternatively in the process stream contained within the equipment piece being bagged (kg/kg-mol);

GC^b = Sample bag organic compound concentration (ppmv), corrected for background bag organic compound concentration (ppmv);[c]

T = Temperature in tent (°C);

ρ = Density of organic liquid collected (g/mℓ);

V_L = Volume of liquid collected (mℓ);

16.67 = A conversion factor to adjust term to units of Kilograms per hour (g × hr)/(kg × min); and

t = Time in which liquid is collected (min).

---

[a] For mixtures calculate MW as:

$$= \sum_{i=1}^{n} MW_i\, X_i \Big/ \sum_{i=1}^{n} X_i$$

where:

MW_i = Molecular weight of organic compound i;

TABLE 4-2. CALCULATION PROCEDURES FOR LEAK RATE WHEN USING THE BLOW-THROUGH METHOD
(Continued)

X_i = Mole fraction of organic compound i; and
n = Number of organic compounds in mixture.

[b] For mixtures, the value of GC is the total concentration of all the organic compounds in the mixture.

[c] Collection of a background bag is optional. If a background bag is not collected, assume the background concentration is zero. To correct for background concentration, use the following equation:

$$\underset{(\text{ppmv})}{\text{GC}} = \text{SB} - \left(\frac{\text{TENT}}{21} \times \text{BG}\right)$$

where:

SB = Sample bag concentration (ppmv);
TENT = Tent oxygen concentration (volume %); and
BG = Background bag concentration (ppmv)

of this document for quantifying mass emissions from the blow through method.

4.3 SOURCE ENCLOSURE

In this section, choosing a bagging material and the approach for bagging specific equipment types are discussed. An important criteria when choosing the bagging material is that it is impermeable to the specific compounds being emitted from the equipment piece. This criteria is also applicable for sample gas bags that are used to transport samples to the laboratory. A bag stability test over time similar to the Flexible Bag Procedure described in section 5.3.2 of the EPA method 18 is one way to check the suitability of a bagging material.[1] After a bag has been used, it must be purged. Bags containing residual organic compounds that cannot be purged should be discarded. Mylar®, Tedlar®, Teflon®, aluminum foil, or aluminized Mylar® are recommended potential bagging materials. The thickness of the bagging material can range from 1.5 to 15 millimeters (mm), depending on the bagging configuration needed for the type of equipment being bagged, and the bagging material. Bag construction for individual sources is discussed in sections 4.3.1 through 4.3.5. For convenience, Mylar® will be used as an example of bagging material in the following discussions.

4.3.1 Valves

When a valve is bagged, only the leak points on the valve should be enclosed. Do not enclose surrounding flanges. The most important property of the valve that affects the type of enclosure selected for use is the metal skin temperature where the bag will be sealed. At skin temperatures of approximately 200 ^{o}C or less, the valve stem and/or stem support can be wrapped with 1.5- to 2.0-mm Mylar® and sealed with duct tape at each end and at the seam. The Mylar® bag must be constructed to enclose the valve stem seal and the packing gland seal.

When skin temperatures are in excess of 200 ^{o}C, a different method of bagging the valve should be utilized. Metal bands, wires, or foil can be wrapped around all hot points that would be in contact with the Mylar® bag material. Seals are then made against the insulation using duct tape or adjustable metal bands of stainless steel. At extremely high temperatures, metal foil can be used as the bagging material and metal bands used to form seals. At points where the shape of the equipment prevent a satisfactory seal with metal bands, the foil can be crimped to make a seal.

4.3.2 Pumps and Agitators

As with valves, a property of concern when preparing to sample a pump or agitator is the metal skin temperature at areas or points that are in contact with the bag material. At skin temperatures below 200 $^{\circ}$C, Mylar® plastic and duct tape are satisfactory materials for constructing a bag around a pump or agitator seal. If the temperature is too high or the potential points of contact are too numerous to insulate, an enclosure made of aluminum foil can be constructed. This enclosure is sealed around the pump and bearing housing using silicone fabric insulting tape, adjustable metal bands, or wire.

The configuration of the bag will depend upon the type of pump. Most centrifugal pumps have a housing or support that connects the pump drive (or bearing housing) to the pump itself. The support normally encloses about one-half of the area between the pump and drive motor, leaving open areas on the sides. The pump can be bagged by cutting panels to fit these open areas. These panels can be made using thicker bagging material such as 14-mm Mylar®. In cases where supports are absent or quite narrow, a cylindrical enclosure around the seal can be made so that it extends from the pump housing to the motor or bearing support. As with the panels, this enclosure should be made with thicker bagging material to provide strength and rigidity.

Reciprocating pumps can present a somewhat more difficult bagging problem. If supports are present, the same type of two-panel Mylar® bag can be constructed as that for centrifugal pumps. In many instances, however, sufficiently large supports are not provided, or the distance between pump and driver is relatively long. In these cases, a cylindrical enclosure as discussed above can be constructed. If it is impractical to extend the enclosure all the way from the pump seal to the pump driver, a seal can be made around the reciprocating shaft. This can usually be best completed by using heavy aluminum foil and crimping it to fit closely around the shaft. The foil is attached to the Mylar® plastic of the enclosure and sealed with the duct tape.

In cases where liquid is leaking from a pump, the outlet from the bag to the sampling train should be placed at the top of the bag and as far away from spraying leaks as practical. A low point should be formed in the bag to collect the liquid so that the volume of the liquid can be measured and converted to a mass rate.

4.3.3 Compressors

In general, the same types of bags that are suitable for pumps can be directly applied to compressors. However, in some cases, compressor seals are enclosed and vented to the atmosphere at a high-point vent. If the seals are vented to a high-point vent, this vent line can be sampled. A Mylar® bag can be constructed and sealed around the outlet of the vent and connected to the sampling train. If the high-point vents are inaccessible, the vent lines from the compressor seal enclosures can be disconnected at some convenient point between the compressor and the normal vent exit. Sampling is then conducted at this intermediate point. In other cases, enclosed compressor seals are vented by means of induced draft blowers or fans. In these cases, if the air flow rate is know or can be determined, the outlet from the blower/fan can be sampled to determine the emission rate.

4.3.4 Connectors

In most cases, the physical configurations of connectors lend themselves well to the determination of leak rates. The same technique can be used for a connector whether it is a flanged or a threaded fitting. To bag a connector with a skin temperature below 200 ^{O}C, a narrow section of Mylar® film is constructed to span the distance between the two flange faces or the threaded fitting of the leaking source. The Mylar® is attached and sealed with duct tape. When testing connectors with skin temperatures above 200 ^{O}C, the outside perimeter of both sides of the connector are wrapped with heat-resistant insulating tape. Then, a narrow strip of aluminum foil can be used to span the distance between the connection. This narrow strip of foil can be sealed against the insulating tape using adjustable bands of stainless steel.

4.3.5 Relief Valves

Relief devices in gas/vapor service generally relieve to the atmosphere through a large-diameter pipe that is normally located at a high point on the process unit that it serves. The "horns" can be easily bagged by placing a Mylar® plastic bag over the opening and sealing it to the horn with duct tape. Because may of these devices are above grade level, accessibility to the sampling train may be limited or prevented. It is sometimes possible to run a long piece of tubing from the outlet connection on the bag to the sampling train located at grade level or on a stable platform.

As discussed previously in section 3.0, the purpose of pressure relief devices makes them inherently dangerous to sample, especially over a long period of time. If these equipment are to be sampled for mass emissions, special care and precautions should be taken to ensure the safety of the personnel conducting the field sampling.

4.4 ANALYTICAL TECHNIQUES

The techniques used in the laboratory analysis of the bagged samples will depend on the type of processes sampled. The following sections describe the analytical instrumentation and calibration, and analytical techniques for condensate. These are guidelines and are not meant to be a detailed protocol for the laboratory personnel. Laboratory personnel should be well-versed in the analysis of organic compound mixtures and should design their specific analyses to the samples being examined.

Also discussed is the calibration protocol for the portable monitoring instrument. When bagging data are collected, it is critical that the screening value associated with mass emission rates is accurate. For this reason, a more rigorous calibration of the portable monitoring instrument is required than if only screening data are being collected.

4.4.1 Analytical Instrumentation

The use of analytical instrumentation in a laboratory is critical to accurately estimate mass emissions. The analytical instrument of choice depends on the type of sample being processed. Gas chromatographs (GC’s) equipped with a flame ionization detector or electron capture detector are commonly used to identify individual constituents of a sample. Other considerations besides instrument choice are the type of column used, and the need for temperature programming to separate individual constituents in the process stream with sufficient resolution. For some process streams, total hydrocarbon analyses may be satisfactory.

4.4.2 Calibration of Analytical Instruments

Gas chromatographs should be calibrated with either gas standards generated from calibrated permeation tubes containing individual VOC components, or bottled standards of common gases. Standards must be in the range of the concentrations to be measured. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within ± 2 percent accuracy, and a shelf life must be specified. Cylinder standards beyond the shelf life must either be reanalyzed or replaced.

Field experience indicates that certified accuracies of ± 2 percent are difficult to obtain for very low-parts per million (ppm) calibration standards (< 10 ppm). Users of low-parts per million calibration standards should strive to obtain calibration standards that are as accurate as possible. The accuracy must be documented for each concentration standard.

The results of all calibrations should be recorded on prepared data sheets. Table 4-3 provides an example of a data collection form for calibrating a GC. If other analytical instruments are used to detect the organic compounds from liquid

TABLE 4-3. EXAMPLE GC CALIBRATION DATA SHEET

Plant ID ____________________
Instrument ID ____________________
Analyst Name ____________________

Date	Time	Certified Gas Conc. (ppmv)	Instrument Reading (ppmv)	Comments

samples, they should be calibrated according to standard calibration procedures for the instrument.

4.4.3 Analytical Techniques for Condensate

Any condensate collected should be brought to the laboratory sealed in the cold trap flask. This material is transferred to a graduated cylinder to measure the volume collected. If there is enough volume to make it feasible, the organic layer should be separated from the aqueous layer (if present) and weighed to determine its density. If water-miscible organic compounds are present, both the aqueous and organic phases should be analyzed by GC to determine the total volume of organic material.

4.4.4. Calibration Procedures for the Portable Monitoring Instrument

To generate precise screening values, a rigorous calibration of the portable monitoring instrument is necessary. Calibrations must be performed at the start and end of each working day, and the instrument reading must be within 10 percent of each of the calibration gas concentrations. A minimum of five calibration gas standards must be prepared including a zero gas standard, a standard approaching the maximum readout of the screening instrument, and three standards between these values. If the monitoring instrument range is from 0 to 10,000 ppmv, the following calibration gases are required:

- A zero gas (0-0.2 ppm) organic in air standard;
- A 9.0 ppm (8-10 ppm) organic in air standard;
- A 90 ppm (80-100 ppm) organic in air standard;
- A 900 ppm (800-1,000 ppm) organic in air standard; and
- A 9,000 ppm (8,000-10,000 ppm) organic in air standard.

The same guidelines for the analysis and certification of the calibration gases as described for calibrating laboratory analytical instruments must be followed for calibrating the portable monitoring instrument.

4.5 QUALITY CONTROL AND QUALITY ASSURANCE GUIDELINES

To ensure that the data collected during the bagging program is of the highest quality, the following QC/QA procedures must be followed. Quality control requirements include procedures to be followed when performing equipment leak mass emissions sampling. Quality assurance requirements include accuracy checks of the instrumentation used to perform mass emissions sampling. Each of these QC/QA requirements are discussed below.

4.5.1 Quality Control Procedures

A standard data collection form must be prepared and used when collecting data in the field. Tables 4-4 and 4-5 are examples of data collection forms for the blow-through and vacuum methods of mass emissions sampling, respectively.

In addition to completing the data collection forms, the following guidelines need to be adhered to when performing the bagging analysis:

- Background levels near equipment that is selected for bagging must not exceed 10 ppmv, as measured with the portable monitoring device.
- Screening values for equipment that is selected for bagging must be readable within the spanned range of the monitoring instruments. If a screening value exceeds the highest reading on the meter (i.e., "pegged reading"), a dilution probe should be used, or in the event that this is not possible, the reading should be identified as pegged.
- Only one piece of equipment can be enclosed per bag; a separate bag must be constructed for each equipment component.
- A separate sample bag must be used for each equipment component that is bagged. Alternatively, bags should be purged and checked for contamination prior to reuse.
- A GC must be used to measure the concentrations from gas samples.
- Gas chromatography analyses of bagged samples must follow the analytical procedures outlined in the EPA method 18.
- To ensure adequate mixing within the bag when using the blow-through method, the dilution gas must be directed onto the equipment leak interface.
- To ensure that steady-state conditions exist within the bag, wait at least five time constants (volume of bag dilution/gas flow rate) before withdrawing a sample for recording the analysis.

TABLE 4-4. EXAMPLE DATA COLLECTION FORM FOR FUGITIVE EMISSIONS BAGGING TEST (BLOW-THROUGH METHOD)

Equipment Type ____________________ Component ID _____________
Equipment Category ________________ Plant ID _________________
Line Size _________________________ Date _______________________
Stream Phase (G/V, LL, HL) _______ Analysis Team ____________
Barometric Pressure _______________ ____________________________
Ambient Temperature _______________ Instrument ID ____________
Stream Temperature ________________ Stream Pressure __________
Stream Composition (Wt %) ___________________,______________________
______________________, ______________________,______________________

Time Bagging Test Measurement Data

_______ Initial Screening (ppmv) Equipment Piece ______ Bkgd.____
_______ Background Bag Organic Compound Conc. (ppmv)[a] ___________
_______ Dilution Gas Flow Rate (ℓ/min) ________
_______ Sample Bag 1 Organic Compound Conc. (ppmv) _____________
_______ O_2 Concentration (volume %) ________
_______ Bag Temperature (°C) ____________________

_______ Dilution Gas Flow Rate (ℓ/min) ___________
_______ Sample Bag 2 Organic Compound Conc. (ppmv) ______________
_______ O_2 Concentration (volume %) _________
_______ Bag Temperature (°C) __________________

Condensate Accumulation: Starting Time ______ Final Time ______
Organic Condensate Collected (mℓ) ____________
Density of Organic Condensate (g/mℓ) ____________

_______ Final Screening (ppmv) Equipment Piece _______ Bkgd._____

---

[a] Collection of a background bag is optional. However, it is recommended in cases where the screening value is less than 10 ppmv and there is a detectable oxygen level in the bag.

TABLE 4-5. EXAMPLE DATA COLLECTION FORM FOR FUGITIVE EMISSIONS BAGGING TEST (VACUUM METHOD)

Equipment Type ____________________ Component ID ____________
Equipment Category _______________ Plant ID ________________
Line Size ________________________ Date _____________________
Stream Phase (G/V, LL, HL) _______ Analysis Team ___________
Barometric Pressure ______________ __________________________
Ambient Temperature ______________ Instrument ID ___________
Stream Temperature _______________ Stream Pressure _________
Stream Composition (Wt %) __________________,____________________
_____________________, _____________________,_____________________
____

Time Bagging Test Measurement Data

______ Initial Screening (ppmv) Equipment Piece[a] _____ Bkgd._____
______ Background Bag Organic Compound Conc. (ppmv)[b] ____________
______ Dry Gas Meter Reading (ℓ/min) ____________
______ Sample Bag 1 Organic Compound Conc. (ppmv) _______________
______ Vacuum Check in Bag (Y/N) (Must be YES to collect sample.)
______ Dry Gas Meter Temperature[c] (°C) ________
______ Dry Gas Meter Pressure[c] (mmHg) ________

______ Dry Gas Meter Reading (ℓ/min) ________
______ Sample Bag 2 Organic Compound Conc. (ppmv) _______________
______ Vacuum Check in Bag (Y/N) (Must be YES to collect sample.)
______ Dry Gas Meter Temperature[c] (°C) ________
______ Dry Gas Meter Pressure[c] (mmHg) ________

Condensate Accumulation: Starting Time ______ Final Time ______
Organic Condensate Collected (mℓ) ____________
Density of Organic Condensate (g/mℓ) ____________

______ Final Screening (ppmv) Equip. Piece[a] ________ Bkgd. ______

---

[a] The vacuum method is not recommended if the screening value is approximately 10 ppmv or less.

[b] Collection of a background bag is optional.

[c] Pressure and temperature are measured at the dry gas meter.

- The carrier gas used in the blow-through method of bagging should be analyzed by GC before it is used, and the concentration of organic compounds in the sample should be documented. For cylinder purge gases, one gas sample should be analyzed. For plant purge gas systems, gas samples should be analyzed with each bagged sample unless plant personnel can demonstrate that the plant gas remains stable enough over time to allow a one-time analysis.

- The portable monitoring instrument calibration procedure described in section 4.4.4 should be performed at the beginning and end of each day.

4.5.2 Quality Assurance Procedures

Accuracy checks on the laboratory instrumentation and portable monitoring device must be performed to ensure data quality. These checks include a leak rate check performed in the laboratory, blind standards to be analyzed by the laboratory instrumentation, and drift checks on the portable monitoring device.

4.5.2.1 Leak Rate Check

A leak rate check is normally performed in the laboratory by sampling an artificially induced leak rate of a known gas. This can clarify the magnitude of any bias in the combination of sampling/test method, and defines the variance in emissions estimation due to the sampling. If the result is outside the 80 to 120 percent recovery range, the problem must be investigated and corrected before sampling continues. The problems and associated solutions should be noted in the test report.

Leak rate checks should be performed at least two times per week during the program. The leak rate checks should be conducted at two concentrations: (1) within the range of 10 multiplied by the calculated lower limit of detection for the laboratory analytical instrument; and (2) within 20 percent of the maximum concentration that has been or is expected to be detected in the field during the bagging program.

To perform a leak rate check, first induce a known flow rate with one of the known gas concentrations into a sampling bag.

For example, this can be done using a gas permeation tube of a known organic compound constituent. Next, determine the concentration of the gas using a laboratory analytical instrument and compare the results to the known gas concentration.

If the calculated leak rate is not within ± 20 percent of the induced leak rate, further analysis should be performed to determine the reason.

Areas that can potentially induce accuracy problems include:

- Condensation,
- Pluggage,
- Seal of bag not tight (leakage),
- Adsorption onto bag, and
- Permeation of bag.

The results of all accuracy checks should be recorded on prepared data sheets.

4.5.2.2 Blind Standards Preparation and Performance

Blind standards are analyzed by the laboratory instrumentation to ensure that the instrument is properly calibrated. Blind standards must be prepared and submitted at least two times per week during the program. The blind standards are prepared by diluting or mixing known gas concentrations in a prescribed fashion so that the resulting concentrations are known. The analytical results should be within ± 25 percent of the blind standard gas concentration. If the results are not within 25 percent of the blind standard concentration, further analyses must be performed to determine the reason. Use of blind standards not only defines the analytical variance component and analytical accuracy, but it can serve to point out equipment malfunctions and/or operator error before questionable data are generated.

4.5.2.3 Drift Checks

Drift checks need to be performed to ensure that the portable monitoring instrument remains calibrated. At a minimum, drift checks must be performed before and after a small group of components (i.e., two or three) are bagged. Preferably, drift checks should be performed on the screening instrument immediately before and after each component is bagged. These checks should be performed by analyzing one of the calibration gases used to calibrate the portable monitoring instrument. The choice of calibration gas concentration should reflect the anticipated screening value of the next component to be monitored. For example, if a component had previously screened at 1,000 ppmv and been identified for bagging, the calibration standard should be approximately 900 ppmv.

Drift check data must be recorded on data sheets containing the information shown in the example in table 4-6. If the observed instrument reading is different from the certified value by greater than ± 20 percent, then a full multipoint calibration must be performed (see section 3.2.4.1). Also, all those components analyzed since the last drift check must be retested.

Drift checks should also be performed if flameout of the portable monitoring instrument occurs. Using the lowest calibration gas standard (i.e., approximately 9 ppmv standard), determine the associated response on the portable monitoring instrument. If the response is not within ± 10 percent of the calibration gas concentration, a full multipoint calibration is required before testing resumes.

TABLE 4-6. EXAMPLE DRIFT TEST REPORT FORM

Plant ID________________________

Instrument ID _________________

Analyst Name _________________

Date	Standard Gas Conc. (ppmv)	Time	Measured Conc. (ppmv)	% Error[a]	ID Number of Component Bagged Since Last Test

[a] % Error = $\frac{\text{Certified Conc. - Measured Conc.}}{\text{Certified Conc.}} * 100$

4.6 REFERENCES

1. Code of Federal Regulations, Title 40, Part 60, Appendix A. Reference Method 21, Determination of Volatile Organic Compound Leaks. Washington, DC. U.S. Government Printing Office. Revised June 22, 1990.

5.0 ESTIMATION OF CONTROL EFFICIENCIES FOR EQUIPMENT LEAK CONTROL TECHNIQUES

5.1 INTRODUCTION

In this chapter, control techniques for reducing equipment leak emissions are described. There are two primary techniques for reducing equipment leak emissions: (1) modifying or replacing existing equipment, and (2) implementing a leak detection and repair (LDAR) program.

Modifying or replacing existing equipment is referred to in this chapter as an "equipment modification." Examples of equipment modifications include installing a cap on an open-ended line, replacing an existing pump with a sealless type, and installing on a compressor a closed-vent system that collects potential leaks and routes them to a control device. In section 5.2, possible equipment modifications for each of the equipment types are briefly described. Also, the estimated control efficiency is presented for each equipment modification.

An LDAR program is a structured program to detect and repair equipment that is identified as leaking. The focus of this chapter is LDAR programs for which a portable monitoring device is used to identify equipment leaks from individual pieces of equipment. In section 5.3, an approach is presented for estimating the control effectiveness of an LDAR program.

5.2 EQUIPMENT MODIFICATION CONTROL EFFICIENCY

Controlling emissions by modifying existing equipment is achieved by either installing additional equipment that eliminates or reduces emissions, or replacing existing equipment with sealless types. Equipment modifications for each equipment type are described in the following sections. A separate section is included on closed-vent systems, which can be installed on more than one type of equipment. Equipment modifications that can be used for each equipment type are summarized in table 5-1. Table 5-1 also contains an approximate control efficiency for each modification.

5.2.1 Closed-Vent Systems

A closed-vent system captures leaking vapors and routes them to a control device. The control efficiency of a closed-vent system depends on the percentage of leaking vapors that are routed to the control device and the efficiency of the control device. A closed-vent system can be installed on a single piece of equipment or on a group of equipment pieces. For use on single pieces of equipment, closed-vent systems are primarily applicable to equipment types with higher potential emission rates, such as pumps, compressors, and pressure relief devices.

5.2.2 Pumps

Equipment modifications that are control options for pumps include routing leaking vapors to a closed-vent system (as discussed in section 5.2.1), installing a dual mechanical seal containing a barrier fluid, or replacing the existing pump with a sealless type.

5.2.2.1 Dual Mechanical Seals. A dual mechanical seal contains two seals between which a barrier fluid is circulated. Depending on the design of the dual mechanical seal, the barrier fluid can be maintained at a pressure that is higher than the pumped fluid or at a pressure that is lower than the pumped fluid. If the barrier fluid is maintained at a higher pressure than the pumped fluid, the pumped fluid will not leak to the atmosphere. The control efficiency of a dual mechanical seal with a barrier fluid at a higher pressure than the pumped fluid is essentially 100 percent, assuming both the inner and outer seal do not fail simultaneously.

If the barrier fluid is maintained at a lower pressure than the pumped fluid, a leak in the inner seal would result in the pumped fluid entering the barrier fluid. To prevent emissions of the pumped fluid to the atmosphere, a barrier fluid reservoir

TABLE 5-1. SUMMARY OF EQUIPMENT MODIFICATIONS

Equipment type	Modification	Approximate control efficiency (%)
Pumps	Sealless design	100[a]
	Closed-vent system	90[b]
	Dual mechanical seal with barrier fluid maintained at a higher pressure than the pumped fluid	100
Compressors	Closed-vent system	90[b]
	Dual mechanical seal with barrier fluid maintained at a higher pressure than the compressed gas	100
Pressure relief devices	Closed-vent system	c
	Rupture disk assembly	100
Valves	Sealless design	100[a]
Connectors	Weld together	100
Open-ended lines	Blind, cap, plug, or second valve	100
Sampling connections	Closed-loop sampling	100

[a] Sealless equipment can be a large source of emissions in the event of equipment failure.

[b] Actual efficiency of a closed-vent system depends on percentage of vapors collected and efficiency of control device to which the vapors are routed.

[c] Control efficiency of closed vent-systems installed on a pressure relief device may be lower than other closed-vent systems, because they must be designed to handle both potentially large and small volumes of vapor.

system should be used. At the reservoir, the pumped fluid can vaporize (i.e., de-gas) and then be collected by a closed-vent system.

The actual emissions reduction achievable through use of dual mechanical seals depends on the frequency of seal failure. Failure of both the inner and outer seals could result in relatively large releases of the process fluid. Pressure monitoring of the barrier fluid may be used to detect failure of the seals, allowing for a quick response to a failure.

5.2.2.2 Sealless Pumps. When operating properly, a sealless pump will not leak because the process fluid cannot escape to the atmosphere. Sealless pumps are used primarily in processes where the pumped fluid is hazardous, highly toxic, or very expensive, and where every effort must be made to prevent all possible leakage of the fluid. Under proper operating conditions, the control efficiency of sealless pumps is essentially 100 percent; however, if a catastrophic failure of a sealless pump occurs, there is a potential for a large quantity of emissions.

5.2.3 Compressors

Emissions from compressors may be reduced by collecting and controlling the emissions from the seal or by improving seal performance. Shaft seals for compressors are of several different types--all of which restrict but do not eliminate leakage. In some cases, compressors can be equipped with ports in the seal area to evacuate collected gases using a closed-vent system. Additionally, for some compressor seal types, emissions can be controlled by using a barrier fluid in a similar manner as described for pumps.

5.2.4 Pressure Relief Valves

Equipment leaks from pressure relief valves (PRV’s) occur as a result of improper reseating of the valve after a release, or if the process is operating too close to the set pressure of the PRV and the PRV does not maintain its seal. Emissions occurring from PRV’s as a result of an overpressure discharge are not considered to be equipment leak emissions. There are two primary alternatives for controlling equipment leaks from pressure relief devices: use of a rupture disk (RD) in conjunction with the PRV, or use of a closed-vent system.

5.2.4.1 Rupture Disk/Pressure Relief Valve Combination. Although they are also pressure relief devices, RD's can be installed upstream of a PRV to prevent fugitive emissions through the PRV seat. Rupture disk/pressure relief valve combinations require certain design constraints and criteria to avoid potential safety hazards, which are not covered in this document. If the RD fails, it must be replaced. The control efficiency of the RD/PRV combination is assumed to be 100 percent when operated and maintained properly.

5.2.4.2 Closed-Vent System. A closed-vent system can be used to transport equipment leaks from a pressure relief device to a control device such as a flare. The equipment leak control efficiency for a closed-vent system installed on a pressure relief device may not be as high as the control efficiency that can be achieved by installing a closed-vent system on other equipment types. This is because emissions from pressure relief devices can be either high flow emissions during an overpressure incident or low flow emissions associated with equipment leaks, and it may be difficult to design a control device to efficiently handle both high and low flow emissions.

5.2.5 Valves

Emissions from process valves can be eliminated if the valve stem can be isolated from the process fluid. Two types of sealless valves are available: diaphragm valves and sealed bellows valves. The control efficiency of both diaphragm and sealed bellows valves is virtually 100 percent. However, a failure of these types of valves has the potential to cause temporary emissions much larger than those from other types of valves.

5.2.6 Connectors

In cases where connectors are not required for safety, maintenance, process modification, or periodic equipment removal, emissions can be eliminated by welding the connectors together.

5.2.7 Open-Ended Lines

Emissions from open-ended lines can be controlled by properly installing a cap, plug, or second valve to the open end. If a second valve is installed, the upstream valve should always be closed first after use of the valves to prevent the trapping of fluids between the valves. The control efficiency of these measures is assumed to be essentially 100 percent.

5.2.8 Sampling Connections

Emissions from sampling connections occur as a result of purging the sampling line to obtain a representative sample of the process fluid. Emissions from sampling connections can be reduced by using a closed-loop sampling system or by collecting the purged process fluid and transferring it to a control device or back to the process. The closed-loop sampling system is designed to return the purged fluid to the process at a point of lower pressure. A throttle valve or other device is used to induce the pressure drop across the sample loop. The efficiency of a closed-loop system is assumed to be 100 percent.

Alternatively, in some cases, sampling connections can be designed to collect samples without purging the line. If such a sampling connection is installed and no emissions to the atmosphere occur when a sample is collected, then the control efficiency can be assumed to be 100 percent.

5.3 LEAK DETECTION AND REPAIR CONTROL EFFECTIVENESS

An LDAR program is designed to identify pieces of equipment that are emitting sufficient amounts of material to warrant reduction of the emissions through repair. These programs are best applied to equipment types that can be repaired on-line, resulting in immediate emissions reduction, and/or to equipment types for which equipment modifications are not feasible. An LDAR program is best suited to valves and pumps, and can also be implemented for connectors.

For other equipment types, an LDAR program is not as applicable. Compressors are repaired in a manner similar to pumps; however, because compressors ordinarily do not have a spare for bypass, a process unit shutdown may be required for repair. Open-ended lines are most easily controlled by equipment modifications. Emissions from sampling connections can only be reduced by changing the method of collecting the sample (since by definition equipment leak emissions are the material purged from the line), and cannot be reduced by an LDAR program. Safety considerations may preclude the use of an LDAR program on pressure relief valves.

In this section, an approach is presented that can be used to estimate the control effectiveness of any given LDAR program for light liquid pumps, gas valves, light liquid valves, and connectors. The approach is based on the relationship between the percentage of equipment pieces that are leaking and the corresponding average leak rate for all of the equipment. In this approach, the three most important factors in determining the control effectiveness are: (1) how a "leak" is defined, (2) the initial leak frequency before the LDAR program is implemented, and (3) the final leak frequency after the LDAR program is implemented. The leak definition (or action level) is the screening value at which a "leak" is indicated if a piece of equipment screens equal to or greater than that value. The leak frequency is the fraction of equipment with screening values equal to or greater than the leak definition.

Once these three factors are determined, a graph that plots leak frequency versus mass emission rate at several different leak definitions is used to predict emissions preceding and subsequent to implementing the LDAR program. In this way the emissions reduction (i.e., control effectiveness) associated with the LDAR program can be easily calculated.

A general description of the approach is provided in the subsections below. This is followed by an example application of the approach. The approach has been applied to determine the control effectiveness at Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refinery process units for the following LDAR programs: (1) monthly LDAR with a leak definition of 10,000 parts per million by volume (ppmv), (2) quarterly LDAR with a leak definition of 10,000 ppmv, and (3) LDAR equivalent to that specified in the proposed hazardous organic National Emission Standard for Hazardous Air Pollutants (NESHAP) equipment leaks negotiated regulation.[1] Tables 5-2 and 5-3 summarize the estimated control effectiveness for the three LDAR programs mentioned above at SOCMI process units and refineries, respectively. It should be noted that, to calculate the control effectiveness values presented in tables 5-2 and 5-3, assumptions were made that may not necessarily be applicable to specific process units. For example, the control effectiveness values in the tables are based on the assumption that the emission rate prior to implementing the LDAR program is the emission rate that would be predicted by the average emission factor. The best way to calculate the effectiveness of an LDAR program is by collecting and analyzing data at the specific process unit.

5.3.1 Approach for Estimating LDAR Control Effectiveness

As previously stated, the key parameters for estimating the control effectiveness of an LDAR program are the leak definition, the initial leak frequency, and the final leak frequency. The leak definition is a given part of an LDAR program. It can either be defined by the process unit implementing the program or by an equipment standard to which the process unit must comply. After the leak definition is established, the control effectiveness of an LDAR program can be estimated based on the average leak rate before the LDAR program is implemented, and the average leak rate after the program is in place.

Figures 5-1 through 5-4 are graphs presenting mass emission rate versus leak frequency for SOCMI-type process units at several leak definitions for gas valves, light liquid valves, light liquid pumps, and connectors, respectively. Figures 5-5 through 5-8 are graphs presenting mass emission rate versus leak frequency for refinery process units at several leak definitions for gas valves, light liquid valves, light liquid pumps, and connectors, respectively. Figures 5-9 through 5-15 are graphs presenting mass emission rate versus leak frequency for gas fittings, light liquid fittings, gas others, light liquid others, light liquid pumps, gas valves, and light liquid valves, for

TABLE 5-2. CONTROL EFFECTIVENESS FOR AN LDAR PROGRAM AT A SOCMI PROCESS UNIT

Equipment type and service	Control effectiveness (%) Monthly monitoring 10,000 ppmv leak definition	Quarterly monitoring 10,000 ppmv leak definition	HON reg neg[a]
Valves - gas	87	67	92
Valves - light liquid	84	61	88
Pumps - light liquid	69	45	75
Connectors - all	b	b	93

[a] Control effectiveness attributable to the requirements of the proposed hazardous organic NESHAP equipment leak negotiated regulation are estimated based on equipment-specific leak definitions and performance levels.

[b] Data are not available to estimate control effectiveness.

TABLE 5-3. CONTROL EFFECTIVENESS FOR AN LDAR PROGRAM AT A REFINERY PROCESS UNIT

	Control effectiveness (%)		
Equipment type and service	Monthly monitoring 10,000 ppmv leak definition	Quarterly monitoring 10,000 ppmv leak definition	HON reg neg[a]
Valves - gas	88	70	96
Valves - light liquid	76	61	95
Pumps - light liquid	68	45	88
Connectors - all	b	b	81

[a] Control effectiveness attributable to the requirements of the proposed hazardous organic NESHAP equipment leak negotiated regulation are estimated based on equipment-specific leak definitions and performance levels.

[b] Data are not available to estimate control effectiveness.

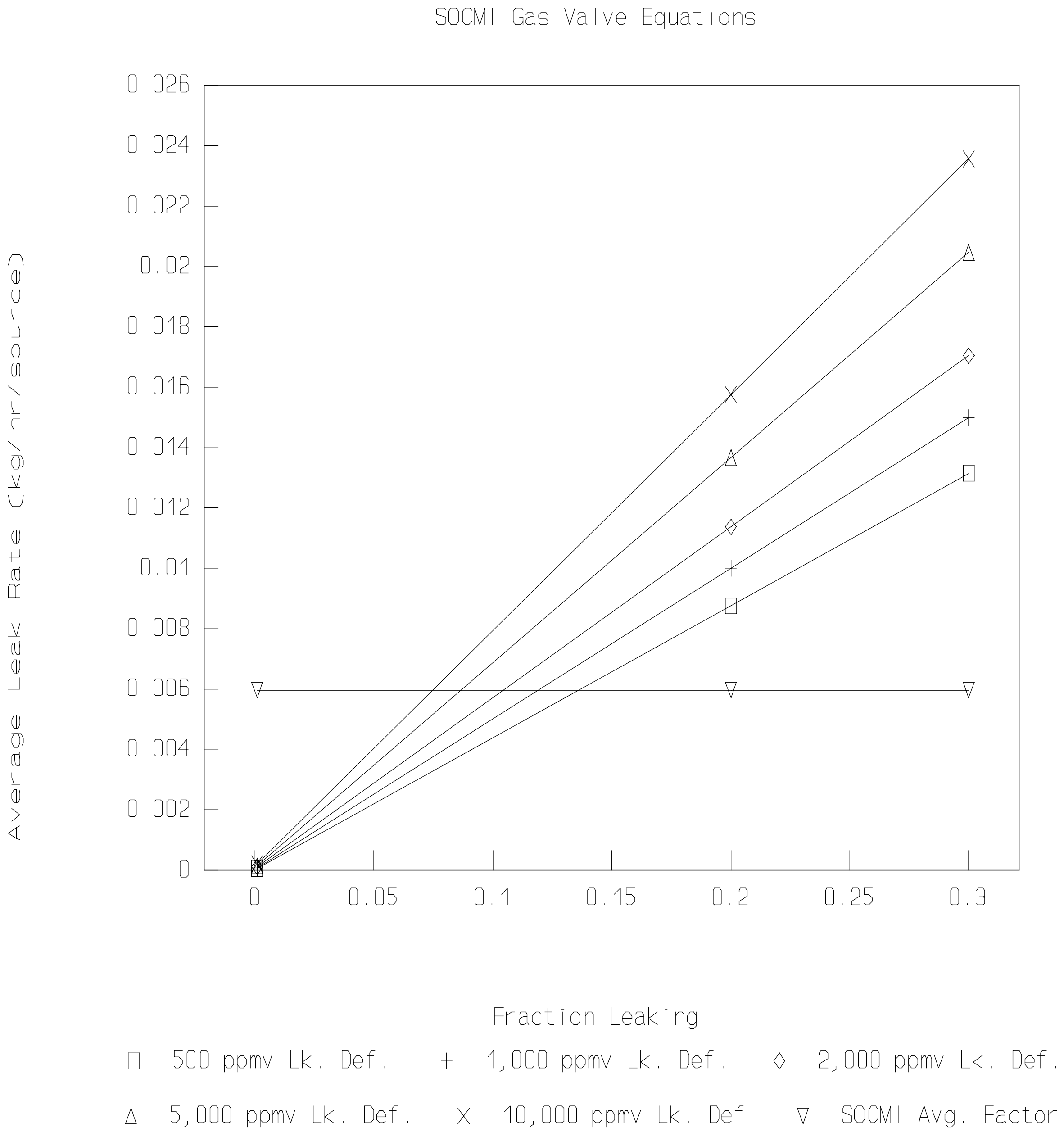


Figure 5-1. SOCMI Gas Valve Average Leak Rate Versus Fraction Leaking at Several Leak Definitions.

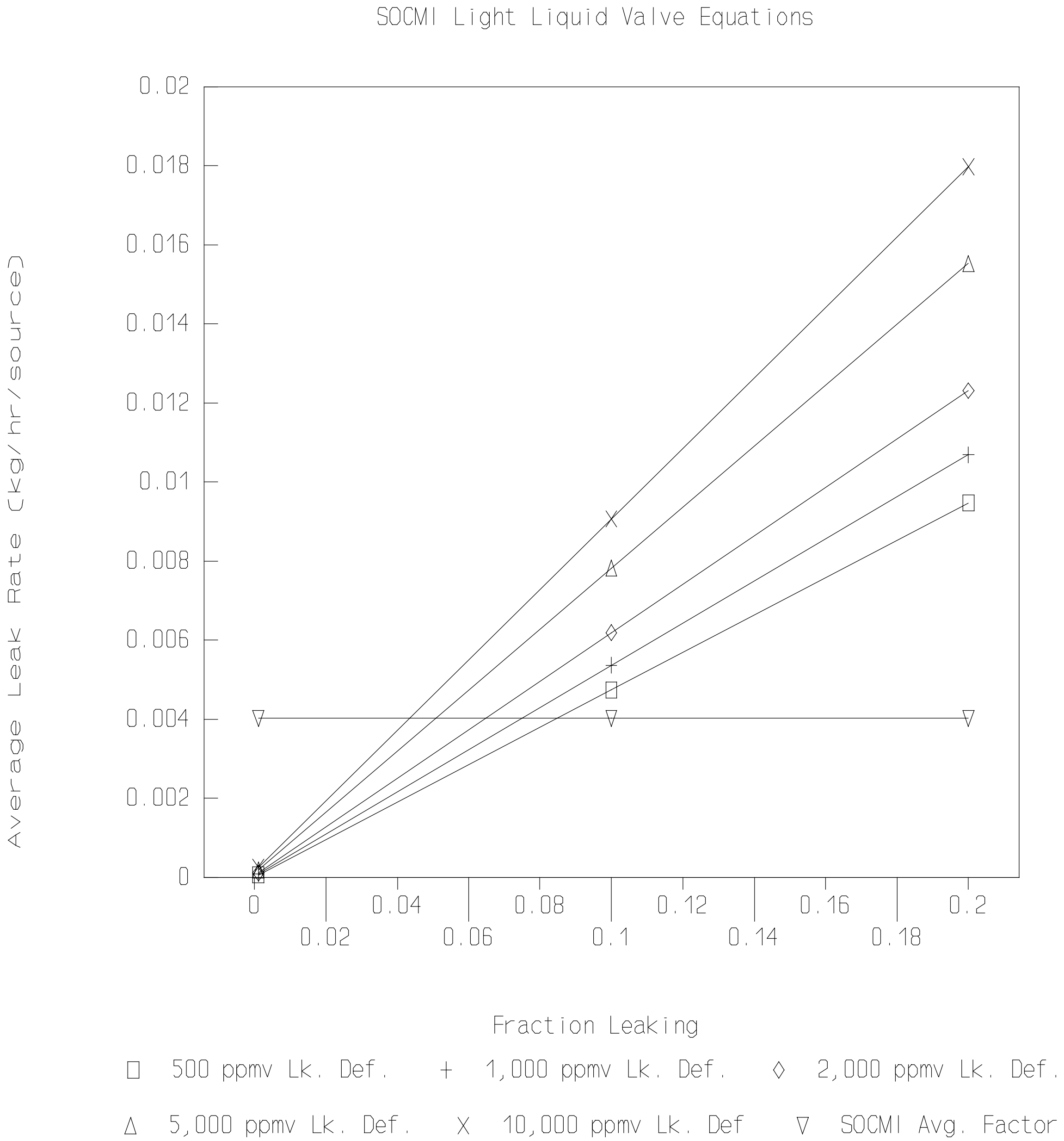


Figure 5-2. SOCMI Light Liquid Valve Average Mass Emission Rate Versus Fraction Leaking at Several Leak Definitions

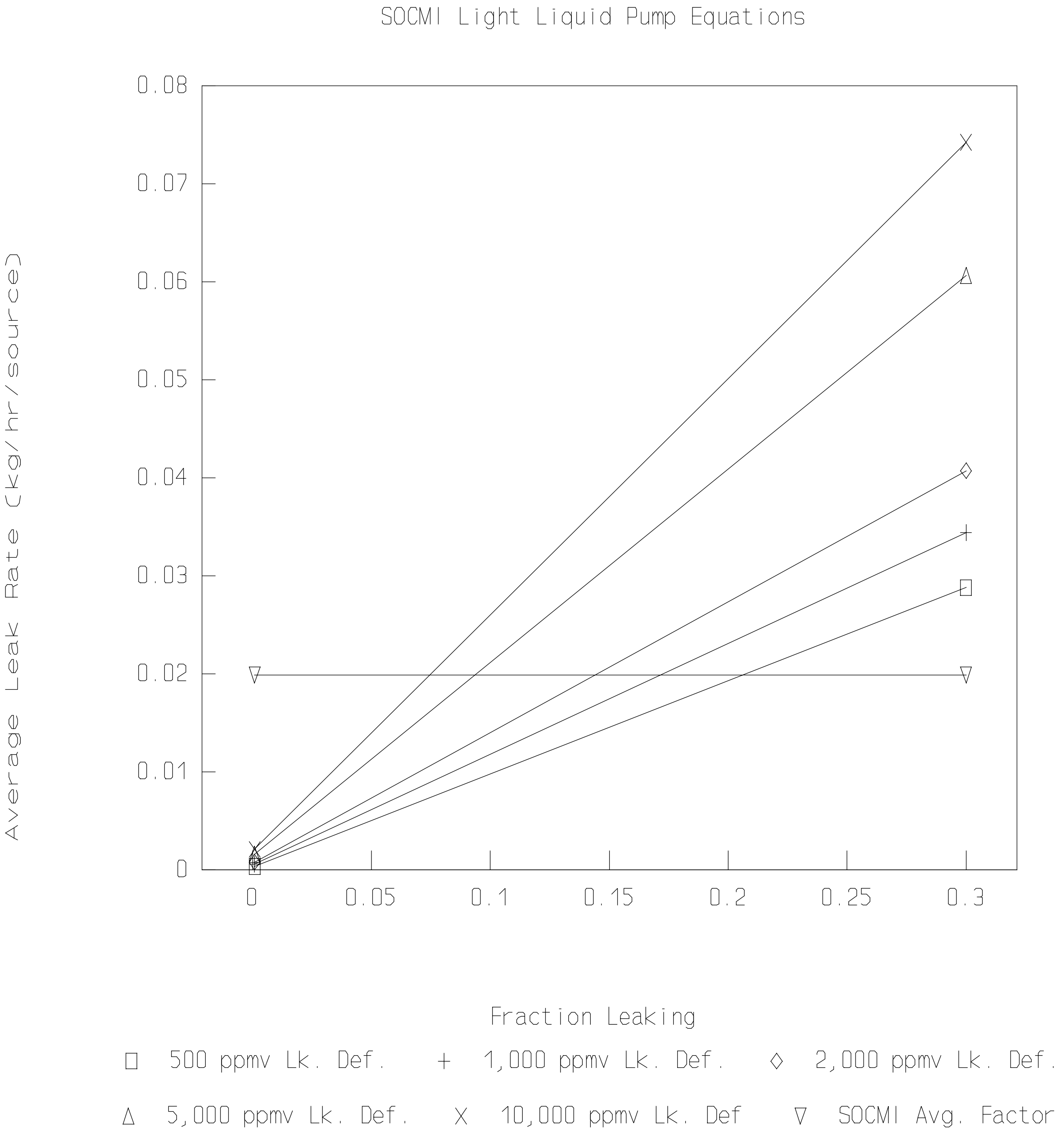


Figure 5-3. SOCMI Light Liquid Pump Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

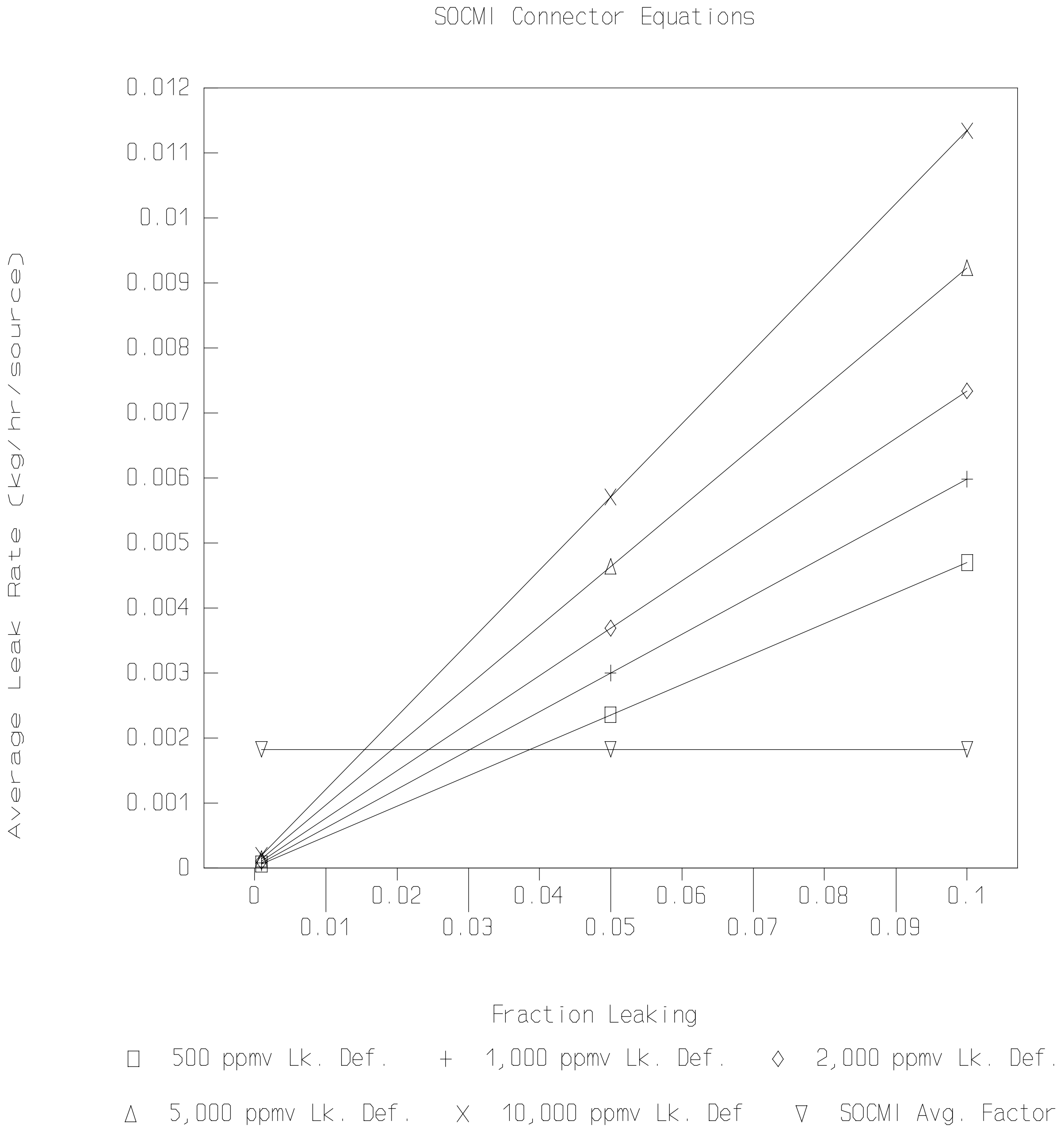


Figure 5-4. SOCMI Connector Average Leak Rate Versus Fraction Leaking at Several Leak Definitions.

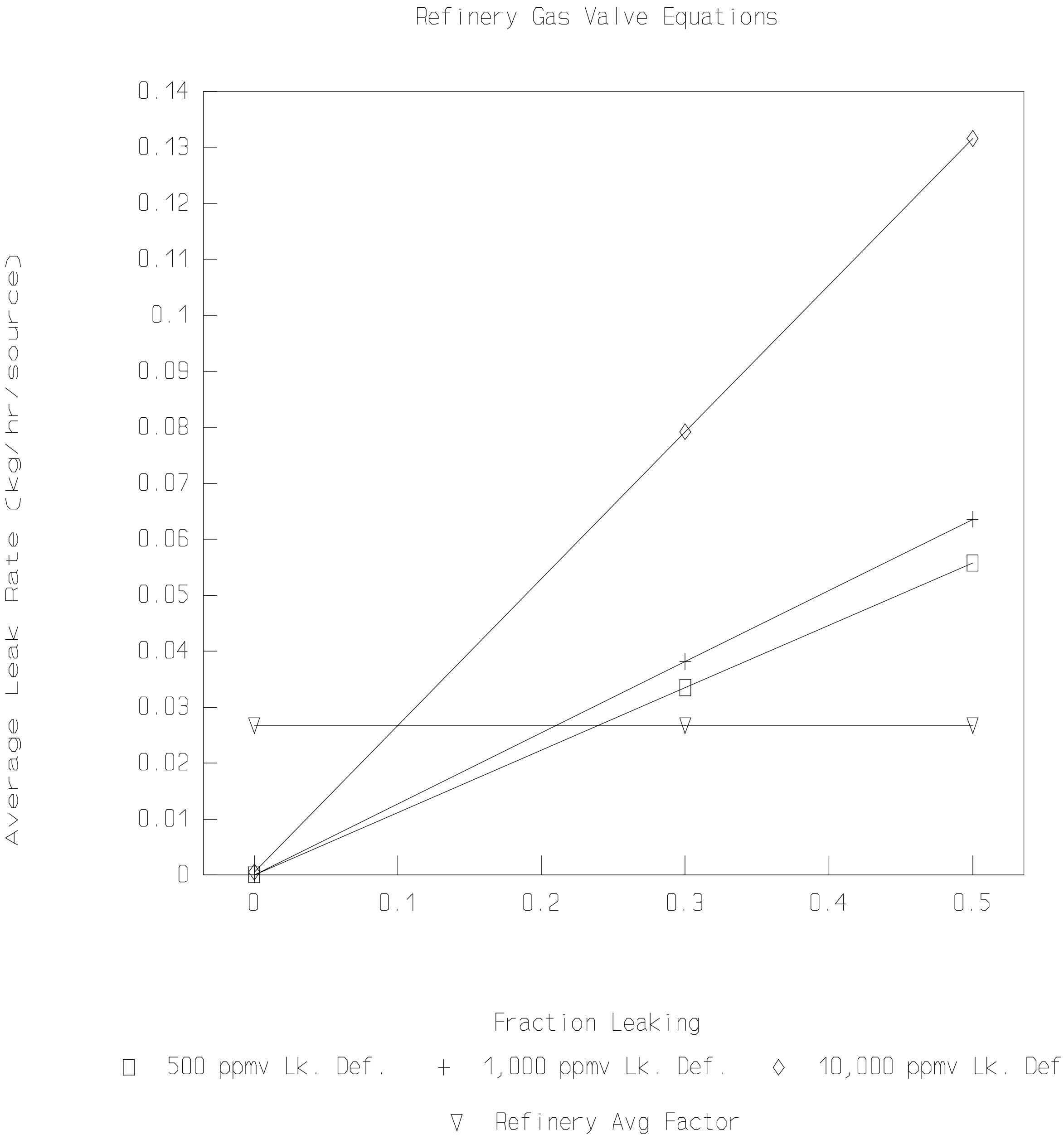


Figure 5-5. Refinery Gas Valve Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

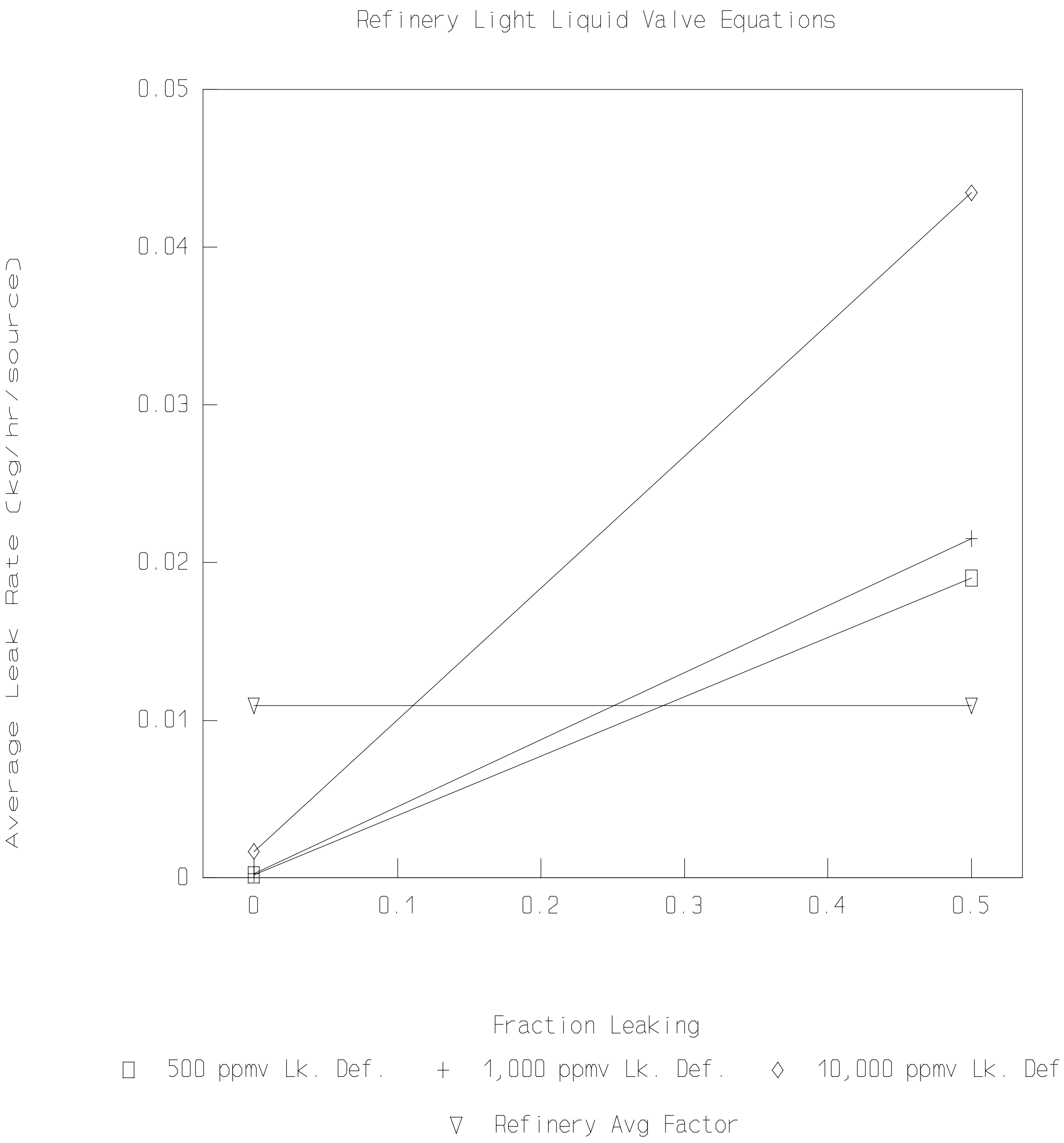


Figure 5-6. Refinery Light Liquid Valve Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

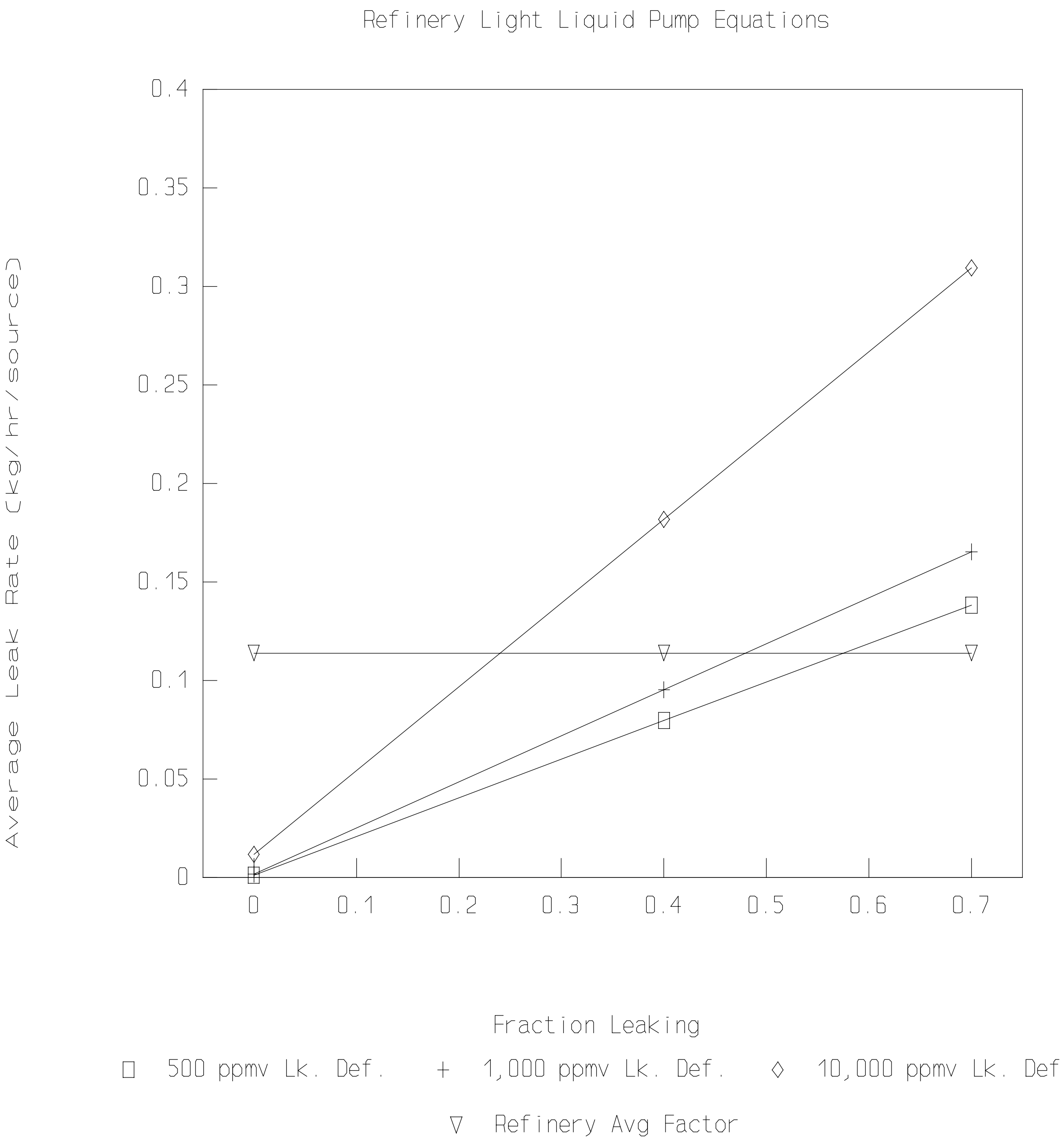


Figure 5-7. Refinery Light Liquid Pump Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

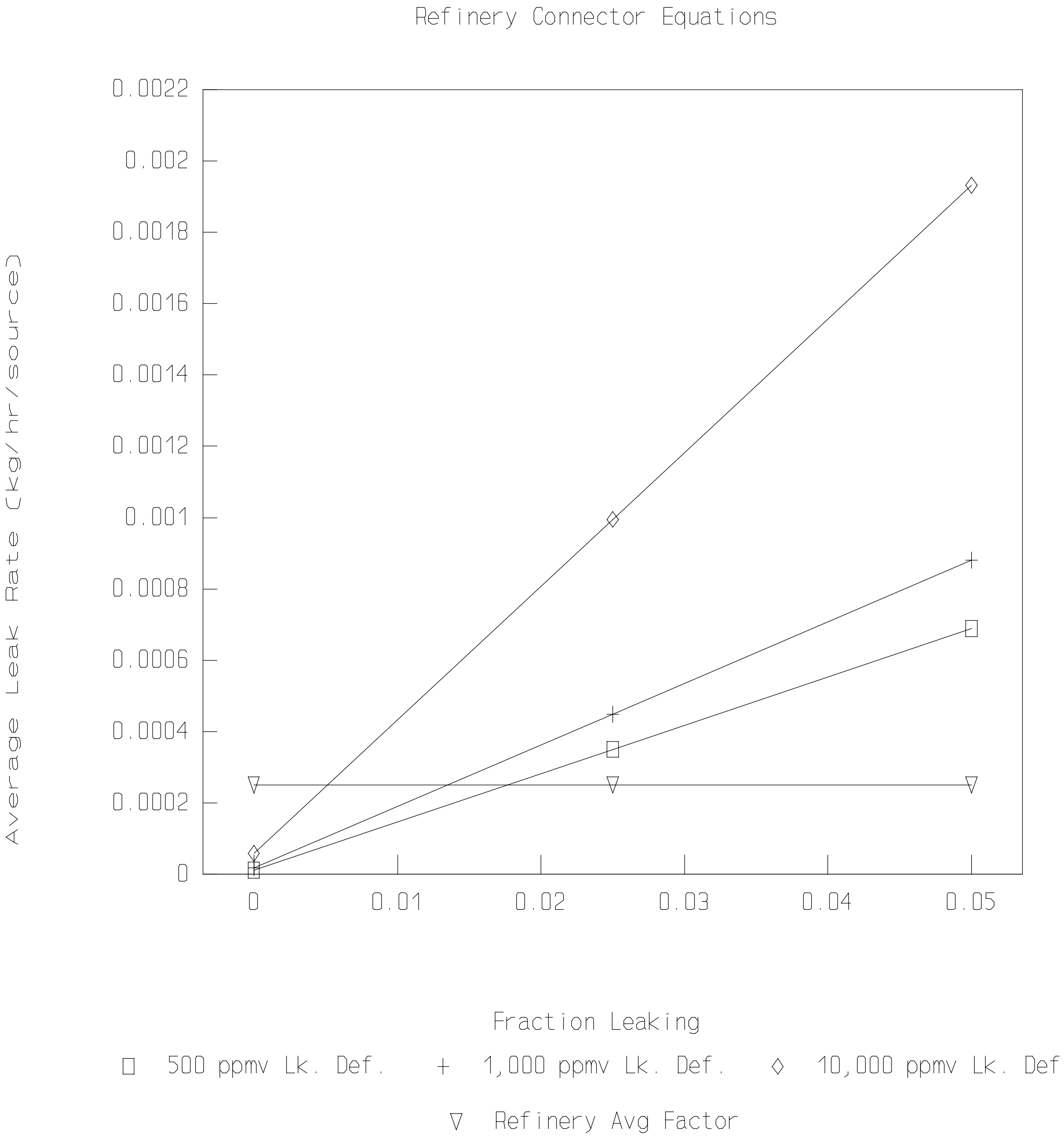


Figure 5-8. Refinery Connector Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

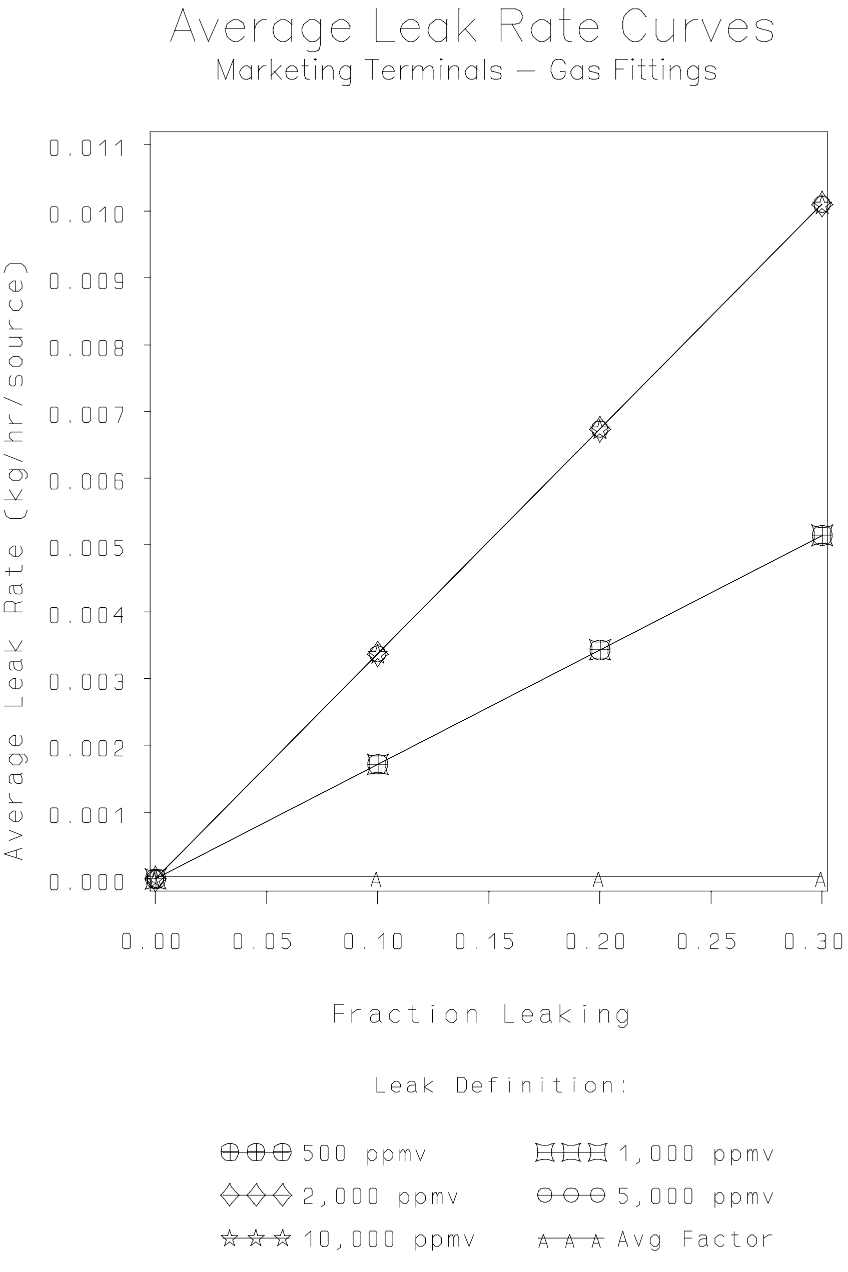


Figure 5-9. Marketing Terminal Gas Fittings Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

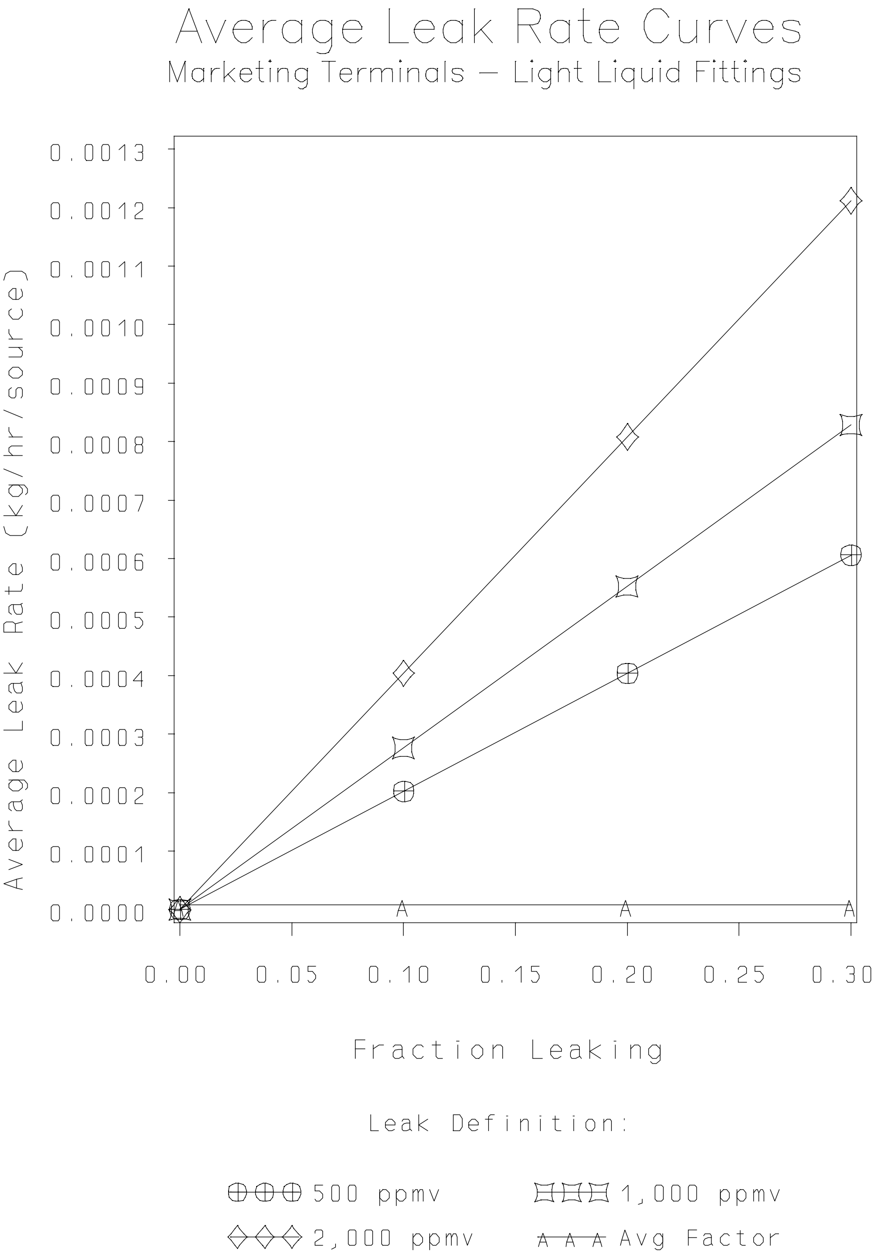


Figure 5-10. Marketing Terminal Light Liquid Fittings Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

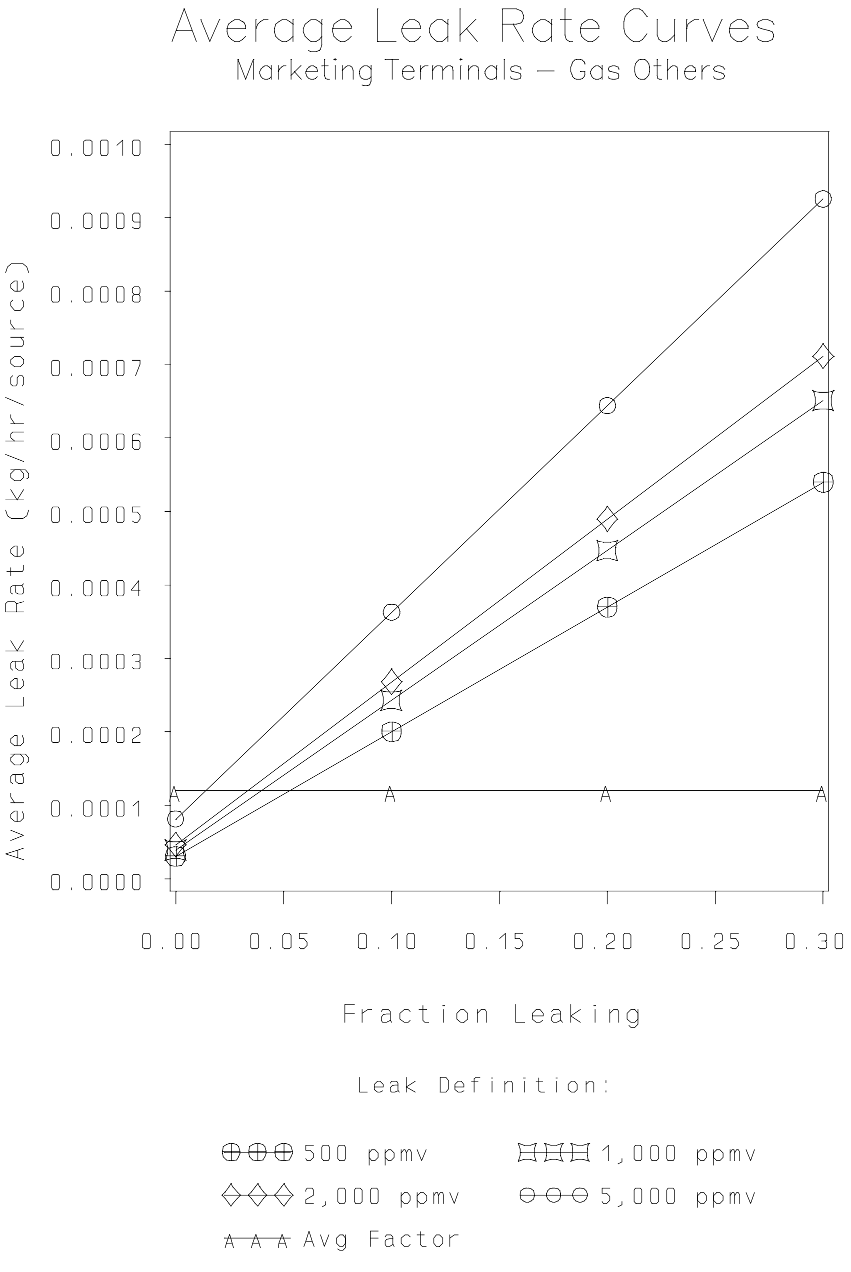


Figure 5-11. Marketing Terminal Gas Others Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

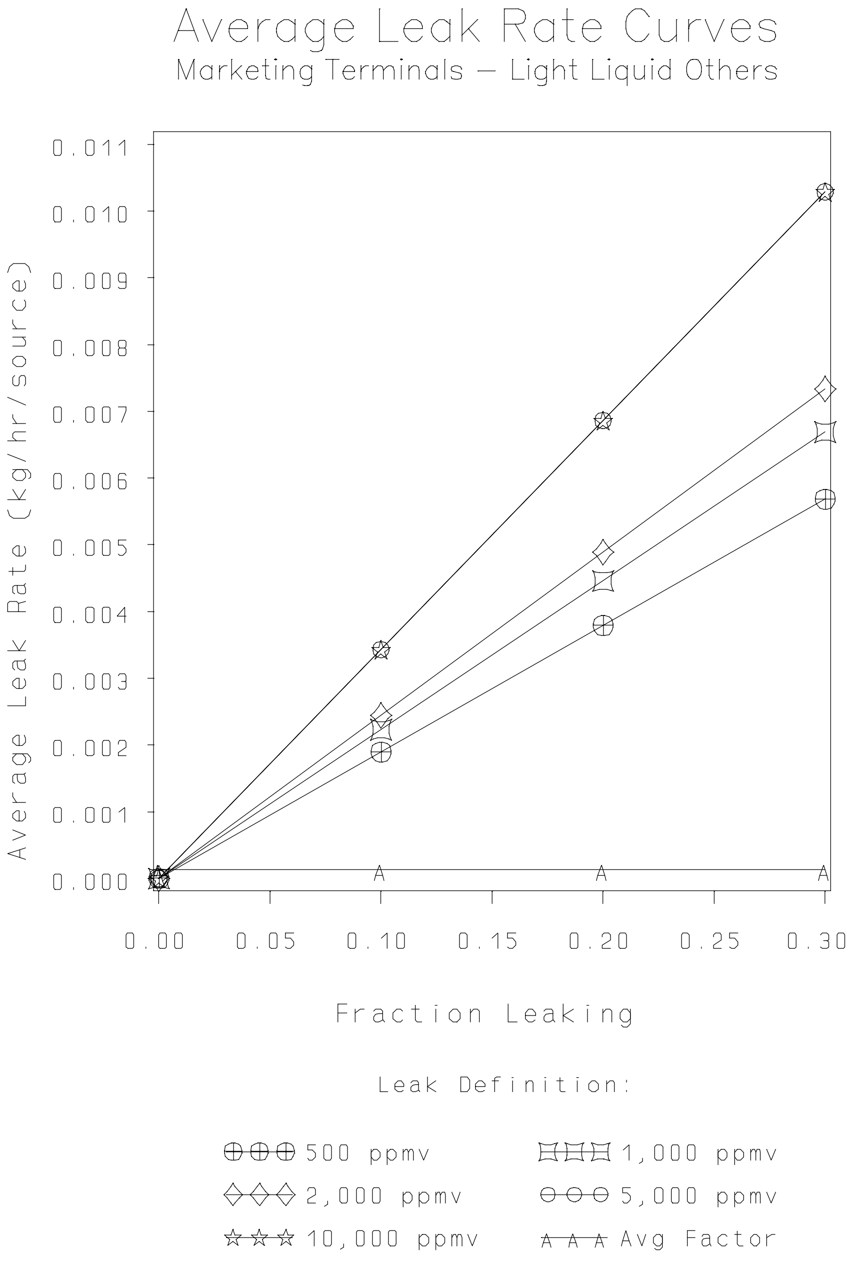


Figure 5-12. Marketing Terminal Light Liquid Others Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

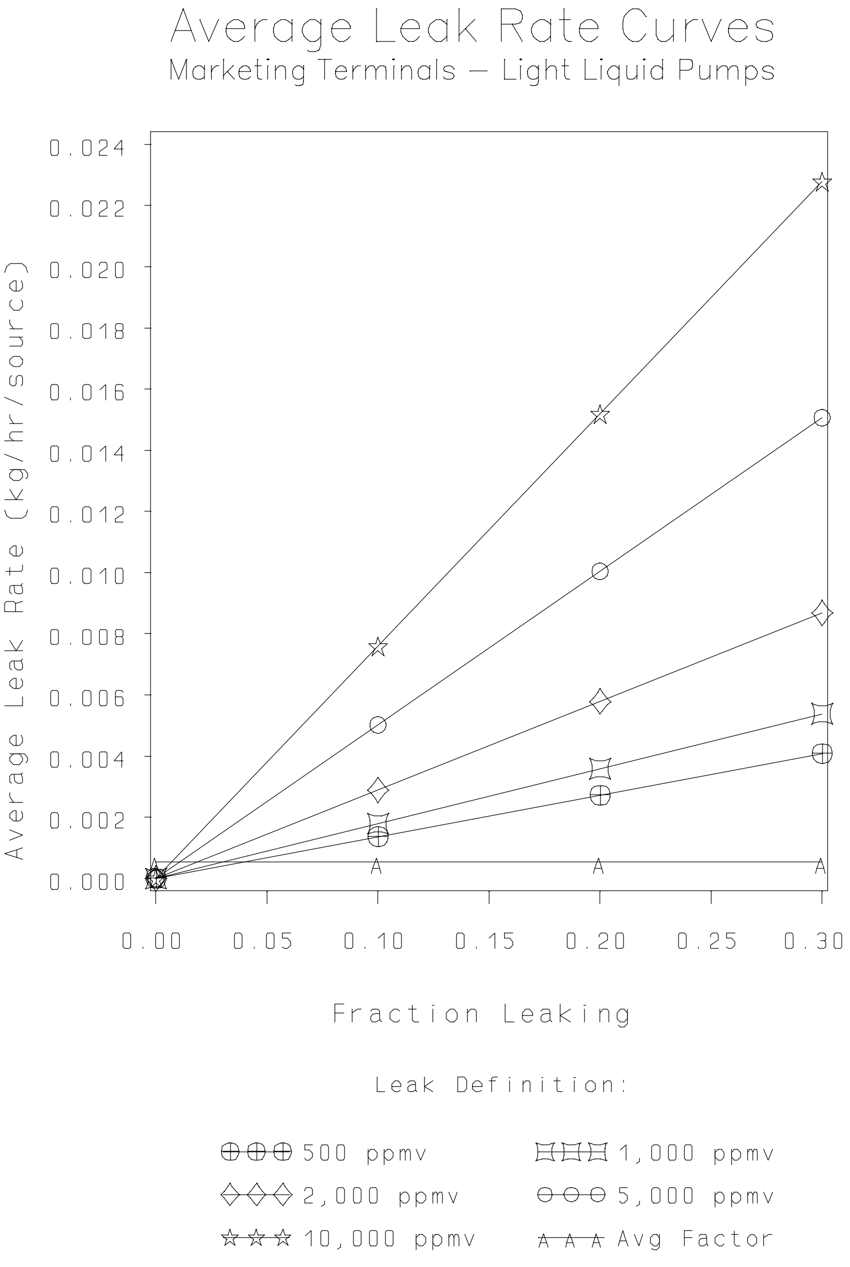


Figure 5-13. Marketing Terminal Light Liquid Pumps Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

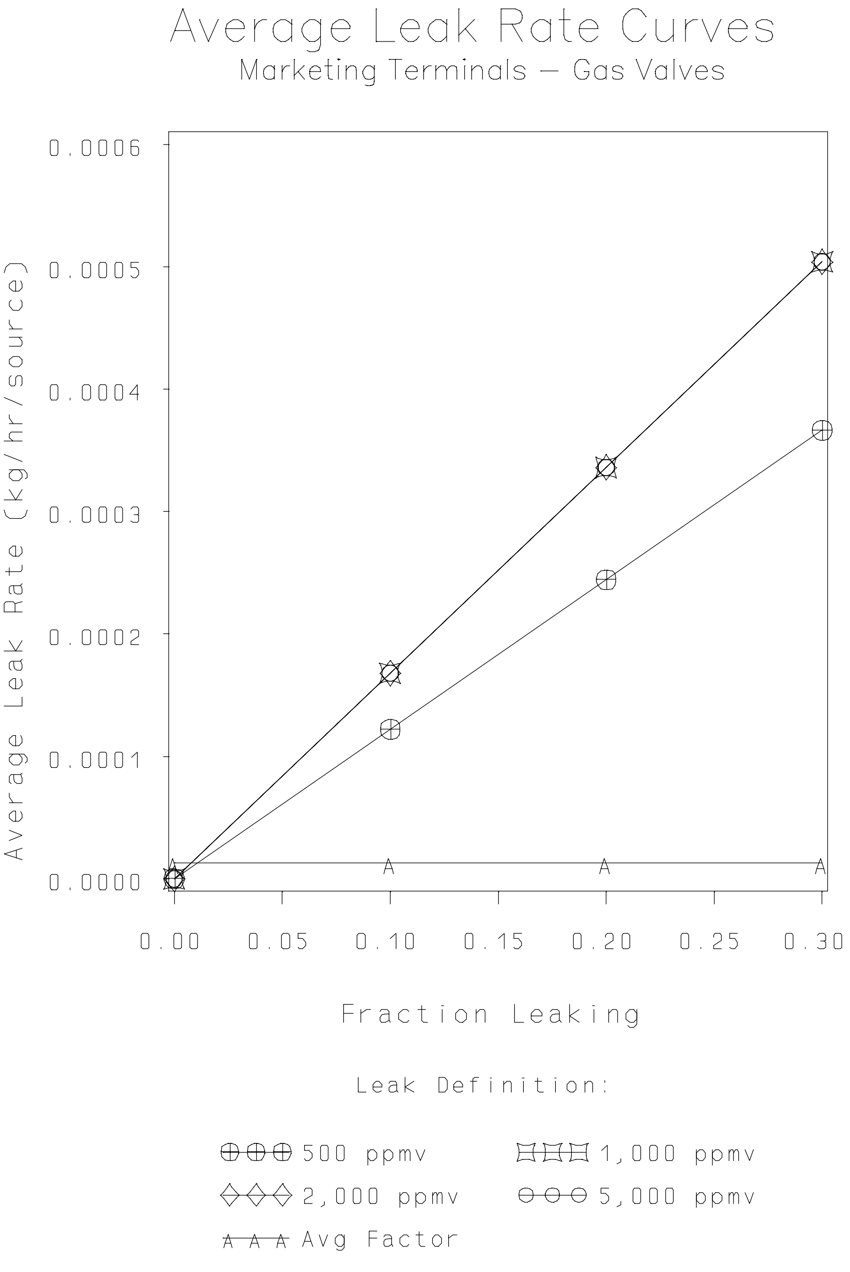


Figure 5-14. Marketing Terminal Gas Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

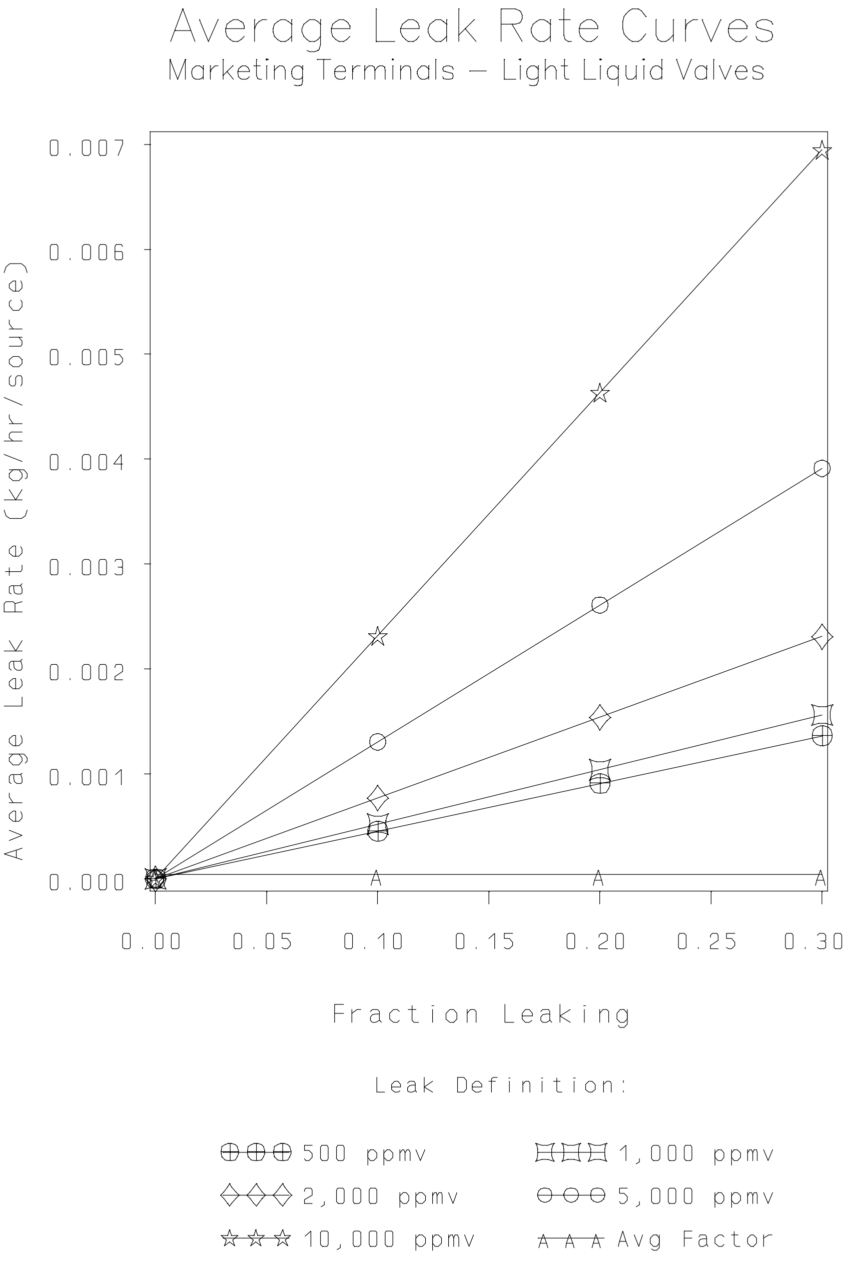


Figure 5-15. Marketing Terminal Liquid Light Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

marketing terminal process units. Figures 5-16 through 5-34 present mass emission rate as a function of leak frequency for connectors, flanges, open-ended lines, others, pumps, and valves at oil and gas production operations. Using these figures, for a given leak definition, the leak rate before and after the LDAR program is implemented, along with the corresponding control effectiveness, can be determined by plotting the initial and final leak frequency on these graphs. Tables 5-4, 5-5, 5-6, and 5-7 present equations for the lines in each of the SOCMI, refinery, marketing terminal, and oil and gas production operations, and graphs, respectively. Appendix G describes the approach that was used to develop the equations.

Figure 5-35 provides guidance on how to determine the initial and final leak frequencies. This figure is a simplified graphical presentation on how the leak frequency will change after an LDAR program is implemented. When generating the figure, it was assumed that all equipment pieces are monitored at the same time. Each occurrence of equipment monitoring is referred to as a "monitoring cycle," and it is assumed that equal time periods lapse between monitoring cycles.

From figure 5-35, it can be seen that there is an immediate reduction in leak frequency after the LDAR program is implemented, and then the leak frequency will oscillate over monitoring cycles. This oscillation occurs because between monitoring cycles a certain percentage of previously non-leaking equipment will begin to leak. There are four key points on the graph presented in figure 5-35. These key points are:

- Point X - initial leak frequency;
- Point Y - leak frequency immediately after monitoring for and repairing leaking equipment (i.e., immediately after a monitoring cycle);
- Point Z - leak frequency immediately preceding a monitoring cycle; and
- Point F - average leak frequency between monitoring cycles (final leak frequency).

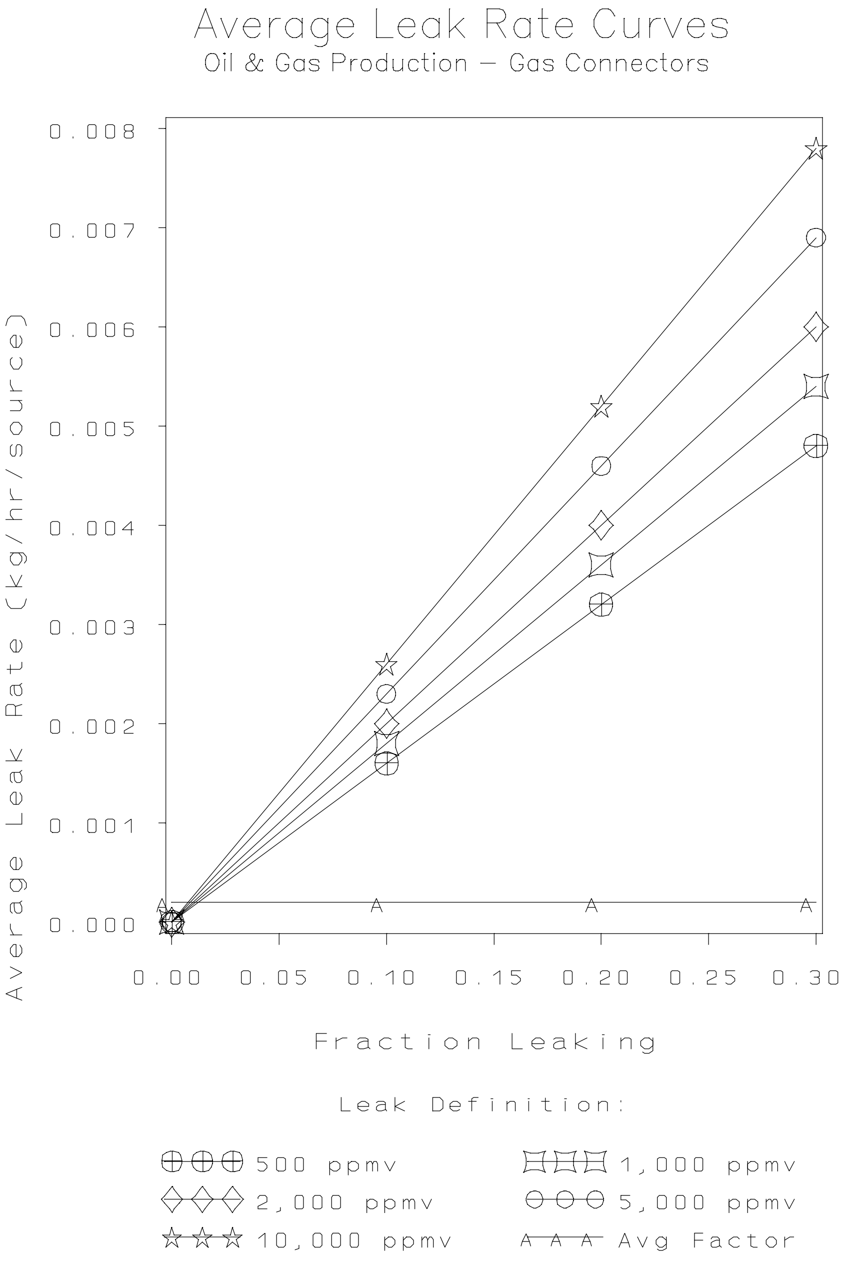


Figure 5-16. Oil and Gas Production Gas Connectors Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

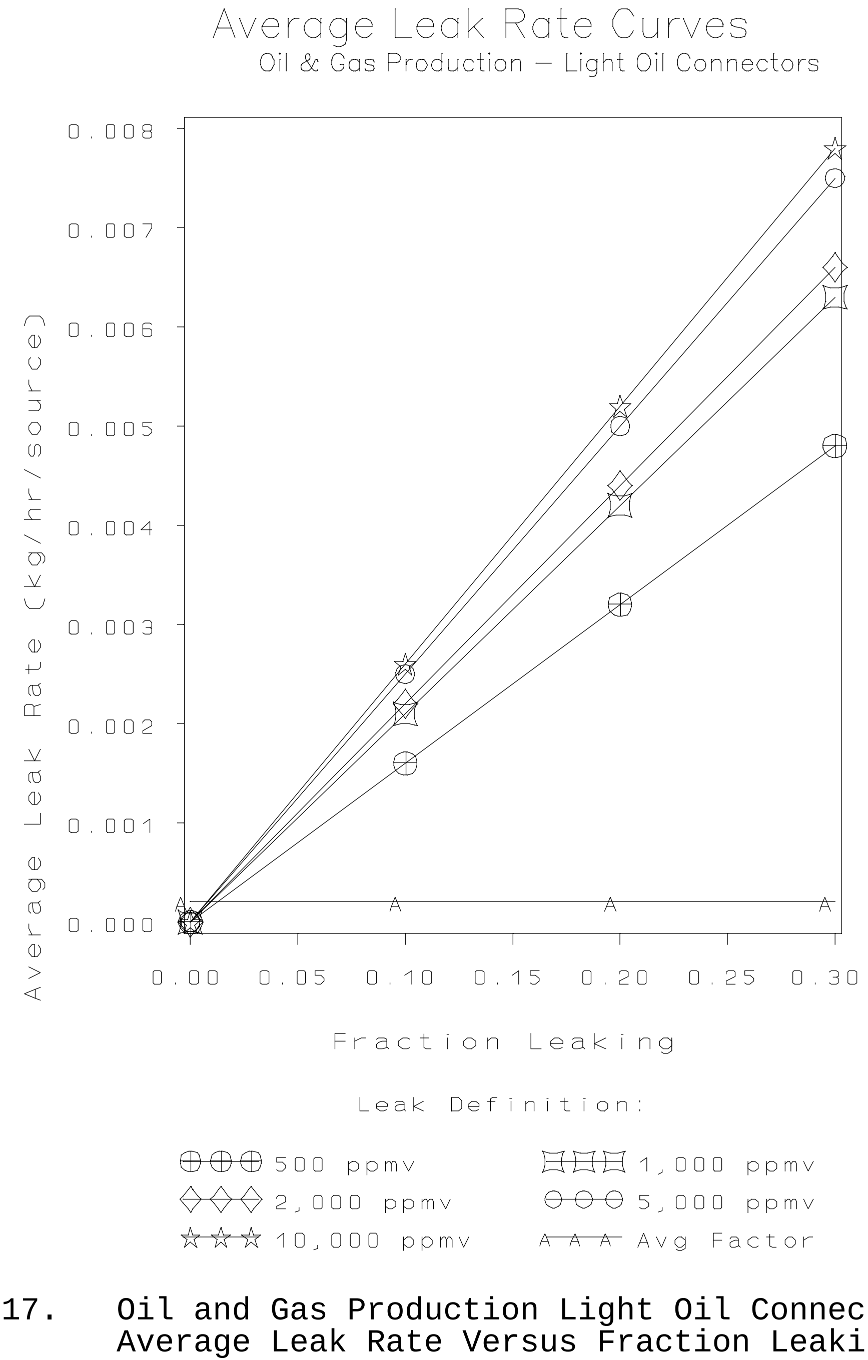


Figure 5-17. Oil and Gas Production Light Oil Connectors Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

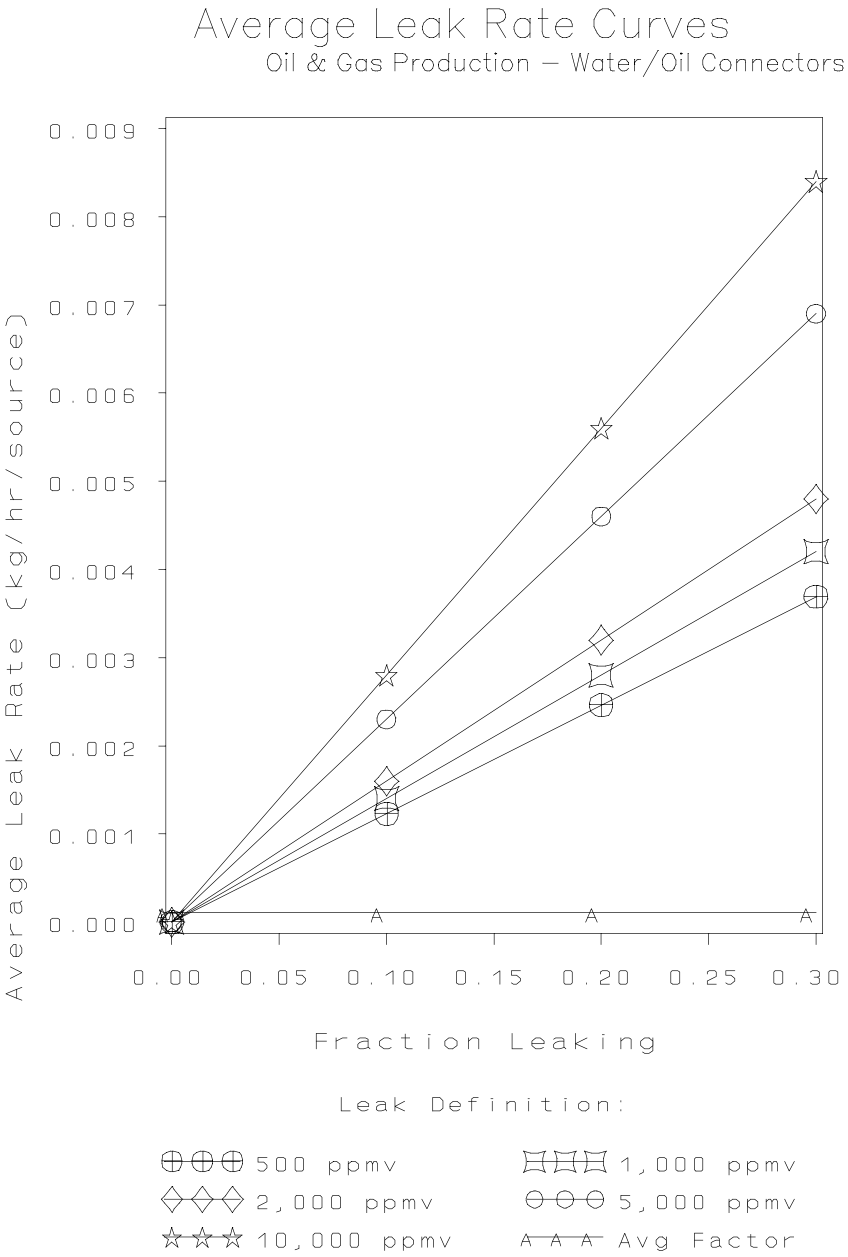


Figure 5-18. Oil and Gas Production Water/Oil Connectors Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

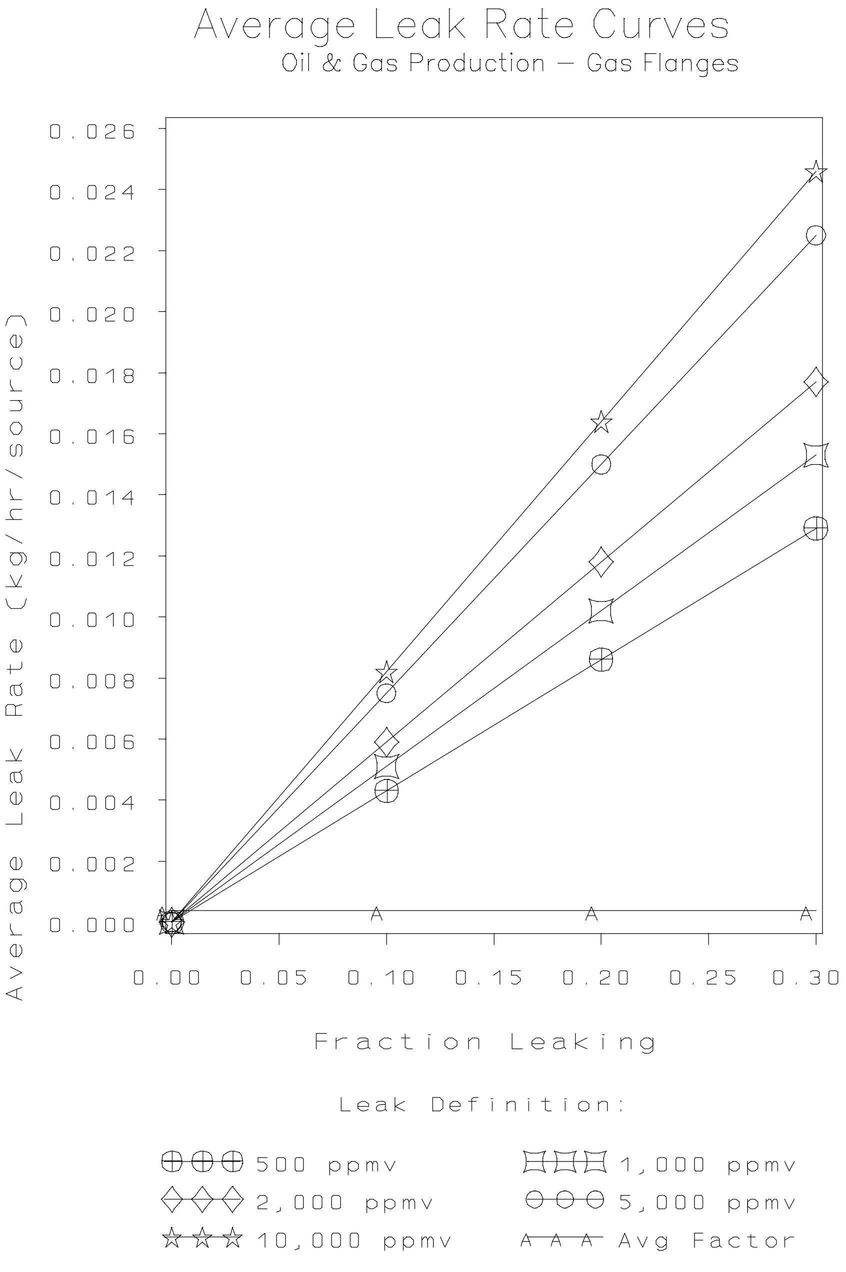


Figure 5-19. Oil and Gas Production Gas Flanges Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

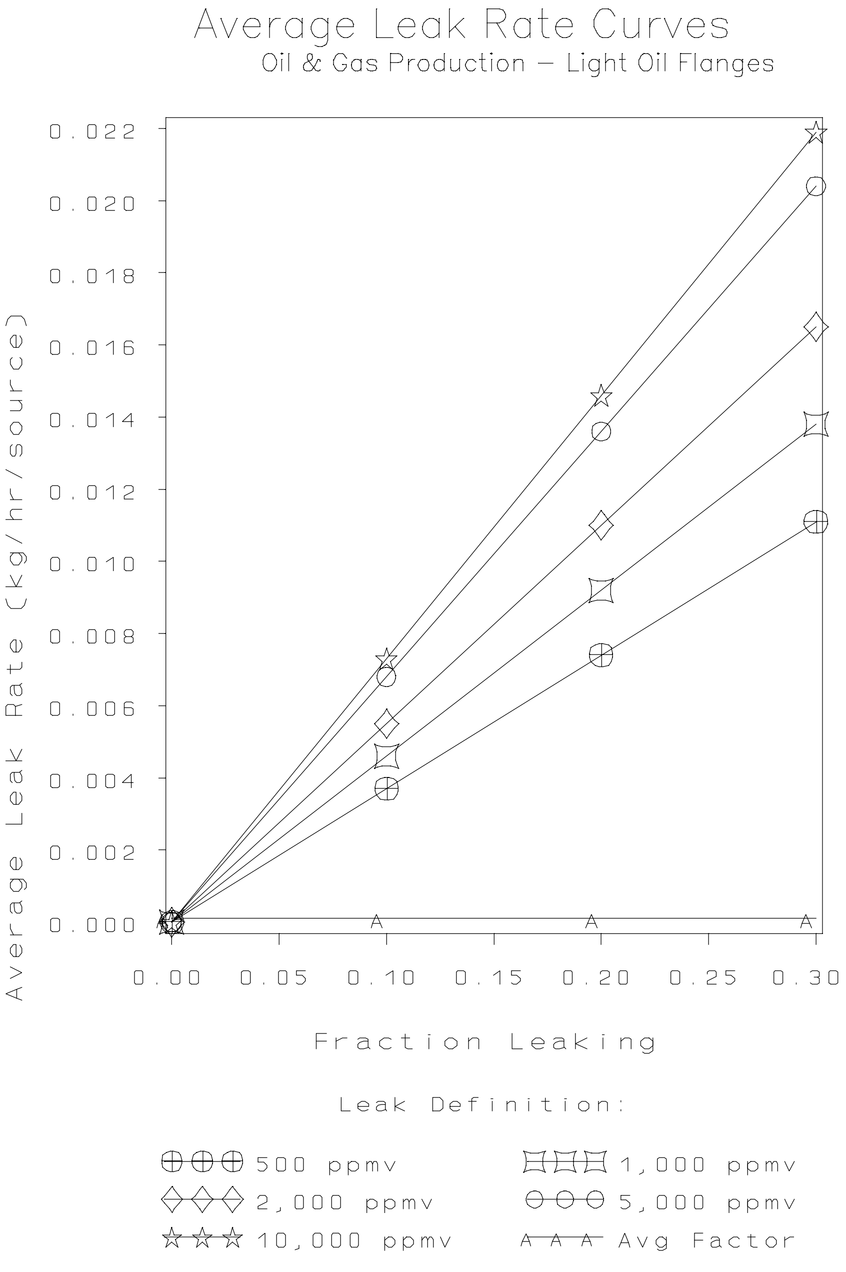


Figure 5-20. Oil and Gas Production Light Oil Flanges Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

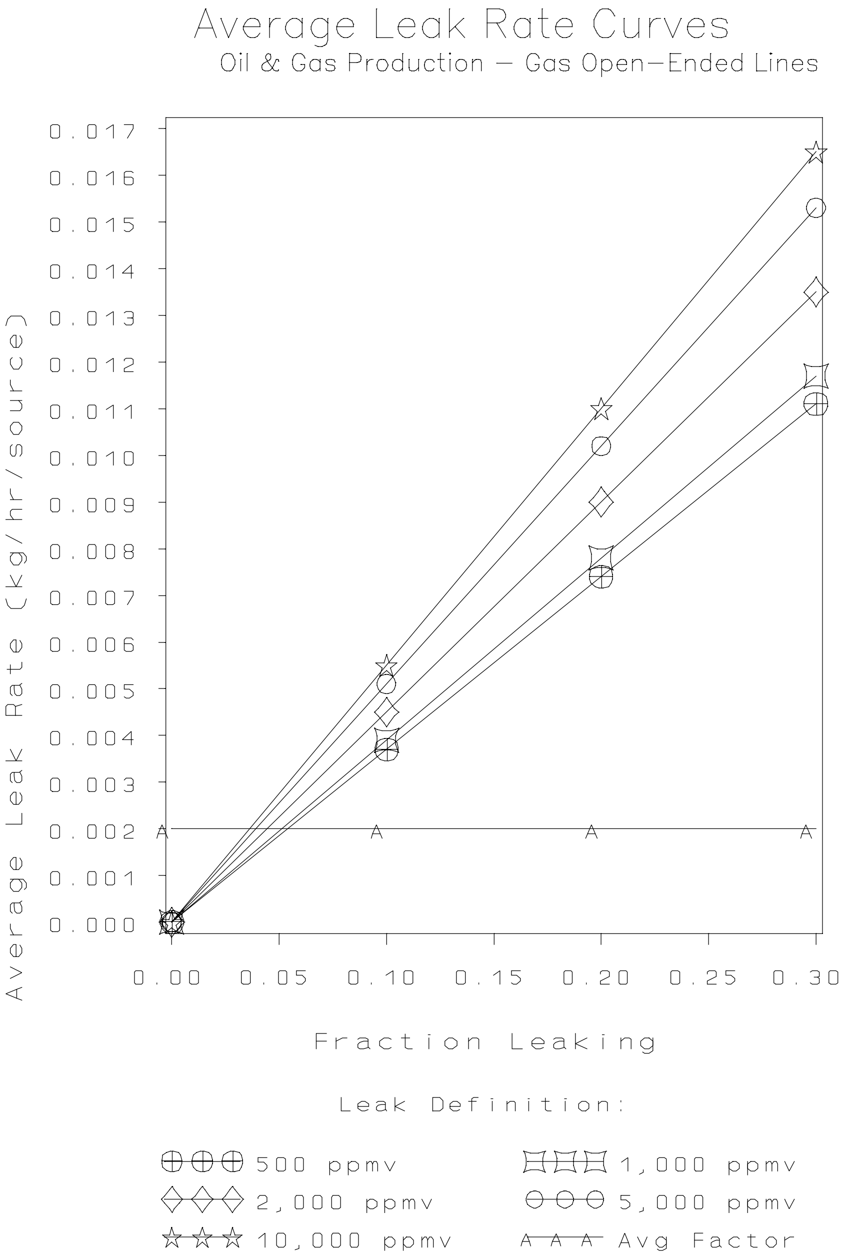


Figure 5-21. Oil and Gas Production Gas Open-Ended Lines Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

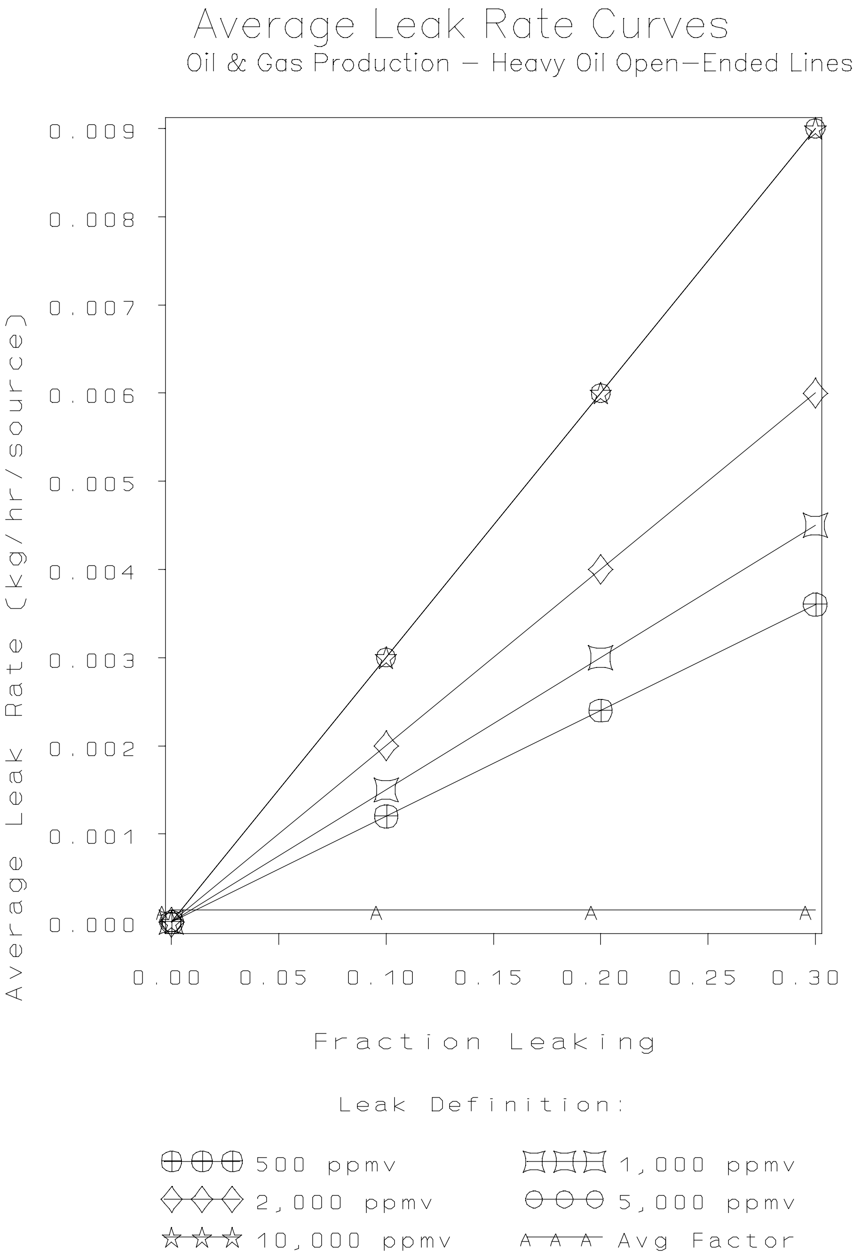


Figure 5-22. Oil and Gas Production Heavy Oil Open-Ended Lines Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

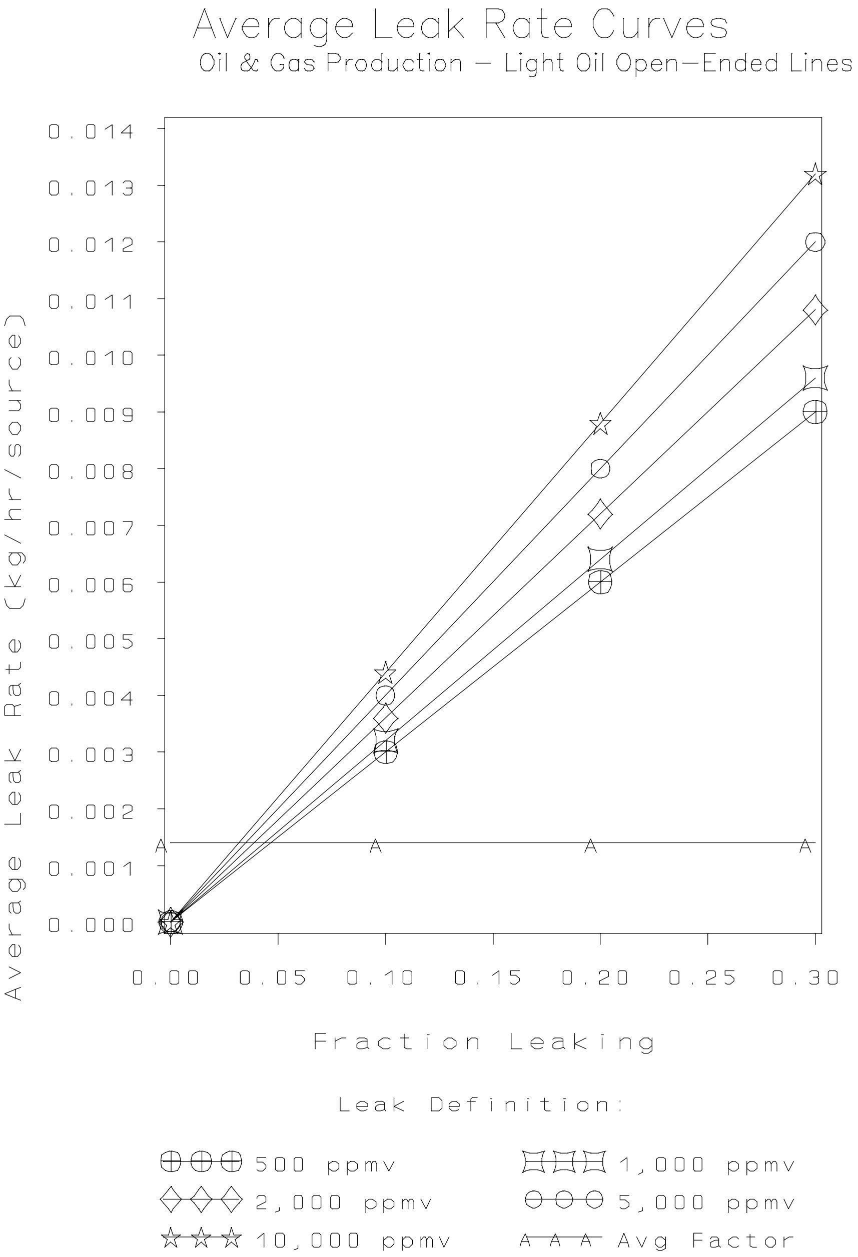


Figure 5-23. Oil and Gas Production Light Oil Open-Ended Lines Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

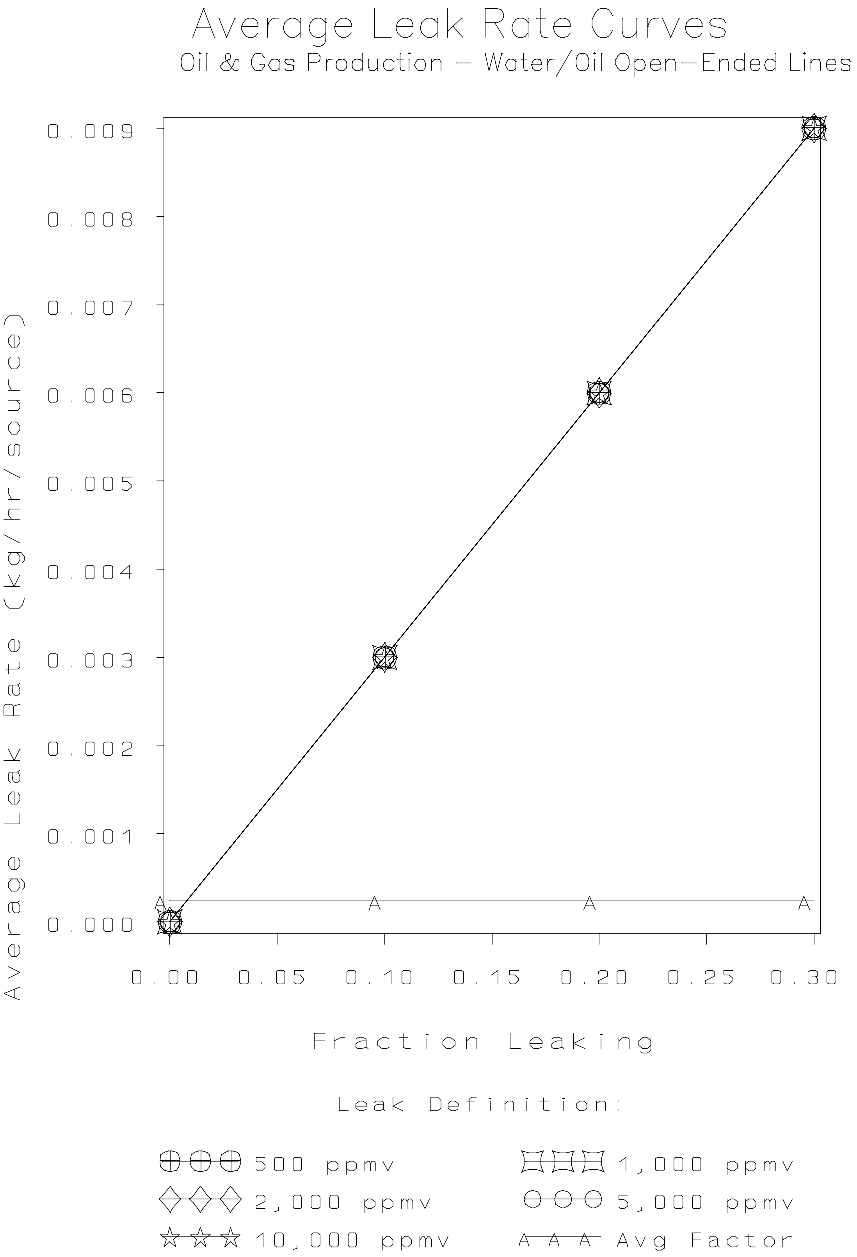


Figure 5-24. Oil and Gas Production Water/Oil Open-Ended Lines Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

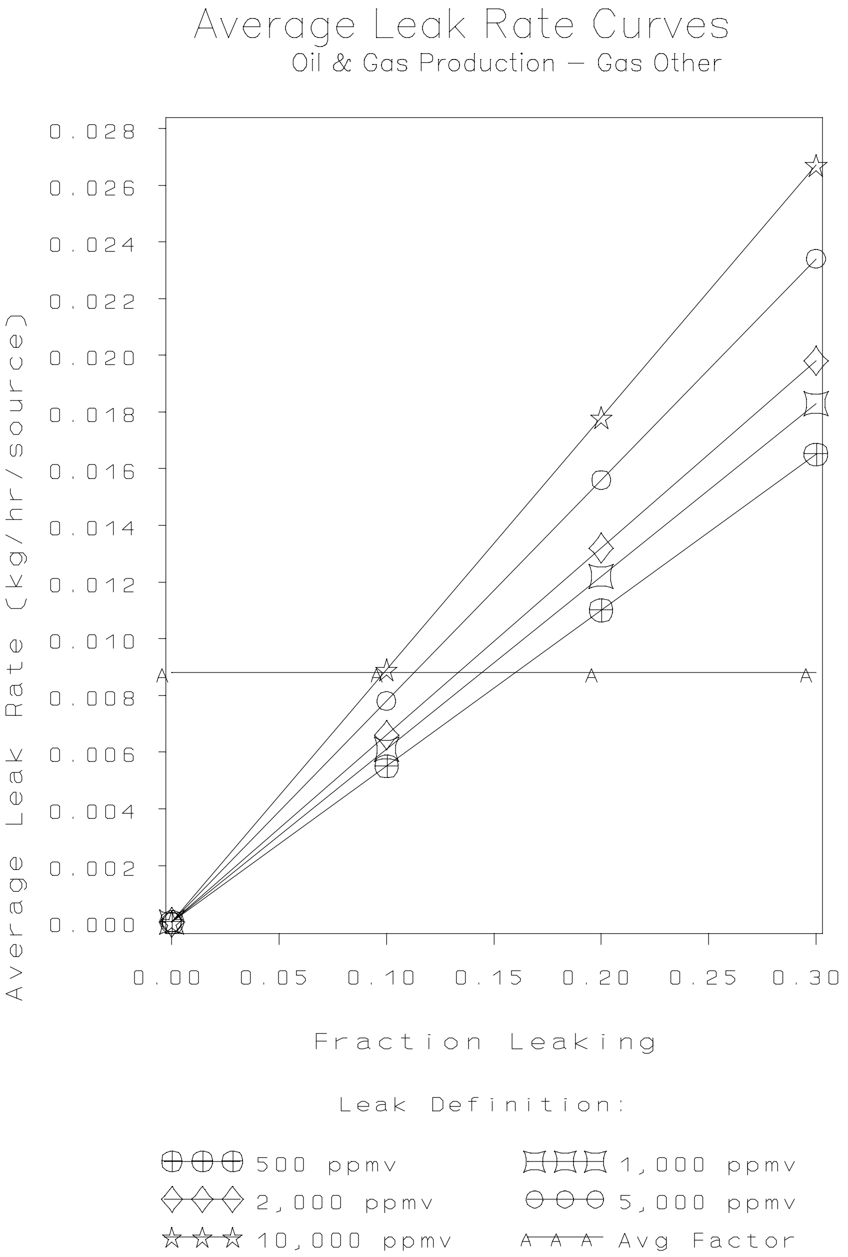


Figure 5-25. Oil and Gas Production Gas Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

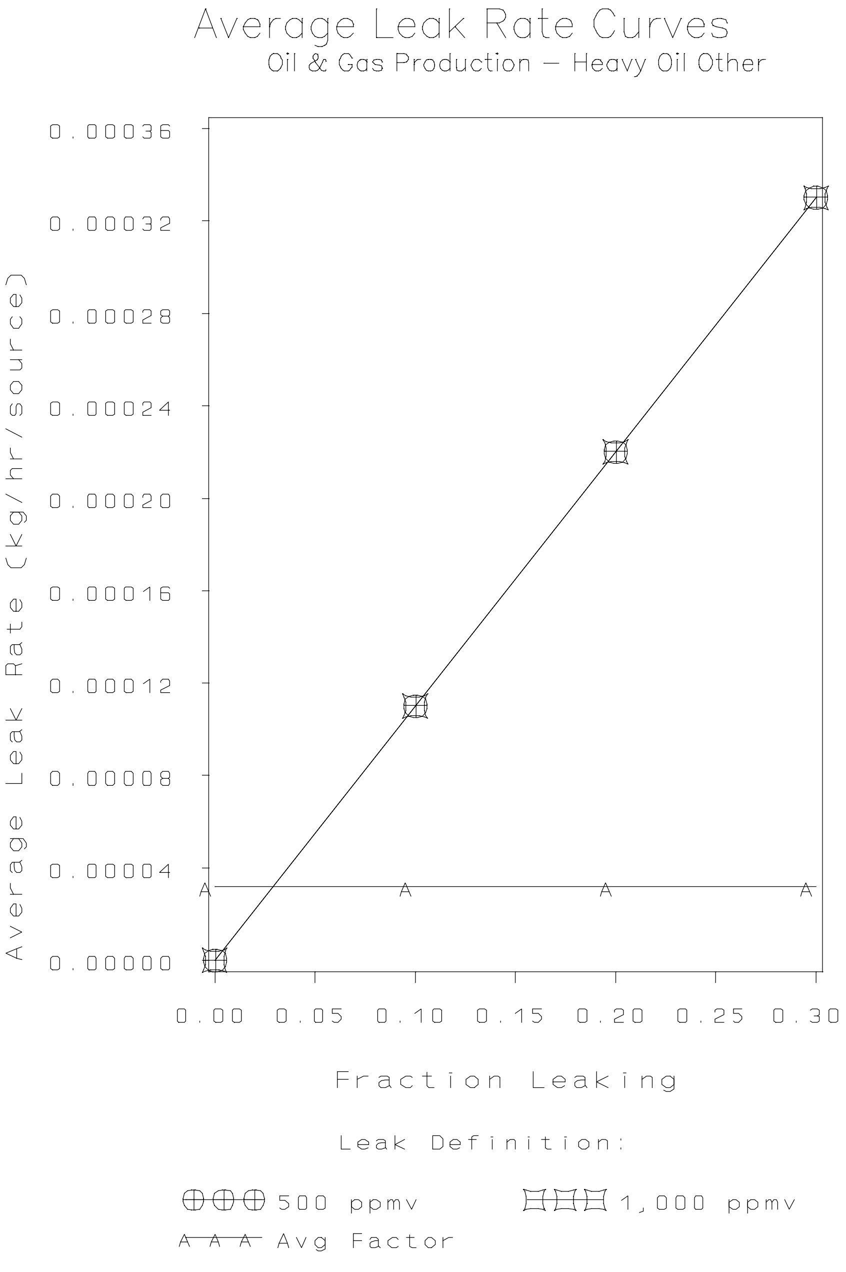


Figure 5-26. Oil and Gas Production Heavy Oil Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

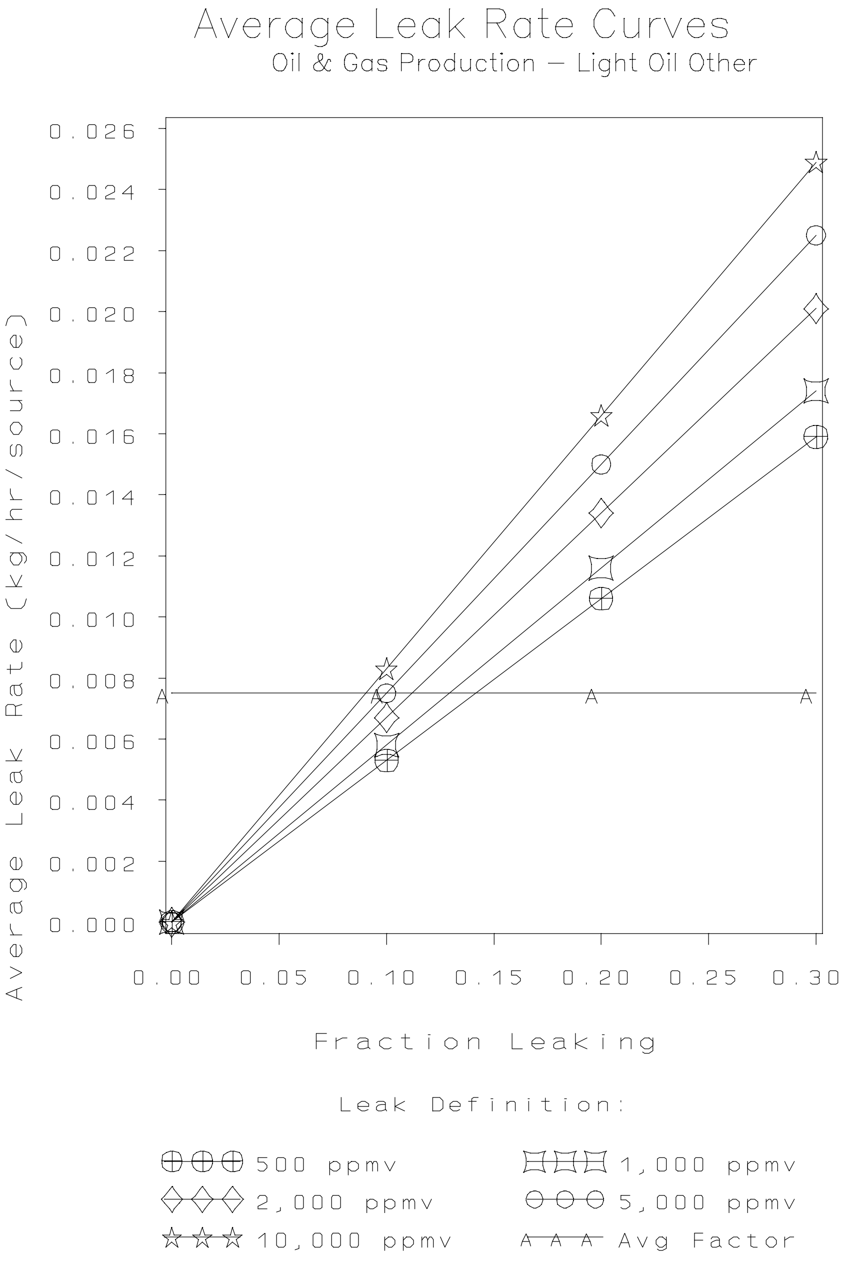


Figure 5-27. Oil and Gas Production Light Oil Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

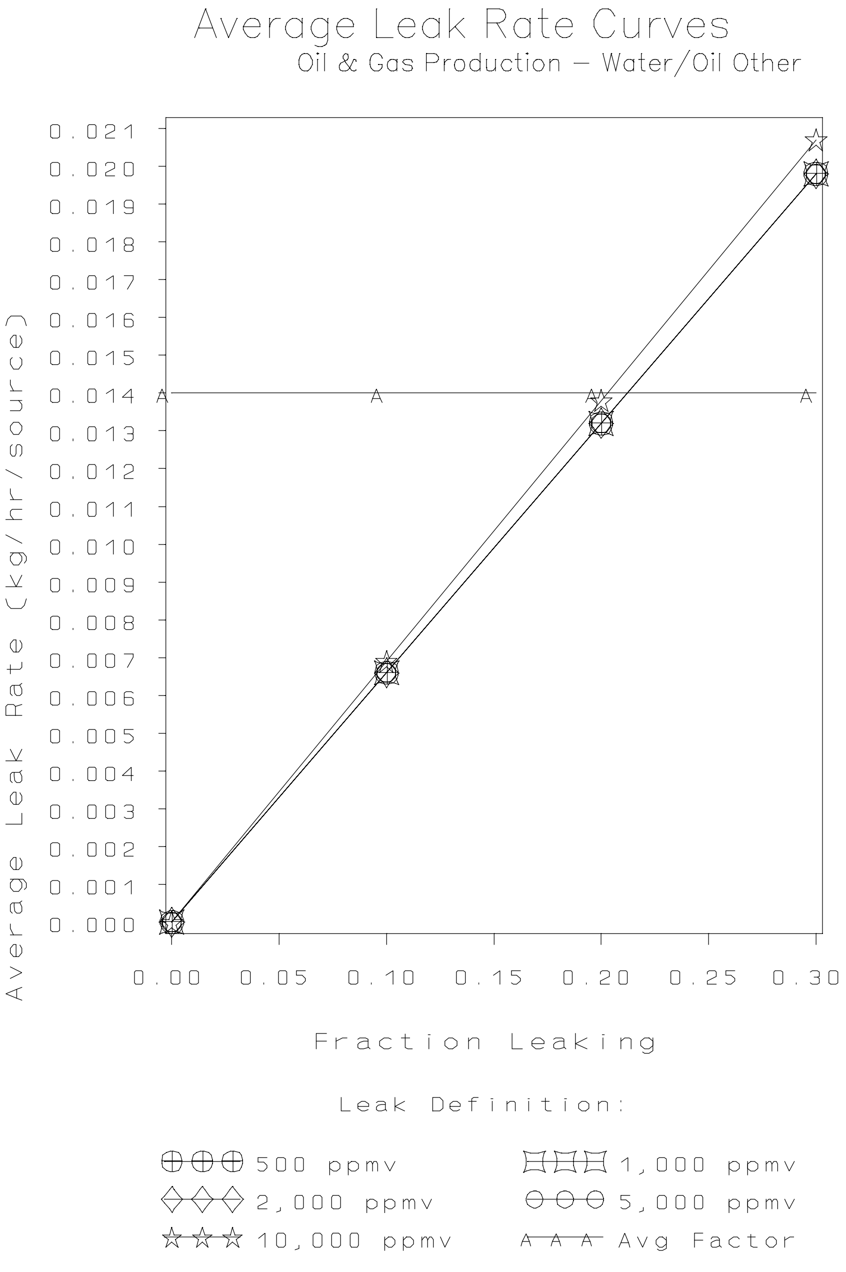


Figure 5-28. Oil and Gas Production Water/Oil Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

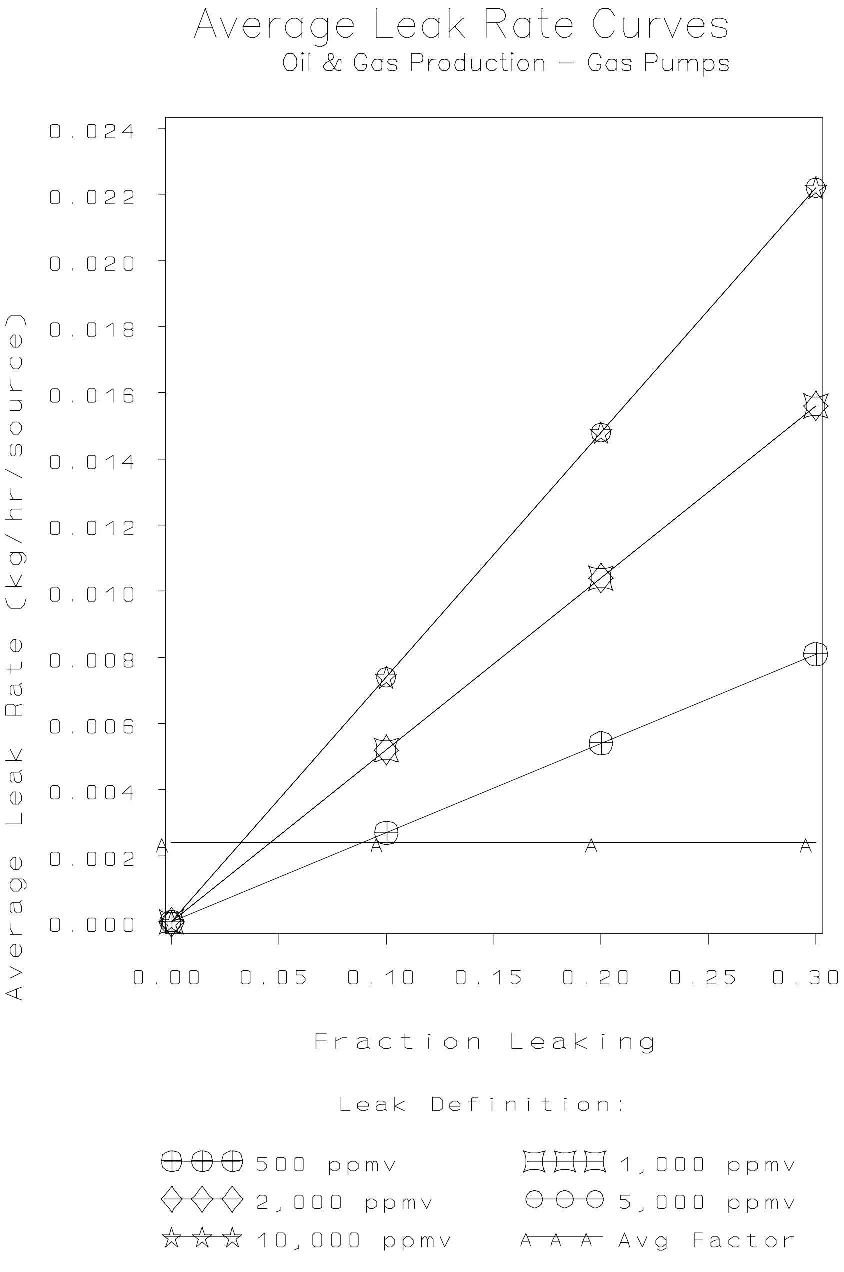


Figure 5-29. Oil and Gas Production Gas Pump Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

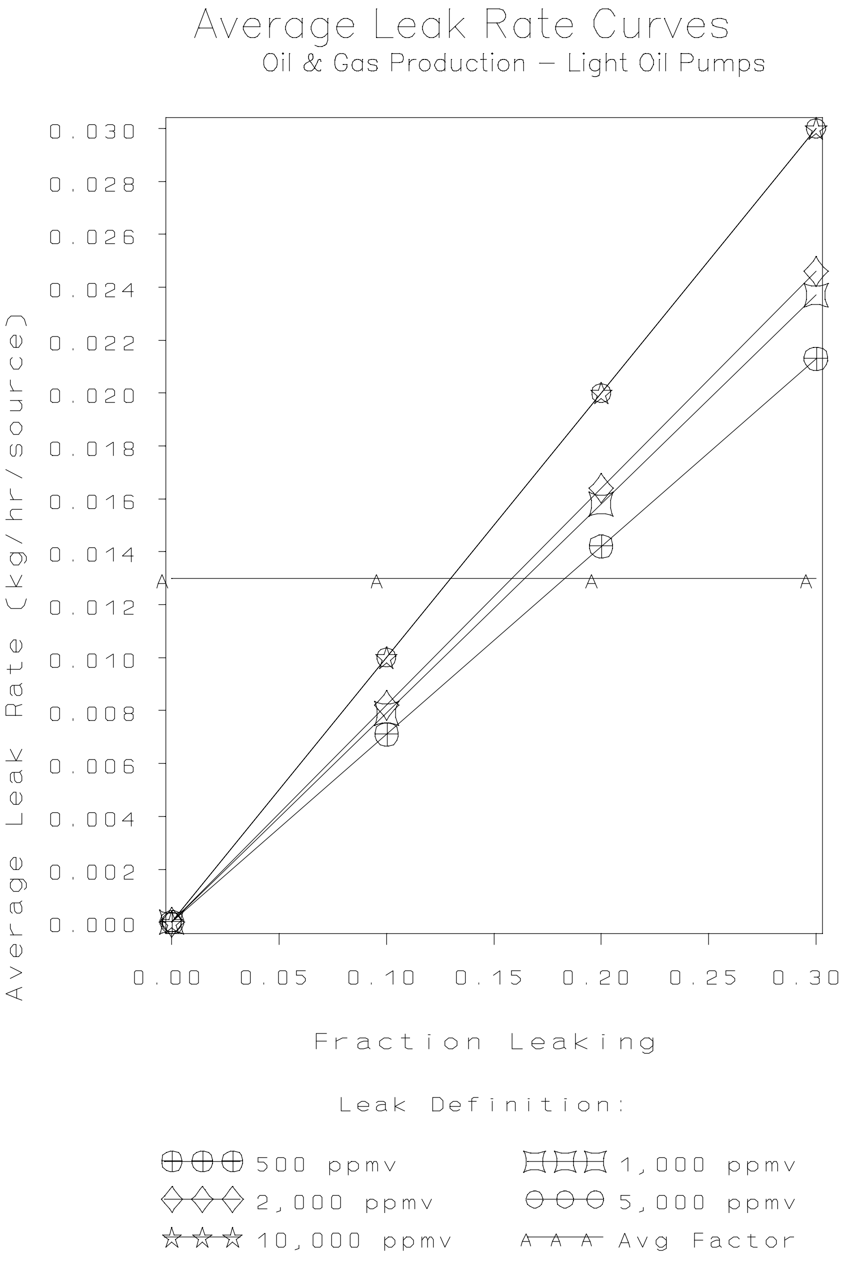


Figure 5-30. Oil and Gas Production Light Oil Pumps Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

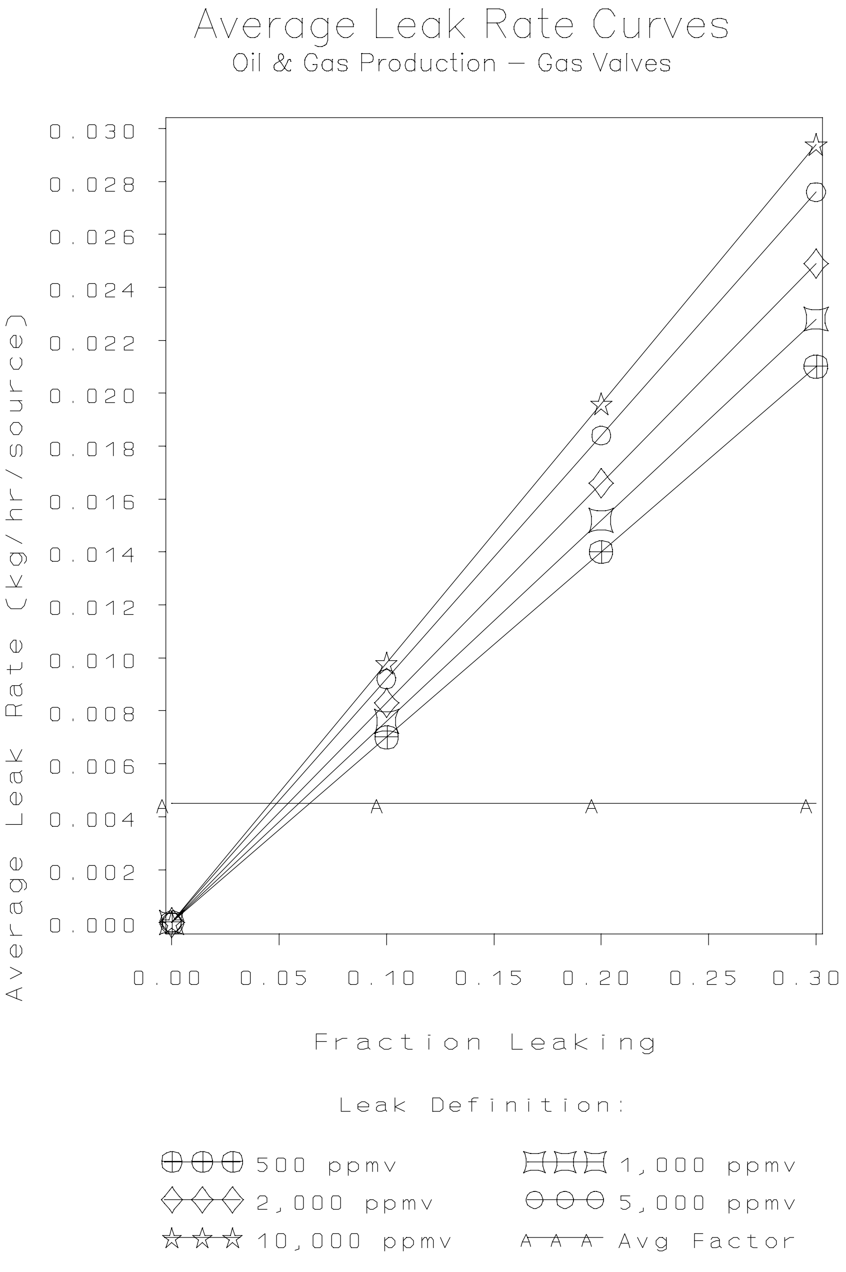


Figure 5-31. Oil and Gas Production Gas Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

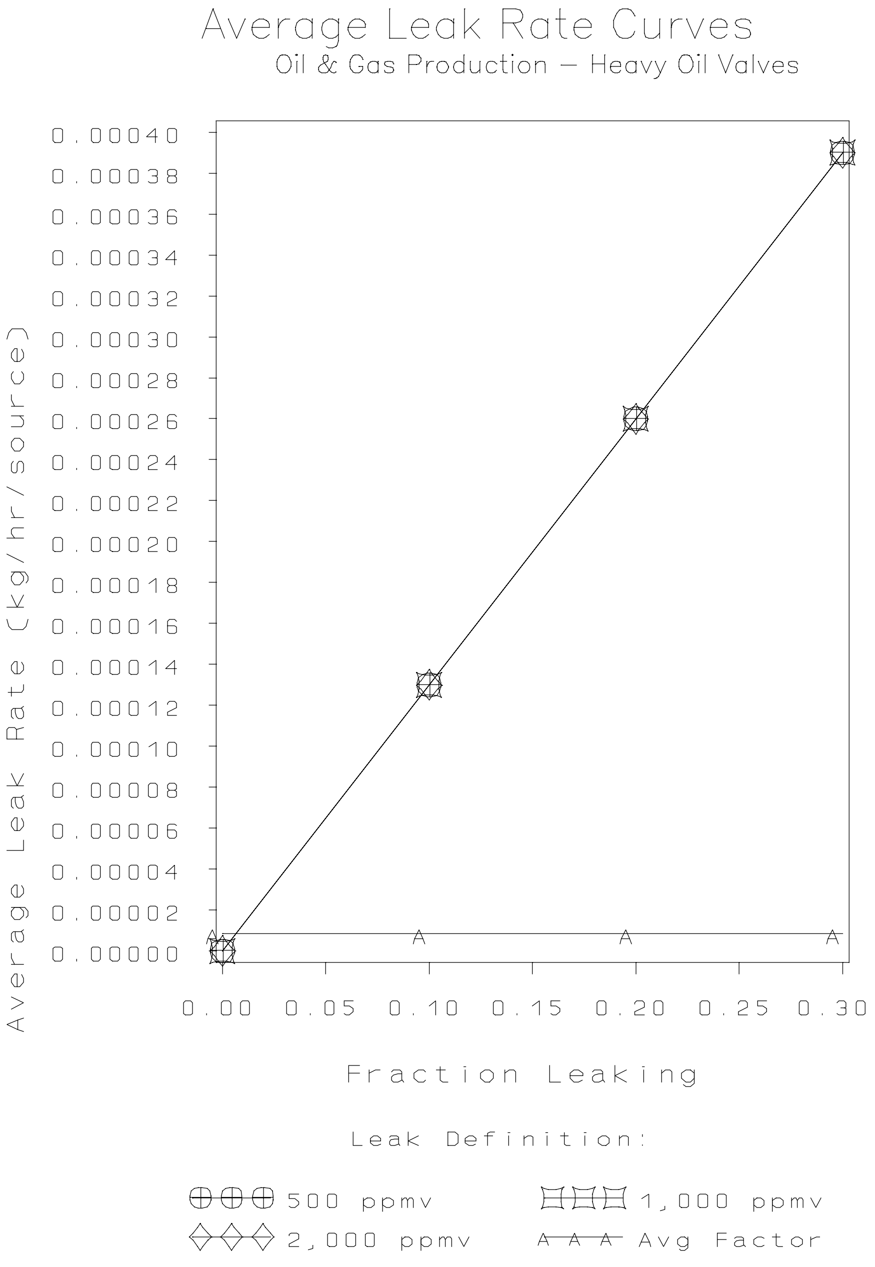


Figure 5-32. Oil and Gas Production Heavy Oil Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

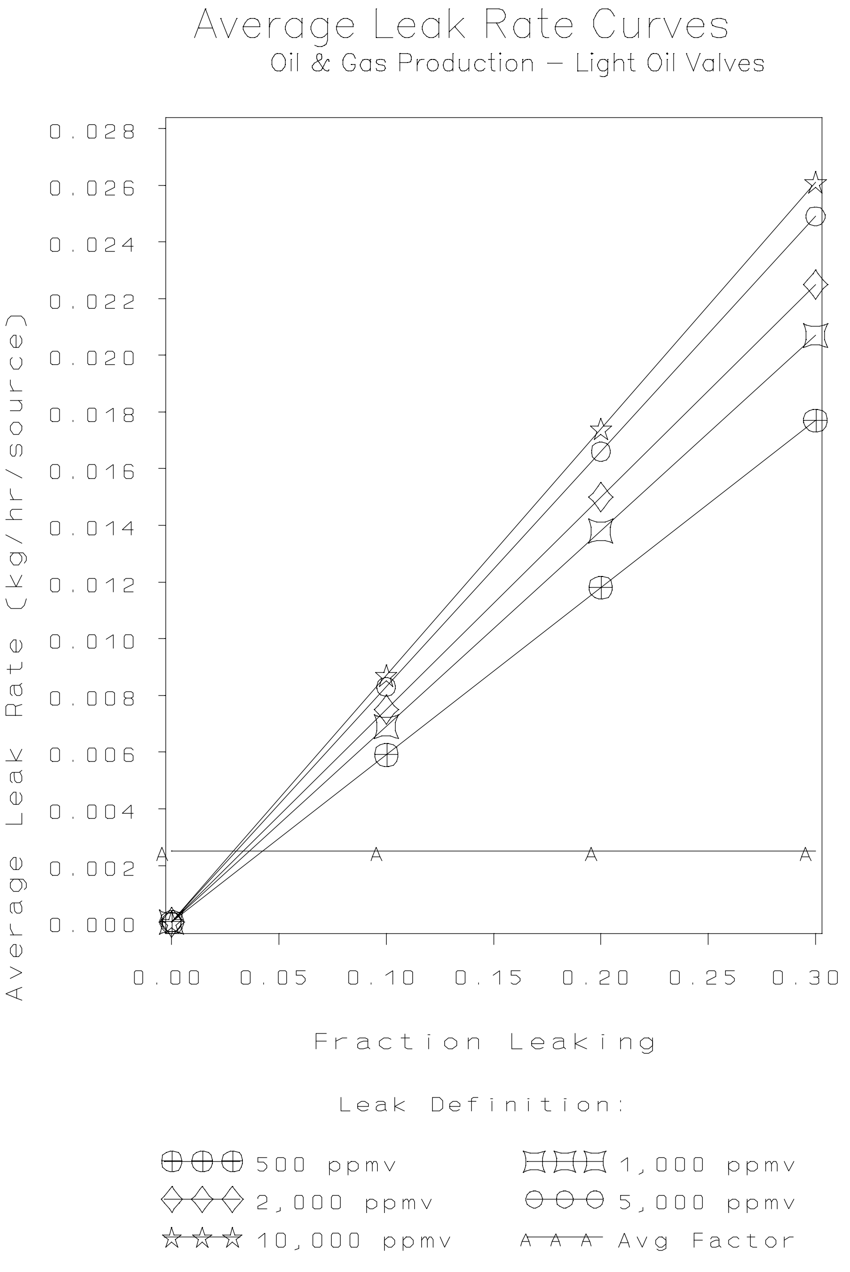


Figure 5-33. Oil and Gas Production Light Oil Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

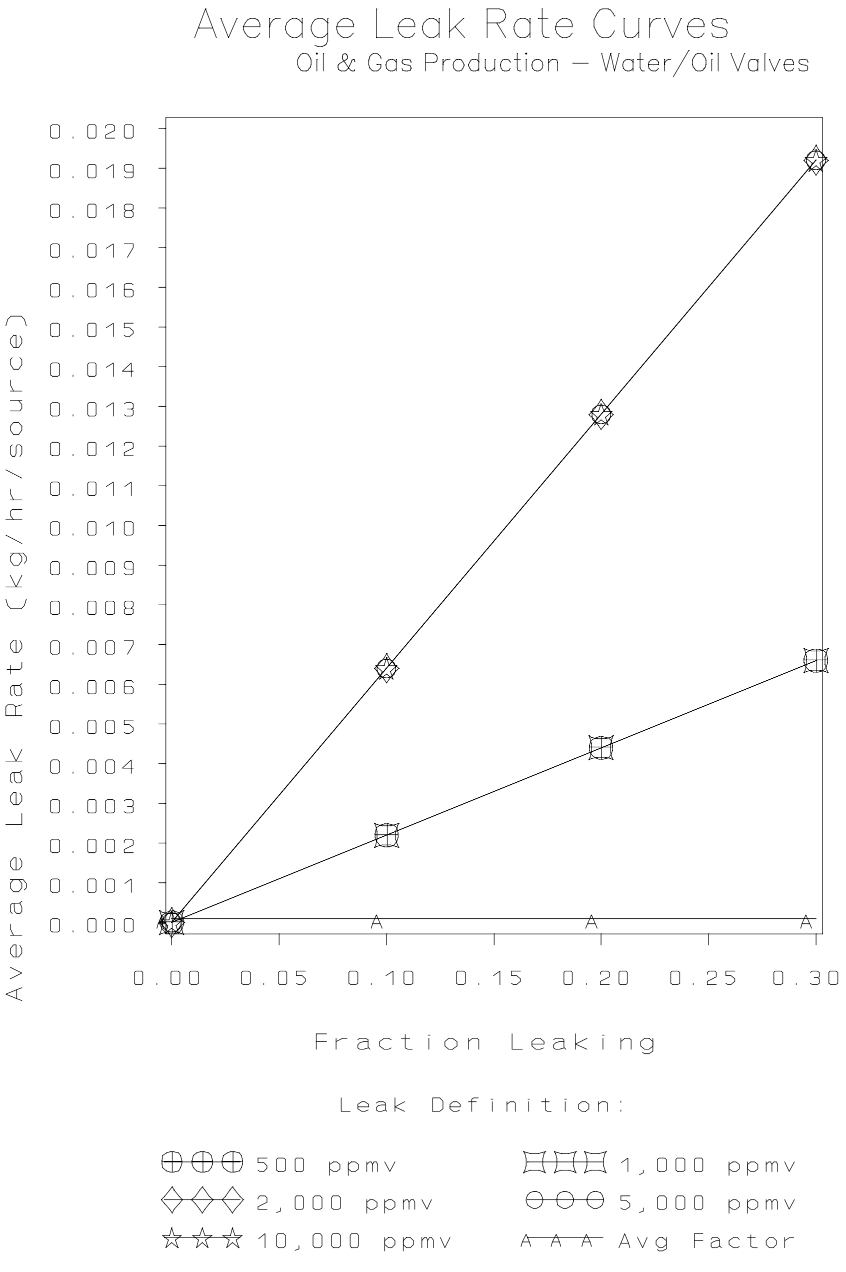


Figure 5-34. Oil and Gas Production Water/Oil Valves Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

TABLE 5-4. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT SOCMI UNITS

Equipment type	Leak definition (ppmv)	Equations[a]
Gas valve	500	ALR = (0.044 × LKFRAC) + 1.7E-05
	1000	ALR = (0.050 × LKFRAC) + 2.8E-05
	2000	ALR = (0.057 × LKFRAC) + 4.3E-05
	5000	ALR = (0.068 × LKFRAC) + 8.1E-05
	10000	ALR = (0.078 × LKFRAC) + 1.3E-04
Light liquid valve	500	ALR = (0.047 × LKFRAC) + 2.7E-05
	1000	ALR = (0.053 × LKFRAC) + 3.9E-05
	2000	ALR = (0.061 × LKFRAC) + 5.9E-05
	5000	ALR = (0.077 × LKFRAC) + 1.1E-04
	10000	ALR = (0.089 × LKFRAC) + 1.7E-04
Light liquid pump	500	ALR = (0.095 × LKFRAC) + 3.1E-04
	1000	ALR = (0.11 × LKFRAC) + 4.6E-04
	2000	ALR = (0.13 × LKFRAC) + 6.7E-04
	5000	ALR = (0.20 × LKFRAC) + 1.4E-03
	10000	ALR = (0.24 × LKFRAC) + 1.9E-03
Connector	500	ALR = (0.047 × LKFRAC) + 1.7E-05
	1000	ALR = (0.060 × LKFRAC) + 2.5E-05
	2000	ALR = (0.073 × LKFRAC) + 3.5E-05
	5000	ALR = (0.092 × LKFRAC) + 5.4E-05
	10000	ALR = (0.11 × LKFRAC) + 8.1E-05

[a] ALR = Average leak rate (kg/hr per source) and LKFRAC = leak fraction.

TABLE 5-5. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT REFINERY UNITS

Equipment type	Leak definition (ppmv)	Equation[a]
Gas valve	500	ALR = (0.11 × LKFRAC) + 8.8E-05
	1000	ALR = (0.13 × LKFRAC) + 1.4E-04
	10000	ALR = (0.26 × LKFRAC) + 6.0E-04
Light liquid valve	500	ALR = (0.038 × LKFRAC) + 2.0E-04
	1000	ALR = (0.042 × LKFRAC) + 2.8E-04
	10000	ALR = (0.084 × LKFRAC) + 1.7E-03
Light liquid pump	500	ALR = (0.20 × LKFRAC) + 1.3E-03
	1000	ALR = (0.23 × LKFRAC) + 2.0E-03
	10000	ALR = (0.43 × LKFRAC) + 1.2E-02
Connector	500	ALR = (0.014 × LKFRAC) + 1.3E-05
	1000	ALR = (0.017 × LKFRAC) + 1.8E-05
	10000	ALR = (0.037 × LKFRAC) + 6.0E-05

[a] ALR = Average leak rate (kg/hr per source) and LKFRAC = leak fraction.

TABLE 5-6. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT MARKETING TERMINAL UNITS

Equipment Type	Leak Definition (ppmv)	Equation[a]
Gas Connector	500	ALR = (0.017 × LKFRAC) + 5.3E-06
	1000	ALR = (0.017 × LKFRAC) + 5.3E-06
	2000	ALR = (0.034 × LKFRAC) + 5.9E-06
	5000	ALR = (0.034 × LKFRAC) + 5.9E-06
	10000	ALR = (0.034 × LKFRAC) + 5.9E-06
Light Liquid Connector	500	ALR = (0.0021 × LKFRAC) + 7.0E-06
	1000	ALR = (0.0028 × LKFRAC) + 7.1E-06
	2000	ALR = (0.0042 × LKFRAC) + 7.1E-06
	5000	ALR = (0.0058 × LKFRAC) + 7.2E-06
	10000	ALR = (0.0065 × LKFRAC) + 7.2E-06
Gas Other	500	ALR = (0.0018 × LKFRAC) + 3.1E-05
	1000	ALR = (0.0021 × LKFRAC) + 4.0E-05
	2000	ALR = (0.0023 × LKFRAC) + 4.8E-05
	5000	ALR = (0.0029 × LKFRAC) + 8.4E-05
	10000	ALR = 1.2E-04
Light Liquid Other	500	ALR = (0.019 × LKFRAC) + 2.1E-05
	1000	ALR = (0.022 × LKFRAC) + 2.2E-05
	2000	ALR = (0.025 × LKFRAC) + 2.2E-05
	5000	ALR = (0.034 × LKFRAC) + 2.4E-05
	10000	ALR = (0.034 × LKFRAC) + 2.4E-05
Light Liquid Pump	500	ALR = (0.014 × LKFRAC) + 9.6E-05
	1000	ALR = (0.018 × LKFRAC) + 1.2E-04
	2000	ALR = (0.029 × LKFRAC) + 1.6E-04
	5000	ALR = (0.051 × LKFRAC) + 2.1E-04
	10000	ALR = (0.077 × LKFRAC) + 2.4E-04

TABLE 5-6. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT MARKETING TERMINAL UNITS (CONTINUED)

Equipment Type	Leak Definition (ppmv)	Equation[a]
Gas Valve	500	ALR = (0.0012 × LKFRAC) + 8.9E-06
	1000	ALR = (0.0017 × LKFRAC) + 9.2E-06
	2000	ALR = (0.0017 × LKFRAC) + 9.2E-06
	5000	ALR = (0.0017 × LKFRAC) + 9.2E-06
	10000	ALR = 1.3E-05
Light Liquid Valve	500	ALR = (0.0045 × LKFRAC) + 9.5E-06
	1000	ALR = (0.0052 × LKFRAC) + 9.8E-06
	2000	ALR = (0.0077 × LKFRAC) + 1.1E-05
	5000	ALR = (0.013 × LKFRAC) + 1.2E-05
	10000	ALR = (0.023 × LKFRAC) + 1.5E-05

[a] ALR = Average leak rate (kg/hr per source)
LKFRAC = Leak fraction.

TABLE 5-7. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT OIL AND GAS PRODUCTION OPERATION UNITS

Equipment Type	Leak Definition (ppmv)	Equation[a]
Gas Connector	500	ALR = (0.016 × LKFRAC) + 7.7E-06
	1000	ALR = (0.018 × LKFRAC) + 8.0E-06
	2000	ALR = (0.020 × LKFRAC) + 8.5E-06
	5000	ALR = (0.023 × LKFRAC) + 9.4E-06
	10000	ALR = (0.026 × LKFRAC) + 1.0E-05
Light Oil Connector	500	ALR = (0.016 × LKFRAC) + 7.7E-06
	1000	ALR = (0.021 × LKFRAC) + 8.3E-06
	2000	ALR = (0.022 × LKFRAC) + 8.6E-06
	5000	ALR = (0.025 × LKFRAC) + 9.2E-06
	10000	ALR = (0.026 × LKFRAC) + 9.7E-06
Water/Oil Connector	500	ALR = (0.013 × LKFRAC) + 7.8E-06
	1000	ALR = (0.014 × LKFRAC) + 7.9E-06
	2000	ALR = (0.016 × LKFRAC) + 8.3E-06
	5000	ALR = (0.023 × LKFRAC) + 9.4E-06
	10000	ALR = (0.028 × LKFRAC) + 1.0E-05
Gas Flange	500	ALR = (0.043 × LKFRAC) + 1.1E-06
	1000	ALR = (0.051 × LKFRAC) + 1.8E-06
	2000	ALR = (0.059 × LKFRAC) + 2.6E-06
	5000	ALR = (0.075 × LKFRAC) + 4.7E-06
	10000	ALR = (0.082 × LKFRAC) + 5.7E-06
Light Oil Flange	500	ALR = (0.037 × LKFRAC) + 9.4E-07
	1000	ALR = (0.046 × LKFRAC) + 1.2E-06
	2000	ALR = (0.055 × LKFRAC) + 1.6E-06
	5000	ALR = (0.068 × LKFRAC) + 2.1E-06
	10000	ALR = (0.073 × LKFRAC) + 2.4E-06

TABLE 5-7. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT OIL AND GAS PRODUCTION OPERATION UNITS (CONTINUED)

Equipment Type	Leak Definition (ppmv)	Equation[a]
Gas Open-Ended Line	500	ALR = (0.037 × LKFRAC) + 4.1E-06
	1000	ALR = (0.039 × LKFRAC) + 5.0E-06
	2000	ALR = (0.045 × LKFRAC) + 7.5E-06
	5000	ALR = (0.051 × LKFRAC) + 1.2E-05
	10000	ALR = (0.055 × LKFRAC) + 1.5E-05
Heavy Oil Open-Ended Line	500	ALR = (0.012 × LKFRAC) + 4.3E-06
	1000	ALR = (0.015 × LKFRAC) + 4.9E-06
	2000	ALR = (0.020 × LKFRAC) + 6.0E-06
	5000	ALR = (0.030 × LKFRAC) + 7.2E-06
	10000	ALR = (0.030 × LKFRAC) + 7.2E-06
Light Oil Open-Ended Line	500	ALR = (0.030 × LKFRAC) + 3.8E-06
	1000	ALR = (0.032 × LKFRAC) + 4.7E-06
	2000	ALR = (0.036 × LKFRAC) + 6.7E-06
	5000	ALR = (0.040 × LKFRAC) + 9.7E-06
	10000	ALR = (0.044 × LKFRAC) + 1.4E-05
Water/Oil Open-Ended Line	500	ALR = (0.030 × LKFRAC) + 3.5E-06
	1000	ALR = (0.030 × LKFRAC) + 3.5E-06
	2000	ALR = (0.030 × LKFRAC) + 3.5E-06
	5000	ALR = (0.030 × LKFRAC) + 3.5E-06
	10000	ALR = (0.030 × LKFRAC) + 3.5E-06
Gas Other	500	ALR = (0.055 × LKFRAC) + 1.8E-05
	1000	ALR = (0.061 × LKFRAC) + 3.1E-05
	2000	ALR = (0.066 × LKFRAC) + 4.5E-05
	5000	ALR = (0.078 × LKFRAC) + 8.2E-05
	10000	ALR = (0.089 × LKFRAC) + 1.2E-04

TABLE 5-7. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT OIL AND GAS PRODUCTION OPERATION UNITS (CONTINUED)

Equipment Type	Leak Definition (ppmv)	Equation[a]
Heavy Oil Other	500	ALR = (0.0011 × LKFRAC) + 2.1E-05
	1000	ALR = (0.0011 × LKFRAC) + 2.1E-05
	2000	ALR = 3.2E-05
	5000	ALR = 3.2E-05
	10000	ALR = 3.2E-05
Light Oil Other	500	ALR = (0.053 × LKFRAC) + 3.4E-05
	1000	ALR = (0.058 × LKFRAC) + 4.4E-05
	2000	ALR = (0.067 × LKFRAC) + 6.4E-05
	5000	ALR = (0.075 × LKFRAC) + 8.6E-05
	10000	ALR = (0.083 × LKFRAC) + 1.4E-04
Water/Oil Other	500	ALR = (0.066 × LKFRAC) + 2.5E-05
	1000	ALR = (0.066 × LKFRAC) + 2.5E-05
	2000	ALR = (0.066 × LKFRAC) + 2.5E-05
	5000	ALR = (0.066 × LKFRAC) + 2.5E-05
	10000	ALR = (0.069 × LKFRAC) + 5.9E-05
Gas Pump	500	ALR = (0.027 × LKFRAC) + 1.1E-04
	1000	ALR = (0.052 × LKFRAC) + 2.3E-04
	2000	ALR = (0.052 × LKFRAC) + 2.3E-04
	5000	ALR = (0.074 × LKFRAC) + 3.5E-04
	10000	ALR = (0.074 × LKFRAC) + 3.5E-04
Light Oil Pump	500	ALR = (0.071 × LKFRAC) + 7.9E-05
	1000	ALR = (0.079 × LKFRAC) + 1.5E-04
	2000	ALR = (0.082 × LKFRAC) + 1.9E-04
	5000	ALR = (0.10 × LKFRAC) + 5.1E-04
	10000	ALR = (0.10 × LKFRAC) + 5.1E-04

TABLE 5-7. EQUATIONS RELATING AVERAGE LEAK RATE TO FRACTION LEAKING AT OIL AND GAS PRODUCTION OPERATION UNITS (CONTINUED)

Equipment Type	Leak Definition (ppmv)	Equation[a]
Gas Valve	500	ALR = (0.070 × LKFRAC) + 9.1E-06
	1000	ALR = (0.076 × LKFRAC) + 1.1E-05
	2000	ALR = (0.083 × LKFRAC) + 1.4E-05
	5000	ALR = (0.092 × LKFRAC) + 1.9E-05
	10000	ALR = (0.098 × LKFRAC) + 2.5E-05
Heavy Oil Valve	500	ALR = (0.0013 × LKFRAC) + 7.8E-06
	1000	ALR = (0.0013 × LKFRAC) + 7.8E-06
	2000	ALR = (0.0013 × LKFRAC) + 7.8E-06
	5000	ALR = 8.4E-06
	10000	ALR = 8.4E-06
Light Oil Valve	500	ALR = (0.059 × LKFRAC) + 9.4E-06
	1000	ALR = (0.069 × LKFRAC) + 1.2E-05
	2000	ALR = (0.075 × LKFRAC) + 1.4E-05
	5000	ALR = (0.083 × LKFRAC) + 1.7E-05
	10000	ALR = (0.087 × LKFRAC) + 1.9E-05
Water/Light Oil Valve	500	ALR = (0.022 × LKFRAC) + 8.1E-06
	1000	ALR = (0.022 × LKFRAC) + 8.1E-06
	2000	ALR = (0.064 × LKFRAC) + 9.7E-06
	5000	ALR = (0.064 × LKFRAC) + 9.7E-06
	10000	ALR = (0.064 × LKFRAC) + 9.7E-06

[a] ALR = Average leak rate (kg/hr per source)
LKFRAC = Leak fraction.

The initial leak frequency is the fraction of sources defined as leaking before the LDAR program is implemented. The initial leak frequency is point X on figure 5-35. The lower the leak definition, the higher the initial leak frequency. At a process unit, the initial leak frequency can be determined based on collected screening data. If no screening data are available, the initial leak frequency can be assumed to be equivalent to the leak frequency associated with the applicable average emission factor. However, if a process unit already has some type of LDAR program in place, the average emission factor may overestimate emissions.

On figures 5-1 through 5-34, the average emission factor for each equipment type is plotted as a horizontal line. From this line, an initial leak frequency can be determined for any of the leak definitions. For example, on figure 5-1, which is for gas valves, the SOCMI average emission factor equals 0.00597 kilograms per hour (kg/hr). For a leak definition of 500 ppmv, this average emission factor corresponds to a fraction leaking of approximately 0.136. Similarly, for a leak definition of 10,000 ppmv, the average emission factor corresponds to a fraction leaking of 0.075. These points are determined by finding the intersection of the SOCMI average emission factor line and the applicable leak definition line and reading off the corresponding fraction leaking. Alternatively the fraction leaking associated with the average factor can be calculated using the equations in tables 5-4, 5-5, 5-6, and 5-7.

The leak frequency immediately after a monitoring cycle is Point Y on figure 5-35. After an LDAR program is implemented for a given time period, point Y will reach a "steady-state" value. As presented in figure 5-35, point Y depends on two key factors: (1) the percentage of equipment successfully repaired after being identified as leaking, and (2) the percentage of equipment that was repaired for which leaks recurred. Two simplifying assumptions when calculating point Y are: (1) that leaking equipment is instantaneously repaired, and (2) that the recurring leaks will occur instantaneously after the equipment is repaired.

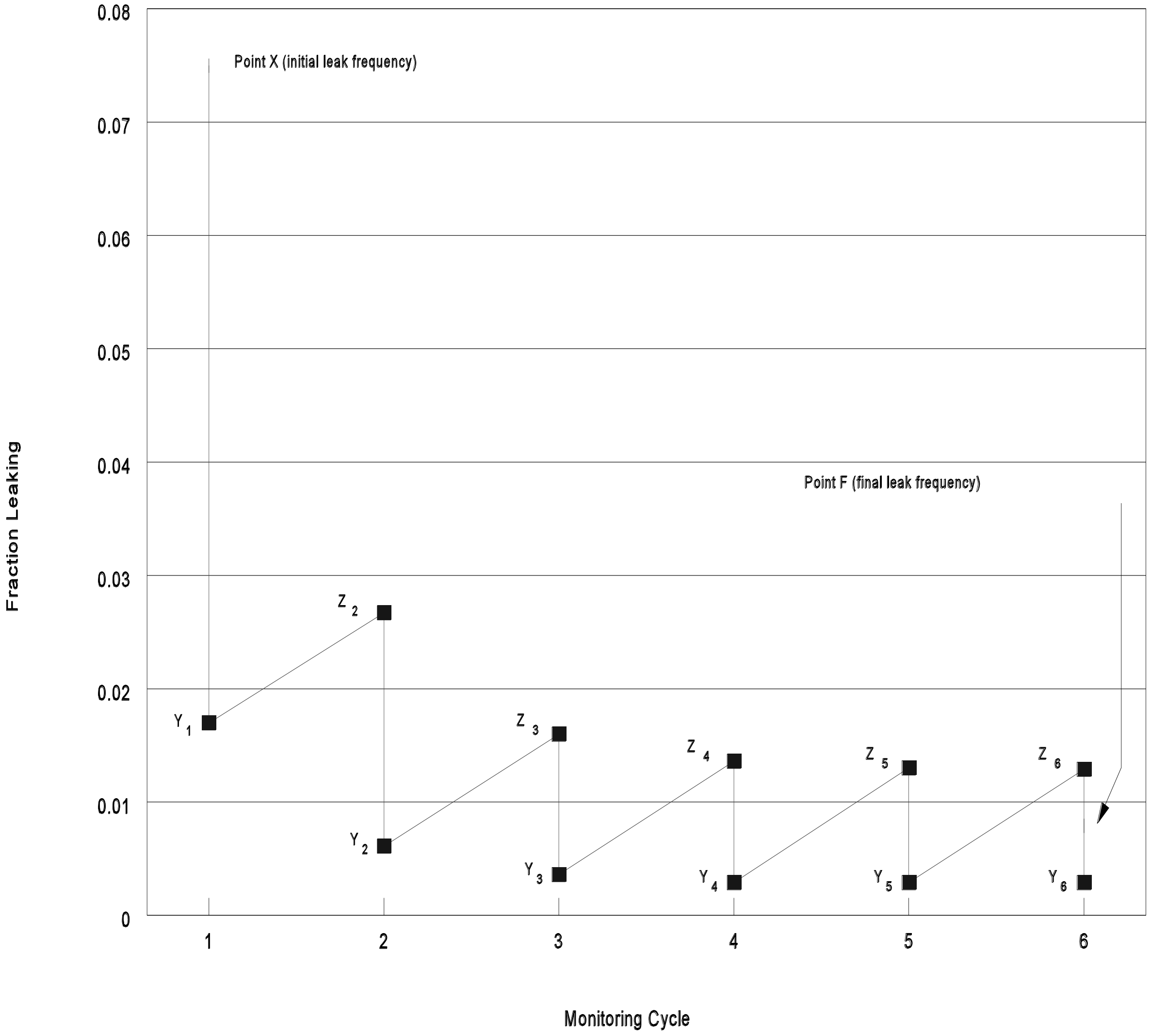


Figure 5-35. Simplified Graphical Presentation of Changes in Leak Frequency After Implementation of an LDAR Program

Based on these assumptions the value for point Y is calculated using the following equation:

$$Y_i = Z_i - (FR \times Z_i) + (FR \times Z_i \times R)$$

where:

Y_i = Leak fraction immediately after monitoring cycle i;

Z_i = Leak fraction immediately preceding monitoring cycle i (note that Z_1 equals point X.);

R = Fraction of repaired sources for which a leak immediately recurs; and

FR = Fraction of leaking sources successfully repaired.

Point Z on figure 5-35 is the leak frequency immediately preceding equipment monitoring. After an LDAR program is implemented for a given time period, point Z will reach a "steady-state" value. To go from point Y to point Z on figure 5-35, the occurrence rate is added to point Y. The occurrence rate equals the percentage of initially nonleaking equipment that starts to leak between monitoring cycles. Use the following equation to go from point Y to point Z:

$$Z_{i+1} = Oc \times (1 - Y_i) + Y_i$$

where:

Z_{i+1} = Leak fraction immediately preceding monitoring cycle i + 1;

Oc = Fraction of nonleaking sources which will leak in the time period between monitoring cycles (i.e, occurrence rate); and

Y_i = Leak fraction immediately after monitoring cycle i.

After several monitoring cycles, the leak frequency will be found to approximately oscillate between points Y and Z. The average value of these two "steady-state" values is the final leak frequency. This is point F on figure 5-35. The final leak frequency is the average percent of sources that are still leaking after an LDAR program has been implemented.

Once the initial and final leak frequencies are determined, they can be entered into the applicable equation from table 5-4 or table 5-5 to calculate the associated average leak rates at these leak frequencies. Based on the initial leak rate and the final leak rate, the control effectiveness for an LDAR program can be calculated. The control effectiveness is calculated as:

$$\mathrm{Eff} = (\mathrm{ILR}-\mathrm{FLR})/\mathrm{ILR} \times 100$$

where:

Eff = Control effectiveness (percent);

ILR = Initial leak rate (kg/hr/source); and

FLR = Final leak rate (kg/hr/source).

5.3.2 Example Application of Approach

As previously mentioned, the approach described in section 5.3.1 was applied to estimate the control effectiveness for three types of LDAR programs: (1) monthly inspection with a leak definition of 10,000 ppmv, (2) quarterly inspection with a leak definition of 10,000 ppmv, and (3) a program complying with the requirements specified in the proposed hazardous organic NESHAP equipment leaks negotiated regulation.[1] Details of these calculations are presented in appendix G. As an example of applying the approach, the control effectiveness for gas valves at a SOCMI process unit implementing a monthly LDAR program with a leak definition of 10,000 ppmv is presented in the following paragraphs.

Table 5-8 presents the SOCMI gas valve occurrence rate, recurrence rate, unsuccessful repair rate, and initial leak frequency. (See appendix G for details on how each of these parameters were determined.) Using the values presented in table 5-6 and the approach presented in section 5.3.1, the LDAR control effectiveness can be calculated. Note that figure 5-9 is also based on monthly monitoring of gas valves in a SOCMI process unit with a leak definition of 10,000 ppmv, and it is referred to in this example demonstration.

For gas valves with a leak definition of 10,000 ppmv, the initial leak frequency is 7.5 percent. This initial leak frequency value is taken from figure 5-1, by finding the value of

TABLE 5-8. VALUES USED IN EXAMPLE CALCULATION[a]

Source Category:	SOCMI
Equipment Type:	Gas Valves
LDAR Program:	Monthly Monitoring with a Leak Definition of 10,000 ppmv
Occurrence Rate:	1.00%
Recurrence Rate:	14%
Unsuccessful Repair Rate:	10%
Initial Leak Frequency:[b]	7.5%

[a] See appendix F for information on how the occurrence rate, recurrence rate, and unsuccessful repair rate were determined.

[b] Based on the SOCMI average emission factor for gas valves.

the fraction leaking at the intersection of the SOCMI average factor line and the 10,000-ppmv leak definition line. The initial leak rate for this leak frequency is the SOCMI gas valve average emission factor, which equals 0.00597. After the LDAR program is implemented and monitoring occurs on a monthly basis, the steady-state leak frequency immediately after monitoring (see point Y_6 on figure 5-35) equals 0.29 percent. The steady-state leak frequency prior to monitoring (see point Z_6 on figure 5-35) equals 1.29 percent. This gives an average of 0.79 percent as the final leak frequency (see point F on figure 5-35). The calculations performed to determine the final leak frequency are shown in table 5-9. Once the estimated gas valve final leak frequency is determined, the associated leak rate can be found using figure 5-1 or the gas valve equation for a leak definition of 10,000 ppmv listed on table 5-4. The corresponding leak rate associated with the final leak frequency of 0.79 percent at a leak definition of 10,000 ppmv is 0.00075 kg/hr. Thus, the control effectiveness of a monthly LDAR program with a leak definition of 10,000 ppmv for gas valves is:

$$= (0.00597-0.00075)/0.00597 \times 100$$

$$= 87 \text{ percent.}$$

TABLE 5-9. EXAMPLE CALCULATION TO DETERMINE THE FINAL LEAK FREQUENCY OF SOCMI GAS VALVES IN A MONTHLY MONITORING LDAR PROGRAM WITH A LEAK DEFINITION OF 10,000 PPMV[a]

Starting parameters	Resulting parameters
1. Leak definition: = 10,000 ppmv	1. Steady-state leak frequency after monitoring (Point Y_6): = 0.29 percent
2. Leak occurrence (Oc): = 1.00 percent	2. Steady-state leak frequency immediately prior to monitoring (Point Z_6): = 1.29 percent
3. Leak recurrence (R): = 14 percent	3. Final leak frequency (Point F)[b]: = 0.79 percent
4. Successful repair rate (FR): = 90 percent	
5. Initial leak frequency (Point X): = 7.5 percent	

Calculations

Monitoring cycle	Leak frequency after monitoring: Point Y_i (percent)[c]	Leak frequency prior to monitoring: Point Z_i (percent)[d]
1	1.70	7.50
2	0.61	2.67
3	0.36	1.60
4	0.31	1.36
5	0.29	1.30
6[e]	0.29	1.29

[a] Refer to Figure 5-4 for graphical presentation of all points identified in this table.

[b] Final Leak Frequency equals the average of the prior to monitoring and after monitoring steady-state leak frequencies.

[c] $Y_i = Z_i - (FR * Z_i) + (FR * Z_i * R)$

[d] $Z_i + 1 = Oc * (1 - Y_i) + Y_i$

[e] After the sixth monitoring cycle, the values for Y_i and Z_i reach steady-state.

5.4 REFERENCES

1. National Emission Standards for Hazardous Air Pollutants for Source Categories; Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry and Seven Other Processes. Subpart H--Equipment Leaks. Federal Register. Vol. 57, No. 252, pp 62765-62785. Washington, DC. Office of the Federal Register. December 31, 1992.

APPENDIX A: EXAMPLE CALCULATIONS

A-1. INTRODUCTION

This appendix provides example calculations demonstrating the approaches described in chapter 2.0. A simple dataset from a hypothetical process unit is expanded as needed to illustrate how the data are is used in each approach. Table A-1 summarizes information used in the example calculations. This information includes the equipment count, hours of operation, and composition for each stream. The stream compositions presented in table A-1 are completely hypothetical and were chosen for the sole purpose of demonstrating the various approaches. Three streams are presented in table A-1. Note that the hours of operation are based on the time in which the equipment contains material. (Even if a process unit is shutdown, if the equipment contains material, then the shutdown time must still be included in the hours of operation.)

Two SOCMI equipment type/service categories are used in the example calculations: pumps/light liquid and valves/gas. The same technique used for these equipment type/service categories can be followed for any equipment type/service. In each of the calculations, emissions are estimated on an annual basis.

The following sections present the example calculations. In section A-2, the Average Emission Factor Approach is presented. Section A-3 presents the Screening Ranges Approach. In section A-4, the EPA Correlation Equation Approach is presented, and in section A-5, the use of the Unit-Specific Correlation is discussed. Section A-6 explains how to speciate emissions. Section A-7 demonstrates three approaches for applying response factors (RF’s). Section A-8 demonstrates how to annualize emissions when more than one screening value is collected from individual equipment pieces over an annual time period. Section A-9 shows how to estimate VOC emissions when screening data are collected from equipment containing organic compounds not classified as VOC’s. Finally, section A-10 addresses estimating emissions from equipment containing inorganic compounds.

TABLE A-1. DATA FOR EXAMPLE CALCULATIONS

Stream ID	Equipment type/service	Equipment count	Hours of operation[a] (hr/yr)	Stream composition	
				Constituent	wt. fraction
A	Pumps/light liquid	15	8,760	ethyl acrylate water	0.80 0.20
B	Pumps/light liquid	12	4,380	ethyl acrylate styrene	0.10 0.90
C	Valves/gas	40	8,760	ethyl acrylate ethane water vapor	0.65 0.25 0.10

[a] Hours or operation include all time in which material is contained in the equipment.

A-2. AVERAGE EMISSION FACTOR APPROACH

The Average Emission Factor Approach is demonstrated for Streams A and B, which contain light liquid pumps. The SOCMI average TOC emission factor for light liquid pumps is 0.0199 kg/hr. Based on this emission factor and data contained in table A-1, total VOC emissions can be calculated. Note that the TOC’s in Stream A are also VOC’s and that stream A contains water, which is not a VOC. This is accounted for when total VOC emissions are estimated from Stream A. Table A-2 summarizes the Average Emission Factor Approach calculations.

A-3. SCREENING RANGES APPROACH

The Screening Ranges Approach is demonstrated for Streams A and B. The calculations for the Screening Ranges Approach are similar to those used for the Average Emission Factor Approach, except that an emission factor for each screening value range is used. In this example, the component screening values are designated as either less than 10,000 ppmv or equal to or greater than 10,000 ppmv. It is assumed that none of the light liquid pumps in Stream A have a screening value greater than or equal to 10,000 ppmv, and one of the light liquid pumps in Stream B screens greater than 10,000 ppmv. It is also assumed that one of the pumps in Stream B could not be screened. Emissions from this pump are calculated using the average emission factor. Table A-3 summarizes the calculations used in the Screening Ranges Approach.

A-4. EPA CORRELATION EQUATION APPROACH

The EPA Correlation Equation Approach is demonstrated for Streams A and B. The EPA Correlation Equation Approach involves entering screening values into a correlation equation to generate an emission rate for each equipment piece. In table A-4, assumed screening values and the resulting emissions for each individual equipment piece are presented. Emissions from the pump that was not screened are estimated using the average emission factor.

TABLE A-2. AVERAGE EMISSION FACTOR METHOD

Stream ID	Equipment count	TOC Emission factor (kg/hr/source)	Weight Fraction of TOC	Hours of operation (hr/yr)	VOC emissions[a] (kg/yr)
A	15	0.0199	0.80	8,760	2,090
B	12	0.0199	1.00	4,380	1,050
Total Emissions					3,140

[a] VOC Emissions = (no. of components) × (emission factor) × (wt. fraction TOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation).

TABLE A-3. SCREENING VALUE RANGES METHOD

Stream ID	Equipment count	TOC Emission factor (kg/hr/source)	Hours of operation (hr/yr)	VOC emissions (kg/yr)
Components screening ≥ 10,000 ppmv[a]				
B	1	0.243	4,380	1,060
Components screening < 10,000 ppmv[a]				
A	15	0.00187	8,760	246
B	10	0.00187	4,380	82
Components not screened[b]				
B (TOC wt. fraction equal to 1.0)	1	0.0199	4,380	87
Total emissions				1,480

[a] VOC emissions = (no. of components) × (TOC emission factor) × (WP_{VOC}/WP_{TOC}) × (hours of operation).

[b] VOC emissions = (no. of components) × (average TOC emission factor) × (wt. fraction of TOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation).

TABLE A-4. EPA CORRELATION EQUATION METHOD[a]

Equipment ID	Screening value (ppmv)	TOC mass emissions[b] (kg/yr)
A-1	0	0.066
A-2	0	0.066
A-3	0	0.066
A-4	0	0.066
A-5	0	0.066
A-6	20	2.0
A-7	50	4.2
A-8	50	4.2
A-9	100	7.4
A-10	100	7.4
A-11	200	13
A-12	400	23
A-13	1,000	49
A-14	2,000	87
A-15	5,000	190
Total Stream A Emissions:		390
B-1	0	0.033
B-2	0	0.033
B-3	0	0.033
B-4	10	0.55
B-5	30	1.4
B-6	250	7.9
B-7	500	14
B-8	2,000	44
B-9	5,000	93
B-10	8,000	140
B-11	25,000	350
B-12 (100% TOC)	Not screened	87
Total Stream B Emissions:		740
Total Emissions		1,130

[a] Equipment type: Light liquid pumps.
Correlation equation: Leak rate (kg/hr) = $1.90\times10^{-5} \times (SV)^{0.824}$
Default-zero mass emission rate: 7.49×10^{-6} kg/hr
Hours of operation: Stream A = 8,760; Stream B = 4,380.

[b] VOC Emissions = (correlation equation or default-zero emission rate) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

[c] VOC Emissions = (average emission factor) × (wt. fraction of TOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

A-5. UNIT-SPECIFIC CORRELATION APPROACH

Correlation equations may be developed for specific units rather than using the more general EPA Correlation Equations. Appendix B presents details on developing unit-specific correlations. Once correlations are developed using the approach outlined in appendix B, they are applied in the same manner as described for the EPA correlations.

A-6. SPECIATING EMISSIONS

The emission rate of specific compounds in a mixture can be calculated if the concentration of the compound in the stream is known. The equation for speciating emissions is

$$E_X = E_{TOC} \times (WP_X/WP_{TOC})$$

where:

E_X = The mass emissions of organic chemical "x" from the equipment piece (mass/time);

E_{TOC} = The TOC mass emissions from the individual equipment piece (mass/time) calculated from either the Average Emission Factor, Screening Ranges, Correlation, or Unit-Specific Correlation approaches;

WP_X = The concentration of organic chemical "x" in the equipment piece (weight percent);

WP_{TOC} = The total TOC concentration in the equipment piece (weight percent).

See table A-5 for a demonstration of speciating emissions of Stream B. Because all of the equipment in Stream B contains the same composition, the emissions can be speciated on a stream-wide basis.

A-7. RESPONSE FACTORS

Response factors are used to correct screening values to compensate for variations in a monitor’s response to different compounds. Determination of whether an adjustment to the screening value will provide more valid emission estimates can be made by reviewing RF’s at actual concentrations of 500 ppmv and 10,000 ppmv for the material in the equipment being screened.

TABLE A-5. SPECIATING EMISSIONS OF STREAM B[a]

Method of calculation	Total TOC emission (kg/yr)	Ethyl acrylate emissions[b] (kg/yr)	Styrene emissions[b] (kg/yr)
Avg. emission factor	1,050[c]	105	945
Screening ranges	1,230[d]	123	1,110
Correlation equation	740[e]	74	666

[a] Equipment type: Light liquid pumps
Total TOC wt. fraction 1.0
Ethyl acrylate wt. fraction 0.1
Styrene wt. fraction 0.9

[b] Emissions for species = (total TOC emissions) × (wt. fraction of individual chemical)/(total TOC wt. fraction).

[c] From Table A-2.

[d] From Table A-3.

[e] From Table A-4.

The RF’s can be taken from table D-1 in appendix D, or may be calculated based on analytical measurement performed in a laboratory. For materials with RF’s below three at both actual concentrations, the screening value does not need to be corrected. If the RF at either concentration is above three, the screening value obtained from the monitoring device should be adjusted.

If it is necessary to adjust the screening value, one of two approaches can be applied:

(1) Use the higher of either the 500 ppmv or 10,000 ppmv RF to adjust all screening values, or

(2) Plot the RF versus screening value and determine the applicable RF for each screening value.

Table D-1 in appendix D presents the RF’s for chemical compounds at actual concentrations of 500 ppmv and 10,000 ppmv for several different monitoring devices. For the example calculations presented here, data for the Foxboro OVA-108 is utilized. Table A-6 presents the RF’s for ethyl acrylate and styrene. From table A-6, it can be seen that at both concentrations, the RF for ethyl acrylate is below three. Therefore, it is not necessary to adjust any of the screening values taken from the equipment in Stream A. (The only TOC constituent in Stream A is ethyl acrylate.) Stream B contains 10 percent ethyl acrylate and 90 percent styrene. The RF’s at both concentration values for Stream B are calculated using the following equation:

$$RF_m = \frac{1}{\sum_{i=1}^{n} (X_i/RF_i)}$$

where:

RF_m = Response factor of the mixture;

n = Number of constituents in the mixture;

X_i = Mole fraction of constituent i in the mixture; and

TABLE A-6. APPLICATION OF RESPONSE FACTORS[a]

Chemical	Molecular weight	Mole fraction for stream B[b]	Response factor at actual conc. of 500 ppmv	Response factor at actual conc. of 10,000 ppmv
Ethyl Acrylate (0.10 wt. frac.)	100.1	0.1036	2.49	0.72
Styrene (0.90 wt. frac.)	104.2	0.8964	1.10	6.06

[a] Response factors are taken from Table D-1 in Appendix D and are based on a Foxboro OVA-108 calibrated with methane.

[b] Mole fraction calculated as:

$$= \frac{\dfrac{\underline{\text{Weight fraction compound i}}}{\text{MW of compound i}}}{\displaystyle\sum_{i=1}^{n} \dfrac{\underline{\text{Weight fraction compound i}}}{\text{MW of compound i}}}$$

RF_i = Response factor of constituent i in the mixture;

The derivation of the above equation is presented in table A-7. Using the RF's and mole fraction information from table A-6, the RF for the mixture in Stream B is calculated as follows:

$$RF_m(@\ 500\ \text{ppmv}) = (0.1036/2.49 + 0.8963/1.10)^{-1} = 1.17$$

and

$$RF_m(@\ 10{,}000\ \text{ppmv}) = (0.1036/0.72 + 0.8964/6.06)^{-1} = 3.43$$

From the above calculations, it can be seen that at an actual concentration of 10,000 ppmv the RF is above three, which means the screening values need to be adjusted. Table A-8 demonstrates the simplest approach for adjusting the screening values. This approach involves multiplying all of the screening values by whichever RF is higher.

Correcting the screening values by the approach described above may be inaccurate in some cases. For example, if all or most of the equipment have low screening values, using the RF based on an actual concentration of 10,000 ppmv may cause an over estimate in the calculated emission rate. A more precise application of RF's is to plot the RF versus the screening value. This can be done by fitting a straight line between the RF and the corresponding screening values associated with the 500 and 10,000 ppmv actual concentrations. For the example case, this is done as follows.

Screening value associated with actual concentration of 500 ppmv:

= (500 ppmv)/(RF at actual concentration of 500 ppmv)

= 500 ppmv/1.17

= 427 ppmv

Screening value associated with actual concentration of 10,000 ppmv:

= (10,000 ppmv)/(RF at actual concentration of 10,000 ppmv)

TABLE A-8. APPLYING RESPONSE FACTORS FROM TABLE C-1a

Equipment ID	Unadjusted screening value (ppmv)	Response factor of mixture	Adjusted screening value[b] (ppmv)	VOC Emission rate[c] (kg/yr)
B-1	0	--	Default zero	0.033
B-2	0	--	Default zero	0.033
B-3	0	--	Default zero	0.033
B-4	10	3.43	34	1.5
B-5	30	3.43	103	3.8
B-6	250	3.43	858	22
B-7	500	3.43	1,715	39
B-8	2,000	3.43	6,860	120
B-9	5,000	3.43	17,150	260
B-10	8,000	3.43	27,440	380
B-11	25,000	3.43	85,750	970
B-12	Not Screened	--	--	87[d]
Total Emissions of Stream B				1,880

[a] Equipment type: Light liquid pumps
Correlation equation: Leak rate (kg/hr) = 1.90×10^{-5} $(SV)^{0.824}$
Default-zero mass emission rate: 7.49×10^{-6} kg/hr
Hours of operation: Stream B = 4,380

[b] Adjusted SV = (unadjusted SV) × (RF of mixture)

[c] VOC Emission = (correlation equation or default-zero emission rate) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

[d] VOC Emission = (average emission factor) × (wt. fraction of VOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

TABLE A-7. DERIVATION OF EQUATION USED TO ESTIMATE RESPONSE FACTOR FOR A MIXTURE

(1) Response Factor (RF) Equation:

$$RF = \frac{\text{Actual Concentration (ppmv)}}{\text{Screening Value (ppmv)}} = \frac{A}{SV}$$

(2) For a mixture, each compound will contribute to the actual concentration and to the screening value, thus:

$$A = A_1 + A_2 + A_3 \; . \; . \; . = A_{TOT}$$

$$SV = SV_1 + SV_2 + SV_3 \; . \; . \; .$$

Thus, the above equation converts to:

$$RF = \frac{A_{TOT}}{SV_1 + SV_2 + SV_3 \ldots}$$

(3) The value for the screening value of each individual compound (SV_i) is calculated as:

$$SV_i = \frac{A_i}{RF_i}\text{; substituting gives:}$$

$$RF = \frac{A_{TOT}}{\frac{A_1}{RF_1} + \frac{A_2}{RF_2} + \frac{A_3}{RF_3} \ldots}$$

(4) The mole fraction of each individual compound (X_i) is calculated as:

$$X_i = \frac{A_i}{A_{TOT}};$$

Thus, the actual concentration of compound i is calculated as:

$A_i = X_i \, A_{TOT}$; substituting gives:

$$RF = \frac{A_{TOT}}{\frac{X_1 A_{TOT}}{RF_1} + \frac{X_2 A_{TOT}}{RF_2} + \frac{X_3 A_{TOT}}{RF_3} \ldots} = \frac{1}{\frac{X_1}{RF_1} + \frac{X_2}{RF_2} + \frac{X_3}{RF_3} \ldots}$$

(5) Thus, the response factor of a mixture is calculated as:

$$RF = \frac{1}{\sum_{i=1}^{n} X_i/RF_i}$$

= 10,000/3.43

= 2,915 ppmv

Figure A-1 plots this screening value/RF relationship. Table A-9 uses this plot to calculate emissions. Note that in table A-9, all of the screening values are adjusted. An alternative would be to adjust only those screening values having an associated RF greater than three. Note that for all screening values less than 427 ppmv, the RF calculated at 427 ppmv is applied, and, similarly, for all screening values above 2,915 ppmv, the RF at 2,915 ppmv is applied.

An alternative to using the RF’s in appendix D is to use the analytical technique described in chapter 3.0 to determine RF’s at several different actual concentrations. These RF’s are then related to the screening value. Once the RF’s and associated screening values are determined, a first-order or second-order (if the relationship appears nonlinear) equation can be fitted to the RF data. Table A-10 demonstrates how the collected data of RF’s at actual concentrations is converted to RF’s for the associated screening values. A hypothetical plot of the RF/screening value relationship is shown in figure A-2. Table A-11 demonstrates how emissions can then be calculated by applying the plot. Note that the line is not extrapolated beyond the highest screening value for which data were obtained.

A-8. ANNUALIZING EMISSIONS

If more than one screening value is obtained from an equipment piece, all of the screening values can be used to estimate emissions, as long as the elapsed time between each screening value obtained is known. This is demonstrated for pump A-15 in Stream A. Table A-12 shows how emissions are calculated for each period between the collection of screening values. Notice that each screening value is used to estimate emissions since the last screening value was obtained.

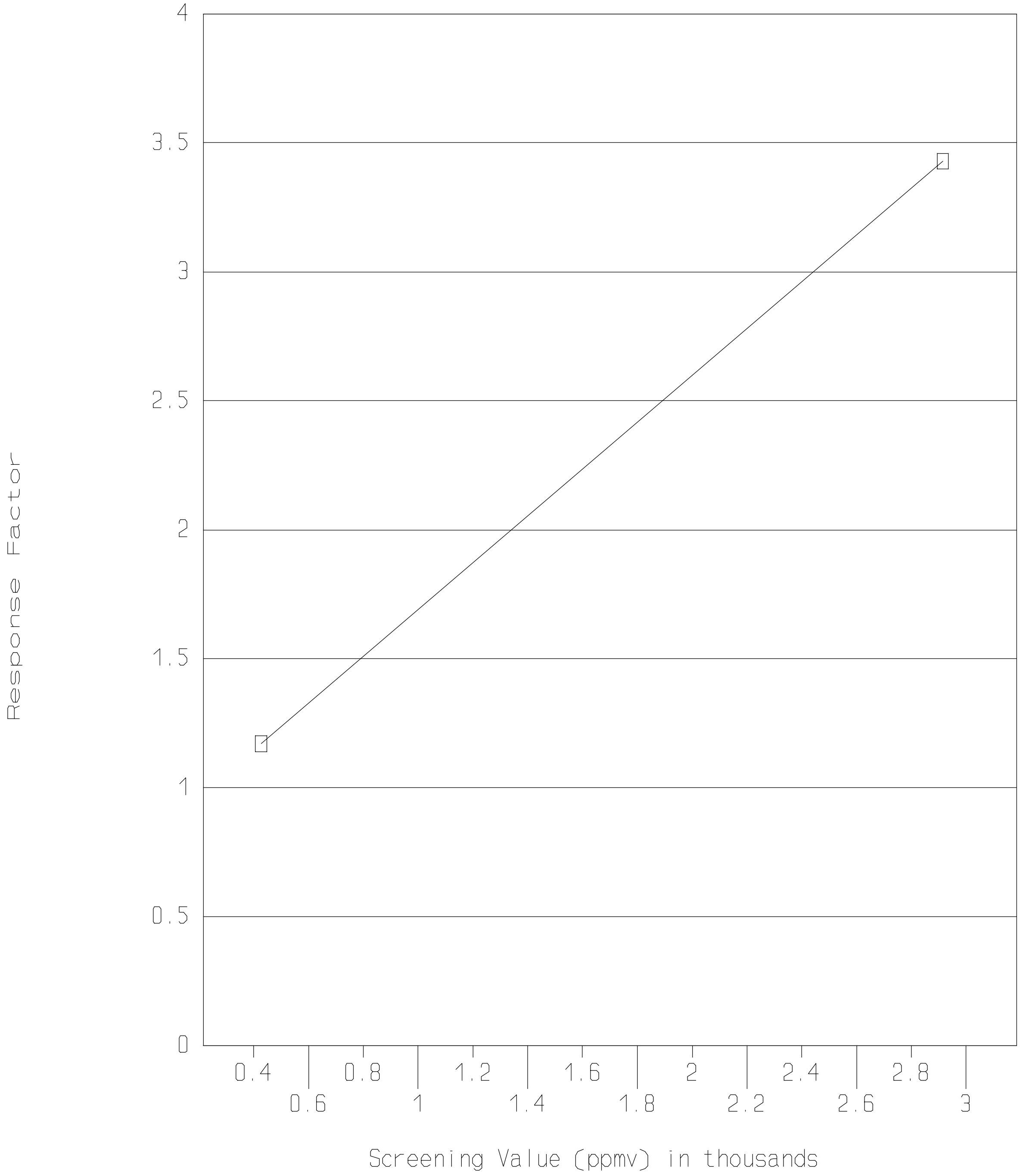


Figure A-1. Response Factor Curve Generated From Response Factor Data in Table C-1

TABLE A-9. ESTIMATING EMISSIONS USING RESPONSE FACTORS GENERATED FROM FIGURE A-1[a]

Equipment ID	Unadjusted screening value (ppmv)	Response factor of mixture	Adjusted screening value[b] (ppmv)	VOC Emission rate[c] (kg/yr)
B-1	0	--	Default zero	0.033
B-2	0	--	Default zero	0.033
B-3	0	--	Default zero	0.033
B-4	10	1.17	12	0.63
B-5	30	1.17	35	1.6
B-6	250	1.17	293	9.0
B-7	500	1.24	620	17
B-8	2000	2.62	5,240	97
B-9	5000	3.43	17,150	260
B-10	8000	3.43	27,440	380
B-11	25000	3.43	85,750	970
B-12	Not screened	--	--	87[d]
Total Emissions of Stream B				1,820

[a] Equipment type: Light liquid pumps
Correlation equation: Leak rate (kg/hr) = 1.90×10^{-5} $(SV)^{0.824}$
Default-zero mass emission rate: 7.49×10^{-6} kg/hr
Hours of operation: Stream B = 4,380

[b] Adjusted SV = (unadjusted SV) × (RF of mixture taken from Figure A-1)

[c] VOC Emission = (correlation equation or default-zero emission rate) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

[d] VOC Emission = (no. of components) × (average emission factor) × (wt. fraction of VOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation)

TABLE A-10. GENERATION OF HYPOTHETICAL RESPONSE FACTOR DATA FOR STREAM B[a]

Actual standard gas concentration (ppmv)	Sample number	Measured screening value (ppmv)	Response factor
500	1	375	1.33
500	2	390	1.28
500	3	390	1.28
		Avg = 385	Avg = 1.30
2,000	1	1,219	1.64
2,000	2	1,205	1.66
2,000	3	1,258	1.59
		Avg = 1,227	Avg = 1.63
5,000	1	1,865	2.68
5,000	2	1,930	2.59
5,000	3	1,872	2.67
		Avg = 1,889	Avg = 2.65
10,000	1	2,976	3.36
10,000	2	3,040	3.29
10,000	3	2,994	3.34
		Avg = 3,003	Avg = 3.33
25,000	1	6,361	3.93
25,000	2	6,394	3.91
25,000	3	6,476	3.86
		Avg = 6,410	Avg = 3.90

[a] This table is a demonstration of how analytical determination of response factors can be used to generate a response factor/screening value relationship.

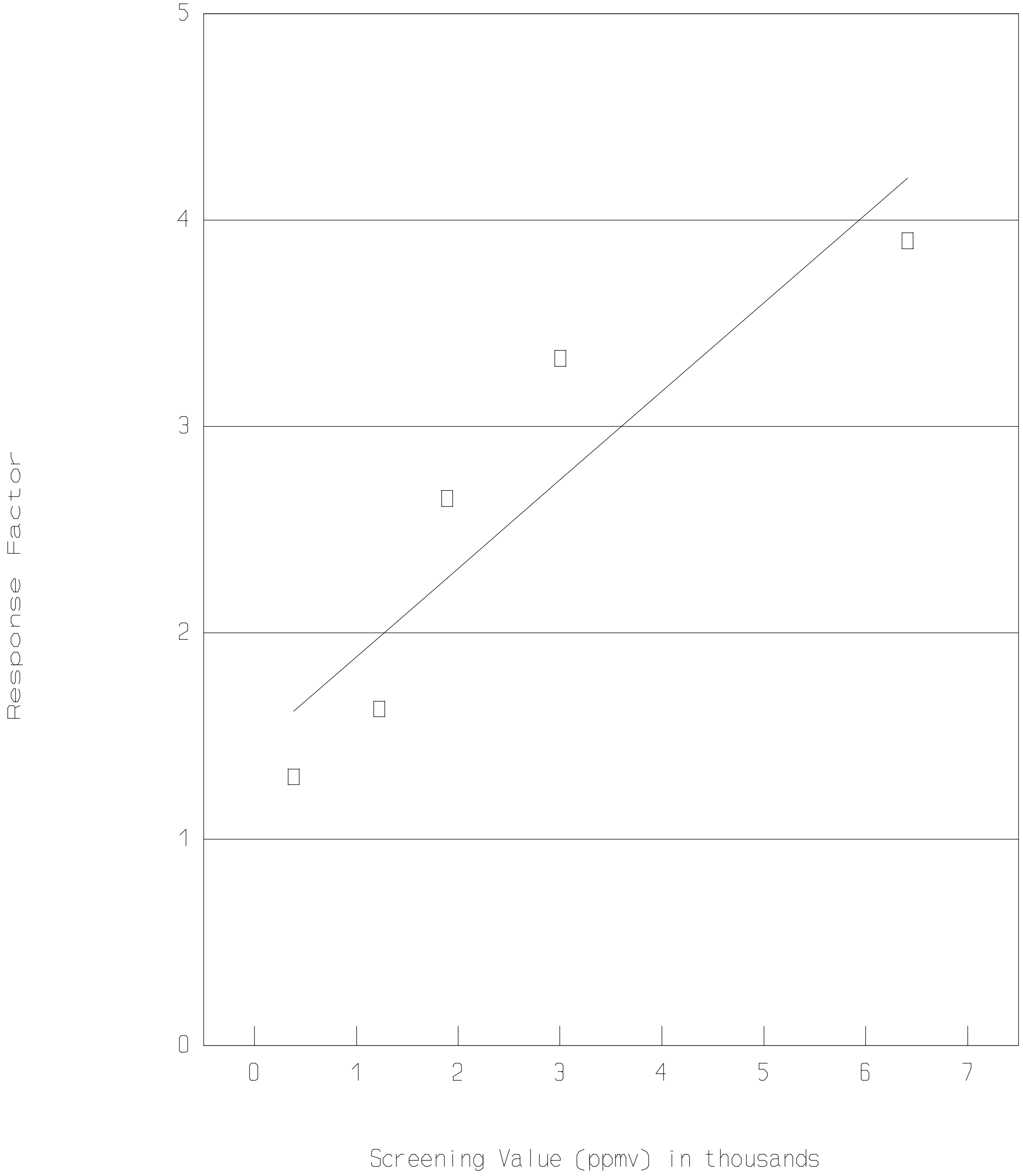


Figure A-2. Response Factor Curve Generated by Analytical Determination of Response Factors

TABLE A-11. RESPONSE FACTORS GENERATED FROM FIGURE A-2[a]

Equipment ID	Unadjusted screening value (ppmv)	Response factor of mixture	Adjusted screening value[b] (ppmv)	VOC Emission rate[c] (kg/yr)
B-1	0	--	Default zero	0.033
B-2	0	--	Default zero	0.033
B-3	0	--	Default zero	0.033
B-4	10	1.46	15	0.76
B-5	30	1.47	44	1.9
B-6	250	1.56	390	11
B-7	500	1.69	845	21
B-8	2,000	2.31	4,620	87
B-9	5,000	3.60	18,000	270
B-10	8,000	4.20	33,600	450
B-11	25,000	4.20	105,000	1,140
B-12	Not screened	--	--	87[d]
Total Emissions of Stream B				2,070

[a] Equipment type: Light liquid pumps
Correlation equation: Leak rate (kg/hr) = 1.90×10^{-5} $(SV)^{0.824}$
Default-zero mass emission rate: 7.49×10^{-6} kg/hr
Hours of operation: Stream B = 4,380

[b] Adjusted SV = (unadjusted SV) × (RF of mixture taken from Figure A-2).

[c] VOC Emissions = (correlation equation or default-zero emission rate) × (WP_{VOC}/WP_{TOC}) × (hours of operation).

[d] VOC Emission = (no. of components) × (average emission factor) × (wt. fraction of VOC) × (WP_{VOC}/WP_{TOC}) × (hours of operation).

TABLE A-12. ANNUALIZING EMISSIONS FOR LIGHT LIQUID PUMP A-15a

Hypothetical date	Screening value (ppmv)	Hours elapsed since last screening value[b]	VOC emissions since last screening value[c] (kg)
January 1	5,000	--	--
February 1	0	744	0.006
March 1	0	672	0.005
April 1	8,000	744	23.3
May 1	100	720	0.6
June 1	1,000	744	4.2
July 1	0	720	0.005
August 1	0	744	0.006
September 1	0	744	0.006
October 1	10,000	720	27.0
November 1	0	744	0.006
December 1	0	720	0.005
January 1	0	744	0.006
	TOTALS:	8,760	55.1

[a] Equipment type: Light liquid pumps
Correlation equation: Leak rate (kg/hr) = $1.90 \times 10^{-5} (SV)^{0.824}$
Default-zero mass emission rate: 7.49×10^{-6} kg/hr

[b] Hours elapsed since the last screening value was obtained. For example, the hours elapsed since the screening value obtained on March 1 are the hours from February 1 to March 1, which equal 24 hr/day × 28 days, or 672 hours.

[c] VOC Emissions = (correlation equation or default-zero emission rate) × (WP_{VOC}/WP_{TOC}) × (hours elapsed).

A-9. ESTIMATING VOC EMISSIONS FROM EQUIPMENT CONTAINING ORGANIC COMPOUNDS NOT CLASSIFIED AS VOC's.

Stream C contains ethane, which is an organic compound, but is not classified as a VOC. When a monitoring instrument is used to screen equipment in Stream C, the resulting screening value will include measurement of the ethane. However, the ethane should not be included in the estimated VOC emission rate. The following equation is applied to subtract out the ethane contribution:

$$E_{VOC} = E_{TOC} \times (WP_{VOC}/WP_{TOC})$$

where:

E_{VOC} = The VOC mass emissions from the equipment (kg/hr);

E_{TOC} = The TOC mass emissions from the equipment (kg/hr); calculated from either the Average Emission Factor, Screening Ranges, Correlation, or Unit-Specific Correlation approaches;

WP_{VOC} = The concentration of VOC in the equipment in weight percent;

WP_{TOC} = The TOC concentration in the equipment in weight percent.

The above calculation is demonstrated below by assuming that screening values have been obtained from equipment in Stream C as either greater than or equal to 10,000 ppmv or less than 10,000 ppmv. Assume 2 of the 40 gas valves in Stream C screened above 10,000 ppmv, and the remainder screened below 10,000 ppmv. Uncorrected VOC emissions are calculated using the Screening Ranges Approach:

$$E_{TOC} = (F_G \times N_G) + (F_L \times N_L)$$

where:

E_{TOC} = TOC emission rate for an equipment type (kg/hr);

F_G = Applicable emission factor for sources with screening values greater than or equal to 10,000 ppmv (kg/hr/source);

N_G = Equipment count (specific equipment type) for sources with screening values greater than or equal to 10,000 ppmv;

F_L = Applicable emission factor for sources with screening values less than 10,000 ppmv (kg/hr/source); and

N_L = Equipment count (specific equipment type) for sources with screening values less than 10,000 ppmv.

Thus,

$$E_{TOC} = 0.0782 \text{ kg/hr} \times 2 + 0.000131 \text{ kg/hr} \times 38$$

$$= 0.161 \text{ kg/hr}$$

Converting to an annual emission rate gives:

$$= 0.161 \text{ kg/hr} \times 8{,}760 \text{ hr/yr}$$

$$= 1{,}410 \text{ kg/yr}$$

Using the weight fraction of the compounds in Stream C given in table A-1 (65% ethyl acrylate, 25% ethane, and 10% water vapor), the above emission rate is corrected as follows:

$$\begin{aligned} E_{VOC} &= E_{TOC} \times (WP_{VOC}/WP_{TOC}) \\ &= 1{,}410 \text{ kg/yr} \times 65/(65 + 25) \\ &= 1{,}020 \text{ kg/yr VOC emissions} \end{aligned}$$

A-10. ESTIMATING INORGANIC EQUIPMENT LEAKS

If the hypothetical process unit also had equipment that contained a volatile inorganic compound, emissions could be estimated using the following guidelines. If a monitoring device is not available, the equipment emissions can be calculated using the Average Emission Factor Approach. If a monitoring device is available, the best approach for estimating the emissions is to generate unit specific correlations, but the EPA Correlation Equations could also be applied as in section A-4. If the monitoring device cannot accurately predict the screening value but can be used to predict concentrations greater than/less than 10,000 ppmv, the emissions may be estimated by applying the Screening Ranges approach presented in section A-3.

APPENDIX B:

LEAK RATE/SCREENING VALUE CORRELATION DEVELOPMENT AND REVISION OF SOCMI CORRELATIONS AND EMISSION FACTORS

APPENDIX B

The purpose of this appendix is to provide supplemental information on the approach for developing site-specific correlations as discussed in chapter 2.0 of this document. Also, this appendix contains background information on the data collection and analysis performed to revise the SOCMI correlations and emission factors, and presents summary parameters associated with the SOCMI and petroleum industry correlations. Section B.1 addresses the following:

- Analysis of bagging and screening data;
- Development of a correlation equation; and
- Development of a default-zero leak rate.

Section B.2 addresses the following:

- Analysis of new SOCMI bagging data;
- Development of revised correlations and default-zero leak rates;
- Development of revised SOCMI emission factors; and
- Summary of SOCMI and petroleum industry correlation parameters.

B.1 DEVELOPMENT OF SITE-SPECIFIC CORRELATION EQUATIONS

Development of site-specific correlations involves bagging individual pieces of equipment. (Refer to chapter 4.0 for details on how equipment is bagged.) The emission rate and associated screening value from several equipment pieces of the same type (valve, pump, connector, etc.) and service (gas, light liquid or heavy liquid) are used to develop a correlation. The correlation predicts a leak rate based on a screening value. To develop a correlation, "bagging data" must be collected. In this appendix, "bagging data" refers to data used to estimate the mass emission rate from an equipment piece, and the screening value obtained with the portable monitoring instrument when the equipment piece is bagged.

B.1.1 Preliminary Analysis of Bagging Data.

For the purposes of this discussion, it is assumed the blow-through method is used to bag the equipment piece. For each bagged (tented) equipment piece, two sample bags should be collected. For each sample bag the following bagging data should be recorded: (1) total organic compound concentration (ppmv) measured in the sample bag at the laboratory using a GC or similar instrument, (2) the mole percent and molecular weight of each of the constituents in the sample bag (or alternatively in the process stream contained within the enclosed equipment piece), (3) the temperature in the tent when the sample bag is collected, (4) the carrier gas flow rate out of the tent, (5) the tent oxygen concentration (6) background bag organic compound concentration measured at the laboratory (optional), and (7) the density and volume of any organic liquid collected from the bagged equipment piece and the time in which the liquid accumulated.

In some cases, the sample bag total organic concentration will be below the GC minimum detection limit. If this occurs, one half the GC minimum detection limit should be used to estimate emissions.

For each sample bag, the vapor leak rate is calculated using the following equation:

$$\text{Vapor leak rate (kg/hr)} = \frac{(1.219\times10^{-5})\times(Q)\times(MW)\times(GC)}{T + 273.15}$$

where:

1.219×10^{-5} = A conversion factor based on the gas constant and assuming a pressure in the tent of 1 atmosphere ($^{o}K \times 10^{6} \times$ kg-mol/m^3)

Q = Flow rate out of tent (m^3/hr)

$$= \frac{N_2 \text{ flow rate } (\ell/\text{min})}{1 - [\text{tent oxygen conc. (volume \%)}/21]} \times \frac{0.06\ m^3/\text{min}}{\ell/\text{hr}}$$

T = Temperature in tent (^{o}C)

MW = Molecular weight of organic compounds in the sample bag or alternatively in the process stream contained within the equipment piece being bagged. For mixtures, MW is calculated as follows:

$$MW = \frac{\sum_{i=1}^{n} MW_i \, x_i}{\sum_{i=1}^{n} x_i}$$

where:

MW_i = Molecular weight of organic compound i;

x_i = Mole fraction of organic compound i; and

n = Number of organic compounds in the mixture.

GC = Sample bag organic compound concentration. If a background sample bag is obtained, the value of GC can be corrected for background organic compound concentration using the following equation:

$$GC = SBC - \left(\frac{Oxy \text{ x } BBC}{21}\right)$$

where:

SBC = Sample bag organic compound concentration (ppmv);

Oxy = Tent oxygen concentration (volume %); and

BBC = Background sample bag organic compound concentration.

The vapor leak rate calculated from the two sample bags is averaged. Added to this average vapor leak rate is the leak rate of any liquid that is collected in the bag. The liquid leak rate is calculated as follows:

$$\text{Liquid leak rate (kg/hr)} = \frac{\rho \, V_L}{16.67 \, t}$$

where:

ρ = Density of organic liquid collected (g/mℓ);

V_L = Volume of organic liquid collected (mℓ);

t = Time in which liquid is collected (minutes); and

16.67 = A conversion factor to adjust term to units of kilograms per hour [g × hr/(kg × min)]

Thus, the total emission rate for the bagged equipment piece is as follows:

$$\text{Leak rate (kg/hr)} = \text{Average vapor leak rate (kg/hr)} + \text{Liquid leak rate (kg/hr)}$$

The screening value associated with each bagged equipment piece is calculated by subtracting the background screening value from the average of the initial and final screening values. In cases where the background concentration was larger than the average of the initial and final screening values, the screening value should be recorded as 0 ppmv.

B.1.2 Correlation Equation Development.

After preliminary analysis of the bagging data is complete, there will be a mass emission rate and corresponding screening value associated with each individual equipment piece that was bagged. All mass emission rate/screening value data pairs with nonzero screening values are used to develop the site-specific correlation. Data pairs with a screening value of zero can be used to develop a default-zero leak rate, and this is discussed in section B.1.3.

Two terms used in conjunction with developing the correlation are defined as follows: "log space"--where the logarithms of both the screening values and mass emission rates are evaluated, and "arithmetic space"--where the actual screening values and emission rates are evaluated. The data is first analyzed in log space to develop an expression relating the logarithm of the screening value to the logarithm of the mass emission rate. This expression is then transformed to arithmetic space to arrive at the correlation equation.

It is necessary to perform the initial analysis in log space because both the screening value and mass emission rate data typically span several orders of magnitude, and the data are not normally distributed in arithmetic space. Normality of the data is important for the validity of the statistical procedures being used. Historically, the data have been shown to be approximately log-normally distributed.

The first step in the development of the correlation equation is to calculate the logarithm of each screening value and mass emission rate. Note that the correlation developed will be the same whether the natural logarithm or base 10 logarithm is used. The next step is to perform simple linear (least squares) regression in log space. The log of the mass emission rate (dependent variable, Y) is regressed on the log of the screening value (independent variable, X). The resulting regression line takes the following form:

$$Y_i = \beta_0 + \beta_1 X_i$$

where:

Y_i = Logarithm of the leak rate determined by bagging equipment piece i;

X_i = Logarithm of the screening value for equipment piece i;

β_o = Intercept of regression line; and

β_1 = Slope of regression line.

The value for the slope and intercept are calculated using the following equations:

$$\beta_1 = \frac{(\overline{XY}) - (\overline{X})(\overline{Y})}{\overline{X^2} - (\overline{X})^2}$$

and

$$\beta_0 = \bar{Y} - \beta_1 \bar{X}$$

where:

$$\bar{X} = \frac{\Sigma X_i}{n}$$

$$\bar{Y} = \frac{\Sigma Y_i}{n}$$

$$\overline{XY} = \frac{\Sigma X_i Y_i}{n}$$

$$\bar{X}^2 = \frac{\Sigma X_i^2}{n}$$

n = number of screening/bagging pairs.

Once these have been calculated, then the Mean Squared Error (MSE) can be given by:

$$MSE = \frac{1}{n-2} \sum_{i=1}^{n} r_i^2$$

where:

$$r_i = Y_i - \beta_0 - \beta_1 X_i$$

The slope and intercept and a scale bias correction factor (SCBF) are used in the final step to transform the regression equation from log space to arithmetic space. The transformed equation is the correlation equation and it is calculated as follows:

$$\text{Leak rate (kg/hr)} = \text{SBCF} \times (\text{e or } 10)^{\beta_0} \times (\text{Screening value})^{\beta_1}$$

Note that if the natural logarithm of the leak rates and screening values is used when developing the regression line, then the "e" term should be raised to the power of the intercept

(β_0). On the other hand, if the base 10 logarithm of the leak rates and screening values is used when developing the regression line, then the "10" term should be raised to the power of the intercept (β_0).

The SBCF is a correction factor which accounts for the variability of the data in the log space (see discussion in section 2.3.4). It is obtained by summing a sufficient number (usually 10-15) of the terms from the infinite series given below:

$$SBCF = 1 + \frac{(m-1)\times T}{m} + \frac{(m-1)^3\times T^2}{m^2\times 2!\times(m+1)} + \frac{(m-1)^5\times T^3}{m^3\times 3!\times(m+1)\times(m+3)} + \ldots,$$

where:

T (when regression performed using base 10 logarithms)
$= (MSE/2)\times((\ln 10)^2)$;

T (when regression performed using natural logarithms)
$= (MSE/2)$;

MSE = mean square error from the regression;

ln10 = natural logarithm of 10; and

m = number of data pairs (n) - 1.

B.1.3 Determination of Default Zero and Pegged Mass Emission Rates

A default zero emission rate can be calculated based on the emission rates measured from bagged equipment that have a screening value of zero ppmv. A pegged emisison rate can be calculated based on the emission rates measured from bagged equipment that have a screening value reported as pegged. The first step to determine the default-zero or pegged leak rate is to take the logarithm of each of the mass emission rates and then determine the average log leak rate. The average log leak rate is used to calculate the default-zero or pegged mass emission rate. Analysis is performed in log space rather than just determining the arithmetic average because this gives the most efficient estimator of the default-zero or pegged leak rate. The average log leak rate and a scale bias correction factor, that takes into account the variance of the log mass emission rates, are then utilized in the following equation to calculate the default zero leak rate:

$$\text{Default Zero or pegged Leak Rate (kg/hr)} = \text{SBCF} \times (10 \text{ or } e)^{\text{LOG:AVG}}$$

where:

SBCF = Scale bias correction factor for the logs of the mass emission rates; and

LOG:AVG = Average of the logs of the mass emission rates.

The SBCF for the default zero or pegged leak rate determination is calculated using the same equation for the SBCF as presented in section B.1.2, with the following two exceptions: (1) the variance of the log mass emission rates is used in the "T" term, rather than the regression mean square error (MSE); and (2) the sample size (n) is used in the "m" term, rather than "n-1". The variance (S^2) of the log mass emission rates is calculated as:

$$S^2 = \frac{1}{n-1} \sum_{i=1}^{n} (\text{LOG:LEAK}_i - \text{LOG:AVG})^2$$

where:

LOG:LEAK_i = Logarithm of leak rate from component i;

LOG:AVG = Average of the logs of the mass emission rates; and

n = Number of data points.

B.2 DEVELOPMENT OF REVISED SOCMI CORRELATIONS AND FACTORS

In 1990 bagging data were obtained from several ethylene oxide (EO) and butadiene (BD) producers. Bagging data were collected from connectors, light liquid pumps, gas valves, and light liquid valves. In 1987 and 1988 screening data had been collected from the same EO/BD process units. These bagging and screening data were used to revise the SOCMI correlations and factors.

(Note that as used in the following discussion, "bagging data" refers to the screening value/mass emission data pairs, and "screening data" to the data set of screening values collected independently of the bagging data. Normally, bagging data are collected from a chosen set of equipment pieces to provide the best data for developing a correlation. On the other hand, screening data are collected from all equipment pieces to give a representative distribution of screening values).

To revise the SOCMI correlations and factors, the data collected from the EO/BD process units were compared with data previously collected from SOCMI process units. In the following discussion this previously collected data are referred to as "old" data. The old SOCMI bagging data were collected in the Six-Unit Maintenance Study (EPA-600/S2-81-080). The old SOCMI screening data were collected in the 24-Unit Study (EPA-600/2-81-003). The EO/BD data are referred to as "new." When the data sets are joined, the resulting data set is referred to as "combined."

B.2.1 Analysis of SOCMI Bagging Data

Following the approach described in section B.1, the new SOCMI bagging data were analyzed to develop new correlations. A comparison of the old and new bagging data was performed to evaluate any differences. Note that for connectors, only new bagging data were analyzed since connectors were not bagged as part of the Six-Unit Maintenance Study. Attachment 1 includes the complete list of each of the emission rate/screening value datapoints and presents summary tables on the regression statistics of the old, new, and combined data.

To evaluate the differences between the new and the old data for light liquid pumps, light liquid valves, and gas valves, the following statistical tests were applied:

- Wilcoxon test of paired differences, and
- F-test of statistical parameters.

The statistical tests did not have consistent results for the three equipment types. For light liquid pumps, no statistically significant differences were found, for light liquid valves, the tests indicated significant differences, and for gas valves, the tests were inconclusive.

A better comparison was a visual comparison of the data plotted in log space. This comparison was made by developing plots of the old and new bagging data with regression lines superimposed. All of the regression equations are plotted in figures B-1 through B-4. Figure B-1 presents the new bagging data and regression equation for connectors. Figures B-2 through B-4 show old and new bagging data superimposed upon the old, new, and combined regression equations for light liquid pumps, gas valves, and light liquid valves, respectively. The regression lines in these four figures are drawn to correspond only to the data points from which they were derived.

Figures B-2 through B-4 suggest the old and new data points appear to lie along a common axis with a similar amount of scatter. Figures B-2 through B-4 also demonstrate that most of the old data were from equipment which had screening values exceeding 1,000 ppmv, whereas a significant portion of the new data came from equipment screening less than 1,000 ppmv. The correlation derived from combining the old and new bagging data spans the greatest range of screening values. Additionally, for each of the equipment types, the combined correlation equation has the best fit. Since the combined regressions span the greatest range of screening values and have the best fit, the combined data set was used to develop the revised SOCMI correlation equations.

B.2.2 Development of Revised SOCMI Correlations and Development of Default-Zero Factors.

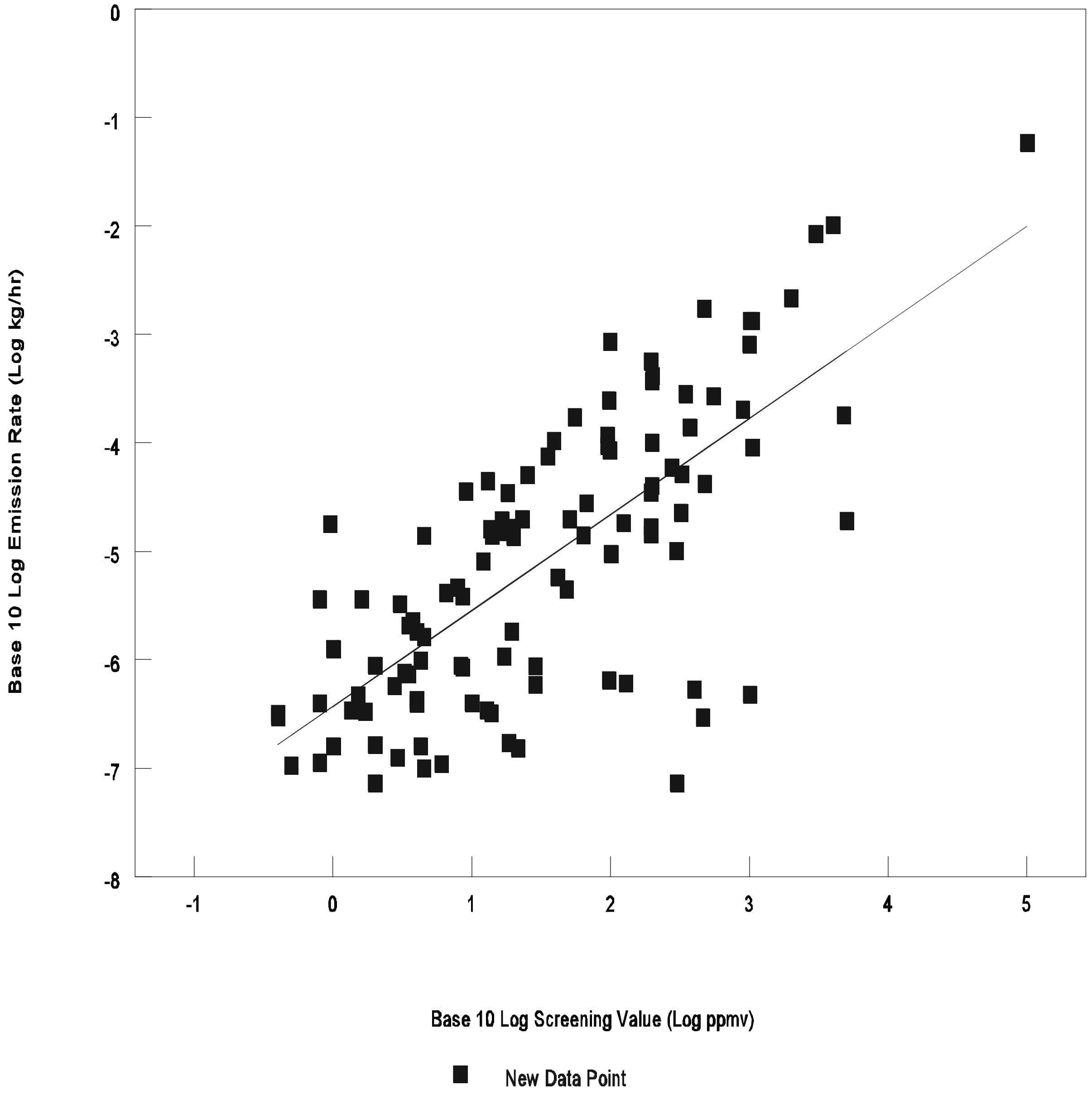


Figure B-1. Connector Regression Equation

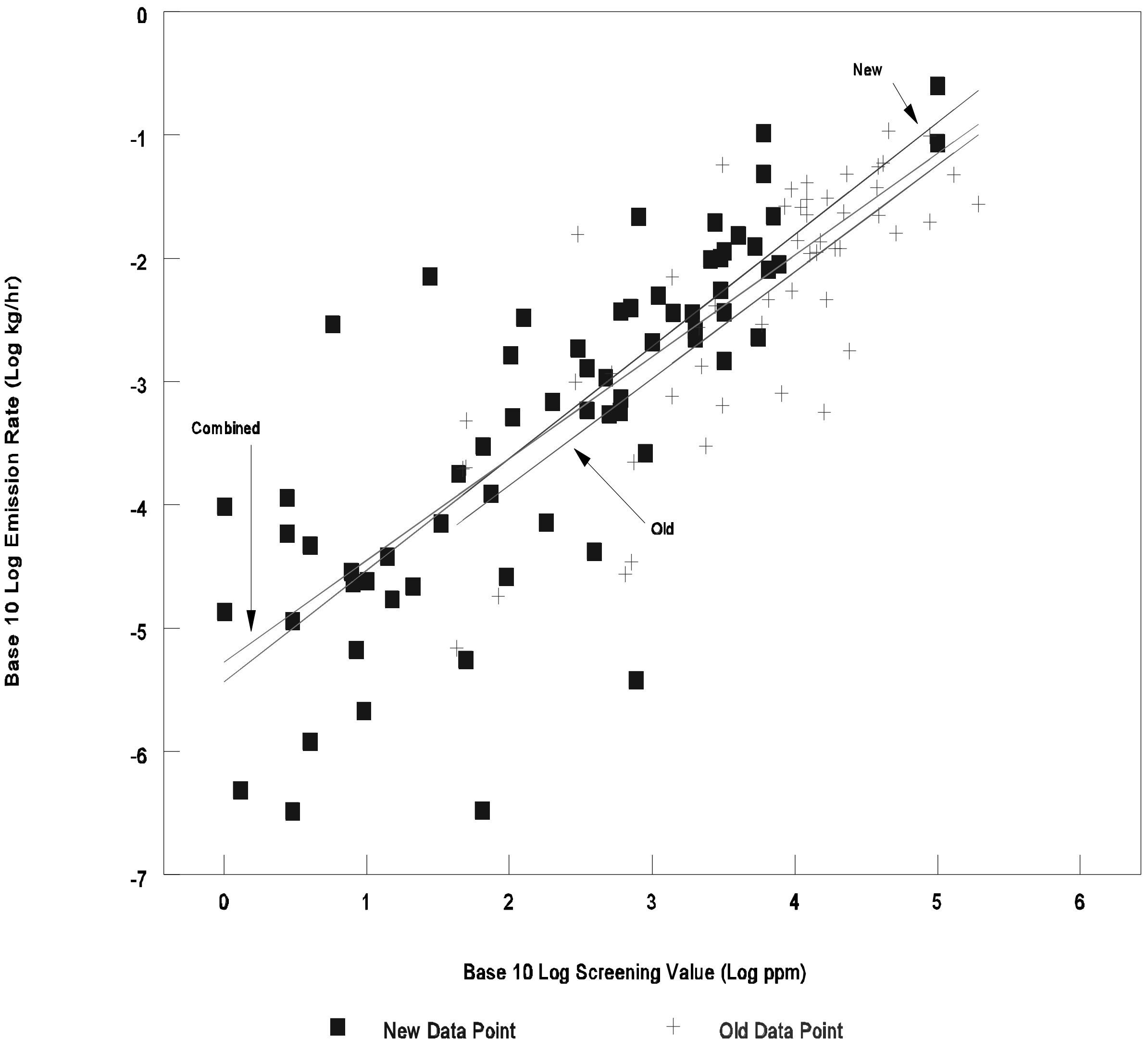


Figure B-2. Light Liquid Pump Regression Equations

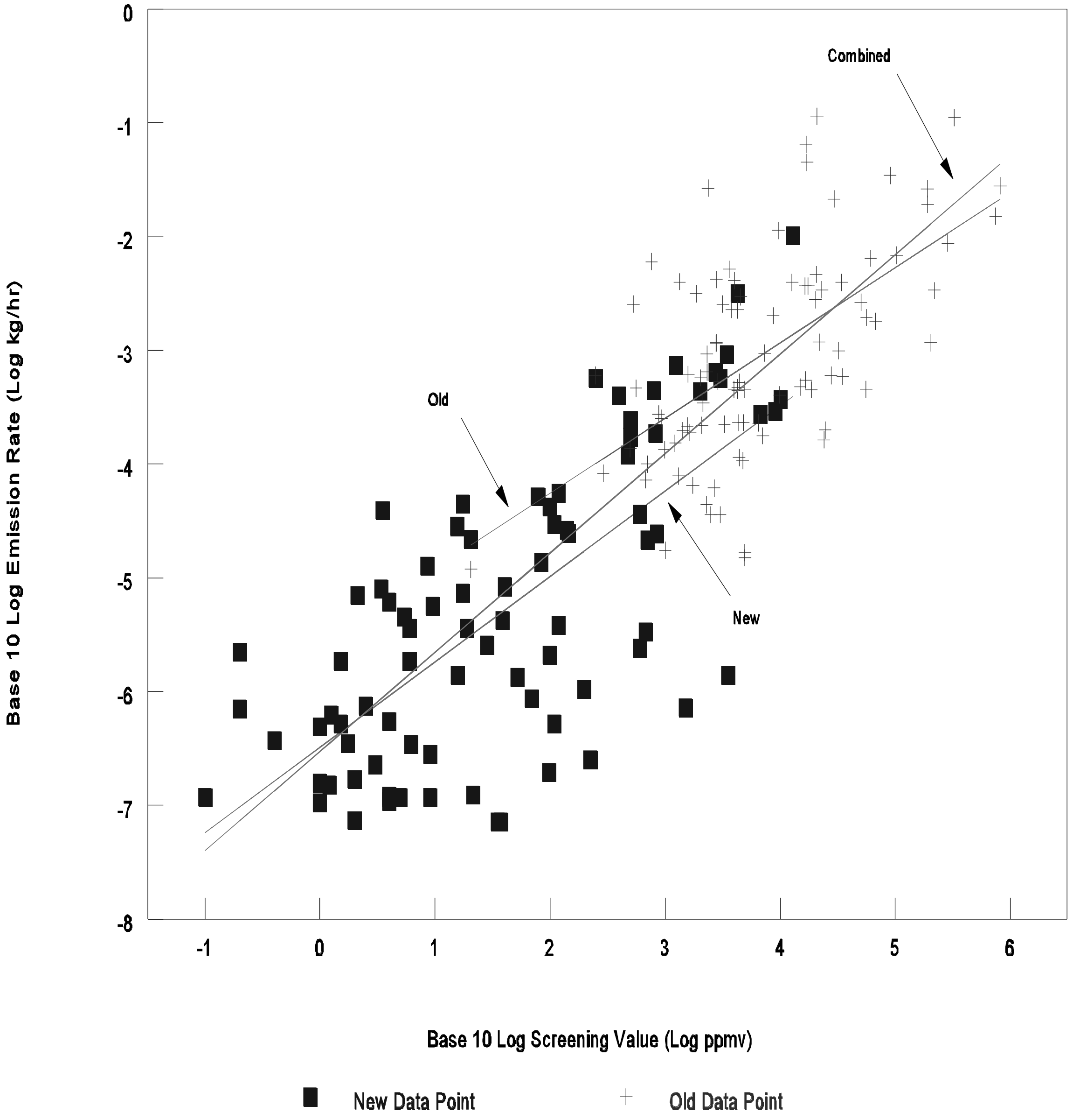


Figure B-3. Gas Valve Regression Equations

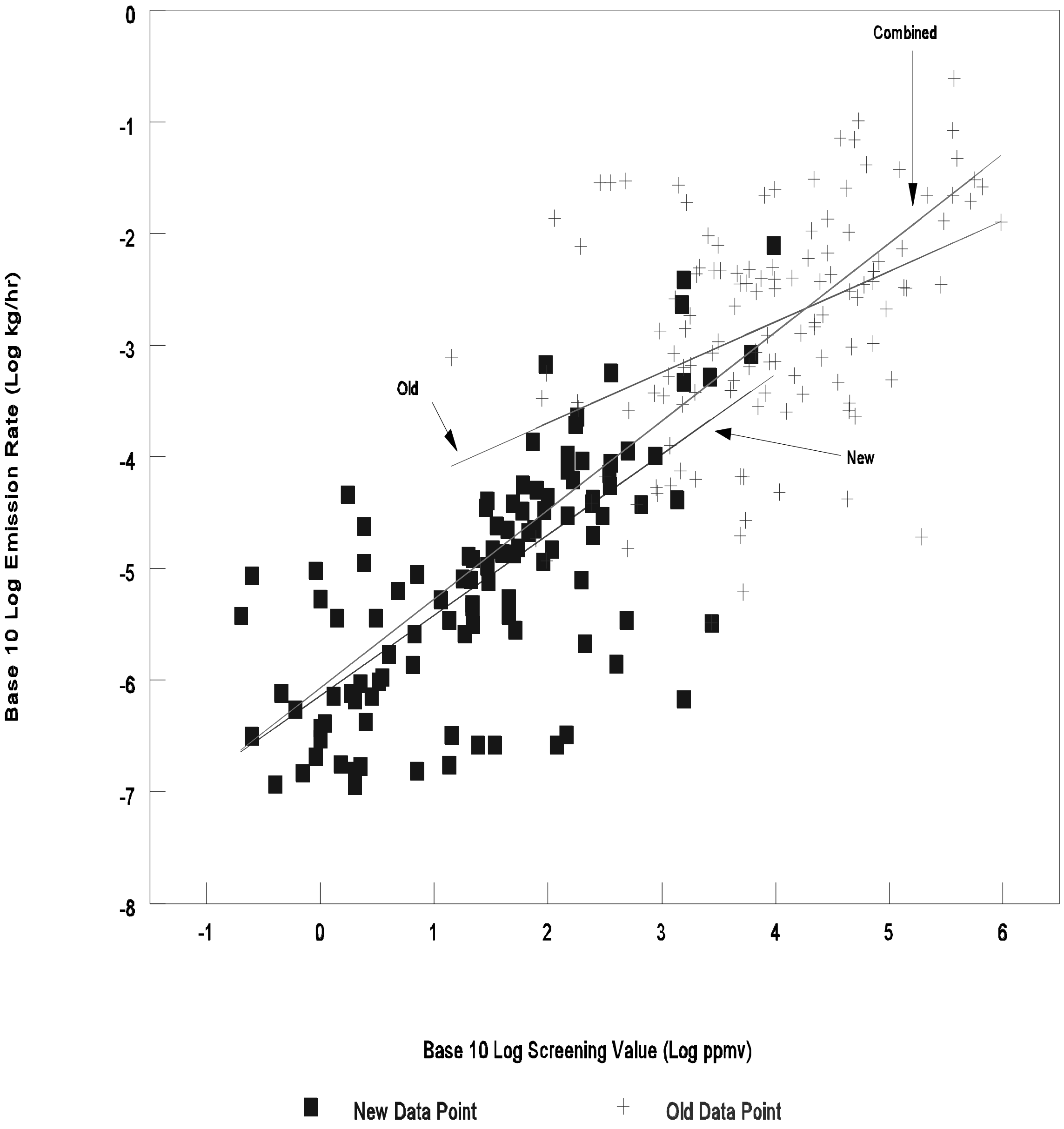


Figure B-4. Light Liquid Valve Regression Equations

After the old and new bagging data were combined, an initial regression analysis was performed on the logarithms of the screening values and mass emission rates following the procedures outlined in section B.1 on the development of correlation equations. For the combined data sets outliers were removed. The residuals (differences between measured log mass emission rates and log mass emission rates predicted by the regression) were used to flag outliers. A data pair was flagged as an outlier whenever the absolute value of its studentized residual (the residual divided by its standard error) was greater than or equal to 3. These data pairs are indicated as outliers in the table contained in attachment 1, which lists the screening values and mass emission rates for the combined bagging data set.

Attachment 2 contains a table listing all of the bagging data used to develop the default zero mass emission rates. These data were collected at the EO/BD process units, and were analyzed using the approach outlined in section B.1.3.

B.2.3 Revision of SOCMI Emission Factors

After the SOCMI correlations were revised, they were utilized in conjunction with the "old", "new", and "combined" screening value data sets to revise the SOCMI emission factors. Recall that the "old" screening data were the data collected in the SOCMI 24-Unit Study (EPA-600/2-81-003), the "new" screening data were the data collected from the EO/BD process units in 1987 and 1988, and the combined data were the two data sets combined.

Using screening data in conjunction with the applicable correlation equation, emission factors are calculated in the following manner.

(1) Screening values with a value of zero are assigned the default zero emission rate,

(2) Pegged screening values were assigned the appropriate pegged emission rate,

(3) All other screening values are entered into the applicable correlation equation to determine the associated mass emission rate, and

(4) The sum of all of the individual emission rates is divided by the total number of screening values (i.e., equipment pieces) to give the average factor.

These steps were followed to revise the SOCMI average emission factors for connectors, light liquid pumps, gas valves, and light liquid valves. The same approach was used to revise the SOCMI Screening Range Emission factors (≥10,000 ppmv / <10,000 ppmv), except that the screening values were segregated into the two ranges to calculate the average of each range.

Consistent with development of the revised SOCMI correlation equations (which were developed from the combined bagging data set), the combined screening data set was used to revise the SOCMI factors. The combined data set has the advantage that it reflects changes that have occurred in SOCMI process units since the 24-Unit Study, and contains data from a representative sampling of SOCMI process units.

To develop the emission factors it was necessary to make adjustments to a small percentage of the screening values. These adjustments were applied to large screening values that were identified as "pegged data." The large screening value data are important in the emission factor calculations and these adjustments were made in an attempt to keep as many screening values in the analysis as possible.

Examination of the frequency distributions of the screening value data sets revealed spikes near 10,000 ppmv (between 9980 and 10,001 ppmv) and near 100,000 ppmv (between 99,980 and 100,001 ppmv). These spikes indicate that the instrument was "pegged" or unable to measure the concentration being sampled because the concentration was beyond the measurement range of the instrument. It was assumed that screening values pegged at 10,000 ppmv had actual values between 10,000 and 100,000 ppmv, and that screening values pegged at 100,000 ppmv had actual values greater than 100,000 ppmv. Because there were several screening values greater than 10,000 ppmv and 100,000 ppmv that were not pegged, an average from the two ranges

(10,000-100,000 ppmv and >100,000 ppv) was calculated to substitute for the pegged readings. For the 10,000-100,000 ppmv range, the average was 33,620 ppm and for the greater than 100,000 ppmv range, the average was 302,367 ppm. These averages were used in the emission factor analysis for pegged data from the screening data sets. Thus, each pegged screening value was assigned the applicable average screening value, which was entered into the correlation to predict emissions.

Attachment 3 lists the average emission factors generated from each of the screening data sets, using the revised SOCMI correlations. There are thousands of screening values in the data sets, and these data sets are not reproduced in this appendix. Instead, figures plotting the distribution of the screening values are presented in attachment 3.

B.2.4 Summary of SOCMI and Petroleum Industry Correlation Parameters

Table B-1 presents the regression line slope and intercept and the SBCF associated with each of the revised SOCMI and petroleum industry correlations contained in tables 2-9 and 2-10 of this document.

TABLE B-1. SUMMARY OF SOCMI AND PETROLEUM INDUSTRY CORRELATION PARAMETERS.

Equipment type	Regression intercept[a] (β_0)	Regression slope (β_0)	SBCF
SOCMI Correlations			
Gas valves	-6.529	0.873	6.315
Light liquid valves	-6.069	0.797	7.520
Light liquid pumps	-5.273	0.824	3.563
Connectors	-6.434	0.885	8.298
Petroleum Industry Correlation			
Valves	-6.154	0.746	3.27
Pumps	-5.014	0.610	5.15
Others	-5.575	0.589	5.14
Connectors	-6.468	0.735	4.51
Flanges	-5.988	0.703	4.48
Open-Ended Lines	-6.366	0.704	5.11

[a] Regression intercepts are based on analysis in log space using Base 10 logarithms of leak rates in kg/hr.

APPENDIX B: ATTACHMENT 1

This attachment lists bagging data used to develop the combined correlation equations for each of the equipment types in table B-1-1. Also included is a summary table (table B-1-2) of the regression statistics associated with the old, new, and combined SOCMI bagging data sets. Note that the regression statistics presented in table B-1-2 are based on development of the regression lines using natural log leak rates and natural log screening values.

Table B-1-1. Bagging data used to develop the combined correlation equations.

---------------------- Equipment Type=CONNECTOR Service=ALL -----------------------

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
EO	NEW	0.0000000728	299.00	-16.4361	5.7004
EO	NEW	0.0000000734	2.00	-16.4271	0.6931
EO	NEW	0.0000001004	4.50	-16.1142	1.5041
EO	NEW	0.0000001061	0.50	-16.0586	-0.6931
EO	NEW	0.0000001101	6.00	-16.0217	1.7918
EO	NEW	0.0000001137	0.80	-15.9900	-0.2231
BD	NEW	0.0000001265	2.90	-15.8832	1.0647
EO	NEW	0.0000001544	21.50	-15.6835	3.0681
EO	NEW	0.0000001613	4.25	-15.6400	1.4469
BD	NEW	0.0000001620	1.00	-15.6354	0.0000
EO	NEW	0.0000001644	2.00	-15.6207	0.6931
EO	NEW	0.0000001731	18.50	-15.5693	2.9178
EO	NEW	0.0000002953	458.50	-15.0354	6.1280
EO	NEW	0.0000002996	0.40	-15.0209	-0.9163
EO	NEW	0.0000003195	0.40	-14.9565	-0.9163
BD	NEW	0.0000003254	13.80	-14.9382	2.6247
BD	NEW	0.0000003346	1.70	-14.9105	0.5306
BD	NEW	0.0000003430	1.35	-14.8856	0.3001
BD	NEW	0.0000003442	12.75	-14.8819	2.5455
BD	NEW	0.0000003939	4.00	-14.7473	1.3863
BD	NEW	0.0000003994	10.00	-14.7334	2.3026
EO	NEW	0.0000004007	0.80	-14.7300	-0.2231
BD	NEW	0.0000004288	4.00	-14.6623	1.3863
BD	NEW	0.0000004757	1.50	-14.5586	0.4055
EO	NEW	0.0000004798	999.00	-14.5499	6.9068
EO	NEW	0.0000005309	399.40	-14.4486	5.9900
EO	NEW	0.0000005812	2.75	-14.3582	1.0116
EO	NEW	0.0000005944	28.50	-14.3357	3.3499
EO	NEW	0.0000006075	128.00	-14.3140	4.8520
BD	NEW	0.0000006524	97.00	-14.2426	4.5747
EO	NEW	0.0000007355	3.50	-14.1227	1.2528
BD	NEW	0.0000007648	3.25	-14.0837	1.1787
BD	NEW	0.0000008560	8.50	-13.9710	2.1401
BD	NEW	0.0000008798	28.50	-13.9436	3.3499
BD	NEW	0.0000008869	2.00	-13.9356	0.6931
EO	NEW	0.0000008924	8.30	-13.9293	2.1163
EO	NEW	0.0000009888	4.25	-13.8267	1.4469
BD	NEW	0.0000010715	17.00	-13.7464	2.8332
EO	NEW	0.0000012661	1.00	-13.5795	0.0000
EO	NEW	0.0000016351	4.50	-13.3238	1.5041
BD	NEW	0.0000017995	4.00	-13.2280	1.3863
BD	NEW	0.0000018303	19.25	-13.2110	2.9575
BD	NEW	0.0000020777	3.50	-13.0842	1.2528
BD	NEW	0.0000022858	3.75	-12.9888	1.3218
EO	NEW	0.0000032725	3.00	-12.6300	1.0986

Table B-1-1. Bagging data used to develop the correlation equations

---------------------- Equipment Type=CONNECTOR Service=ALL -----------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
EO	NEW	0.0000036190	1.60	-12.5293	0.4700
BD	NEW	0.0000036396	0.80	-12.5236	-0.2231
BD	NEW	0.0000038387	8.50	-12.4704	2.1401
EO	NEW	0.0000041625	6.50	-12.3894	1.8718
EO	NEW	0.0000044784	48.00	-12.3162	3.8712
BD	NEW	0.0000046207	7.80	-12.2850	2.0541
BD	NEW	0.0000057784	41.50	-12.0614	3.7257
BD	NEW	0.0000080668	12.00	-11.7278	2.4849
BD	NEW	0.0000095125	100.00	-11.5629	4.6052
EO	NEW	0.0000100797	297.00	-11.5050	5.6937
BD	NEW	0.0000137255	19.75	-11.1963	2.9832
BD	NEW	0.0000140845	4.50	-11.1704	1.5041
BD	NEW	0.0000140911	14.00	-11.1700	2.6391
EO	NEW	0.0000142252	63.50	-11.1605	4.1510
BD	NEW	0.0000143958	195.50	-11.1486	5.2756
BD	NEW	0.0000151611	16.00	-11.0968	2.7726
BD	NEW	0.0000161064	13.50	-11.0363	2.6027
EO	NEW	0.0000166253	18.50	-11.0046	2.9178
BD	NEW	0.0000168916	195.00	-10.9887	5.2730
EO	NEW	0.0000178679	0.95	-10.9325	-0.0513
BD	NEW	0.0000183124	123.50	-10.9079	4.8162
BD	NEW	0.0000191290	4995.00	-10.8643	8.5162
BD	NEW	0.0000194650	16.50	-10.8469	2.8034
EO	NEW	0.0000197515	50.50	-10.8323	3.9220
BD	NEW	0.0000198244	23.00	-10.8286	3.1355
BD	NEW	0.0000227951	320.50	-10.6890	5.7699
BD	NEW	0.0000279813	67.00	-10.4840	4.2047
BD	NEW	0.0000348217	18.00	-10.2653	2.8904
BD	NEW	0.0000351763	195.50	-10.2551	5.2756
BD	NEW	0.0000359334	9.00	-10.2338	2.1972
BD	NEW	0.0000403480	198.00	-10.1180	5.2883
BD	NEW	0.0000423987	472.00	-10.0684	6.1570
BD	NEW	0.0000445724	13.00	-10.0184	2.5649
EO	NEW	0.0000509982	25.00	-9.8837	3.2189
EO	NEW	0.0000512445	323.00	-9.8789	5.7777
BD	NEW	0.0000595643	275.00	-9.7285	5.6168
BD	NEW	0.0000758688	35.00	-9.4865	3.5553
BD	NEW	0.0000860423	98.00	-9.3607	4.5850
BD	NEW	0.0000910990	1049.00	-9.3036	6.9556
BD	NEW	0.0000947099	94.40	-9.2647	4.5475
BD	NEW	0.0001007398	197.50	-9.2030	5.2857
BD	NEW	0.0001051050	38.80	-9.1606	3.6584
BD	NEW	0.0001178839	94.80	-9.0458	4.5518
BD	NEW	0.0001397861	371.00	-8.8754	5.9162

Table B-1-1. Bagging data used to develop the correlation equations

---------------------- Equipment Type=CONNECTOR Service=ALL -----------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
BD	NEW	0.0001721438	54.90	-8.6672	4.0055
BD	NEW	0.0001806903	4747.00	-8.6187	8.4653
BD	NEW	0.0002038979	895.00	-8.4979	6.7968
BD	NEW	0.0002463283	97.00	-8.3088	4.5747
BD	NEW	0.0002731277	549.00	-8.2056	6.3081
BD	NEW	0.0002853205	345.00	-8.1619	5.8435
BD	NEW	0.0003727741	198.50	-7.8945	5.2908
BD	NEW	0.0004184529	199.00	-7.7789	5.2933
BD	NEW	0.0005627360	195.00	-7.4827	5.2730
EO	NEW	0.0008093015	997.00	-7.1193	6.9048
BD	NEW	0.0008566981	99.00	-7.0624	4.5951
BD	NEW	0.0013381945	1049.00	-6.6164	6.9556
BD	NEW	0.0013408366	999.00	-6.6145	6.9068
BD	NEW	0.0017192076	471.50	-6.3659	6.1559
BD	NEW	0.0021650014	1997.00	-6.1353	7.5994
BD	NEW	0.0085056085	2999.00	-4.7670	8.0060
BD	NEW	0.0101785661	3996.00	-4.5875	8.2930
BD	NEW	0.0587476684	99998.80	-2.8345	11.5129

N = 107 (0 outliers)

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=PUMP Service=LL ------------------------

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0000003333	3.00	-14.9141	1.0986	
BD	NEW	0.0000003346	64.40	-14.9104	4.1651	OUTLIER
BD	NEW	0.0000004908	1.30	-14.5272	0.2624	
EO	NEW	0.0000012091	4.00	-13.6256	1.3863	
BD	NEW	0.0000021532	9.50	-13.0486	2.2513	
EO	NEW	0.0000038359	768.00	-12.4711	6.6438	OUTLIER
EO	NEW	0.0000055733	49.00	-12.0975	3.8918	
EO	NEW	0.0000067016	8.40	-11.9132	2.1282	
RE	OLD	0.0000068315	42.53	-11.8940	3.7503	
EO	NEW	0.0000115240	3.00	-11.3711	1.0986	
EO	NEW	0.0000137032	1.00	-11.1979	0.0000	
BD	NEW	0.0000173708	15.00	-10.9607	2.7081	
RE	OLD	0.0000182707	83.26	-10.9102	4.4220	
BD	NEW	0.0000218470	21.00	-10.7314	3.0445	
BD	NEW	0.0000234610	8.00	-10.6602	2.0794	
BD	NEW	0.0000243023	10.00	-10.6249	2.3026	
BD	NEW	0.0000262744	95.00	-10.5469	4.5539	
RE	OLD	0.0000273344	647.80	-10.5074	6.4736	
BD	NEW	0.0000287475	7.80	-10.4570	2.0541	
RE	OLD	0.0000343297	719.36	-10.2795	6.5784	
EO	NEW	0.0000385230	13.90	-10.1643	2.6319	
BD	NEW	0.0000418537	394.00	-10.0813	5.9764	
BD	NEW	0.0000474696	4.00	-9.9554	1.3863	
EO	NEW	0.0000588925	2.75	-9.7398	1.0116	
BD	NEW	0.0000715064	33.00	-9.5457	3.4965	
EO	NEW	0.0000722114	180.00	-9.5359	5.1930	
BD	NEW	0.0000978468	1.00	-9.2321	0.0000	
BD	NEW	0.0001152858	2.75	-9.0681	1.0116	
EO	NEW	0.0001232483	74.00	-9.0013	4.3041	
EO	NEW	0.0001803724	44.00	-8.6205	3.7842	
RE	OLD	0.0001957145	47.12	-8.5389	3.8526	
RE	OLD	0.0001991513	49.68	-8.5214	3.9057	
RE	OLD	0.0002209241	744.91	-8.4177	6.6133	
BD	NEW	0.0002667811	892.50	-8.2291	6.7940	
RE	OLD	0.0002999432	2388.28	-8.1119	7.7783	
BD	NEW	0.0003013546	65.00	-8.1072	4.1744	
RE	OLD	0.0004782523	49.86	-7.6454	3.9091	
EO	NEW	0.0005168934	105.00	-7.5677	4.6540	
EO	NEW	0.0005477897	499.00	-7.5096	6.2126	
RE	OLD	0.0005646821	16033.45	-7.4792	9.6824	
EO	NEW	0.0005681949	595.00	-7.4730	6.3886	
EO	NEW	0.0005857415	349.00	-7.4426	5.8551	
RE	OLD	0.0006402389	3102.49	-7.3537	8.0400	
EO	NEW	0.0006886734	199.00	-7.2807	5.2933	
BD	NEW	0.0007364641	598.00	-7.2137	6.3936	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=PUMP Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
RE	OLD	0.0007563452	1378.39	-7.1870	7.2287	
RE	OLD	0.0007987816	8095.43	-7.1324	8.9991	
RE	OLD	0.0009912542	289.26	-6.9165	5.6673	
BD	NEW	0.0010889569	471.00	-6.8225	6.1549	
RE	OLD	0.0011480956	521.79	-6.7697	6.2573	
BD	NEW	0.0012930833	348.00	-6.6507	5.8522	
RE	OLD	0.0013248663	2221.10	-6.6264	7.7058	
BD	NEW	0.0014886548	3197.00	-6.5099	8.0700	
EO	NEW	0.0016401471	101.20	-6.4130	4.6171	
RE	OLD	0.0017660014	24145.32	-6.3390	10.0918	
BD	NEW	0.0018539657	299.00	-6.2904	5.7004	
BD	NEW	0.0021087390	997.00	-6.1617	6.9048	
EO	NEW	0.0022296212	2000.00	-6.1059	7.6009	
BD	NEW	0.0023007567	5499.25	-6.0745	8.6124	
BD	NEW	0.0025947420	1993.80	-5.9543	7.5978	
RE	OLD	0.0027435637	2125.99	-5.8985	7.6620	
RE	OLD	0.0029144932	5870.47	-5.8381	8.6777	
BD	NEW	0.0029456140	5.75	-5.8274	1.7492	
BD	NEW	0.0033415187	125.00	-5.7013	4.8283	
BD	NEW	0.0036014533	1899.00	-5.6264	7.5491	
BD	NEW	0.0036569429	1393.90	-5.6111	7.2399	
EO	NEW	0.0037009240	3197.50	-5.5992	8.0701	
BD	NEW	0.0037297151	599.00	-5.5914	6.3953	
BD	NEW	0.0039913442	700.00	-5.5236	6.5511	
RE	OLD	0.0041248489	2775.53	-5.4907	7.9286	
RE	OLD	0.0046220969	16654.09	-5.3769	9.7204	
RE	OLD	0.0046281246	6538.83	-5.3756	8.7855	
BD	NEW	0.0050222262	1099.00	-5.2939	7.0022	
RE	OLD	0.0054013839	9501.80	-5.2211	9.1592	
BD	NEW	0.0055450728	2998.00	-5.1948	8.0057	
RE	OLD	0.0070361493	1381.77	-4.9567	7.2311	
BD	NEW	0.0071307927	27.60	-4.9433	3.3178	
BD	NEW	0.0081605157	6498.00	-4.8084	8.7792	
EO	NEW	0.0090139120	7696.90	-4.7090	8.9486	
BD	NEW	0.0098565101	2548.00	-4.6196	7.8431	
BD	NEW	0.0101206645	2997.00	-4.5932	8.0054	
RE	OLD	0.0108936908	12820.53	-4.5196	9.4588	
RE	OLD	0.0110475772	14254.89	-4.5055	9.5649	
BD	NEW	0.0115165376	3194.50	-4.4640	8.0692	
RE	OLD	0.0120415404	20840.78	-4.4194	9.9447	
RE	OLD	0.0120492786	19187.09	-4.4188	9.8620	
BD	NEW	0.0126046858	5248.25	-4.3737	8.5656	
RE	OLD	0.0135546418	15011.05	-4.3010	9.6165	
RE	OLD	0.0138366847	10491.80	-4.2804	9.2583	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=PUMP Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0154757686	3998.50	-4.1685	8.2937	
BD	NEW	0.0155724932	3998.00	-4.1622	8.2935	
RE	OLD	0.0156873305	300.60	-4.1549	5.7058	
RE	OLD	0.0159032925	51041.21	-4.1412	10.8404	
RE	OLD	0.0196113751	88270.79	-3.9316	11.3882	
BD	NEW	0.0198424922	2748.50	-3.9199	7.9188	
BD	NEW	0.0219422932	797.00	-3.8193	6.6809	
RE	OLD	0.0220953073	38632.61	-3.8124	10.5619	
BD	NEW	0.0221617288	6996.50	-3.8094	8.8532	
RE	OLD	0.0226278893	12142.30	-3.7886	9.4045	
RE	OLD	0.0232021936	22078.88	-3.7635	10.0024	
RE	OLD	0.0258831450	10996.59	-3.6542	9.3053	
RE	OLD	0.0263221310	8527.17	-3.6373	9.0510	
RE	OLD	0.0274280572	193253.34	-3.5962	12.1718	
RE	OLD	0.0300037851	12130.06	-3.5064	9.4034	
RE	OLD	0.0305561087	16850.04	-3.4882	9.7321	
RE	OLD	0.0361388265	9472.44	-3.3204	9.1561	
RE	OLD	0.0371630240	37500.32	-3.2924	10.5321	
RE	OLD	0.0409811410	12196.61	-3.1946	9.4089	
RE	OLD	0.0476567087	130564.77	-3.0437	11.7796	
RE	OLD	0.0480145702	23101.38	-3.0363	10.0476	
BD	NEW	0.0492542578	5998.00	-3.0108	8.6992	
RE	OLD	0.0556463965	38446.34	-2.8887	10.5570	
RE	OLD	0.0572488867	3111.50	-2.8603	8.0429	
RE	OLD	0.0586671574	41504.10	-2.8359	10.6335	
BD	NEW	0.0863688407	99996.00	-2.4491	11.5129	
RE	OLD	0.0977863072	88269.36	-2.3250	11.3881	
BD	NEW	0.1039387219	5997.00	-2.2640	8.6990	
RE	OLD	0.1074526291	45285.17	-2.2307	10.7207	
BD	NEW	0.2535689673	99994.00	-1.3721	11.5129	

N = 119 (2 outliers)

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=VALVE Service=G ------------------------

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
EO	NEW	0.0000000717	37.50	-16.4508	3.6243	
EO	NEW	0.0000000720	35.00	-16.4468	3.5553	
EO	NEW	0.0000000737	2.00	-16.4235	0.6931	
BD	NEW	0.0000001062	1.00	-16.0577	0.0000	
EO	NEW	0.0000001082	4.00	-16.0396	1.3863	
EO	NEW	0.0000001147	4.00	-15.9811	1.3863	
EO	NEW	0.0000001167	0.10	-15.9641	-2.3026	
EO	NEW	0.0000001170	9.00	-15.9608	2.1972	
EO	NEW	0.0000001172	5.00	-15.9591	1.6094	
EO	NEW	0.0000001198	4.00	-15.9374	1.3863	
EO	NEW	0.0000001251	21.50	-15.8945	3.0681	
EO	NEW	0.0000001525	1.20	-15.6963	0.1823	
EO	NEW	0.0000001579	1.00	-15.6615	0.0000	
EO	NEW	0.0000001705	2.00	-15.5848	0.6931	
EO	NEW	0.0000001964	98.25	-15.4430	4.5875	
EO	NEW	0.0000002292	3.00	-15.2887	1.0986	
EO	NEW	0.0000002537	224.30	-15.1869	5.4130	
EO	NEW	0.0000002824	9.00	-15.0800	2.1972	
BD	NEW	0.0000003468	6.20	-14.8747	1.8245	
BD	NEW	0.0000003511	1.75	-14.8622	0.5596	
EO	NEW	0.0000003724	0.40	-14.8032	-0.9163	
BD	NEW	0.0000004915	1.00	-14.5259	0.0000	
BD	NEW	0.0000005202	1.50	-14.4690	0.4055	
EO	NEW	0.0000005222	108.00	-14.4652	4.6821	
EO	NEW	0.0000005551	4.00	-14.4041	1.3863	
BD	NEW	0.0000006288	1.25	-14.2795	0.2231	
EO	NEW	0.0000007041	0.20	-14.1663	-1.6094	
EO	NEW	0.0000007204	1497.50	-14.1434	7.3116	
BD	NEW	0.0000007597	2.50	-14.0903	0.9163	
EO	NEW	0.0000008744	68.90	-13.9497	4.2327	
EO	NEW	0.0000010541	198.00	-13.7628	5.2883	
BD	NEW	0.0000013384	51.50	-13.5241	3.9416	
BD	NEW	0.0000013799	3499.30	-13.4935	8.1603	
BD	NEW	0.0000013870	15.70	-13.4884	2.7537	
BD	NEW	0.0000018645	6.00	-13.1925	1.7918	
BD	NEW	0.0000018779	1.50	-13.1854	0.4055	
EO	NEW	0.0000021100	99.00	-13.0688	4.5951	
EO	NEW	0.0000022366	0.20	-13.0105	-1.6094	
EO	NEW	0.0000024148	598.00	-12.9339	6.3936	
BD	NEW	0.0000025627	28.00	-12.8744	3.3322	
EO	NEW	0.0000034003	678.00	-12.5916	6.5191	
BD	NEW	0.0000036200	6.00	-12.5290	1.7918	
EO	NEW	0.0000036375	19.00	-12.5242	2.9444	
EO	NEW	0.0000038715	118.25	-12.4619	4.7728	
EO	NEW	0.0000042396	38.40	-12.3710	3.6481	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=VALVE Service=G ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0000045549	5.40	-12.2993	1.6864	
EO	NEW	0.0000056834	9.50	-12.0780	2.2513	
BD	NEW	0.0000061124	4.00	-12.0052	1.3863	
EO	NEW	0.0000070548	2.10	-11.8618	0.7419	
BD	NEW	0.0000074252	17.50	-11.8106	2.8622	
BD	NEW	0.0000080241	3.40	-11.7331	1.2238	
EO	NEW	0.0000083624	40.15	-11.6918	3.6926	
RE	OLD	0.0000118648	20.46	-11.3419	3.0184	
BD	NEW	0.0000128110	8.50	-11.2652	2.1401	
BD	NEW	0.0000137662	83.90	-11.1933	4.4296	
RE	OLD	0.0000149663	4952.69	-11.1097	8.5077	
RE	OLD	0.0000166075	4954.50	-11.0057	8.5081	
RE	OLD	0.0000175591	1007.37	-10.9499	6.9151	
EO	NEW	0.0000214657	698.50	-10.7491	6.5489	
BD	NEW	0.0000220929	20.50	-10.7203	3.0204	
EO	NEW	0.0000243523	850.00	-10.6229	6.7452	
BD	NEW	0.0000246644	144.50	-10.6101	4.9733	
BD	NEW	0.0000263657	139.25	-10.5434	4.9363	
BD	NEW	0.0000285391	15.50	-10.4642	2.7408	
BD	NEW	0.0000298709	109.00	-10.4186	4.6913	
RE	OLD	0.0000357822	2987.55	-10.2381	8.0022	
RE	OLD	0.0000359337	2497.04	-10.2338	7.8229	
BD	NEW	0.0000365393	598.00	-10.2171	6.3936	
BD	NEW	0.0000395358	3.50	-10.1383	1.2528	
BD	NEW	0.0000421641	98.50	-10.0739	4.5901	
RE	OLD	0.0000440123	2282.07	-10.0310	7.7328	
EO	NEW	0.0000445925	17.50	-10.0179	2.8622	
BD	NEW	0.0000523996	78.00	-9.8566	4.3567	
BD	NEW	0.0000557747	119.00	-9.7942	4.7791	
RE	OLD	0.0000617007	2670.91	-9.6932	7.8902	
RE	OLD	0.0000647076	1740.60	-9.6456	7.4620	
RE	OLD	0.0000724907	680.87	-9.5321	6.5234	
RE	OLD	0.0000779572	1315.53	-9.4594	7.1820	
RE	OLD	0.0000833618	290.43	-9.3923	5.6714	
RE	OLD	0.0000996210	700.59	-9.2141	6.5519	
RE	OLD	0.0001071514	4740.81	-9.1413	8.4640	
RE	OLD	0.0001137777	4385.68	-9.0813	8.3861	
BD	NEW	0.0001197735	474.40	-9.0299	6.1621	
RE	OLD	0.0001341897	987.15	-8.9163	6.8948	
RE	OLD	0.0001376705	496.21	-8.8906	6.2070	
RE	OLD	0.0001518078	1224.74	-8.7929	7.1105	
RE	OLD	0.0001625511	24157.28	-8.7245	10.0923	
EO	NEW	0.0001720041	498.75	-8.6680	6.2121	
RE	OLD	0.0001766026	7061.58	-8.6416	8.8624	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=VALVE Service=G ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0001866845	824.40	-8.5861	6.7147	
RE	OLD	0.0001904680	1643.51	-8.5660	7.4046	
RE	OLD	0.0001964120	1423.98	-8.5353	7.2612	
RE	OLD	0.0001977607	24689.43	-8.5285	10.1141	
RE	OLD	0.0002152405	1556.44	-8.4438	7.3502	
RE	OLD	0.0002180108	2095.88	-8.4310	7.6477	
RE	OLD	0.0002232184	3292.43	-8.4074	8.0994	
RE	OLD	0.0002275124	6482.10	-8.3883	8.7768	
RE	OLD	0.0002307162	4804.03	-8.3743	8.4772	
RE	OLD	0.0002322459	4368.95	-8.3677	8.3823	
BD	NEW	0.0002437423	499.40	-8.3194	6.2134	
RE	OLD	0.0002528838	928.66	-8.2826	6.8337	
RE	OLD	0.0002757637	877.50	-8.1960	6.7771	
BD	NEW	0.0002760188	6695.10	-8.1950	8.8091	
EO	NEW	0.0002904846	8998.00	-8.1440	9.1048	
RE	OLD	0.0003425098	2139.46	-7.9792	7.6683	
EO	NEW	0.0003724437	9998.00	-7.8954	9.2101	
BD	NEW	0.0003991030	394.00	-7.8263	5.9764	
RE	OLD	0.0004050504	9863.86	-7.8115	9.1966	
BD	NEW	0.0004404057	1999.00	-7.7278	7.6004	
RE	OLD	0.0004427801	4287.44	-7.7224	8.3634	
RE	OLD	0.0004461460	18661.82	-7.7149	9.8342	
BD	NEW	0.0004471948	799.00	-7.7125	6.6834	
RE	OLD	0.0004520589	55794.96	-7.7017	10.9294	
RE	OLD	0.0004529831	4949.37	-7.6997	8.5070	
RE	OLD	0.0004536846	3965.77	-7.6981	8.2855	
RE	OLD	0.0004640417	560.84	-7.6755	6.3294	
RE	OLD	0.0004685177	4279.25	-7.6659	8.3615	
RE	OLD	0.0004728028	14956.09	-7.6568	9.6129	
RE	OLD	0.0005228957	4399.96	-7.5561	8.3894	
RE	OLD	0.0005323154	2867.11	-7.5383	7.9611	
RE	OLD	0.0005465275	16699.10	-7.5119	9.7231	
BD	NEW	0.0005634682	2999.70	-7.4814	8.0063	
BD	NEW	0.0005651718	247.00	-7.4784	5.5094	
RE	OLD	0.0005730494	2037.49	-7.4645	7.6195	
RE	OLD	0.0005839129	35105.41	-7.4458	10.4661	
RE	OLD	0.0005991093	246.51	-7.4201	5.5074	
RE	OLD	0.0006007199	27836.27	-7.4174	10.2341	
RE	OLD	0.0006146615	1592.14	-7.3944	7.3728	
BD	NEW	0.0006404920	2743.50	-7.3533	7.9170	
RE	OLD	0.0006448431	2313.46	-7.3465	7.7465	
BD	NEW	0.0007363507	1247.00	-7.2138	7.1285	
EO	NEW	0.0009188385	3448.00	-6.9924	8.1455	
RE	OLD	0.0009212745	2316.36	-6.9898	7.7478	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=VALVE Service=G ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
RE	OLD	0.0009386789	7331.62	-6.9710	8.9000	
RE	OLD	0.0009859662	32119.44	-6.9219	10.3772	
RE	OLD	0.0011533445	2785.34	-6.7651	7.9321	
RE	OLD	0.0011636438	2797.20	-6.7562	7.9364	
RE	OLD	0.0011668930	203224.00	-6.7534	12.2221	
RE	OLD	0.0011712242	21751.69	-6.7497	9.9874	
RE	OLD	0.0017829290	67504.85	-6.3295	11.1200	
RE	OLD	0.0019401846	56199.96	-6.2450	10.9367	
RE	OLD	0.0020010182	8684.64	-6.2141	9.0693	
RE	OLD	0.0022581253	4284.86	-6.0932	8.3628	
RE	OLD	0.0022870889	3791.44	-6.0805	8.2405	
RE	OLD	0.0025260448	3163.33	-5.9811	8.0594	
RE	OLD	0.0025348896	534.08	-5.9776	6.2805	
RE	OLD	0.0026295658	50201.19	-5.9409	10.8238	
RE	OLD	0.0027833322	20393.42	-5.8841	9.9230	
RE	OLD	0.0029409798	4530.72	-5.8290	8.4186	
RE	OLD	0.0031312882	1860.09	-5.7663	7.5284	
BD	NEW	0.0031778789	4297.80	-5.7515	8.3659	
RE	OLD	0.0033409352	219611.97	-5.7015	12.2996	
RE	OLD	0.0033838729	23015.69	-5.6887	10.0439	
RE	OLD	0.0036846059	17536.22	-5.6036	9.7720	
RE	OLD	0.0036971583	16495.48	-5.6002	9.7108	
RE	OLD	0.0039426484	12647.22	-5.5359	9.4452	
RE	OLD	0.0039504089	34241.04	-5.5339	10.4412	
RE	OLD	0.0040050325	1333.88	-5.5202	7.1958	
RE	OLD	0.0041065399	4005.05	-5.4952	8.2953	
RE	OLD	0.0041660267	2803.86	-5.4808	7.9388	
RE	OLD	0.0046273787	20516.30	-5.3758	9.9290	
RE	OLD	0.0051511364	3629.80	-5.2685	8.1969	
RE	OLD	0.0060064387	760.42	-5.1149	6.6339	
RE	OLD	0.0064640997	61150.08	-5.0415	11.0211	
RE	OLD	0.0067947745	102781.04	-4.9916	11.5404	
RE	OLD	0.0086599432	287461.04	-4.7490	12.5688	
BD	NEW	0.0102338821	12994.00	-4.5821	9.4722	
RE	OLD	0.0112479155	9730.32	-4.4876	9.1830	
RE	OLD	0.0150883255	749143.47	-4.1938	13.5267	
RE	OLD	0.0192079955	191834.63	-3.9524	12.1644	
RE	OLD	0.0212769340	29340.67	-3.8501	10.2867	
RE	OLD	0.0262475666	189629.11	-3.6402	12.1528	
RE	OLD	0.0265051976	2373.75	-3.6304	7.7722	
RE	OLD	0.0277367164	820321.32	-3.5850	13.6175	
RE	OLD	0.0342721260	90882.86	-3.3734	11.4173	
RE	OLD	0.0449106195	17031.74	-3.1031	9.7428	
RE	OLD	0.0645502674	16874.50	-2.7403	9.7336	

Table B-1-1. Bagging data used to develop the correlation equations

------------------------ Equipment Type=VALVE Service=G ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
RE	OLD	0.1109042134	326432.21	-2.1991	12.6960	
RE	OLD	0.1140677949	20836.56	-2.1710	9.9445	

N = 179 (0 outliers)

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
EO	NEW	0.0000001148	2.00	-15.9798	0.6931	
EO	NEW	0.0000001182	0.40	-15.9509	-0.9163	
EO	NEW	0.0000001490	0.70	-15.7195	-0.3567	
EO	NEW	0.0000001545	7.00	-15.6828	1.9459	
BD	NEW	0.0000001546	2.00	-15.6825	0.6931	
BD	NEW	0.0000001705	2.25	-15.5843	0.8109	
EO	NEW	0.0000001748	13.50	-15.5593	2.6027	
BD	NEW	0.0000001777	1.50	-15.5431	0.4055	
EO	NEW	0.0000002092	0.90	-15.3801	-0.1054	
EO	NEW	0.0000002655	24.25	-15.1418	3.1884	
EO	NEW	0.0000002662	34.00	-15.1392	3.5264	
EO	NEW	0.0000002674	119.00	-15.1344	4.7791	
EO	NEW	0.0000002973	1.00	-15.0285	0.0000	
BD	NEW	0.0000003209	0.25	-14.9523	-1.3863	
BD	NEW	0.0000003246	14.00	-14.9406	2.6391	
BD	NEW	0.0000003272	145.00	-14.9326	4.9767	
BD	NEW	0.0000003761	1.00	-14.7934	0.0000	
EO	NEW	0.0000004160	1.10	-14.6925	0.0953	
BD	NEW	0.0000004269	2.50	-14.6668	0.9163	
EO	NEW	0.0000005550	0.60	-14.4043	-0.5108	
EO	NEW	0.0000006711	2.00	-14.2144	0.6931	
EO	NEW	0.0000006800	1547.50	-14.2011	7.3444	
EO	NEW	0.0000007182	2.80	-14.1465	1.0296	
BD	NEW	0.0000007281	1.30	-14.1328	0.2624	
EO	NEW	0.0000007741	1.85	-14.0715	0.6152	
EO	NEW	0.0000007760	0.45	-14.0691	-0.7985	
BD	NEW	0.0000009403	2.25	-13.8770	0.8109	
BD	NEW	0.0000009766	3.25	-13.8391	1.1787	
BD	NEW	0.0000010750	3.50	-13.7432	1.2528	
BD	NEW	0.0000013768	6.45	-13.4957	1.8641	
EO	NEW	0.0000014189	398.00	-13.4656	5.9865	
BD	NEW	0.0000017270	4.00	-13.2691	1.3863	

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0000021600	209.00	-13.0454	5.3423	
EO	NEW	0.0000026370	6.70	-12.8459	1.9021	
BD	NEW	0.0000026381	18.50	-12.8455	2.9178	
EO	NEW	0.0000028522	51.20	-12.7674	3.9357	
EO	NEW	0.0000031653	21.80	-12.6633	3.0819	
RE	OLD	0.0000032615	2740.82	-12.6333	7.9160	
BD	NEW	0.0000034734	13.50	-12.5704	2.6027	
BD	NEW	0.0000034854	486.75	-12.5669	6.1878	
BD	NEW	0.0000036357	1.40	-12.5247	0.3365	
BD	NEW	0.0000036487	3.05	-12.5211	1.1151	
BD	NEW	0.0000038172	0.20	-12.4760	-1.6094	
EO	NEW	0.0000038185	45.00	-12.4756	3.8067	
EO	NEW	0.0000045401	21.50	-12.3026	3.0681	
BD	NEW	0.0000048429	21.50	-12.2380	3.0681	
EO	NEW	0.0000053288	11.40	-12.1424	2.4336	
EO	NEW	0.0000054257	1.00	-12.1244	0.0000	
BD	NEW	0.0000054590	44.90	-12.1182	3.8044	
RE	OLD	0.0000061236	5194.17	-12.0034	8.5553	
EO	NEW	0.0000063620	4.80	-11.9652	1.5686	
EO	NEW	0.0000076923	30.00	-11.7753	3.4012	
BD	NEW	0.0000079625	195.50	-11.7408	5.2756	
BD	NEW	0.0000080291	20.85	-11.7324	3.0374	
BD	NEW	0.0000081895	17.75	-11.7127	2.8764	
BD	NEW	0.0000087183	0.25	-11.6501	-1.3863	
BD	NEW	0.0000090393	7.00	-11.6139	1.9459	
EO	NEW	0.0000096017	0.90	-11.5536	-0.1054	
EO	NEW	0.0000106063	29.00	-11.4541	3.3673	
BD	NEW	0.0000114056	2.40	-11.3814	0.8755	
EO	NEW	0.0000116662	90.00	-11.3588	4.4998	
RE	OLD	0.0000118300	97.72	-11.3449	4.5821	
BD	NEW	0.0000123249	21.90	-11.3039	3.0865	
BD	NEW	0.0000130315	20.00	-11.2481	2.9957	
BD	NEW	0.0000136318	49.80	-11.2031	3.9080	
EO	NEW	0.0000138914	39.40	-11.1842	3.6738	
RE	OLD	0.0000150006	500.63	-11.1074	6.2159	
EO	NEW	0.0000150217	108.00	-11.1060	4.6821	
BD	NEW	0.0000150810	32.50	-11.1021	3.4812	
BD	NEW	0.0000155478	54.50	-11.0716	3.9982	
RE	OLD	0.0000185551	78.10	-10.8948	4.3580	
RE	OLD	0.0000191256	191501.42	-10.8645	12.1627	OUTLIER
RE	OLD	0.0000196624	4878.72	-10.8368	8.4926	
BD	NEW	0.0000200735	250.00	-10.8161	5.5215	
BD	NEW	0.0000212478	67.00	-10.7593	4.2047	
EO	NEW	0.0000226439	44.10	-10.6956	3.7865	

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
EO	NEW	0.0000228716	74.80	-10.6856	4.3148	
EO	NEW	0.0000242425	2.40	-10.6274	0.8755	
BD	NEW	0.0000244394	35.50	-10.6193	3.5695	
RE	OLD	0.0000269514	5443.31	-10.5215	8.6021	
BD	NEW	0.0000298536	298.90	-10.4192	5.7001	
EO	NEW	0.0000301615	148.00	-10.4089	4.9972	
EO	NEW	0.0000330901	59.25	-10.3163	4.0818	
BD	NEW	0.0000336994	92.50	-10.2980	4.5272	
BD	NEW	0.0000354699	28.50	-10.2468	3.3499	
RE	OLD	0.0000378083	604.46	-10.1830	6.4043	
EO	NEW	0.0000382742	657.80	-10.1707	6.4889	
EO	NEW	0.0000383797	243.60	-10.1680	5.4955	
RE	OLD	0.0000387557	242.12	-10.1582	5.4894	
EO	NEW	0.0000387574	48.90	-10.1582	3.8898	
BD	NEW	0.0000407202	29.00	-10.1088	3.3673	
BD	NEW	0.0000415953	1349.80	-10.0875	7.2077	
RE	OLD	0.0000417925	42609.46	-10.0828	10.6598	
BD	NEW	0.0000429883	248.00	-10.0546	5.5134	
BD	NEW	0.0000443510	99.00	-10.0234	4.5951	
BD	NEW	0.0000462778	1.75	-9.9808	0.5596	
RE	OLD	0.0000470621	906.10	-9.9640	6.8091	
RE	OLD	0.0000482670	10833.21	-9.9388	9.2904	
EO	NEW	0.0000508340	79.00	-9.8869	4.3694	
RE	OLD	0.0000529921	890.55	-9.8454	6.7918	
RE	OLD	0.0000546755	1193.53	-9.8141	7.0847	
EO	NEW	0.0000561055	348.00	-9.7883	5.8522	
EO	NEW	0.0000569507	60.00	-9.7733	4.0943	
EO	NEW	0.0000626293	163.70	-9.6783	5.0980	
RE	OLD	0.0000626636	1985.67	-9.6777	7.5937	
RE	OLD	0.0000654535	318.60	-9.6342	5.7639	
RE	OLD	0.0000660567	5226.31	-9.6250	8.5615	
RE	OLD	0.0000664281	4914.24	-9.6194	8.4999	
EO	NEW	0.0000713497	343.00	-9.5479	5.8377	
RE	OLD	0.0000749810	1458.90	-9.4983	7.2854	
EO	NEW	0.0000778658	148.50	-9.4605	5.0006	
BD	NEW	0.0000893438	350.00	-9.3230	5.8579	
BD	NEW	0.0000936958	199.75	-9.2755	5.2971	
BD	NEW	0.0001029548	872.75	-9.1812	6.7716	
EO	NEW	0.0001063538	148.75	-9.1487	5.0023	
BD	NEW	0.0001147397	499.50	-9.0728	6.2136	
RE	OLD	0.0001266782	1183.21	-8.9739	7.0760	
BD	NEW	0.0001377292	73.00	-8.8902	4.2905	
BD	NEW	0.0001972580	174.75	-8.5310	5.1634	
RE	OLD	0.0002313295	50044.57	-8.3717	10.8207	

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
BD	NEW	0.0002317965	180.00	-8.3697	5.1930	
RE	OLD	0.0002524777	12405.49	-8.2842	9.4259	
RE	OLD	0.0002580228	44328.29	-8.2625	10.6994	
RE	OLD	0.0002594664	510.60	-8.2569	6.2356	
RE	OLD	0.0002714139	185.88	-8.2119	5.2251	
RE	OLD	0.0002825941	6976.92	-8.1715	8.8504	
RE	OLD	0.0002947841	1516.43	-8.1293	7.3241	
RE	OLD	0.0003011106	44592.42	-8.1080	10.7053	
RE	OLD	0.0003056054	181.92	-8.0932	5.2036	
RE	OLD	0.0003367527	88.38	-7.9962	4.4816	
RE	OLD	0.0003494725	1041.01	-7.9591	6.9479	
RE	OLD	0.0003655199	17367.57	-7.9142	9.7624	
RE	OLD	0.0003726697	856.19	-7.8948	6.7525	
RE	OLD	0.0003738730	8088.28	-7.8916	8.9982	
RE	OLD	0.0003743390	1959.19	-7.8903	7.5803	
RE	OLD	0.0003964414	4048.28	-7.8330	8.3060	
RE	OLD	0.0004653107	35414.65	-7.6728	10.4749	
BD	NEW	0.0004698821	1543.75	-7.6630	7.3420	
RE	OLD	0.0004809845	4284.78	-7.6397	8.3628	
RE	OLD	0.0004922594	104088.32	-7.6165	11.5530	
BD	NEW	0.0005246367	2645.50	-7.5528	7.8806	
RE	OLD	0.0005251847	1151.37	-7.5518	7.0487	
RE	OLD	0.0005308943	14765.02	-7.5409	9.6000	
RE	OLD	0.0005614771	97.30	-7.4849	4.5778	
BD	NEW	0.0005705547	358.30	-7.4689	5.8814	
RE	OLD	0.0006267770	1565.55	-7.3749	7.3560	
RE	OLD	0.0006426108	5861.53	-7.3500	8.6762	
RE	OLD	0.0006597100	1793.09	-7.3237	7.4917	
BD	NEW	0.0006830173	94.75	-7.2890	4.5512	
RE	OLD	0.0007019466	8827.10	-7.2617	9.0856	
RE	OLD	0.0007129023	9940.79	-7.2462	9.2044	
RE	OLD	0.0007649183	25559.24	-7.1757	10.1488	
RE	OLD	0.0007702967	14.18	-7.1687	2.6518	
RE	OLD	0.0008350761	1281.36	-7.0880	7.1557	
BD	NEW	0.0008369235	6097.00	-7.0858	8.7156	
RE	OLD	0.0008536995	2810.09	-7.0659	7.9410	
RE	OLD	0.0008577230	6709.07	-7.0612	8.8112	
RE	OLD	0.0009616788	46673.57	-6.9468	10.7509	
RE	OLD	0.0010351161	71798.27	-6.8732	11.1816	
RE	OLD	0.0010736310	3136.03	-6.8367	8.0507	
RE	OLD	0.0012337497	8519.07	-6.6977	9.0501	
RE	OLD	0.0012793343	16658.85	-6.6614	9.7207	
RE	OLD	0.0013448227	962.89	-6.6115	6.8699	
RE	OLD	0.0013933013	1602.40	-6.5761	7.3793	

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
RE	OLD	0.0014732045	22177.98	-6.5203	10.0069	
RE	OLD	0.0016009142	22172.87	-6.4372	10.0066	
RE	OLD	0.0018373887	1769.15	-6.2994	7.4783	
RE	OLD	0.0018697565	25877.90	-6.2819	10.1611	
RE	OLD	0.0021076721	93629.13	-6.1622	11.4471	
RE	OLD	0.0022196068	4376.80	-6.1104	8.3841	
BD	NEW	0.0023716142	1495.00	-6.0442	7.3099	
RE	OLD	0.0026041383	1313.08	-5.9507	7.1801	
RE	OLD	0.0026564280	52084.68	-5.9308	10.8606	
RE	OLD	0.0030068935	45068.90	-5.8068	10.7159	
RE	OLD	0.0030297587	6771.42	-5.7993	8.8205	
RE	OLD	0.0032025436	9836.80	-5.7438	9.1939	
RE	OLD	0.0032489277	140865.29	-5.7294	11.8556	
RE	OLD	0.0032868739	134149.17	-5.7178	11.8067	
RE	OLD	0.0034814651	284948.25	-5.6603	12.5601	
RE	OLD	0.0034830527	59618.63	-5.6598	10.9957	
RE	OLD	0.0035502018	4839.96	-5.6408	8.4847	
RE	OLD	0.0036059944	5555.74	-5.6252	8.6226	
RE	OLD	0.0037109239	72002.57	-5.5965	11.1845	
RE	OLD	0.0037115648	24755.46	-5.5963	10.1168	
RE	OLD	0.0038957946	9810.65	-5.5479	9.1912	
BD	NEW	0.0038969686	1544.40	-5.5476	7.3424	
RE	OLD	0.0039248950	7476.44	-5.5404	8.9195	
RE	OLD	0.0040089261	13953.59	-5.5192	9.5435	
RE	OLD	0.0042596218	30597.64	-5.4586	10.3287	
RE	OLD	0.0043498677	2026.05	-5.4376	7.6138	
RE	OLD	0.0043951332	4587.13	-5.4273	8.4310	
RE	OLD	0.0046094493	73036.68	-5.3796	11.1987	
RE	OLD	0.0046247477	2875.27	-5.3763	7.9639	
RE	OLD	0.0046555934	3279.62	-5.3697	8.0955	
RE	OLD	0.0047542941	5891.43	-5.3487	8.6813	
RE	OLD	0.0049436538	2135.71	-5.3097	7.6666	
RE	OLD	0.0049687260	9436.54	-5.3046	9.1523	
RE	OLD	0.0055770694	80485.19	-5.1891	11.2958	
RE	OLD	0.0059962681	19368.05	-5.1166	9.8714	
RE	OLD	0.0066867186	28552.82	-5.0076	10.2595	
RE	OLD	0.0073478291	129657.01	-4.9134	11.7726	
RE	OLD	0.0076182294	194.63	-4.8772	5.2711	
RE	OLD	0.0078722531	3118.82	-4.8444	8.0452	
BD	NEW	0.0079621021	9500.00	-4.8331	9.1590	
RE	OLD	0.0095095298	2553.37	-4.6555	7.8452	
RE	OLD	0.0102176741	44254.56	-4.5836	10.6977	
RE	OLD	0.0105761365	20652.95	-4.5492	9.9356	
RE	OLD	0.0126755860	960160.86	-4.3681	13.7749	

Table B-1-1. Bagging data used to develop the correlation equations

----------------------- Equipment Type=VALVE Service=LL ------------------------
(continued)

Plant Type	Data Origin	Measured Emission Rate (kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)	Outlier Flag
RE	OLD	0.0128994159	301945.80	-4.3506	12.6180	
RE	OLD	0.0134752877	28558.21	-4.3069	10.2597	
RE	OLD	0.0137156706	114.30	-4.2892	4.7388	
RE	OLD	0.0190054451	1649.34	-3.9630	7.4081	
RE	OLD	0.0194889771	518201.90	-3.9379	13.1581	
RE	OLD	0.0220373843	213772.09	-3.8150	12.2727	
RE	OLD	0.0220386022	7980.81	-3.8150	8.9848	
RE	OLD	0.0221003955	362645.26	-3.8122	12.8012	
RE	OLD	0.0248459751	9843.83	-3.6951	9.1946	
RE	OLD	0.0254155227	41862.00	-3.6724	10.6421	
RE	OLD	0.0263386824	659517.01	-3.6367	13.3993	
RE	OLD	0.0272779071	1399.25	-3.6017	7.2437	
RE	OLD	0.0283621432	288.41	-3.5627	5.6644	
RE	OLD	0.0283930499	352.85	-3.5616	5.8660	
RE	OLD	0.0293848208	480.98	-3.5273	6.1758	
RE	OLD	0.0303470196	562236.45	-3.4951	13.2397	
RE	OLD	0.0305360632	21853.55	-3.4888	9.9921	
RE	OLD	0.0372725448	122666.22	-3.2895	11.7172	
RE	OLD	0.0410821388	62573.58	-3.1922	11.0441	
RE	OLD	0.0468639667	393961.70	-3.0605	12.8840	
RE	OLD	0.0687821973	49473.43	-2.6768	10.8092	
RE	OLD	0.0713743302	36751.32	-2.6398	10.5119	
RE	OLD	0.0838252864	360547.09	-2.4790	12.7954	
RE	OLD	0.1027415340	53569.80	-2.2755	10.8887	
RE	OLD	0.2448798474	371111.15	-1.4070	12.8243	

N = 233   (1 outliers)

Table B-1-2. Comparison of regression results for the old, new, and combined bagging data sets.

Equipment Type/Service: Connectors/All

	Data Used in Regression
Statistical Parameter	New
Number of data pairs	107
Regression intercept	-14.815
Regression slope	0.885
Regression R^2	0.525
Regression correlation coefficient	0.725
Regression mean square error	4.355
Regression root mean square error	2.087
Average ln screening value	3.472
Sum of squares of ln screening values	646.821
Scale bias correction factor	8.298
Correlation equation constant	3.05E-6

Equipment Type/Service: Pumps/Light Liquid

	Data Used in Regression		
Statistical Parameter	Old[a]	New	Combined
Number of data pairs	51	68	117
Regression intercept	-12.827	-12.515	-12.142
Regression slope	0.865	0.907	0.824
Regression R^2	0.613	0.644	0.710
Regression correlation coefficient	0.783	0.803	0.842
Regression mean square error	2.246	3.783	2.591
Regression root mean square error	1.499	1.945	1.610
Average ln screening value	8.582	5.393	6.783
Sum of squares of ln screening values	233.223	548.793	1071.500
Scale bias correction factor	2.941	6.149	3.563
Correlation equation constant	7.91E-6	2.26E-5	1.90E-5

a Indicates that the parameter were derived from the digitized data pairs for the OLD regression.

Table B-1-2. (continued)

Equipment Type/Service: Valves/Gas

Statistical Parameter	Data Used in Regression		
	Old[a]	New	Combined
Number of data pairs	95	84	179
Regression intercept	-12.848	-14.936	-15.033
Regression slope	0.661	0.750	0.873
Regression R^2	0.359	0.516	0.715
Regression correlation coefficient	0.599	0.711	0.846
Regression mean square error	2.767	4.392	3.745
Regression root mean square error	1.663	2.096	1.935
Average ln screening value	8.823	3.691	6.415
Sum of squares of ln screening values	329.550	682.442	2186.020
Scale bias correction factor	3.858	8.311	6.315
Correlation equation constant	1.02E-5	2.71E-6	1.87E-6

[a] Indicates that the parameter were derived from the digitized data pairs for the OLD regression.

Equipment Type/Service: Valves/Light Liquid

Statistical Parameter	Data Used in Regression		
	Old[a]	New	Combined
Number of data pairs	126	107	232
Regression intercept	-10.585	-14.137	-13.975
Regression slope	0.452	0.721	0.797
Regression R^2	0.194	0.502	0.677
Regression correlation coefficient	0.441	0.709	0.823
Regression mean square error	4.413	3.115	4.088
Regression root mean square error	2.101	1.765	2.022
Average ln screening value	8.978	3.300	6.345
Sum of squares of ln screening values	644.683	633.647	3110.310
Scale bias correction factor	8.608	4.580	7.520
Correlation equation constant	2.18E-4	3.32E-6	6.41E-6

[a] indicates that the parameter were derived from the digitized data pairs for the OLD regression

APPENDIX B: ATTACHMENT 2

This attachment lists the data used to develop the default-zero emission leak rates in table B-2-1. Table B-2-2 lists summary information on the default-zero development.

Table B-2-1. Data used for default zero calculations.

------------Equipment Type=CONNECTORS Service=ALL-------

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000000475	-16.86331619
EO	0.00	0.0000000608	-16.61499543
EO	0.00	0.0000000613	-16.60715372
EO	0.00	0.0000000790	-16.35377339
EO	0.00	0.0000000988	-16.13056673
EO	0.00	0.0000001027	-16.09179287
BD	0.00	0.0000001033	-16.08517422
BD	0.00	0.0000001037	-16.08139097
EO	0.00	0.0000001065	-16.05508510
EO	0.00	0.0000001079	-16.04208307
EO	0.00	0.0000001085	-16.03689892
EO	0.00	0.0000001089	-16.03320436
EO	0.00	0.0000001112	-16.01231281
EO	0.00	0.0000001113	-16.01113856
EO	0.00	0.0000001115	-16.00911113
EO	0.00	0.0000001120	-16.00437388
EO	0.00	0.0000001125	-16.00075170
EO	0.00	0.0000001133	-15.99300732
EO	0.00	0.0000001146	-15.98221965
EO	0.00	0.0000001146	-15.98146212
EO	0.00	0.0000001150	-15.97834935
EO	0.00	0.0000001166	-15.96444127
EO	0.00	0.0000001176	-15.95559511
EO	0.00	0.0000001177	-15.95545662
EO	0.00	0.0000001178	-15.95391595
EO	0.00	0.0000001181	-15.95192362
EO	0.00	0.0000001189	-15.94478891
EO	0.00	0.0000001213	-15.92488652
EO	0.00	0.0000001234	-15.90745448
EO	0.00	0.0000001240	-15.90308275
EO	0.00	0.0000001296	-15.85882804
EO	0.00	0.0000001320	-15.84081663
BD	0.00	0.0000001349	-15.81855266
EO	0.00	0.0000001376	-15.79862472
EO	0.00	0.0000001390	-15.78899513
BD	0.00	0.0000001412	-15.77318199
EO	0.00	0.0000001413	-15.77244897
BD	0.00	0.0000001440	-15.75326730
BD	0.00	0.0000001446	-15.74929429
BD	0.00	0.0000001448	-15.74817023
BD	0.00	0.0000001454	-15.74382504
BD	0.00	0.0000001455	-15.74329360
BD	0.00	0.0000001485	-15.72271562
BD	0.00	0.0000001490	-15.71949421
BD	0.00	0.0000001497	-15.71483698
BD	0.00	0.0000001505	-15.70909501

Table B-2-1. Data used for default zero calculations.

-------- Equipment Type=CONNECTORS Service=ALL ---------
(continued)

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000001511	-15.70514515
EO	0.00	0.0000001544	-15.68403336
BD	0.00	0.0000001547	-15.68204363
EO	0.00	0.0000001563	-15.67144879
BD	0.00	0.0000001573	-15.66508859
BD	0.00	0.0000001574	-15.66465227
BD	0.00	0.0000001596	-15.65073157
BD	0.00	0.0000001614	-15.63962500
BD	0.00	0.0000001621	-15.63500235
BD	0.00	0.0000001625	-15.63229582
EO	0.00	0.0000001631	-15.62914831
EO	0.00	0.0000001636	-15.62557049
EO	0.00	0.0000001641	-15.62273582
EO	0.00	0.0000001642	-15.62198449
EO	0.00	0.0000001648	-15.61837621
EO	0.00	0.0000001648	-15.61837621
EO	0.00	0.0000001650	-15.61705986
EO	0.00	0.0000001650	-15.61705962
EO	0.00	0.0000001651	-15.61656953
EO	0.00	0.0000001657	-15.61295101
EO	0.00	0.0000001657	-15.61295101
EO	0.00	0.0000001660	-15.61112981
EO	0.00	0.0000001688	-15.59463081
EO	0.00	0.0000001692	-15.59241662
EO	0.00	0.0000001717	-15.57752890
BD	0.00	0.0000001741	-15.56347827
BD	0.00	0.0000001747	-15.56001908
EO	0.00	0.0000001750	-15.55828552
EO	0.00	0.0000001807	-15.52620814
EO	0.00	0.0000001812	-15.52341721
BD	0.00	0.0000001904	-15.47417798
BD	0.00	0.0000001920	-15.46559058
BD	0.00	0.0000001932	-15.45958528
EO	0.00	0.0000001990	-15.43018880
EO	0.00	0.0000002086	-15.38283699
EO	0.00	0.0000002194	-15.33220908
EO	0.00	0.0000002431	-15.22964242
EO	0.00	0.0000002476	-15.21159451
EO	0.00	0.0000002508	-15.19874994
EO	0.00	0.0000002570	-15.17423032
BD	0.00	0.0000002585	-15.16823490
EO	0.00	0.0000002593	-15.16532554
BD	0.00	0.0000002594	-15.16500428
EO	0.00	0.0000002602	-15.16174131
EO	0.00	0.0000002607	-15.15994436

Table B-2-1. Data used for default zero calculations.

-------- Equipment Type=CONNECTORS Service=ALL ---------
(continued)

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000002626	-15.15272411
EO	0.00	0.0000002626	-15.15272411
EO	0.00	0.0000002659	-15.13996186
EO	0.00	0.0000002664	-15.13812531
BD	0.00	0.0000002959	-15.03330632
EO	0.00	0.0000003055	-15.00115460
BD	0.00	0.0000003140	-14.97386313
EO	0.00	0.0000003276	-14.93133352
BD	0.00	0.0000003303	-14.92340849
BD	0.00	0.0000003315	-14.91955531
BD	0.00	0.0000003346	-14.91035517
BD	0.00	0.0000003436	-14.88372774
BD	0.00	0.0000003436	-14.88368692
BD	0.00	0.0000003442	-14.88192105
BD	0.00	0.0000003461	-14.87648133
BD	0.00	0.0000003504	-14.86410580
BD	0.00	0.0000003672	-14.81747447
BD	0.00	0.0000003946	-14.74527193
BD	0.00	0.0000004121	-14.70207785
EO	0.00	0.0000004133	-14.69904106
BD	0.00	0.0000004212	-14.68010001
EO	0.00	0.0000004468	-14.62113094
BD	0.00	0.0000004720	-14.56621062
EO	0.00	0.0000005089	-14.49108397
EO	0.00	0.0000005180	-14.47320006
EO	0.00	0.0000005187	-14.47197698
EO	0.00	0.0000005908	-14.34186784
EO	0.00	0.0000006166	-14.29899587
BD	0.00	0.0000006960	-14.17794549
EO	0.00	0.0000007110	-14.15652787
EO	0.00	0.0000007192	-14.14510177
EO	0.00	0.0000008267	-14.00581175
EO	0.00	0.0000009572	-13.85929011
EO	0.00	0.0000010002	-13.81535039
BD	0.00	0.0000010065	-13.80901606
EO	0.00	0.0000010071	-13.80841513
EO	0.00	0.0000011795	-13.65045667
EO	0.00	0.0000011927	-13.63931593
EO	0.00	0.0000021315	-13.05868377
BD	0.00	0.0000023492	-12.96141917
EO	0.00	0.0000024557	-12.91711588
BD	0.00	0.0000024895	-12.90342759
BD	0.00	0.0000025620	-12.87473675
BD	0.00	0.0000030901	-12.68731235
BD	0.00	0.0000033269	-12.61346713

Table B-2-1. Data used for default zero calculations.

--------- Equipment Type=CONNECTORS Service=ALL --------
(continued)

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
BD	0.00	0.0000037589	-12.49138454
BD	0.00	0.0000040185	-12.42460572
BD	0.00	0.0000042414	-12.37062573
BD	0.00	0.0000044626	-12.31978282
BD	0.00	0.0000066833	-11.91589131
BD	0.00	0.0000075709	-11.79119727
BD	0.00	0.0000105577	-11.45865639
BD	0.00	0.0000144776	-11.14290744
BD	0.00	0.0000154005	-11.08111125
BD	0.00	0.0000165494	-11.00916328

N = 146

------------------ Equipment Type=PUMP Service=LL

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000002532	-15.18920187
EO	0.00	0.0000002674	-15.13444207
BD	0.00	0.0000003397	-14.89520337
BD	0.00	0.0000006493	-14.24738145
BD	0.00	0.0000013801	-13.49334976
BD	0.00	0.0000031715	-12.66130995
EO	0.00	0.0000061497	-11.99910617
BD	0.00	0.0000978267	-9.232313175

N = 8

Table B-2-1. Data used for default zero calculations.

----------- Equipment Type=VALVE Service=G -------------

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000000591	-16.64400086
EO	0.00	0.0000000722	-16.44327301
EO	0.00	0.0000000737	-16.42283692
EO	0.00	0.0000000786	-16.35920326
EO	0.00	0.0000000790	-16.35376554
EO	0.00	0.0000000796	-16.34647953
EO	0.00	0.0000001079	-16.04237697
EO	0.00	0.0000001081	-16.04053084
EO	0.00	0.0000001083	-16.03863245
EO	0.00	0.0000001312	-15.84631356
EO	0.00	0.0000001321	-15.83996505
EO	0.00	0.0000001325	-15.83639998
BD	0.00	0.0000001382	-15.79429751
BD	0.00	0.0000001436	-15.75651804
EO	0.00	0.0000001446	-15.74956966
BD	0.00	0.0000001516	-15.70207714
EO	0.00	0.0000001581	-15.65972752
BD	0.00	0.0000001595	-15.65122577
BD	0.00	0.0000001602	-15.64710329
EO	0.00	0.0000001750	-15.55828552
EO	0.00	0.0000002350	-15.26347692
BD	0.00	0.0000002539	-15.18638489
EO	0.00	0.0000002612	-15.15814418
BD	0.00	0.0000002633	-15.14979281
EO	0.00	0.0000002674	-15.13444207
BD	0.00	0.0000003272	-14.93266093
BD	0.00	0.0000003339	-14.91228255
EO	0.00	0.0000003878	-14.76283680
EO	0.00	0.0000004091	-14.70928502
BD	0.00	0.0000004607	-14.59056027
EO	0.00	0.0000006457	-14.25286952
BD	0.00	0.0000007014	-14.17014032
EO	0.00	0.0000009932	-13.82235860
BD	0.00	0.0000009955	-13.81999480
BD	0.00	0.0000022122	-13.02153380
BD	0.00	0.0000022562	-13.00184573
BD	0.00	0.0000025712	-12.87114036
BD	0.00	0.0000033699	-12.60062417
BD	0.00	0.0000044219	-12.32894306
BD	0.00	0.0000106176	-11.45299698

N = 40

Table B-2-1. Data used for default zero calculations.

---------- Equipment Type=VALVE Service=LL -------------

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000001121	-16.00352165
EO	0.00	0.0000001173	-15.95857877
EO	0.00	0.0000001211	-15.92634574
EO	0.00	0.0000001229	-15.91229458
EO	0.00	0.0000001337	-15.82756192
BD	0.00	0.0000001440	-15.75311308
BD	0.00	0.0000001461	-15.73913742
BD	0.00	0.0000001498	-15.71376221
BD	0.00	0.0000001503	-15.71042334
BD	0.00	0.0000001513	-15.70424314
EO	0.00	0.0000001642	-15.62246991
EO	0.00	0.0000001644	-15.62066973
EO	0.00	0.0000001644	-15.62066973
EO	0.00	0.0000001645	-15.62017964
EO	0.00	0.0000001648	-15.61837621
EO	0.00	0.0000001654	-15.61475957
EO	0.00	0.0000001656	-15.61343643
EO	0.00	0.0000001657	-15.61294634
EO	0.00	0.0000001660	-15.61112981
EO	0.00	0.0000001663	-15.60930997
BD	0.00	0.0000001669	-15.60596798
EO	0.00	0.0000001758	-15.55382679
EO	0.00	0.0000001758	-15.55382679
BD	0.00	0.0000001780	-15.54144504
BD	0.00	0.0000001804	-15.52802656
EO	0.00	0.0000001827	-15.51543605
BD	0.00	0.0000001853	-15.50155175
EO	0.00	0.0000002507	-15.19885548
EO	0.00	0.0000002568	-15.17511567
EO	0.00	0.0000002623	-15.15362868
EO	0.00	0.0000002645	-15.14545135
EO	0.00	0.0000002654	-15.14208066
EO	0.00	0.0000002657	-15.14094135
EO	0.00	0.0000002664	-15.13812531
EO	0.00	0.0000002750	-15.10635430
BD	0.00	0.0000002786	-15.09348218
BD	0.00	0.0000002807	-15.08603323
BD	0.00	0.0000002831	-15.07737541
BD	0.00	0.0000003292	-14.92670035
BD	0.00	0.0000003296	-14.92525863
BD	0.00	0.0000003327	-14.91592554
EO	0.00	0.0000003803	-14.78222371
EO	0.00	0.0000003997	-14.73266021
EO	0.00	0.0000004350	-14.64784669
EO	0.00	0.0000004933	-14.52205744
BD	0.00	0.0000005121	-14.48467228

Table B-2-1. Data used for default zero calculations.

------------ Equipment Type=VALVE Service=LL ------------
(continued)

PLT_TYPE	Screening Value (ppmv)	Mass Emission Rate (kg/hr)	Natural Log of Mass Emission Rate (kg/hr
EO	0.00	0.0000007099	-14.15820731
BD	0.00	0.0000011219	-13.70046348
BD	0.00	0.0000022380	-13.00992148
EO	0.00	0.0000028444	-12.77016392
BD	0.00	0.0000041389	-12.39507152
BD	0.00	0.0000053490	-12.13860411
EO	0.00	0.0000121637	-11.31705756

N = 53

Table B-2-2. Comparison of Default Zero Mass Emission Rates from the Original EPA Protocol and from the CMA/EPA EO/BD Study

			Results from CMA/EPA EO/BD Bagging Data Study					
						Default Zero		
Equipment Type	Service	Old Default Zero Emission Rate (kg/hr)	Number of Observations	Scale Bias Correction Factor	Revised Default Zero Emission Rate (kg/hr)	Lower 95% Confidence Limit	Upper 95% Confidence Limit	Screening Value[a] (ppmv)
CONNEC	ALL	9.34E-5	146	2.06	6.12E-7	5.02E-7	7.45E-7	0.163
PUMP	LL	3.91E-5	8	4.73	7.49E-6	1.36E-6	4.11E-5	0.323
VALVE	G	3.31E-5	40	2.19	6.56E-7	4.35E-7	9.87E-7	0.301
VALVE	LL	4.52E-4	53	1.65	4.85E-7	3.67E-7	6.42E-7	0.039

[a] The "default zero" screening value is the screening value that would result in emissions equal to the default zero mass emission rate when entered into the applicable correlation. The revised SOCMI correlations were used to estimate the "default zero" screening values.

APPENDIX B: ATTACHMENT 3

This attachment summarizes information on each of the screening data sets. Table B-3-1 summarizes data used to revise the SOCMI emission factors. Figures B-3-1 through B-3-4 plot the screening value distributions for each data set.

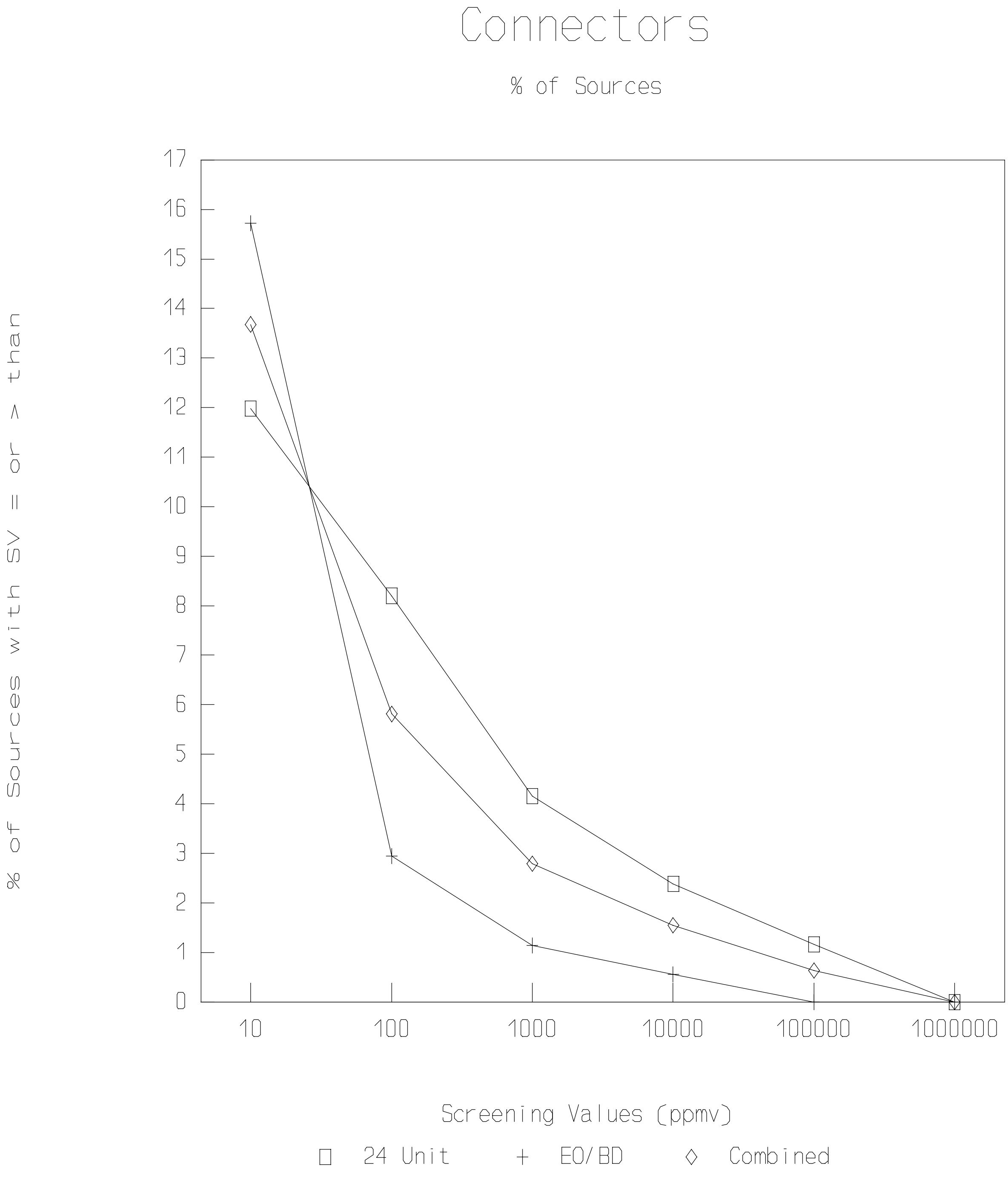


Figure B-3-1. Distribution of Connectors Screening Values for SOCMI

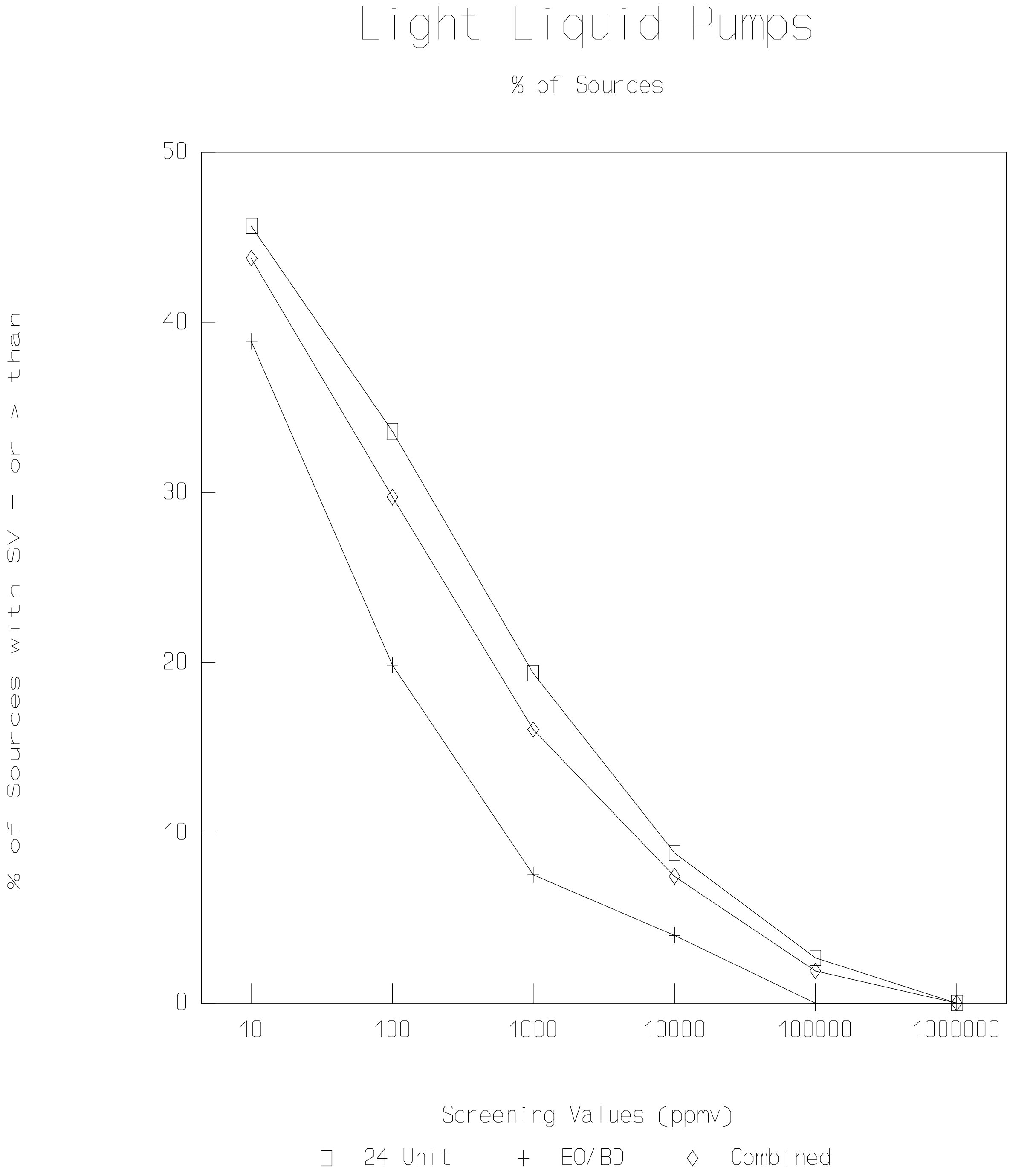


Figure B-3-2. Distribution of Light Liquid Pumps Screening Values for SOCMI

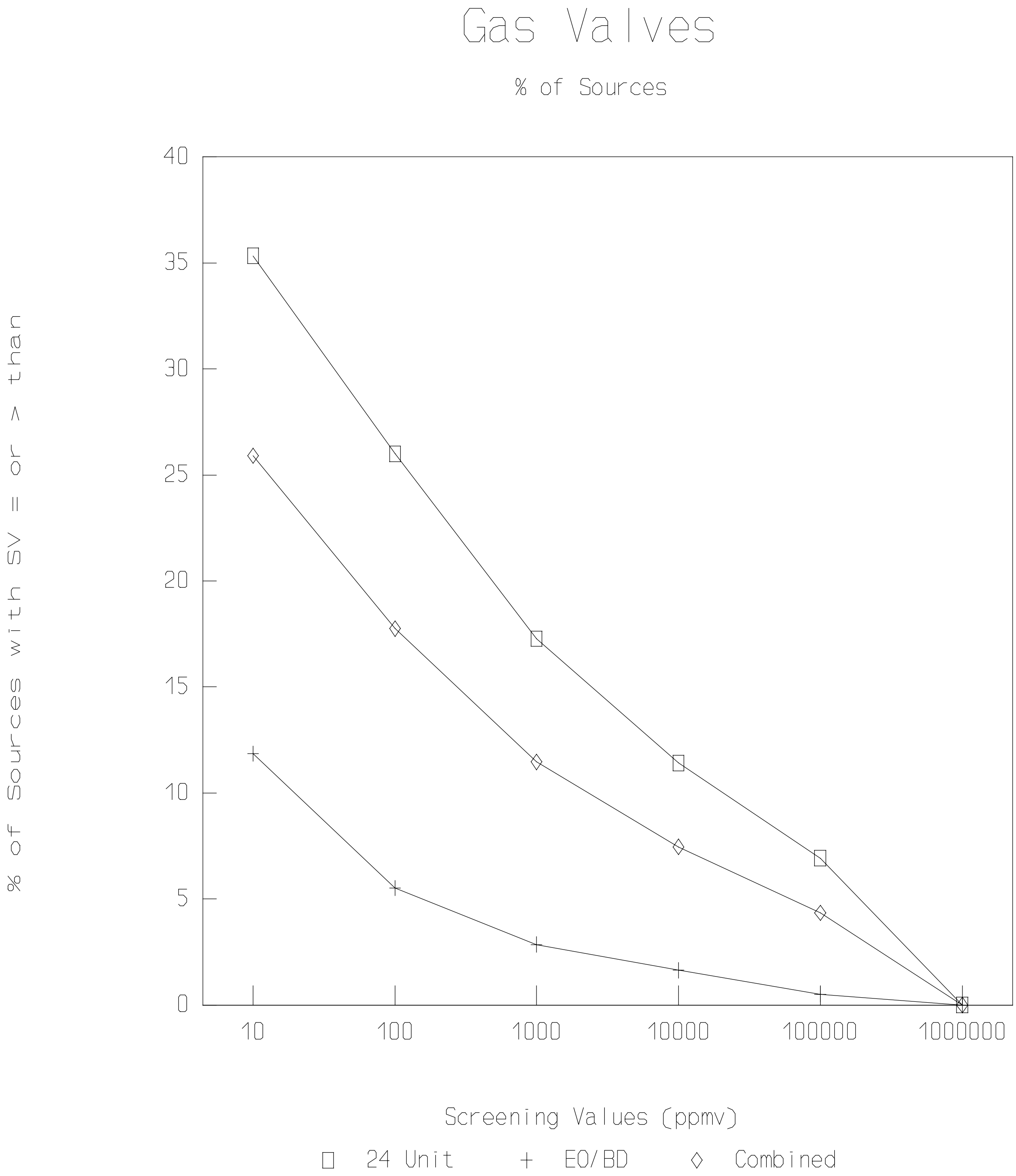


Figure B-3-3. Distributio of Gas Valves Screening Values for SOCMI

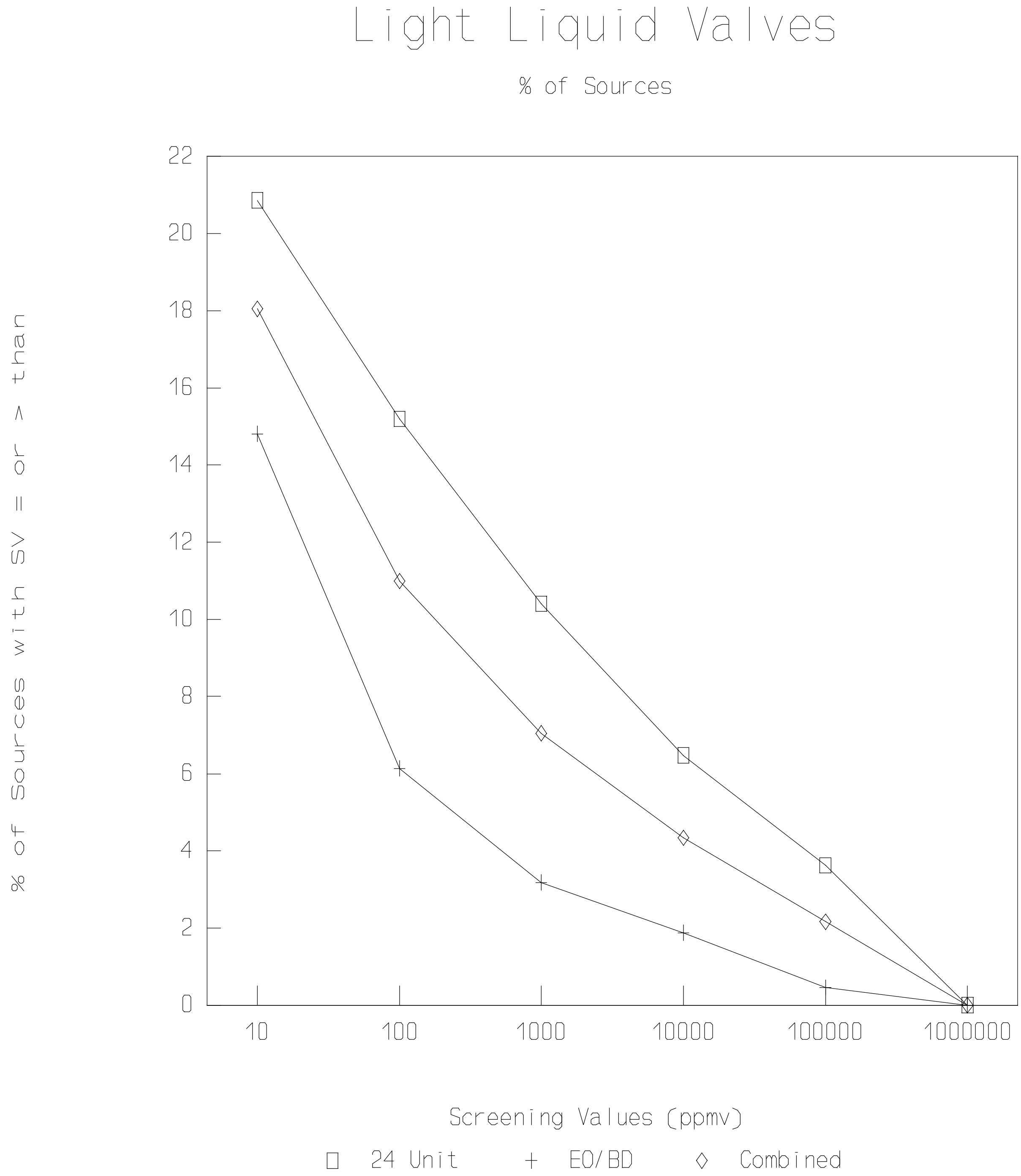


Figure B-3-4. Distribution of Light Liquid Valves Screening Values for SOCMI

Table B-3-1. Emission Factors Calculated From Revised SOCMI Correlation Equations.

Screening data set	Equipment type	Phase	Old emission factor (kg/hr)	Total number of screening values	Average nonzero emission rate (kg/hr)	Number of zero screening values	Default zero emission rate (kg/hr)	Average emission factor (kg/hr)
24 UNIT	CONNEC	ALL	8.30E-04	4,283	2.50E-02	3,740	6.12E-07	3.16E-03
24 UNIT	PUMP	LL	4.94E-02	646	5.36E-02	335	7.45E-06	2.58E-02
24 UNIT	VALVE	G	5.60E-03	9,669	2.47E-02	5,962	6.56E-07	9.45E-03
24 UNIT	VALVE	LL	7.10E-03	18,300	2.99E-02	14,292	4.85E-07	6.55E-03
EO/BD	CONNEC	ALL	8.30E-04	3,562	3.76E-04	1,381	6.12E-07	2.30E-04
EO/BD	PUMP	LL	4.94E-02	252	7.12E-03	85	7.45E-06	4.72E-03
EO/BD	VALVE	G	5.60E-03	6,507	2.83E-03	4,685	6.56E-07	7.92E-04
EO/BD	VALVE	LL	7.10E-03	15,810	3.26E-03	10,429	4.85E-07	1.11E-03
COMBINED	CONNEC	ALL	8.30E-04	7,845	5.28E-03	5,121	6.12E-07	1.83E-03[a]
COMBINED	PUMP	LL	4.94E-02	898	3.73E-02	420	7.45E-06	1.99E-02[a]
COMBINED	VALVE	G	5.60E-03	16,176	1.75E-02	10,647	6.56E-07	5.97E-03[a]
COMBINED	VALVE	LL	7.10E-03	34,110	1.46E-02	24,721	4.85E-07	4.03E-03[a]

[a] These average emission factors are the revised SOCMI average emission factors.

APPENDIX C:

Revision of Petroleum Industry Correlations and Emisison Factors

APPENDIX C

The purpose of this appendix is to provide background information on the data collection and analysis performed to revise the petroleum industry (refineries, marketing terminals, and oil and gas production operations) correlations and to develop marketing terminal and oil and gas production operation average emission factors. Section C.1 addresses the following:

- Comparison of old (1980) and new (1993) refinery data;
- Development of revised petroleum industry correlation equations, default zero emission rates, and pegged emission rates;
- Summary of petroleum industry correlation parameters; and
- Development of marketing terminal and oil and gas production operation average emission factors.

The figures for this section appear at the end of section C.1.

Several attachments that list all of the data are also included for this appendix. Attachment 1 lists the bagging data used to develop the correlation equations, attachment 2 lists the bagging data used to develop pegged emission rates, attachment 3 lists the bagging data used to develop default zero emission rates, and attachment 4 summarizes the screening data for average emission factors.

C.1 DEVELOPMENT OF REVISED PETROLEUM INDUSTRY CORRELATIONS AND FACTORS

During the early-1990’s, new petroleum industry equipment leak data were collected and analyzed. The Western States Petroleum Association (WSPA) and the American Petroleum Institute (API) jointly commissioned the 1994 refinery equipment leak report[1] to evaluate fugitive emissions at petroleum refineries. The API also commissioned the 1993 marketing terminal equipment leak report,[2] and, along with the Gas Research Institute (GRI), jointly commissioned the 1993 oil and gas production operations reports.[3,4] These data are referred to in this discussion as the 1993 petroleum industry data. In contrast to the data collected during the late-1970’s for the 1980 refinery report[5] (these are referred to in this discussion as the 1980 refinery data) which came from uncontrolled facilities and were used to develop correlations and emission factors that appear in previous versions of this protocol, the 1993 petroleum industry data came from controlled facilities and were collected using current procedures that are considered state of the art for the 1990’s.

The purpose of this section is to explain how and why the 1993 data were used to update the petroleum industry correlations and to present the data that were used in this update. The conclusions presented in this section were based on a combination of engineering judgement and quantitative statistical analysis of the available emission data. Judgments were made based on an understanding of possible mechanisms of equipment leak emissions and qualitative assessment of the data. A more detailed explanation of the analyses highlighted in this section appear in a technical memorandum[6] that is available on EPA’s web site.7

C.1.1 Overview of Data Analysis

Based on guidelines presented in chapter 4 of this document, the quality control/quality assurance (QC/QA) procedures for data collection and laboratory analysis of the 1993 petroleum industry data were evaluated and found to be of sufficient quality for the development of correlations. However, a few data pairs were excluded from correlation development due to large background concentrations or high screening value variability. Several options were considered for using the 1993 petroleum industry equipment leak data, including:

- Combine the 1980 refinery data and the 1993 refinery data to develop revised refinery correlations and, based on 1993 data, provide separate new correlations for marketing terminals and oil and gas production operations.

- Combine the 1980 refinery data with the 1993 refinery, marketing terminal, and oil and gas production data to develop new petroleum industry correlations that apply to all three industry segments.

- Drop the 1980 data and correlations from further use. Combine the 1993 refinery, marketing terminal, and oil and gas production operations data to develop a single correlation that applies to all three industry segments or keep the three industry segment correlations separate.

Judgments based upon an understanding of equipment leak emission mechanisms and a qualitative assessment of the data were used in conjunction with the following visual comparisons and statistical tests, that quantitatively evaluate the similarities or differences between the data being compared, to assess the options listed above:

- Visual comparison of the plotted data, regression lines, and 95 percent confidence intervals for the regression lines, to identify general characteristics of the data and to put the results of statistical tests into perspective.

- F-test for the mean square error (MSE) differences between the regression equations, to compare the variability of the errors of the predictions.

- T-tests for intercept (b_0) and slope (b_1) differences between the regression equations, to determine whether the regressions were statistically different. If the t-test for the intercepts indicated similarities, but the t-test for the slopes indicated differences or vice versa, the regressions were considered statistically different. However, when both the intercept and slope t-tests indicated similarities, the regressions were considered statistically the same.

- Mass verification analysis. Because of the statistical requirement for normality of the data distributions for the above tests to be valid, the visual and statistical tests were evaluated in log-log space (i.e., the mathematical space that results when regressing the natural logarithm of the mass emission rate against the natural logarithm of the screening value). The mass verification analysis was conducted to assess the impact of the correlations on the nontransformed data. The total measured mass was compared to the total mass predicted from each of the industry segment correlations and from the combined correlations. Mass ratios (the ratio of the total predicted mass to the total measured mass) formed the basis for evaluating the results. The mass verification was considered good when mass ratio was close to 1.0, indicating that the predicted mass was close to the measured mass (a mass ratio of 1.0 indicates a perfect prediction because the predicted mass equals the measured mass).

C.1.2 Comparison of the 1993 Refinery Data with the 1980 Refinery Data

The 1980 refinery data were collected and analyzed in the laboratory using procedures that were not as stringent as the current procedures. Thus, the 1993 refinery data are of better quality than the 1980 data, as evaluated by today's standards.

Also, the 1980 data were screened with a TLV calibrated with hexane and the 1993 refinery data were screened with an OVA calibrated with methane. Thus, any comparisons between the two datasets must be made on a common basis. The conversion from TLV to OVA is not totally clear or understood. Multiple conversion equations exist and the TLV/OVA relationship changes at different screening levels. Also, the TLV and OVA use different methods to obtain measurements that give different results for the same data. This difficulty was overcome sufficiently to perform a crude comparison; however no adjustments could be made to compare both datasets on a common basis with regards to data quality. The following relationship (taken from Figure C3-18a)[8] was used to approximate an OVA-methane screening value from a TLV-hexane screening value:

$$SV_{OVA\text{-}methane} = 10^{C} \qquad \text{(C-1)}$$

where:

$SV_{OVA\text{-}methane}$ = screening value taken with OVA-methane

$$C = \frac{[\log_{10}(SV_{TLV\text{-}hexane}) + 0.193]}{0.952}$$

$SV_{TLV\text{-}hexane}$ = screening value taken with TLV-hexane.

However, this transformation was achieved in the 1993 refinery report[1] using another conversion equation (from the 1979 valve screening report[9]) that gave results that were different from those obtained using Equation C-1 above, thereby emphasizing the uncertainty that exists for any of the transformations from TLV to OVA.

Additionally, pegged data were identified in the 1980 dataset and removed prior to comparisons with the 1993 refinery data, because separate emission rates are now calculated for pegged readings. Thus, the 1980 correlations were adjusted for screening instrument (TLV) and pegged data. Using available screening data from 17 marketing terminals as an example, the adjusted 1980 correlations gave estimations of total facility emissions that ranged between 42% to 116% of the total facility emissions obtained from the published 1980 correlations. The adjusted 1980 correlations gave an estimation of the total emissions from all 17 marketing terminals that were 61% of the total emissions estimated from the published 1980 correlations.

The comparisons between the 1980 refinery data and the 1993 refinery data were made for matching equipment types/services. The following four equipment types/services were compared: all connectors, light liquid pumps, gas valves, and light liquid valves. Plots that compare the raw data, the regression lines, and the 95 percent confidence intervals of the regression lines for the 1980 and 1993 refinery data were constructed for the four equipment types/services. The plot for all connector data, which illustrates the largest visual differences, is shown in Figure C-1 and the plot for gas valve data, which illustrates the smallest visual differences, is shown in figure c-2. All of the plots revealed a general separation of data pairs and 95 percent confidence intervals of the regression lines, thereby suggesting that there were differences between the 1980 and 1993 refinery data.

The results of the statistical tests (not shown) for differences between the 1980 and 1993 refinery regressions indicated that the regression lines were different because statistically significant differences between the 1980 refinery data and the 1993 refinery data existed for both the slope and intercept for all equipment types/services. Figure C-3 shows the ratios of predicted to measured mass that were calculated from the 1980 refinery data, the 1993 refinery data, and the combined 1980/1993 refinery data (a predicted to measured mass ratio of 1.0 would indicate a perfect prediction). In all cases, either the combined correlation or the 1993 refinery correlation did a better job of predicting the total mass of the 1980 refinery data than did the 1980 correlation, and the 1993 refinery correlation always gave the best mass ratios for the 1993 refinery data. The ratios of predicted to measured mass using the combined 1980/1993 refinery correlations were further from 1.0 than those obtained individually with either the 1980 or 1993 refinery correlations for the respective datasets, and thus, a rather poor verification of the combined correlation was indicated.

Based on the above results, the 1980 refinery data were not used to develop the revised correlations that are presented in this revised version of the protocol.

C.1.3 Comparison of the 1993 Refinery Data, the 1993 Marketing Terminal Data, and the 1993 Oil and Gas Production Operations Data

An underlying concern with all of the comparisons discussed in this section was the relatively small sample size for most of the equipment types/services. This problem was also encountered in the 1980 refinery report.[5] Table C-1 shows the sample size for each equipment type/service for the 1993 refinery data, the 1993 marketing terminal data, and the 1993 oil and gas production operations data that were deemed suitable for correlation development. (For comparative purposes, the corresponding sample sizes from the 1980 refinery analysis[5] are footnoted in Table C-1.) The sample size was 30 or larger for only 9 of the 46 equipment types/services for which data were collected. It is recommended in chapter 2 that the sample size should be 30 or larger for the development of correlations. In addition, the sample size was 10 or less for 23 of the 46 equipment types/services. Sample sizes that are this small may produce results of only limited usefulness and meaning.

Two-way statistical comparisons were made between the 1993 refinery, marketing terminal, and oil and gas production operations data for equipment types/services where data were collected. All comparisons were service-specific. The following equipment types/services were compared: light liquid connectors, light liquid flanges, light liquid open-ended lines, light liquid

TABLE C-1. SUMMARY OF THE SAMPLE SIZE FOR EACH EQUIPMENT TYPE/SERVICE FOR THE 1993 REFINERY DATA, THE 1993 MARKETING TERMINAL DATA, AND THE 1993 OIL AND GAS PRODUCTION OPERATIONS DATA

		Sample Size			
Equipment Type	Stream Service	1993 Refinery Data	1993 Marketing Terminal Data	1993 Oil & Gas Production Operations Data	Total
Connector	Gas	8	2	24	34
	Heavy Liquid	2	0	1	3
	Light Liquid	18	21	42	81
Flange	Gas	4	1	9	14
	Heavy Liquid	1	0	1	2
	Light Liquid	15	12	13	40
Instrument[a]	Gas	0	0	2	2
	Light Liquid	0	0	1	1
Loading Arm[a]	Gas	0	7	0	7
	Light Liquid	0	16	0	16
Open-Ended Line	Gas	7	0	48	55
	Heavy Liquid	3	0	13	16
	Light Liquid	15	16	39	70
Other[a]	Gas	0	1	0	1
	Light Liquid	0	3	0	1
Pressure Relief Valve[a]	Gas	1	0	6	7
	Light Liquid	1	0	3	4
Pump	Heavy Liquid	11	0	0	11
	Light Liquid	30	11	1	42
Stuffing Box[a]	Heavy Liquid	0	0	11	11
	Light Liquid	0	0	12	12
Valve	Gas	50	2	84	136
	Heavy Liquid	22	0	1	23
	Light Liquid	82	45	51	178
Vent[a]	Gas	0	0	3	3
	Light Liquid	0	0	3	3
1993 Petroleum Industry Total		270	137	368	775
1980 Refinery Total[b]					678

[a] Components with small sample sizes will be grouped together to form an "OTHERS" category.

[b] For comparative purposes, sample sizes from the 1980 refinery report are: all flanges-52; light liquid pumps-259, gas valves-79; light liquid values-119; valves and compressors in hydrogen service-47; all drains-61; and heavy liquid pumps-61.

pumps, gas valves, and light liquid valves.

Plots that compare the 1993 refinery, marketing terminal, and oil and gas production operations raw data, regression lines, and 95 percent confidence intervals for the regression lines were constructed for all equipment types/services listed above. The plot for light liquid flange data, which illustrates the largest visual differences, is shown in Figure C-4 and the plot for light liquid valve data, which illustrates the smallest visual differences, is shown in Figure C-5. In general, all of the data plots revealed a general intermingling of data pairs from the three petroleum industry segments and an overlapping of 95 percent confidence intervals of the regression lines. No clear separation of petroleum industry segments was evident in most of the data plots.

The results of the statistical tests (not shown) for two-way differences between regressions for the petroleum industry segment datasets indicated statistically significant differences for all of the equipment types/services; however, the visual plots indicated that these differences may be too small to really be relevant, especially when compared to the magnitude of the differences between the 1980 and 1993 refinery data.

Figure C-6 presents the ratios of predicted to measured mass that were calculated from the 1993 refinery, marketing terminal, and oil and gas production operations data. The mass ratios from facility type-specific correlations for the predictions that were closest to 1.0 for a given facility type dataset were usually from the correlation based on another facility type. For example, for light liquid valves, the marketing terminal correlation gave a mass ratio of 1.06 for the refinery data, whereas the refinery correlation gave a mass ratio of 1.50 for the refinery data.

In several cases, the combined petroleum industry correlation gave an even closer ratio of predicted to measured mass than any of the individual facility type-specific correlations. For example, for light liquid flanges, the combined correlation gave a mass ratio of 0.94 for the marketing terminal data, which is better than the 1.34 obtained when using the marketing terminal correlation. Overall, the combined 1993 petroleum industry correlations gave mass ratios ranging between 0.10 and 2.85 for facility type-specific datasets. The mass ratios using the combined correlations to predict the total mass of the combined dataset ranged between 0.28 and 1.42 for all equipment types/services. Thus, the ratios of predicted to measured mass obtained from the combined 1993 petroleum industry correlations were closer to 1.0 than those obtained individually with facility type-specific correlations, thus supporting the combination of data from the three petroleum industry segments.

It is not surprising that the visual and statistical results showed similarities between the petroleum industry segment datasets because the three industry segments produce similar products of similar molecular weights, viscosities, and densities. Therefore the leak mechanisms and screening instrument response rates are not expected to be different between the industry segments. Although some small differences were identified, there is not compelling evidence to believe that these differences were large enough to be real or meaningful.

C.1.4 Development of the Combined Refinery/Marketing Terminal/Oil and Gas Production Pperations Correlations, Default Zero Emission Rates, and Pegged Emission Rates

Based on the results presented in the above section, the 1993 refinery, marketing terminal data, and oil and gas production operations data were combined to develop petroleum industry correlations using the procedures outlined in chapter 2 and appendix B. Due to the small sample size for some equipment types, an "others" category was developed to provide a correlation for cases not otherwise covered. The equipment types flagged in Table C-1 (instruments, loading arms, other, pressure relief valves, stuffing boxes, and vents, compressors, and dump lever arms) were combined to form this "other" equipment type.

The visual and statistical tests for differences between regression equations were applied to the combined dataset to aid in the decision of what equipment type(s)/service(s), if any, to combine for developing the correlations. Visual inspection of the data plots (not shown) revealed that the gas, light liquid, and heavy liquid service data were generally well intermingled. The p-values from the t-tests for b_0 and b_1 differences indicated that the services were statistically similar only for gas/heavy liquid open-ended lines and for gas/light liquid open-ended lines. However, most of the statistically significant differences appeared too small in the visual plots to really be relevant. As with the comparisons between the refinery, marketing terminal, and oil and gas production operations data, the mass verification analysis for the services showed that when differences were identified for the service comparisons, they were small, thereby lending support towards combining the data. Other factors that support combining services include:

- The leak mechanism is the same regardless of service. However, screening value distributions, which affect total emissions (not correlations), may be different for each service.
- When services were segregated, sample sizes for nearly all equipment types were less than 30, the sample size recommended in chapter 2 for developing correlations, even after combining all of the petroleum industry segment data. Combination of data from all services increased the sample size to above 30 for nearly all equipment types.
- The importance of the component service was investigated in the 1994 refinery report,[1] using additional statistical tests. The analyses of variance that were presented in the refinery report showed that services should be combined because there were no statistically significant differences between the correlations for different services for a given equipment type.

The visual analysis that was conducted to compare the regression equations for the different equipment types revealed that the raw data for the different equipment types were well intermingled for some equipment types and separated for other types. However, a stacking of regression lines and confidence intervals was evident, such that some equations overlapped (connectors and open-ended lines), but there were rather large differences between other equations (pumps versus connectors). Thus, in contrast to other comparisons, where the differences were either consistently large (1980 versus 1993 refinery data) or small (1993 petroleum industry segment data), differences between the equipment types varied. Based on the visual results, it was felt that further analysis outside the objectives of this study was necessary to determine which equipment types to combine. Therefore, the equipment types remained segregated.

Correlations, default zero emission rates, and pegged emission rates were developed from the combined 1993 refinery, marketing terminal, and oil and gas production operations data for combined services for connectors, flanges, open-ended lines, pumps, valves, and "other" equipment types. Table C-2 shows the regression statistics for correlations. The R^2 values ranged from 0.32 for "others" to 0.54 for valves, thereby indicating that the equations were capable of predicting about half of the variability of the mass emission rates. These R^2 values corresponded to correlation coefficients (r, the square root of R^2) ranging from 0.57 to 0.73. Although these R^2 values were sometimes less than those obtained for individual facility/service types, they were more consistent across equipment types than the R^2 values for the individual facility/service types which ranged from 0.04 to 0.75. These R^2 values revealed the inherent limits of this tool for predicting mass emission rates (an inability to account for 25% to 50% of the mass emission variance) and were not substantially different from those shown in other reports.[1,2,3,5] Table C-3 shows the petroleum industry correlations, default zero emission rates, and pegged emission rates for each equipment type as calculated from the combined 1993 refinery, marketing terminal, and oil and gas production operations data.

Emission estimates from the revised correlations depend on the distribution of equipment types and screening values at a given facility. Comparisons of the results obtained from the 1993 correlations and previously published correlations can vary greatly from facility-to-facility. For screening data that contained a large number of low screening values from 17 marketing terminals, the 1993 correlations gave estimations of

TABLE C-2. REGRESSION STATISTICS FOR THE COMBINED 1993 REFINERY, MARKETING TERMINAL, AND OIL AND GAS PRODUCTION OPERATIONS DATA

Equipment Type/ Service	Number of Data Pairs	Intercept (b_0)	Slope (b_1)	Coefficient of Simple Determination (R^2)	Standard Error of Estimate	Mean ln Screening Value[a]	Sum of Squared Differences[b]	Scale Bias Correction Factor (SBCF)	Half-Width of the 95% Confidence Interval[c]
Valve/All	337	-14.169	0.746	0.54	1.544	6.477	1705.07	3.27	0.17
Connector/All	118	-14.893	0.735	0.47	1.754	6.214	592.09	4.51	0.32
Pump/All	53	-11.546	0.610	0.46	1.856	5.816	409.21	5.15	0.51
Other[d]/All	70	-12.838	0.589	0.32	1.843	5.437	316.36	5.14	0.44
Flange/All	56	-13.788	0.703	0.37	1.771	5.767	204.71	4.48	0.47
Open-Ended Line/All	141	-14.658	0.704	0.44	1.823	6.166	745.97	5.11	0.30

[a] The mean ln screening value is the average of all of the ln screening values: $\bar{X} = (1/n)\times\Sigma(X_i)$.

[b] The sum of squared differences refers to the difference between the individual ln screening values and the average ln screening value: $\Sigma(X_i-\bar{X})^2$. (The mean ln screening value and the sum of squared differences are used to calculate confidence intervals.)

[c] The half-width of the 95 percent confidence interval is calculated using the mean ln screening value as the X-value being evaluated in the confidence interval calculation.

[d] The "other" equipment type includes instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms.

TABLE C-3. CORRELATION EQUATIONS, DEFAULT ZERO EMISSION RATES, AND PEGGED EMISSION RATES FOR PREDICTING TOTAL ORGANIC COMPOUND EMISSIONS FROM THE COMBINED 1993 REFINERY, MARKETING TERMINAL, AND OIL AND GAS PRODUCTION OPERATIONS DATA[a]

Equipment Type/Service	Default Zero Emission Rate (kg/hr/source)[b]	Pegged Emission Rates (kg/hr/source)[c]		Correlation Equation[d] (kg/hr/source)
		10,000 ppmv	100,000 ppmv	
Valve/All	7.8E-06	0.064	0.140	$\text{LEAK} = 2.29\text{E-}06 \times (\text{SV})^{0.746}$
Pump/All	2.4E-05	0.074	0.160[e]	$\text{LEAK} = 5.03\text{E-}05 \times (\text{SV})^{0.610}$
Other[f]/All	4.0E-06	0.073	0.110	$\text{LEAK} = 1.36\text{E-}05 \times (\text{SV})^{0.589}$
Connector/All	7.5E-06	0.028	0.030	$\text{LEAK} = 1.53\text{E-}06 \times (\text{SV})^{0.735}$
Flange/All	3.1E-07	0.085	0.084	$\text{LEAK} = 4.61\text{E-}06 \times (\text{SV})^{0.703}$
Open-Ended Line/All	2.0E-06	0.030	0.079	$\text{LEAK} = 2.20\text{E-}06 \times (\text{SV})^{0.704}$

[a] To estimate emissions: use the default zero emission rates only when the screening value (adjusted for background) equals 0.0 ppmv; otherwise use the correlation equations. If the monitoring device registers a pegged value, use the appropriate pegged emission rate.

[b] Default zero emission rates were based on the combined 1993 refinery and marketing terminal data only (default zero data were not collected from oil and gas production facilities).

[c] The 10,000 ppmv pegged emission rate was based on components screened at greater than 10,000 ppmv; however, in some cases, most of the data could have come from components screened at greater than 100,000 ppmv, thereby resulting in similar pegged emission rates for both the 10,000 and 100,000 pegged levels (e.g., connector and flanges).

[d] LEAK is the predicted mass emission rate (kg/hr) and SV is the screening value (ppmv) measured by the monitoring device.

[e] Only 2 data points were available for the pump 100,000 pegged emission rate; therefore the ratio of the pump 10,000 pegged emission rate to the overall 10,000 ppmv pegged emission rate was multiplied by the overall 100,000 ppmv pegged emission rate to approximate the pump 100,000 ppmv pegged emission rate.

[f] The "other" equipment type was developed from instruments, loading arms, pressure relief devices, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters, and polished rods. This "other" equipment type sould be applied to any equipment other than connectors, flanges, open-ended lines, pumps or valves.

the total facility emissions that ranged from less than 10% to over 800% of the total facility emissions obtained from the adjusted 1980 correlations presented in this paper. When the total emissions from all 17 marketing terminals were evaluated, the 1993 correlations gave an estimate that was 40% of the total estimated by the adjusted 1980 correlations. Though the 17 marketing terminals do not represent the entire petroleum industry, these results illustrate the differences encountered when comparing emission estimates for individual facilities versus evaluating all facilities as a single group.

C.1.4 Marketing Terminal and Oil and Gas Production Operation Screening Data for Development of Average Emission Factors

Screening data from 17 marketing terminals[10] and from 24 oil and gas production operation facilities[11,12] were available to EPA for the development of average emission factors using the same procedures as discussed in appendix B.2.3 for the revision of SOCMI average factors. Attachment 4 to appendix C summarizes the screening data used to develop the emission factors.

Little documentation is available for the marketing terminal data because the data were collected and delivered directly to EPA with no formal report being written. The marketing terminal emission factors (shown in Tables 2-3 and 2-7) represent emissions from uncontrolled facilities.

The following five facility types were represented in the oil and gas production operations screening dataset:

- light crude facilities,
- heavy crude facilities,
- gas plants,
- gas production facilities, and
- offshore facilities.

The 24 oil and gas production operations facilities generally represent uncontrolled facilities, however, a couple of gas plants have agency-mandated inspection and maintenance programs. Anecdotal data were available regarding the control level at other facilities. A statistical analysis revealed that there were no significant differences between emission factors for those groups of sites with some form of inspection and maintenance program versus those sites with no such programs[13]. Thus, the oil and gas production operations emission factors (shown in Tables 2-4 and 2-8) represent emissions from uncontrolled facilities.

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13. Fax to Eric Peterson, Santa Barbara APCD, Santa Barbara, CA from G.E. Harris, Radian/Austin, August 31, 1995.

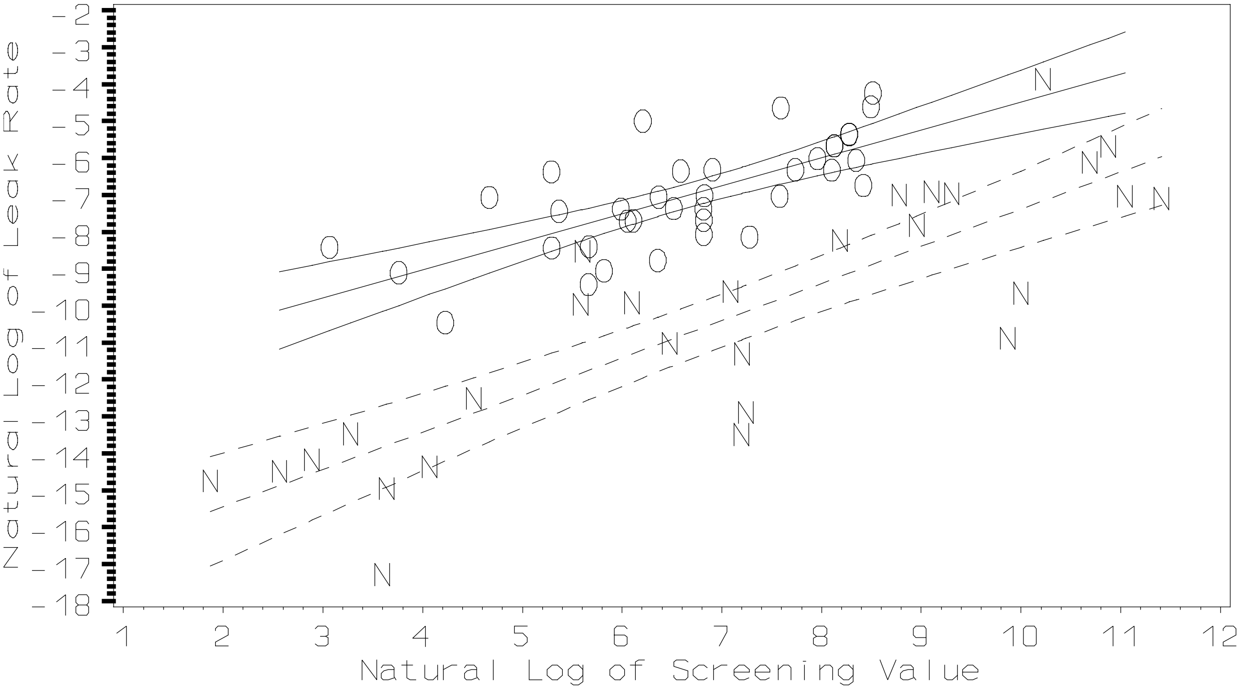

Figure C-1. Plot of data and regression lines with 95 percent confidence intervals for the all connector data from the 1980 (solid lines for regression equations and confidence bounds; O for individual data points) and 1993 (dashed lines for regression equations and confidence bounds; N for individual data points) refinery reports (screening values are in ppmv and leak rates in kg/hr).

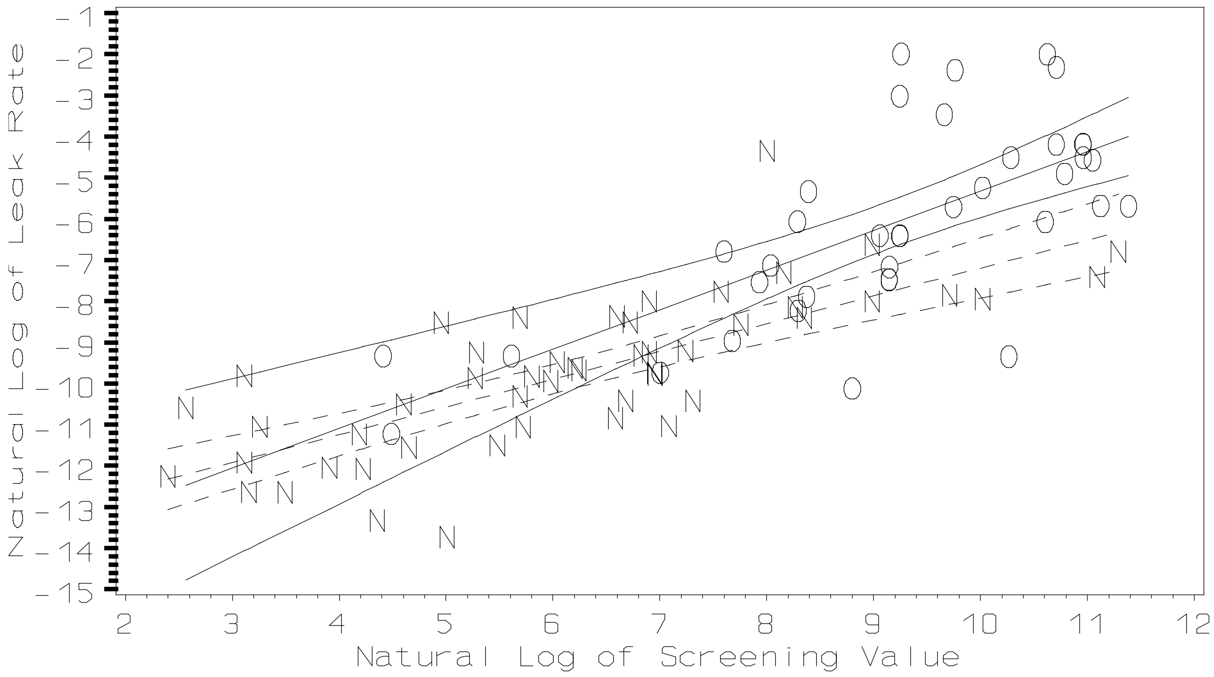

Figure C-2. Plot of data and regression lines with 95 percent confidence intervals for the gas valve data from the 1980 (solid lines for regression equations and confidence bounds; O for individual data points) and 1993 (dashed lines for regression equations and confidence bounds; N for individual data points) refinery reports (screening values are in ppmv and leak rates in kg/hr).

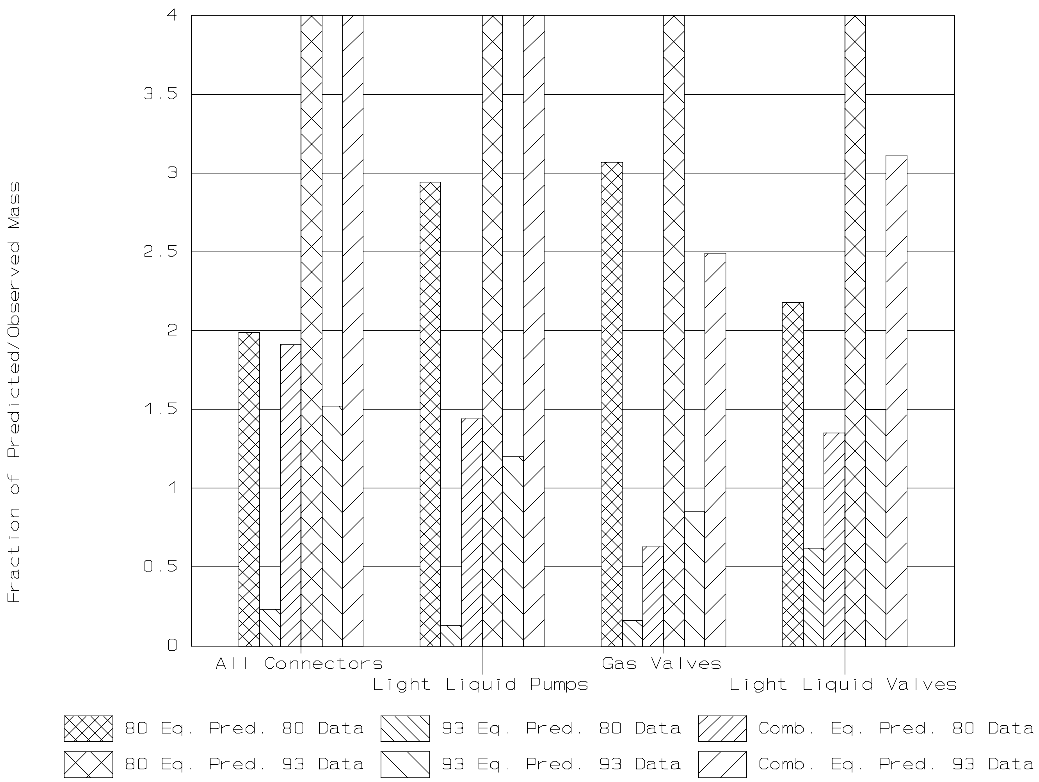

Figure C-3. Comparison of ratios of predicted to measured mass formthe 1980 refinery, the 1993 refinery, and the combined 1980/1993 refinery data (a predicted-to-measured mass ratio of 1.0 indicates a perfect prediction). Bars that reach 4.0 on the chart actually extend beyond 4.0.

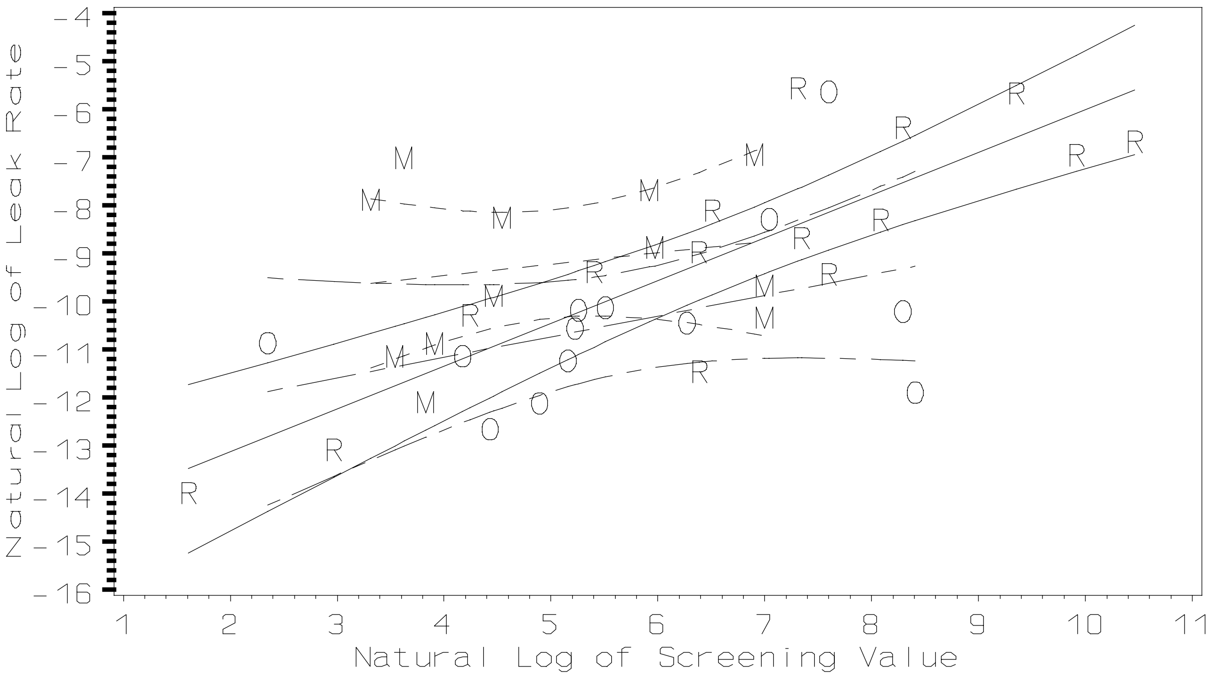

Figure C-4. Plot of data and regression lines with 95 percent confidence intervals for the light liquid flange data from the 1993 refinery (solid lines for regression equations and confidence bounds; R for individual data points), the 1993 marketing terminal (short dashed lines for regression equations and confidence bounds; M for individual data points), and the 1993 oil and gas production operations (alternating short and long dashed lines for regression equations and confidence bounds; M for individual data points) reports (screening values are in ppmv and leak rates in kg/hr).

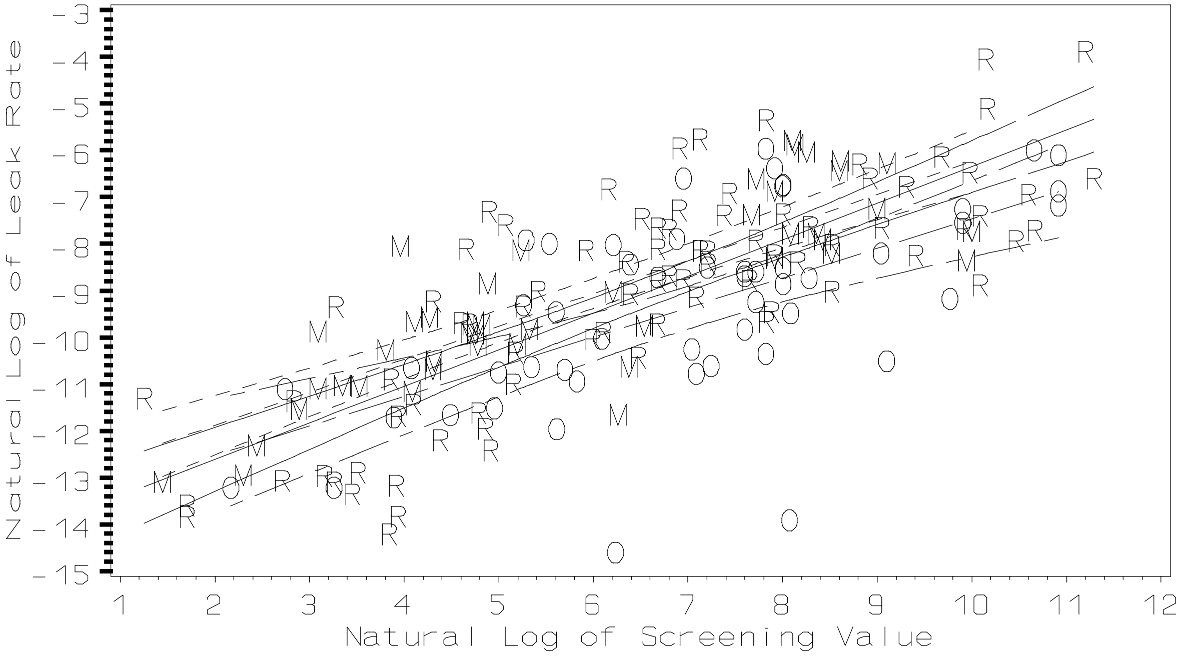

Figure C-5. Plot of data and regression lines with 95 percent confidence intervals for the light liquid valve data from the 1993 refinery (solid lines for regression equations and confidence bounds; R for individual data points), the 1993 marketing terminal (short dashed lines for regression equations and confidence bounds; M for individual data points), and the 1993 oil and gas production operations (alternating short and long dashed lines for regression equations and confidence bounds; M for individual data points) reports (screening values are in ppmv and leak rates in kg/hr).

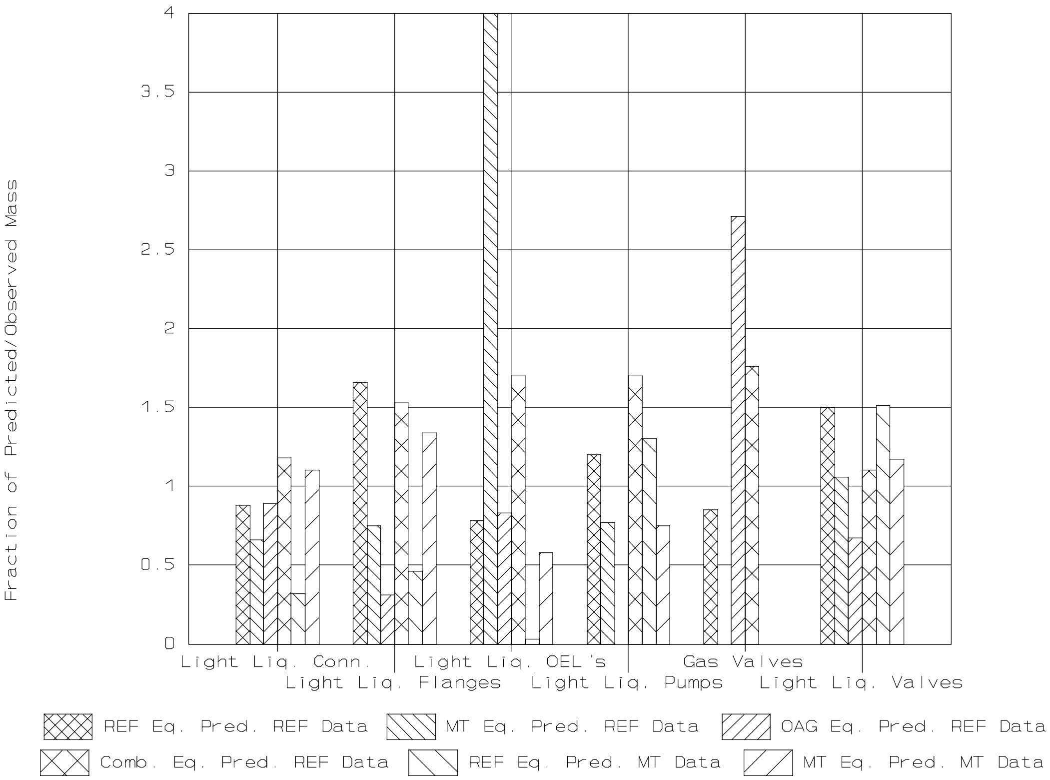

Figure C-6. Comparison of the ratios of predicted to observed mass from the 1993 refinery, marketing terminal, oil and gas production operations, and the combined refinery/marketing terminal/oil and gas production operations data (a predicted-to-measured mass ratio of 1.0 indicates a perfect prediction). Bars that reach 4.0 on the chart actually extend beyond 4.0.

APPENDIX C: ATTACHMENT 1

This attachment lists the bagging data used to develop the correlation equations for each of the equipment types in table C-1-1. Also included is a summary table (table C-1-2) of the regression statistics for the 1993 refinery, marketing terminal and oil and gas production operations data individually. Note that the regression statistics presented in table C-1-2 are based on the development of the regression lines using natural logarithms of the leak rates and screening values. Table C-1-3 lists the bagging data for the 1980 refinery data while table C-1-4 presents regression statistics for the 1980 and 1993 refinery data sets.

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS

--------------------- Equipment Type=CONNECTOR SERVICE=G ---------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000045360	8.00	-14.606	2.079
REF	0.00000050826	13.00	-14.492	2.565
ONOFF	0.00000181439	1.75	-13.220	0.560
ONOFF	0.00000272158	106.00	-12.814	4.663
ONOFF	0.00000272158	145.00	-12.814	4.977
ONOFF	0.00000453597	70.00	-12.303	4.248
ONOFF	0.00000498957	98.00	-12.208	4.585
ONOFF	0.00000498957	1,045.00	-12.208	6.952
ONOFF	0.00000680396	1,450.00	-11.898	7.279
ONOFF	0.00000725755	440.00	-11.833	6.087
ONOFF	0.00001043273	195.00	-11.471	5.273
ONOFF	0.00001360791	6,240.00	-11.205	8.739
ONOFF	0.00001632949	4,982.00	-11.023	8.514
MT	0.00001732831	30.00	-10.963	3.401
ONOFF	0.00001995827	93.00	-10.822	4.533
ONOFF	0.00002313345	43.00	-10.674	3.761
ONOFF	0.00002903021	890.00	-10.447	6.791
ONOFF	0.00002993740	549.00	-10.416	6.308
ONOFF	0.00003084460	130.50	-10.387	4.871
REF	0.00004677946	267.00	-9.970	5.587
REF	0.00004909734	446.00	-9.922	6.100
REF	0.00006622970	1,196.50	-9.622	7.087
ONOFF	0.00010659530	2,742.00	-9.146	7.916
ONOFF	0.00013245033	1,999.00	-8.929	7.600
ONOFF	0.00014061508	1,985.00	-8.869	7.593
REF	0.00019757326	271.00	-8.529	5.602
MT	0.00027662615	30.00	-8.193	3.401
ONOFF	0.00033566180	790.00	-7.999	6.672
REF	0.00039860292	7,745.00	-7.828	8.955
ONOFF	0.00046040098	3,996.00	-7.683	8.293
ONOFF	0.00049850313	5,498.00	-7.604	8.612
REF	0.00094198494	10,995.00	-6.968	9.305
ONOFF	0.00105688107	8,995.00	-6.852	9.104
REF	0.00220312075	43,995.00	-6.118	10.692

N = 34

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

--------------------- Equipment Type=CONNECTOR SERVICE=HL ---------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000057407	58.50	-14.371	4.069
ONOFF	0.00001360791	19.50	-11.205	2.970
REF	0.00098339835	8,994.00	-6.924	9.104

N = 3

--------------------- Equipment Type=CONNECTOR SERVICE=LL ---------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000003124	36.50	-17.282	3.597
REF	0.00000032133	38.00	-14.951	3.638
REF	0.00000039502	6.50	-14.744	1.872
ONOFF	0.00000045360	13.50	-14.606	2.603
REF	0.00000069890	18.00	-14.174	2.890
REF	0.00000138429	1,335.00	-13.490	7.197
REF	0.00000140733	26.50	-13.474	3.277
ONOFF	0.00000226799	1,547.00	-12.997	7.344
REF	0.00000252558	1,393.00	-12.889	7.239
ONOFF	0.00000272158	20.00	-12.814	2.996
ONOFF	0.00000272158	41.00	-12.814	3.714
ONOFF	0.00000272158	155.00	-12.814	5.043
ONOFF	0.00000272158	498.00	-12.814	6.211
ONOFF	0.00000362878	75.00	-12.527	4.317
REF	0.00000366230	91.00	-12.517	4.511
ONOFF	0.00000408237	56.00	-12.409	4.025
ONOFF	0.00000408237	96.00	-12.409	4.564
MT	0.00000418117	35.00	-12.385	3.555
ONOFF	0.00000544316	157.50	-12.121	5.059
ONOFF	0.00000589676	200.00	-12.041	5.298
ONOFF	0.00000635036	290.00	-11.967	5.670
ONOFF	0.00000680396	39.00	-11.898	3.664
ONOFF	0.00000816475	4,400.00	-11.716	8.389
MT	0.00001033612	317.00	-11.480	5.759
ONOFF	0.00001133993	294.00	-11.387	5.684
ONOFF	0.00001133993	1,240.00	-11.387	7.123
REF	0.00001226163	1,345.50	-11.309	7.205
ONOFF	0.00001270072	123.00	-11.274	4.812
MT	0.00001529121	23.00	-11.088	3.135
ONOFF	0.00001542230	322.00	-11.080	5.775

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

--------------------- Equipment Type=CONNECTOR SERVICE=LL ---------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00001542230	395.00	-11.080	5.979
MT	0.00001610768	23.00	-11.036	3.135
REF	0.00001628413	649.00	-11.025	6.475
ONOFF	0.00001814388	56.00	-10.917	4.025
REF	0.00001880613	19,304.00	-10.881	9.868
ONOFF	0.00002222625	945.00	-10.714	6.851
ONOFF	0.00002267985	825.00	-10.694	6.715
ONOFF	0.00002313345	5,900.00	-10.674	8.683
ONOFF	0.00002585503	172.00	-10.563	5.147
MT	0.00002609816	45.00	-10.554	3.807
MT	0.00002844053	321.00	-10.468	5.771
ONOFF	0.00002993740	121.00	-10.416	4.796
ONOFF	0.00003356618	450.00	-10.302	6.109
MT	0.00003923025	42.50	-10.146	3.750
MT	0.00004271251	670.00	-10.061	6.507
MT	0.00004451148	446.50	-10.020	6.101
MT	0.00004481675	542.00	-10.013	6.295
ONOFF	0.00005080287	6,930.00	-9.888	8.844
ONOFF	0.00005216366	1,996.00	-9.861	7.599
MT	0.00005430464	112.00	-9.821	4.718
MT	0.00005460855	96.00	-9.815	4.564
ONOFF	0.00006304999	3,248.00	-9.672	8.086
REF	0.00006329946	21,996.00	-9.668	9.999
MT	0.00006931416	141.50	-9.577	4.952
MT	0.00008792071	511.00	-9.339	6.236
ONOFF	0.00009570897	8,450.00	-9.254	9.042
ONOFF	0.00010886329	1,245.00	-9.125	7.127
ONOFF	0.00011612084	3,495.00	-9.061	8.159
ONOFF	0.00012247120	1,900.00	-9.008	7.550
ONOFF	0.00013381112	6,998.00	-8.919	8.853
MT	0.00013952191	420.00	-8.877	6.040
ONOFF	0.00018461399	2,992.00	-8.597	8.004
MT	0.00021457407	621.50	-8.447	6.432
ONOFF	0.00021863377	5,990.00	-8.428	8.698
MT	0.00025722126	41.00	-8.266	3.714
ONOFF	0.00026263268	1,249.00	-8.245	7.130
REF	0.00026441985	3,595.50	-8.238	8.187
MT	0.00030734827	270.00	-8.088	5.598
MT	0.00031839790	171.50	-8.052	5.145
ONOFF	0.00032341468	1,993.00	-8.037	7.597
ONOFF	0.00033475460	2,240.00	-8.002	7.714
ONOFF	0.00041640207	290.00	-7.784	5.670
MT	0.00071681938	6,996.00	-7.241	8.853
MT	0.00075932142	940.00	-7.183	6.846

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

--------------------- Equipment Type=CONNECTOR SERVICE=LL ---------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00082713417	89,996.50	-7.098	11.408
REF	0.00087190420	62,482.50	-7.045	11.043
REF	0.00090365599	6,492.50	-7.009	8.778
ONOFF	0.00152363240	2,490.00	-6.487	7.820
REF	0.00337970607	52,843.00	-5.690	10.875
REF	0.02082463939	27,493.00	-3.872	10.222
ONOFF	0.15713462760	44,990.00	-1.851	10.714

N = 81

----------------------- Equipment Type=FLANGE SERVICE=G ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000133929	344.50	-13.523	5.842
ONOFF	0.00000272158	46.00	-12.814	3.829
REF	0.00000347791	97.00	-12.569	4.575
MT	0.00000944344	37.50	-11.570	3.624
ONOFF	0.00000952554	122.00	-11.562	4.804
ONOFF	0.00001133993	398.00	-11.387	5.986
ONOFF	0.00003220539	597.00	-10.343	6.392
REF	0.00003784088	81.00	-10.182	4.394
ONOFF	0.00003810215	39.00	-10.175	3.664
ONOFF	0.00005533884	197.00	-9.802	5.283
ONOFF	0.00007076114	1,996.00	-9.556	7.599
ONOFF	0.00054068765	424.00	-7.523	6.050
REF	0.00268479543	4,996.00	-5.920	8.516
ONOFF	0.00444751882	999.00	-5.415	6.907

N = 14

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

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        Table C-1-1.  Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=FLANGE SERVICE=HL -----------------------

                                                  Natural      Natural
                                                   Log of      Log of
                      Measured                    Emission    Screening
        Plant         Emission      Screening       Rate        Value
        Type        Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

        REF      0.00000585594          22.50     -12.048        3.114
        ONOFF    0.00000907194         345.00     -11.610        5.844

                                    N = 2
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TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=FLANGE SERVICE=LL -----------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000084061	5.00	-13.989	1.609
REF	0.00000206056	19.50	-13.093	2.970
ONOFF	0.00000317518	84.00	-12.660	4.431
ONOFF	0.00000544316	133.50	-12.121	4.894
MT	0.00000558151	46.00	-12.096	3.829
ONOFF	0.00000680396	4,480.00	-11.898	8.407
REF	0.00001045859	595.50	-11.468	6.389
ONOFF	0.00001315431	174.00	-11.239	5.159
MT	0.00001445342	34.50	-11.145	3.541
ONOFF	0.00001451510	65.00	-11.140	4.174
MT	0.00001889096	50.00	-10.877	3.912
ONOFF	0.00001905108	10.50	-10.868	2.351
ONOFF	0.00002585503	186.00	-10.563	5.226
ONOFF	0.00002903021	530.00	-10.447	6.273
MT	0.00003226209	1,096.50	-10.342	7.000
REF	0.00003390230	69.50	-10.292	4.241
ONOFF	0.00003674136	3,997.00	-10.212	8.293
ONOFF	0.00003764855	192.00	-10.187	5.257
ONOFF	0.00003991654	247.00	-10.129	5.509
MT	0.00005107956	87.00	-9.882	4.466
MT	0.00006298648	1,096.50	-9.673	7.000
REF	0.00007970607	1,996.00	-9.437	7.599
REF	0.00008327588	222.50	-9.393	5.405
REF	0.00012617255	593.00	-8.978	6.385
MT	0.00013896398	392.00	-8.881	5.971
REF	0.00016897850	1,548.00	-8.686	7.345
REF	0.00024779098	3,244.50	-8.303	8.085
ONOFF	0.00025129275	1,145.00	-8.289	7.043
MT	0.00025963440	94.00	-8.256	4.543
REF	0.00030001361	671.00	-8.112	6.509
MT	0.00037563277	27.50	-7.887	3.314
MT	0.00046017418	372.50	-7.684	5.920
MT	0.00090079833	37.50	-7.012	3.624
REF	0.00095309807	20,246.00	-6.956	9.916
MT	0.00096566271	997.00	-6.943	6.905
REF	0.00125641840	34,995.50	-6.679	10.463
REF	0.00169028395	3,997.50	-6.383	8.293
REF	0.00344683843	11,547.00	-5.670	9.354
ONOFF	0.00355030391	1,998.00	-5.641	7.600
REF	0.00382985576	1,495.00	-5.565	7.310

N = 40

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

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        Table C-1-1.  Bagging Data Used to Develop Correlation Equations

--------------------- Equipment Type=INSTRUMENT SERVICE=G ----------------------

                                                 Natural      Natural
                                                  Log of      Log of
                      Measured                   Emission    Screening
        Plant         Emission     Screening       Rate        Value
        Type       Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

        ONOFF    0.00007302912       1,992.00      -9.525        7.597
        ONOFF    0.00028259095      29,998.00      -8.172       10.309

                                     N = 2


--------------------- Equipment Type=INSTRUMENT SERVICE=LL ---------------------

                                                 Natural      Natural
                                                  Log of      Log of
                      Measured                   Emission    Screening
        Plant         Emission     Screening       Rate        Value
        Type       Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

        ONOFF    0.00000272158       2,743.00     -12.814        7.917

                                     N = 1


----------------------- Equipment Type=LOADARM SERVICE=G -----------------------

                                                 Natural      Natural
                                                  Log of      Log of
                      Measured                   Emission    Screening
        Plant         Emission     Screening       Rate        Value
        Type       Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

        MT       0.00000641205          18.00     -11.957        2.890
        MT       0.00002664338          45.00     -10.533        3.807
        MT       0.00007439445          70.00      -9.506        4.248
        MT       0.00036316339          19.50      -7.921        2.970
        MT       0.00134378118       2,498.50      -6.612        7.823
        MT       0.00294180350         387.00      -5.829        5.958
        MT       0.00397654903       1,096.00      -5.527        6.999

                                     N = 7
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TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

---------------------- Equipment Type=LOADARM SERVICE=LL -----------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
MT	0.00000263449	3.00	-12.847	1.099
MT	0.00000483852	75.00	-12.239	4.317
MT	0.00000647374	76.00	-11.948	4.331
MT	0.00001007893	6.00	-11.505	1.792
MT	0.00001144289	4.50	-11.378	1.504
MT	0.00001305906	5.50	-11.246	1.705
MT	0.00001802640	33.00	-10.924	3.497
MT	0.00001825229	6.00	-10.911	1.792
MT	0.00002585775	79.00	-10.563	4.369
MT	0.00002943210	26.50	-10.433	3.277
MT	0.00004225755	46.50	-10.072	3.839
MT	0.00005778372	15.00	-9.759	2.708
MT	0.00007896671	70.00	-9.446	4.248
MT	0.00010795156	96.00	-9.134	4.564
MT	0.00012671233	10.50	-8.974	2.351
MT	0.00021594394	145.50	-8.440	4.980

N = 16

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=OEL SERVICE=G ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000077642	20.30	-14.069	3.011
ONOFF	0.00000090719	9.00	-13.913	2.197
ONOFF	0.00000136079	8.00	-13.507	2.079
REF	0.00000177710	60.50	-13.241	4.103
ONOFF	0.00000181439	20.50	-13.220	3.020
ONOFF	0.00000181439	26.50	-13.220	3.277
ONOFF	0.00000181439	30.50	-13.220	3.418
ONOFF	0.00000226799	84.00	-12.997	4.431
ONOFF	0.00000272158	48.00	-12.814	3.871
ONOFF	0.00000272158	195.00	-12.814	5.273
ONOFF	0.00000272158	63.00	-12.814	4.143
ONOFF	0.00000272158	113.50	-12.814	4.732
ONOFF	0.00000362878	440.00	-12.527	6.087
ONOFF	0.00000362878	499.00	-12.527	6.213
REF	0.00000391912	16.50	-12.450	2.803
ONOFF	0.00000408237	546.00	-12.409	6.303
ONOFF	0.00000453597	377.00	-12.303	5.932
ONOFF	0.00000498957	59.00	-12.208	4.078
ONOFF	0.00000544316	24.00	-12.121	3.178
ONOFF	0.00000544316	930.00	-12.121	6.835
ONOFF	0.00000589676	755.00	-12.041	6.627
ONOFF	0.00000771115	65.00	-11.773	4.174
ONOFF	0.00000861834	740.00	-11.662	6.607
ONOFF	0.00000907194	383.00	-11.610	5.948
ONOFF	0.00001043273	600.00	-11.471	6.397
ONOFF	0.00001088633	4,430.00	-11.428	8.396
ONOFF	0.00001133993	250.00	-11.387	5.521
REF	0.00001313209	893.00	-11.240	6.795
ONOFF	0.00001587590	349.00	-11.051	5.855
ONOFF	0.00001859748	2,725.00	-10.892	7.910
ONOFF	0.00002177266	1,745.00	-10.735	7.465
ONOFF	0.00002812302	1,747.00	-10.479	7.466
ONOFF	0.00002857661	1,143.00	-10.463	7.041
ONOFF	0.00003039100	1,400.00	-10.401	7.244
REF	0.00003324186	1,295.00	-10.312	7.166
ONOFF	0.00003447337	1,845.00	-10.275	7.520
REF	0.00004146875	15,068.00	-10.091	9.620
ONOFF	0.00004853488	17,499.00	-9.933	9.770
ONOFF	0.00007166833	820.00	-9.543	6.709
ONOFF	0.00008845142	483.50	-9.333	6.181
ONOFF	0.00010024494	170.00	-9.208	5.136
ONOFF	0.00012065681	1,043.00	-9.023	6.950
ONOFF	0.00013743990	3,400.00	-8.892	8.132
ONOFF	0.00016057335	999.00	-8.737	6.907
ONOFF	0.00016737730	80.00	-8.695	4.382

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------- Equipment Type=OEL SERVICE=G -------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00020729384	3,746.00	-8.481	8.228
ONOFF	0.00025991109	849.00	-8.255	6.744
ONOFF	0.00029257008	13,497.00	-8.137	9.510
ONOFF	0.00043046358	1,980.00	-7.751	7.591
ONOFF	0.00057652182	27,497.00	-7.458	10.222
ONOFF	0.00084278327	5,998.00	-7.079	8.699
REF	0.00087367323	44,998.00	-7.043	10.714
ONOFF	0.00107184977	5,998.00	-6.838	8.699
ONOFF	0.00229792253	14,999.00	-6.076	9.616
ONOFF	0.04543499955	1,800.00	-3.091	7.496

N = 55

------------------------ Equipment Type=OEL SERVICE=HL -------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000137984	195.00	-13.494	5.273
ONOFF	0.00000453597	107.50	-12.303	4.677
ONOFF	0.00000498957	33.50	-12.208	3.512
ONOFF	0.00000544316	75.00	-12.121	4.317
ONOFF	0.00000544316	170.00	-12.121	5.136
ONOFF	0.00000635036	85.50	-11.967	4.449
ONOFF	0.00001224712	75.00	-11.310	4.317
ONOFF	0.00002948381	95.00	-10.432	4.554
ONOFF	0.00005533884	142.00	-9.802	4.956
ONOFF	0.00005715323	58.00	-9.770	4.060
ONOFF	0.00006304999	329.50	-9.672	5.798
ONOFF	0.00008074027	2,994.00	-9.424	8.004
REF	0.00011177991	1,097.50	-9.099	7.001
REF	0.00018571169	15,496.50	-8.591	9.648
ONOFF	0.00045904019	1,194.00	-7.686	7.085
ONOFF	0.00109226163	4,990.00	-6.820	8.515

N = 16

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=OEL SERVICE=LL ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000045360	698.00	-14.606	6.548
REF	0.00000079071	100.00	-14.050	4.605
ONOFF	0.00000090719	293.00	-13.913	5.680
MT	0.00000109340	1.00	-13.726	0.000
ONOFF	0.00000136079	122.00	-13.507	4.804
MT	0.00000179606	2.00	-13.230	0.693
ONOFF	0.00000181439	3.75	-13.220	1.322
REF	0.00000269491	14.50	-12.824	2.674
ONOFF	0.00000272158	96.00	-12.814	4.564
ONOFF	0.00000272158	75.00	-12.814	4.317
ONOFF	0.00000272158	110.00	-12.814	4.700
REF	0.00000272462	1,448.00	-12.813	7.278
MT	0.00000289948	8.00	-12.751	2.079
MT	0.00000312574	1.75	-12.676	0.560
ONOFF	0.00000317518	63.00	-12.660	4.143
ONOFF	0.00000317518	547.00	-12.660	6.304
REF	0.00000396675	488.00	-12.438	6.190
ONOFF	0.00000453597	1,004.00	-12.303	6.912
ONOFF	0.00000725755	180.00	-11.833	5.193
ONOFF	0.00000725755	1,148.00	-11.833	7.046
ONOFF	0.00000771115	148.00	-11.773	4.997
ONOFF	0.00000771115	1,000.50	-11.773	6.908
REF	0.00000810124	247.00	-11.723	5.509
ONOFF	0.00000861834	535.00	-11.662	6.282
MT	0.00001089767	175.50	-11.427	5.168
ONOFF	0.00001224712	3.00	-11.310	1.099
MT	0.00001287898	545.50	-11.260	6.302
ONOFF	0.00001360791	996.00	-11.205	6.904
REF	0.00001366144	522.50	-11.201	6.259
ONOFF	0.00001496870	2.50	-11.110	0.916
ONOFF	0.00002131906	44.00	-10.756	3.784
ONOFF	0.00002585503	1,498.00	-10.563	7.312
ONOFF	0.00002721582	99.00	-10.512	4.595
REF	0.00003169282	1,493.00	-10.359	7.309
REF	0.00003332713	66.50	-10.309	4.197
MT	0.00003502223	296.00	-10.260	5.690
ONOFF	0.00004127733	2,144.00	-10.095	7.670
ONOFF	0.00004399891	1,492.00	-10.031	7.308
MT	0.00004551393	51.00	-9.997	3.932
ONOFF	0.00007529711	849.00	-9.494	6.744
REF	0.00007992833	3,243.00	-9.434	8.084
REF	0.00009666606	14,846.00	-9.244	9.605
ONOFF	0.00010659530	1,748.00	-9.146	7.466
ONOFF	0.00010704890	6,985.00	-9.142	8.852
ONOFF	0.00011067767	796.00	-9.109	6.680

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=OEL SERVICE=LL ------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00012428558	2,200.00	-8.993	7.696
ONOFF	0.00013063594	34,996.00	-8.943	10.463
REF	0.00013571623	535.00	-8.905	6.282
ONOFF	0.00020956183	2,097.00	-8.470	7.648
ONOFF	0.00023541686	2,248.00	-8.354	7.718
MT	0.00028113490	142.00	-8.177	4.956
ONOFF	0.00029483807	1,744.00	-8.129	7.464
REF	0.00035645469	1,996.00	-7.939	7.599
ONOFF	0.00035970244	1,190.00	-7.930	7.082
ONOFF	0.00038510387	4,489.00	-7.862	8.409
MT	0.00053411050	495.00	-7.535	6.205
REF	0.00056373038	12,493.50	-7.481	9.433
MT	0.00056382110	93.00	-7.481	4.533
MT	0.00076480994	1,186.00	-7.176	7.078
MT	0.00082414043	210.00	-7.101	5.347
MT	0.00086428377	1,039.00	-7.054	6.946
REF	0.00092007620	12,990.00	-6.991	9.472
ONOFF	0.00120112492	37,492.00	-6.724	10.532
MT	0.00175405969	990.00	-6.346	6.898
ONOFF	0.00219268802	19,992.00	-6.123	9.903
ONOFF	0.00361471469	42,493.00	-5.623	10.657
ONOFF	0.00594257462	69,994.00	-5.126	11.156
ONOFF	0.00753968974	347.00	-4.888	5.849
REF	0.00883470924	26,795.00	-4.729	10.196
MT	0.05022226254	7,992.00	-2.991	8.986

N = 70

------------------------ Equipment Type=OTHER SERVICE=G ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
MT	0.00001317427	970.00	-11.237	6.877

N = 1

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

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       Table C-1-1.  Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=OTHER SERVICE=LL ------------------------

                                                Natural      Natural
                                                 Log of      Log of
                 Measured                       Emission    Screening
       Plant      Emission      Screening         Rate        Value
       Type      Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

       MT       0.00000408142          73.00    -12.409        4.290
       MT       0.00001337113       3,995.00    -11.222        8.293
       MT       0.00003222716       2,991.00    -10.343        8.003

                                    N = 3


------------------------- Equipment Type=PRV SERVICE=G -------------------------

                                                Natural      Natural
                                                 Log of      Log of
                 Measured                       Emission    Screening
       Plant      Emission      Screening         Rate        Value
       Type      Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

       REF      0.00000184074       2,595.00    -13.205        7.861
       ONOFF    0.00000408237          19.00    -12.409        2.944
       ONOFF    0.00001451510          81.00    -11.140        4.394
       ONOFF    0.00007393631         149.00     -9.512        5.004
       ONOFF    0.00010387372         578.50     -9.172        6.360
       ONOFF    0.00014651184       1,345.00     -8.828        7.204
       ONOFF    0.00029166289       1,741.00     -8.140        7.462

                                    N = 7


------------------------ Equipment Type=PRV SERVICE=LL -------------------------

                                                Natural      Natural
                                                 Log of      Log of
                 Measured                       Emission    Screening
       Plant      Emission      Screening         Rate        Value
       Type      Rate(kg/hr)    Value (ppmv)    (kg/hr)      (ppmv)

       REF      0.00000105779           3.80    -13.759        1.335
       ONOFF    0.00001496870         297.00    -11.110        5.694
       ONOFF    0.00002812302         997.00    -10.479        6.905
       ONOFF    0.00024312801       5,491.00     -8.322        8.611

                                    N = 4
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TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=PUMP SERVICE=HL ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000090434	281.00	-13.916	5.638
REF	0.00000241563	10.00	-12.934	2.303
REF	0.00000450227	6.80	-12.311	1.917
REF	0.00001091808	19.00	-11.425	2.944
REF	0.00002612447	18.00	-10.553	2.890
REF	0.00006783543	9.50	-9.598	2.251
REF	0.00032885331	45.50	-8.020	3.818
REF	0.00082590946	323.00	-7.099	5.778
REF	0.00089771387	1,145.50	-7.016	7.044
REF	0.00290669509	277.00	-5.841	5.624
REF	0.01268710877	9,496.50	-4.367	9.159

N = 11

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=PUMP SERVICE=LL ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
MT	0.00000569400	24.50	-12.076	3.199
REF	0.00002452599	107.00	-10.616	4.673
MT	0.00002501950	2.00	-10.596	0.693
MT	0.00002550576	20.00	-10.577	2.996
MT	0.00003079742	95.00	-10.388	4.554
REF	0.00003737186	7,999.00	-10.195	8.987
MT	0.00003825274	45.50	-10.171	3.818
REF	0.00004112537	126.00	-10.099	4.836
REF	0.00004198993	192.00	-10.078	5.257
REF	0.00005151955	66.50	-9.874	4.197
REF	0.00006067767	4.50	-9.710	1.504
MT	0.00006509571	5.00	-9.640	1.609
MT	0.00006677855	7.50	-9.614	2.015
REF	0.00014387644	22.00	-8.847	3.091
REF	0.00018934954	21.50	-8.572	3.068
REF	0.00028473646	7,999.00	-8.164	8.987
REF	0.00034099156	136.00	-7.984	4.913
MT	0.00034670235	8,945.50	-7.967	9.099
REF	0.00048530346	127.00	-7.631	4.844
REF	0.00052476640	15.50	-7.553	2.741
REF	0.00059974599	1,780.00	-7.419	7.484
REF	0.00062650821	66.00	-7.375	4.190
MT	0.00066574435	43.00	-7.315	3.761
REF	0.00082055702	27,996.00	-7.106	10.240
REF	0.00086514560	33,744.50	-7.053	10.427
MT	0.00092406786	6,868.00	-6.987	8.835
REF	0.00095527533	5,970.00	-6.954	8.695
REF	0.00119445704	22,995.00	-6.730	10.043
REF	0.00121223805	1,394.00	-6.715	7.240
REF	0.00122534700	621.00	-6.705	6.431
REF	0.00153538057	183.50	-6.479	5.212
REF	0.00179438447	1,697.00	-6.323	7.437
REF	0.00220076204	947.00	-6.119	6.853
REF	0.00301020593	996.00	-5.806	6.904
REF	0.00489884786	395.00	-5.319	5.979
REF	0.00679034746	5,745.50	-4.992	8.656
REF	0.00757234873	4,997.00	-4.883	8.517
REF	0.00958087635	41,995.00	-4.648	10.645
REF	0.00968248208	13,995.00	-4.637	9.546
MT	0.01317699356	4,488.00	-4.329	8.409
REF	0.03439081920	17,694.50	-3.370	9.781
ONOFF	0.07243808401	4,992.00	-2.625	8.516

N = 42

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

-------------------- Equipment Type=STUFFING BOX SERVICE=HL --------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000317518	26.00	-12.660	3.258
ONOFF	0.00000317518	46.00	-12.660	3.829
ONOFF	0.00000317518	47.50	-12.660	3.861
ONOFF	0.00000544316	75.00	-12.121	4.317
ONOFF	0.00000589676	162.00	-12.041	5.088
ONOFF	0.00001043273	145.00	-11.471	4.977
ONOFF	0.00001451510	145.00	-11.140	4.977
ONOFF	0.00004127733	127.00	-10.095	4.844
ONOFF	0.00007076114	294.00	-9.556	5.684
ONOFF	0.00089630772	795.00	-7.017	6.678
ONOFF	0.00129592670	1,095.00	-6.649	6.999

N = 11

-------------------- Equipment Type=STUFFING BOX SERVICE=LL --------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00014197587	293.00	-8.860	5.680
ONOFF	0.00032114669	842.00	-8.044	6.736
ONOFF	0.00046266896	630.00	-7.678	6.446
ONOFF	0.00052390456	71.00	-7.554	4.263
ONOFF	0.00059421210	647.00	-7.428	6.472
ONOFF	0.00107321056	4,498.00	-6.837	8.411
ONOFF	0.00114442529	1,246.00	-6.773	7.128
ONOFF	0.00120611449	992.00	-6.720	6.900
ONOFF	0.00142293387	748.00	-6.555	6.617
ONOFF	0.00371586682	3,994.00	-5.595	8.293
ONOFF	0.00399664338	4,498.00	-5.522	8.411
ONOFF	0.00602331489	3,496.00	-5.112	8.159

N = 12

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=VALVE SERVICE=G ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000045360	1.25	-14.606	0.223
ONOFF	0.00000045360	9.00	-14.606	2.197
ONOFF	0.00000045360	52.50	-14.606	3.961
ONOFF	0.00000045360	1,997.00	-14.606	7.599
ONOFF	0.00000090719	122.00	-13.913	4.804
REF	0.00000108460	150.00	-13.734	5.011
ONOFF	0.00000136079	142.00	-13.507	4.956
REF	0.00000162324	78.00	-13.331	4.357
MT	0.00000211567	295.50	-13.066	5.689
MT	0.00000226853	1.00	-12.996	0.000
ONOFF	0.00000272158	46.50	-12.814	3.839
ONOFF	0.00000272158	227.50	-12.814	5.427
ONOFF	0.00000317518	31.50	-12.660	3.450
ONOFF	0.00000317518	42.00	-12.660	3.738
REF	0.00000322045	33.00	-12.646	3.497
REF	0.00000323338	23.50	-12.642	3.157
ONOFF	0.00000453597	180.00	-12.303	5.193
REF	0.00000474236	11.00	-12.259	2.398
ONOFF	0.00000498957	1,497.00	-12.208	7.311
ONOFF	0.00000498957	1,780.00	-12.208	7.484
REF	0.00000566633	68.50	-12.081	4.227
REF	0.00000584324	50.00	-12.050	3.912
ONOFF	0.00000635036	749.00	-11.967	6.619
REF	0.00000662796	22.50	-11.924	3.114
ONOFF	0.00000725755	1,620.00	-11.833	7.390
ONOFF	0.00000907194	648.00	-11.610	6.474
ONOFF	0.00000952554	299.00	-11.562	5.700
REF	0.00000959040	105.00	-11.555	4.654
ONOFF	0.00000997913	3.50	-11.515	1.253
ONOFF	0.00000997913	3.50	-11.515	1.253
REF	0.00001004944	240.00	-11.508	5.481
REF	0.00001313209	66.00	-11.240	4.190
REF	0.00001568266	306.00	-11.063	5.724
REF	0.00001582872	26.00	-11.054	3.258
REF	0.00001608773	1,194.50	-11.037	7.085
ONOFF	0.00001905108	1,300.00	-10.868	7.170
REF	0.00001952236	724.00	-10.844	6.585
ONOFF	0.00002177266	96.00	-10.735	4.564
ONOFF	0.00002404064	236.50	-10.636	5.466
REF	0.00002500272	13.00	-10.597	2.565
ONOFF	0.00002721582	115.00	-10.512	4.745
REF	0.00002723941	100.00	-10.511	4.605
REF	0.00002964075	1,495.00	-10.426	7.310
REF	0.00002977456	798.50	-10.422	6.683
ONOFF	0.00002993740	71.00	-10.416	4.263

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=VALVE SERVICE=G ------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00003039100	3,485.00	-10.401	8.156
ONOFF	0.00003129819	1,880.00	-10.372	7.539
REF	0.00003320285	297.00	-10.313	5.694
ONOFF	0.00003538057	870.00	-10.249	6.768
ONOFF	0.00004581330	1,746.00	-9.991	7.465
REF	0.00004823551	396.50	-9.939	5.983
ONOFF	0.00004853488	490.00	-9.933	6.194
REF	0.00005161027	195.50	-9.872	5.276
ONOFF	0.00005171006	1,048.00	-9.870	6.955
REF	0.00005379207	331.50	-9.830	5.804
REF	0.00005465391	22.50	-9.814	3.114
REF	0.00005555656	1,049.00	-9.798	6.956
ONOFF	0.00005760682	918.00	-9.762	6.822
REF	0.00005882700	1,045.00	-9.741	6.952
REF	0.00006236052	515.00	-9.683	6.244
ONOFF	0.00006441078	169.00	-9.650	5.130
REF	0.00006601651	496.50	-9.626	6.208
ONOFF	0.00006713236	795.00	-9.609	6.678
ONOFF	0.00007030754	498.00	-9.563	6.211
ONOFF	0.00007166833	1,497.00	-9.543	7.311
REF	0.00007594121	420.00	-9.486	6.040
ONOFF	0.00008618343	249.00	-9.359	5.517
REF	0.00008973964	922.00	-9.319	6.827
ONOFF	0.00009434818	1,748.00	-9.269	7.466
REF	0.00009616711	197.50	-9.249	5.286
REF	0.00009735099	996.00	-9.237	6.904
REF	0.00010011794	1,397.00	-9.209	7.242
ONOFF	0.00010160573	525.00	-9.194	6.263
ONOFF	0.00010523451	3,993.00	-9.159	8.292
ONOFF	0.00010886329	8,180.00	-9.125	9.009
ONOFF	0.00011158487	1,996.00	-9.101	7.599
ONOFF	0.00011294566	499.00	-9.089	6.213
ONOFF	0.00012564638	749.00	-8.982	6.619
ONOFF	0.00013154314	780.00	-8.936	6.659
ONOFF	0.00013426472	785.00	-8.916	6.666
ONOFF	0.00013426472	8,400.00	-8.916	9.036
ONOFF	0.00014605824	3,999.00	-8.832	8.294
ONOFF	0.00014651184	1,997.00	-8.828	7.599
ONOFF	0.00017327406	1,994.00	-8.661	7.598
ONOFF	0.00018053162	290.00	-8.620	5.670
REF	0.00018855575	2,343.00	-8.576	7.759
REF	0.00019906105	142.00	-8.522	4.956
REF	0.00019947836	830.00	-8.520	6.721
ONOFF	0.00021727297	243.00	-8.434	5.493

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=VALVE SERVICE=G ------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00021818017	5,725.00	-8.430	8.653
REF	0.00022242130	4,246.00	-8.411	8.354
REF	0.00022387281	297.00	-8.404	5.694
REF	0.00023074027	735.00	-8.374	6.600
ONOFF	0.00023904563	798.00	-8.339	6.682
ONOFF	0.00026898304	999.00	-8.221	6.907
ONOFF	0.00026898304	1,165.00	-8.221	7.060
REF	0.00028817473	3,898.40	-8.152	8.268
ONOFF	0.00029257008	14,995.00	-8.137	9.615
ONOFF	0.00031887871	1,998.00	-8.051	7.600
ONOFF	0.00031978590	1,339.00	-8.048	7.200
ONOFF	0.00032114669	1,339.00	-8.044	7.200
ONOFF	0.00033203302	2,999.00	-8.010	8.006
REF	0.00033339381	7,995.50	-8.006	8.987
REF	0.00033416946	996.00	-8.004	6.904
ONOFF	0.00034972331	7,492.00	-7.958	8.922
REF	0.00035323415	22,495.00	-7.948	10.021
REF	0.00038567541	16,496.00	-7.861	9.711
REF	0.00041993559	1,949.00	-7.775	7.575
ONOFF	0.00043137077	2,997.00	-7.749	8.005
ONOFF	0.00043227796	3,990.00	-7.746	8.292
ONOFF	0.00053070852	3,998.00	-7.541	8.294
REF	0.00060437268	65,699.00	-7.411	11.093
ONOFF	0.00066542683	1,045.00	-7.315	6.952
REF	0.00066864737	3,493.00	-7.310	8.159
ONOFF	0.00069445704	740.00	-7.272	6.607
ONOFF	0.00074027034	699.00	-7.208	6.550
ONOFF	0.00082191781	7,495.00	-7.104	8.922
ONOFF	0.00090220448	69,995.00	-7.011	11.156
ONOFF	0.00094484260	14,999.00	-6.964	9.616
ONOFF	0.00102558287	3,241.00	-6.882	8.084
ONOFF	0.00109815840	44,998.00	-6.814	10.714
REF	0.00111190239	79,998.80	-6.802	11.290
ONOFF	0.00111358069	1,444.00	-6.800	7.275
ONOFF	0.00115621882	4,491.00	-6.763	8.410
ONOFF	0.00124965980	6,000.00	-6.685	8.700
REF	0.00132495691	7,998.00	-6.626	8.987
ONOFF	0.00145377846	2,499.00	-6.534	7.824
ONOFF	0.00155719858	5,235.00	-6.465	8.563
ONOFF	0.00207339200	3,465.00	-6.179	8.150
ONOFF	0.00244851674	2,696.00	-6.012	7.900
ONOFF	0.00269255194	44,995.00	-5.917	10.714
ONOFF	0.00380250386	7,499.00	-5.572	8.923
REF	0.01290846412	2,993.00	-4.350	8.004

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

------------------------ Equipment Type=VALVE SERVICE=G ------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.01376394811	3,498.00	-4.286	8.160
ONOFF	0.01612628141	49,998.00	-4.127	10.820
ONOFF	0.04505624603	64,998.00	-3.100	11.082

N = 136

----------------------- Equipment Type=VALVE SERVICE=HL ------------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00000007416	22.00	-16.417	3.091
REF	0.00000024878	31.00	-15.207	3.434
REF	0.00000384555	28.00	-12.469	3.332
REF	0.00000417178	23.50	-12.387	3.157
REF	0.00000515059	30.50	-12.176	3.418
REF	0.00000583507	18.50	-12.052	2.918
ONOFF	0.00001043273	120.00	-11.471	4.787
REF	0.00002810986	121.00	-10.479	4.796
REF	0.00003200898	505.00	-10.349	6.225
REF	0.00003625011	122.50	-10.225	4.808
REF	0.00004638030	42.00	-9.979	3.738
REF	0.00007379116	167.00	-9.514	5.118
REF	0.00012682573	92.00	-8.973	4.522
REF	0.00022685294	183.00	-8.391	5.209
REF	0.00025173728	290.00	-8.287	5.670
REF	0.00028499501	464.00	-8.163	6.140
REF	0.00031120838	540.00	-8.075	6.292
REF	0.00040606459	446.00	-7.809	6.100
REF	0.00042830899	956.50	-7.756	6.863
REF	0.00047713871	2,097.50	-7.648	7.649
REF	0.00049600835	2,993.00	-7.609	8.004
REF	0.00223700445	11,494.00	-6.103	9.350
REF	0.01003356618	1,996.00	-4.602	7.599

N = 23

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=VALVE SERVICE=LL -----------------------

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000045360	510.00	-14.606	6.234
REF	0.00000067060	46.50	-14.215	3.839
ONOFF	0.00000090719	3,210.00	-13.913	8.074
REF	0.00000097029	5.50	-13.846	1.705
REF	0.00000097655	51.00	-13.839	3.932
REF	0.00000124345	5.50	-13.598	1.705
REF	0.00000157471	31.50	-13.361	3.450
ONOFF	0.00000181439	8.75	-13.220	2.169
ONOFF	0.00000181439	26.00	-13.220	3.258
REF	0.00000189545	50.00	-13.176	3.912
REF	0.00000203465	26.00	-13.105	3.258
MT	0.00000205103	4.25	-13.097	1.447
REF	0.00000209952	15.00	-13.074	2.708
REF	0.00000232450	23.50	-12.972	3.157
MT	0.00000237776	10.00	-12.949	2.303
REF	0.00000248467	33.50	-12.905	3.512
REF	0.00000401492	136.00	-12.425	4.913
MT	0.00000447800	11.50	-12.316	2.442
REF	0.00000502041	80.00	-12.202	4.382
ONOFF	0.00000635036	274.00	-11.967	5.613
REF	0.00000640298	128.50	-11.959	4.856
ONOFF	0.00000816475	49.00	-11.716	3.892
REF	0.00000834528	51.00	-11.694	3.932
ONOFF	0.00000861834	89.00	-11.662	4.489
MT	0.00000862560	524.00	-11.661	6.261
REF	0.00000895128	119.50	-11.624	4.783
MT	0.00000984079	18.00	-11.529	2.890
ONOFF	0.00000997913	142.00	-11.515	4.956
REF	0.00001072938	60.00	-11.443	4.094
REF	0.00001154767	17.00	-11.369	2.833
REF	0.00001223850	3.50	-11.311	1.253
MT	0.00001432233	59.50	-11.154	4.086
ONOFF	0.00001496870	15.50	-11.110	2.741
MT	0.00001524449	22.00	-11.091	3.091
MT	0.00001602150	34.00	-11.042	3.526
MT	0.00001613626	28.50	-11.034	3.350
REF	0.00001662116	173.00	-11.005	5.153
ONOFF	0.00001769028	339.00	-10.942	5.826
REF	0.00001839744	47.50	-10.903	3.861
ONOFF	0.00002086546	1,197.00	-10.777	7.088
ONOFF	0.00002131906	148.00	-10.756	4.997
ONOFF	0.00002267985	298.00	-10.694	5.697
MT	0.00002288442	74.00	-10.685	4.304
ONOFF	0.00002358705	59.00	-10.655	4.078
ONOFF	0.00002404064	210.00	-10.636	5.347

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=VALVE SERVICE=LL -----------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
MT	0.00002413726	588.00	-10.632	6.377
ONOFF	0.00002449424	1,398.00	-10.617	7.243
MT	0.00002719722	75.00	-10.512	4.317
ONOFF	0.00002721582	8,960.00	-10.512	9.101
REF	0.00002937177	646.00	-10.435	6.471
ONOFF	0.00003175179	2,497.00	-10.358	7.823
REF	0.00003262633	176.00	-10.330	5.170
MT	0.00003474508	45.00	-10.267	3.807
ONOFF	0.00003492697	1,143.00	-10.262	7.041
MT	0.00003817473	119.00	-10.173	4.779
MT	0.00003920348	181.00	-10.147	5.198
REF	0.00004325547	400.50	-10.048	5.993
ONOFF	0.00004399891	441.00	-10.031	6.089
MT	0.00004902930	116.00	-9.923	4.754
MT	0.00005014515	109.00	-9.901	4.691
REF	0.00005050349	447.50	-9.893	6.104
MT	0.00005156491	22.00	-9.873	3.091
ONOFF	0.00005352445	1,998.00	-9.835	7.600
MT	0.00005386918	205.00	-9.829	5.323
MT	0.00005803320	691.00	-9.754	6.538
MT	0.00005873628	124.00	-9.742	4.820
REF	0.00005976594	108.80	-9.725	4.690
REF	0.00005993377	793.00	-9.722	6.676
REF	0.00006152590	100.00	-9.696	4.605
MT	0.00006221537	116.00	-9.685	4.754
REF	0.00006287762	2,496.00	-9.674	7.822
MT	0.00006335843	61.00	-9.667	4.111
MT	0.00006978137	71.50	-9.570	4.270
ONOFF	0.00007575070	3,249.00	-9.488	8.086
ONOFF	0.00007756509	272.00	-9.464	5.606
REF	0.00007775560	2,645.50	-9.462	7.881
REF	0.00008625601	26.50	-9.358	3.277
REF	0.00008785721	192.00	-9.340	5.257
ONOFF	0.00009026581	193.00	-9.313	5.263
ONOFF	0.00009661617	2,246.00	-9.245	7.717
REF	0.00009754604	74.00	-9.235	4.304
ONOFF	0.00010342012	17,499.00	-9.177	9.770
REF	0.00010648644	1,196.00	-9.147	7.087
REF	0.00011324050	595.00	-9.086	6.389
MT	0.00012015785	496.50	-9.027	6.208
REF	0.00012067949	5,000.00	-9.022	8.517
REF	0.00012075660	224.00	-9.022	5.412
REF	0.00013744443	23,996.00	-8.892	10.086
ONOFF	0.00014106867	2,998.00	-8.866	8.006

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=VALVE SERVICE=LL ------------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
MT	0.00014320058	132.00	-8.851	4.883
REF	0.00015138801	796.50	-8.796	6.680
REF	0.00015260365	2,096.50	-8.788	7.648
REF	0.00015486256	1,044.00	-8.773	6.951
ONOFF	0.00016102694	3,950.00	-8.734	8.281
ONOFF	0.00016374853	798.00	-8.717	6.682
REF	0.00016769028	894.00	-8.693	6.796
ONOFF	0.00016783090	1,997.00	-8.693	7.599
ONOFF	0.00018461399	1,995.00	-8.597	7.598
ONOFF	0.00018461399	2,244.00	-8.597	7.716
ONOFF	0.00019867550	2,998.00	-8.524	8.006
ONOFF	0.00020185068	1,344.00	-8.508	7.203
ONOFF	0.00021545859	596.00	-8.443	6.390
REF	0.00021628867	1,348.00	-8.439	7.206
REF	0.00022579153	3,493.00	-8.396	8.159
REF	0.00022907557	568.00	-8.381	6.342
MT	0.00023388370	20,897.00	-8.361	9.947
MT	0.00024798603	2,744.00	-8.302	7.917
REF	0.00025930781	12,145.50	-8.257	9.405
REF	0.00026239681	2,736.00	-8.246	7.914
ONOFF	0.00027306541	8,450.00	-8.206	9.042
MT	0.00027484804	4,996.50	-8.199	8.516
REF	0.00028502676	1,345.00	-8.163	7.204
REF	0.00028960809	1,248.00	-8.147	7.129
REF	0.00029077384	372.50	-8.143	5.920
MT	0.00029242947	187.50	-8.137	5.234
REF	0.00029891137	105.00	-8.115	4.654
REF	0.00029939672	794.00	-8.114	6.677
MT	0.00031903747	52.50	-8.050	3.961
REF	0.00032606822	4,997.50	-8.028	8.517
ONOFF	0.00032704345	498.00	-8.025	6.211
ONOFF	0.00033611540	253.50	-7.998	5.535
REF	0.00035377846	34,996.50	-7.947	10.463
REF	0.00035974780	2,240.00	-7.930	7.714
ONOFF	0.00036106323	198.00	-7.926	5.288
MT	0.00036868820	4,545.00	-7.906	8.422
ONOFF	0.00037240316	975.00	-7.896	6.882
MT	0.00041536787	3,243.00	-7.786	8.084
MT	0.00042058423	4,246.50	-7.774	8.354
MT	0.00043848771	21,994.00	-7.732	9.999
REF	0.00044372675	42,745.50	-7.720	10.663
REF	0.00045395990	893.00	-7.698	6.795
REF	0.00046035562	20,246.50	-7.684	9.916
REF	0.00046933684	796.00	-7.664	6.680

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

----------------------- Equipment Type=VALVE SERVICE=LL -----------------------
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.00047251202	8,490.00	-7.657	9.047
REF	0.00047945205	3,996.00	-7.643	8.293
REF	0.00049981856	159.50	-7.601	5.072
ONOFF	0.00052617255	19,998.00	-7.550	9.903
REF	0.00057253016	674.00	-7.465	6.513
REF	0.00060782001	23,994.50	-7.406	10.086
REF	0.00061521364	1,598.00	-7.394	7.377
MT	0.00062442166	2,147.50	-7.379	7.672
REF	0.00063122562	2,992.00	-7.368	8.004
REF	0.00066533612	133.50	-7.315	4.894
REF	0.00068511295	995.00	-7.286	6.903
ONOFF	0.00070443618	19,994.00	-7.258	9.903
MT	0.00071074118	8,091.00	-7.249	8.999
ONOFF	0.00075932142	54,997.00	-7.183	10.915
REF	0.00095572893	39,996.50	-6.953	10.597
REF	0.00098348907	1,695.00	-6.924	7.435
ONOFF	0.00102558287	54,995.00	-6.882	10.915
MT	0.00103914542	2,745.00	-6.869	7.918
REF	0.00107547854	474.00	-6.835	6.161
REF	0.00113353896	10,997.00	-6.782	9.305
ONOFF	0.00114669328	2,982.00	-6.771	8.000
ONOFF	0.00118570262	2,998.00	-6.737	8.006
MT	0.00134518734	2,257.50	-6.611	7.722
REF	0.00134786356	79,997.00	-6.609	11.290
ONOFF	0.00135444071	1,046.00	-6.604	6.953
REF	0.00135698086	7,497.00	-6.602	8.922
REF	0.00153742175	21,495.00	-6.478	9.976
MT	0.00160918080	5,434.00	-6.432	8.600
ONOFF	0.00169010251	2,740.00	-6.383	7.916
REF	0.00183253198	6,690.00	-6.302	8.808
MT	0.00188274517	8,994.00	-6.275	9.104
MT	0.00197233058	5,494.00	-6.229	8.611
REF	0.00213984396	15,998.50	-6.147	9.680
ONOFF	0.00223351175	54,998.00	-6.104	10.915
MT	0.00239059240	3,844.00	-6.036	8.254
ONOFF	0.00247028939	42,492.00	-6.003	10.657
ONOFF	0.00256236959	2,496.00	-5.967	7.822
REF	0.00258328041	1,004.00	-5.959	6.912
MT	0.00279048353	3,389.00	-5.882	8.128
MT	0.00305193686	3,302.00	-5.792	8.102
REF	0.00312115577	1,243.00	-5.770	7.125
REF	0.00471287308	2,498.00	-5.357	7.823
REF	0.00601378935	25,895.50	-5.114	10.162
REF	0.01730744806	25,490.00	-4.057	10.146

TABLE C-1-1. BAGGING DATA USED TO DEVELOP CORRELATION EQUATIONS (CONTINUED)

Table C-1-1. Bagging Data Used to Develop Correlation Equations

Equipment Type=VALVE SERVICE=LL
(continued)

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
REF	0.02037603193	72,924.00	-3.893	11.197

N = 178

Equipment Type=VENT SERVICE=G

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00000952554	99.00	-11.562	4.595
ONOFF	0.00005261725	1,998.00	-9.852	7.600
ONOFF	0.00033883698	894.00	-7.990	6.796

N = 3

Equipment Type=VENT SERVICE=LL

Plant Type	Measured Emission Rate(kg/hr)	Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of Screening Value (ppmv)
ONOFF	0.00010478091	1,496.00	-9.164	7.311
ONOFF	0.00014877982	396.00	-8.813	5.981
ONOFF	0.00093168829	3,497.00	-6.979	8.160

N = 3

Table C-1-2. REGRESSION STATISTICS FOR THE 1993 REFINERY, MARKETING TERMINAL, AND OIL AND GAS PRODUCTION OPERATIONS DATA

Equipment		Facility Type[a]	Sample Size	Intercept (b_0)	Slope (b_1)	Root Mean Square Error (RMSE)	Coefficient of Simple Determination (R^2)	Scale Bias Correction Factor (SBCF)	Mean ln Screening Value	Sum of Squared Deviations from the Mean ln Screening Value
Type	**Service**									
Connector	Light Liquid	REF93	18	-18.01355	1.005	1.960	0.7353	5.2595	7.12669	169.2060
		MT93	21	-12.57236	0.560	1.144	0.3456	1.8293	5.28173	41.9152
		OAG93	42	-15.95523	0.860	1.564	0.5223	3.1956	6.40961	144.7306
Flange	Light Liquid	REF93	15	-14.91663	0.891	1.316	0.7503	2.1504	6.79160	85.2498
		MT93	12	-10.41103	0.237	1.748	0.0413	3.5250	5.00211	23.3301
		OAG93	13	-12.88458	0.430	1.715	0.1721	3.4347	5.73992	36.3270
Open-Ended Line	Light Liquid	REF93	15	-16.36068	0.907	1.693	0.5966	3.4293	6.97954	66.9792
		MT93	16	-14.01355	0.995	1.614	0.7372	3.1160	4.71076	103.1866
		OAG93	39	-14.59519	0.668	1.929	0.4218	5.6760	6.50333	225.1838
Pump	Light Liquid	REF93	30	-10.07607	0.419	1.579	0.3281	3.1882	6.71261	194.3916
		MT93	11	-11.40718	0.527	1.617	0.5128	2.2985	4.45340	89.1903
Valve	Gas	REF93	50	-13.94624	0.675	1.245	0.5725	2.1124	6.22836	218.6160
		OAG93	84	-15.20999	0.858	1.708	0.5296	4.1228	6.92689	365.7776
Valve	Light Liquid	REF93	82	-14.17854	0.783	1.453	0.6340	2.7995	6.56265	476.8908
		MT93	45	-13.29112	0.705	1.071	0.7036	1.7392	5.89259	235.3645
		OAG93	51	-13.79570	0.633	1.635	0.3949	3.5907	7.02241	213.3342

[a] Facility types are: REF93=1993 refinery data, MT93=1993 marketing terminal data, and OAG93=1993 oil and gas production operations data

Table C-1-3. 1980 Refinery Data

--------------------- Equipment Type=CONNECTOR SERVICE=ALL ---------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00002862	68.49	135.17	-10.461	4.227	4.907
0.00007993	287.96	611.03	-9.434	5.663	6.415
0.00011026	43.00	82.89	-9.113	3.761	4.418
0.00011643	336.64	719.98	-9.058	5.819	6.579
0.00015369	576.42	1,266.67	-8.781	6.357	7.144
0.00021599	199.00	414.48	-8.440	5.293	6.027
0.00021940	21.47	39.96	-8.425	3.066	3.688
0.00022339	289.36	614.14	-8.407	5.668	6.420
0.00029047	1,447.68	3,332.47	-8.144	7.278	8.111
0.00031247	914.91	2,057.90	-8.071	6.819	7.629
0.00044767	425.98	921.92	-7.711	6.054	6.826
0.00045162	451.40	979.81	-7.703	6.112	6.887
0.00045829	914.48	2,056.87	-7.688	6.818	7.629
0.00058280	214.08	447.53	-7.448	5.366	6.104
0.00061930	398.97	860.61	-7.387	5.989	6.758
0.00062396	912.27	2,051.66	-7.379	6.816	7.626
0.00062744	677.13	1,500.12	-7.374	6.518	7.313
0.00084939	106.60	215.14	-7.071	4.669	5.371
0.00085546	582.26	1,280.16	-7.064	6.367	7.155
0.00087692	1,959.67	4,580.42	-7.039	7.581	8.430
0.00089035	921.20	2,072.75	-7.024	6.826	7.637
0.00117035	4,529.79	11,044.58	-6.750	8.418	9.310
0.00170106	198.70	413.81	-6.377	5.292	6.025
0.00173544	726.19	1,614.50	-6.356	6.588	7.387
0.00177404	3,302.89	7,925.90	-6.334	8.103	8.978
0.00179269	2,290.01	5,394.75	-6.324	7.736	8.593
0.00179403	999.45	2,258.09	-6.323	6.907	7.722
0.00231632	4,214.88	10,239.49	-6.068	8.346	9.234
0.00242557	2,860.43	6,814.53	-6.022	7.959	8.827
0.00342813	3,385.21	8,133.54	-5.676	8.127	9.004
0.00342813	3,385.21	8,133.54	-5.676	8.127	9.004
0.00467383	3,933.75	9,523.33	-5.366	8.277	9.161
0.00468673	3,933.74	9,523.31	-5.363	8.277	9.161
0.00468673	3,933.74	9,523.31	-5.363	8.277	9.161
0.00670911	496.56	1,083.02	-5.004	6.208	6.988
0.00956087	1,981.92	4,635.07	-4.650	7.592	8.441
0.00988148	4,890.96	11,971.40	-4.617	8.495	9.390
0.01433650	4,984.13	12,211.05	-4.245	8.514	9.410

N = 38

Table C-1-3. 1980 Refinery Data (Con't.)

----------------------- Equipment Type=DRAIN SERVICE=ALL -----------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00000165	124.56	253.38	-13.318	4.825	5.535
0.00001587	124.20	252.60	-11.051	4.822	5.532
0.00002657	125.41	255.18	-10.536	4.832	5.542
0.00006707	306.36	652.11	-9.610	5.725	6.480
0.00016828	1,084.56	2,460.50	-8.690	6.989	7.808
0.00025242	110.79	224.04	-8.284	4.708	5.412
0.00066593	4.88	8.44	-7.314	1.586	2.133
0.00067665	247.44	521.05	-7.298	5.511	6.256
0.00109637	255.86	539.70	-6.816	5.545	6.291
0.00111300	1,093.11	2,480.86	-6.801	6.997	7.816
0.00163974	9,675.85	24,512.03	-6.413	9.177	10.107
0.00164782	84.27	168.08	-6.408	4.434	5.124
0.00168344	249.76	526.17	-6.387	5.520	6.266
0.00168969	249.75	526.16	-6.383	5.520	6.266
0.00169157	1,095.50	2,486.57	-6.382	6.999	7.819
0.00169595	249.75	526.16	-6.380	5.520	6.266
0.00170673	337.53	721.97	-6.373	5.822	6.582
0.00263438	344.99	738.73	-5.939	5.844	6.605
0.00271318	126.27	257.03	-5.910	4.838	5.549
0.00282061	85.42	170.48	-5.871	4.448	5.139
0.00286144	205.12	427.86	-5.856	5.324	6.059
0.00414221	3,256.12	7,808.06	-5.487	8.088	8.963
0.00414368	1,082.80	2,456.31	-5.486	6.987	7.806
0.00420110	345.22	739.25	-5.472	5.844	6.606
0.00428421	255.41	538.69	-5.453	5.543	6.289
0.00433189	204.22	425.90	-5.442	5.319	6.054
0.00690873	1,213.08	2,767.64	-4.975	7.101	7.926
0.00691392	209.53	437.53	-4.974	5.345	6.081
0.00696835	413.59	893.79	-4.966	6.025	6.795
0.00716594	252.19	531.56	-4.938	5.530	6.276
0.00716625	252.52	532.30	-4.938	5.531	6.277
0.00719254	252.19	531.55	-4.935	5.530	6.276
0.00722439	2,659.82	6,313.44	-4.930	7.886	8.750
0.01088314	672.51	1,489.38	-4.521	6.511	7.306
0.01097489	254.74	537.20	-4.512	5.540	6.286
0.01097489	254.74	537.20	-4.512	5.540	6.286
0.01117409	610.07	1,344.46	-4.494	6.414	7.204
0.01119616	414.95	896.86	-4.492	6.028	6.799
0.01147153	2,922.21	6,969.21	-4.468	7.980	8.849
0.01147253	2,929.91	6,988.51	-4.468	7.983	8.852
0.01673968	254.28	536.20	-4.090	5.538	6.285
0.01673968	254.28	536.20	-4.090	5.538	6.285
0.01748345	600.96	1,323.40	-4.047	6.399	7.188
0.01761340	600.95	1,323.36	-4.039	6.399	7.188
0.01778718	414.14	895.03	-4.029	6.026	6.797

Table C-1-3. 1980 Refinery Data (Con’t.)

----------------------- Equipment Type=DRAIN SERVICE=ALL -----------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.01794441	9,705.86	24,591.90	-4.020	9.180	10.110
0.02777731	9,675.31	24,510.60	-3.584	9.177	10.107
0.02864463	2,945.66	7,027.99	-3.553	7.988	8.858
0.04440422	2,195.64	5,161.48	-3.114	7.694	8.549
0.04565131	1,658.94	3,845.08	-3.087	7.414	8.255
0.11170747	2,216.10	5,212.02	-2.192	7.704	8.559
0.11520974	9,757.82	24,730.22	-2.161	9.186	10.116
0.28962977	9,643.68	24,426.45	-1.239	9.174	10.103
0.28962977	9,643.68	24,426.45	-1.239	9.174	10.103
0.28965511	9,669.08	24,494.01	-1.239	9.177	10.106
0.43111208	2,966.41	7,079.99	-0.841	7.995	8.865
0.43111208	2,966.41	7,079.99	-0.841	7.995	8.865
1.12802623	9,741.28	24,686.17	0.120	9.184	10.114
1.14068097	9,753.65	24,719.09	0.132	9.185	10.115
1.77893548	9,735.45	24,670.65	0.576	9.184	10.113
1.78553430	9,735.29	24,670.24	0.580	9.184	10.113

N = 61

Table C-1-3. 1980 Refinery Data (Con't.)

------------------------ Equipment Type=PUMP SERVICE=HL ------------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00002962	8.11	14.37	-10.427	2.093	2.665
0.00003944	90.04	180.18	-10.141	4.500	5.194
0.00015933	330.36	705.88	-8.745	5.800	6.559
0.00030611	115.55	234.17	-8.092	4.750	5.456
0.00043153	181.88	377.09	-7.748	5.203	5.932
0.00043691	711.47	1,580.13	-7.736	6.567	7.365
0.00044418	712.29	1,582.04	-7.719	6.568	7.366
0.00044597	198.46	413.29	-7.715	5.291	6.024
0.00089174	257.29	542.85	-7.022	5.550	6.297
0.00121225	713.23	1,584.25	-6.715	6.570	7.368
0.00121225	713.23	1,584.25	-6.715	6.570	7.368
0.00121559	714.87	1,588.07	-6.713	6.572	7.370
0.00121579	607.33	1,338.12	-6.712	6.409	7.199
0.00125953	913.98	2,055.71	-6.677	6.818	7.628
0.00168810	3,960.24	9,590.69	-6.384	8.284	9.169
0.00178173	710.83	1,578.63	-6.330	6.566	7.364
0.00180113	846.36	1,896.25	-6.319	6.741	7.548
0.00183552	1,188.93	2,709.80	-6.300	7.081	7.905
0.00242435	789.16	1,761.85	-6.022	6.671	7.474
0.00244487	661.26	1,463.22	-6.014	6.494	7.288
0.00245776	844.47	1,891.79	-6.009	6.739	7.545
0.00250471	1,176.77	2,680.70	-5.990	7.071	7.894
0.00251852	1,179.48	2,687.17	-5.984	7.073	7.896
0.00345651	916.25	2,061.05	-5.667	6.820	7.631
0.00479664	10,438.79	26,546.18	-5.340	9.253	10.187
0.00481697	2,376.33	5,608.57	-5.336	7.773	8.632
0.00483651	648.56	1,433.70	-5.332	6.475	7.268
0.00697471	504.98	1,102.31	-4.965	6.225	7.005
0.00962437	425.60	921.06	-4.643	6.053	6.826
0.00978532	392.28	845.47	-4.627	5.972	6.740
0.00986119	10,464.10	26,613.82	-4.619	9.256	10.189
0.00986121	10,440.11	26,549.72	-4.619	9.253	10.187
0.00995942	1,982.33	4,636.09	-4.609	7.592	8.442
0.00996275	1,422.56	3,271.75	-4.609	7.260	8.093
0.01438591	4,733.39	11,566.60	-4.242	8.462	9.356
0.01931711	3,127.43	7,484.21	-3.947	8.048	8.921
0.01950717	10,513.52	26,745.84	-3.937	9.260	10.194
0.01966882	10,513.54	26,745.91	-3.929	9.260	10.194
0.01970286	1,861.25	4,339.10	-3.927	7.529	8.375
0.02633481	506.84	1,106.58	-3.637	6.228	7.009
0.02731456	3,677.22	8,872.08	-3.600	8.210	9.091
0.02754090	3,681.46	8,882.81	-3.592	8.211	9.092
0.02775928	5,249.27	12,894.31	-3.584	8.566	9.465
0.02815822	199.52	415.60	-3.570	5.296	6.030
0.02818559	1,184.04	2,698.10	-3.569	7.077	7.900

Table C-1-3. 1980 Refinery Data (Con't.)

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.02842387	1,003.61	2,267.96	-3.561	6.911	7.727
0.02850212	1,003.61	2,267.96	-3.558	6.911	7.727
0.02850212	1,004.76	2,270.70	-3.558	6.913	7.728
0.02859211	10,538.38	26,812.30	-3.555	9.263	10.197
0.02859211	10,538.38	26,812.30	-3.555	9.263	10.197
0.03691188	1,018.75	2,303.91	-3.299	6.926	7.742
0.03917114	3,092.10	7,395.43	-3.240	8.037	8.909
0.03955608	10,526.89	26,781.58	-3.230	9.262	10.195
0.05258516	2,621.03	6,216.74	-2.945	7.871	8.735
0.05616945	2,837.15	6,756.30	-2.879	7.951	8.818
0.07550022	10,588.68	26,946.74	-2.584	9.268	10.202
0.11098012	9,451.61	23,915.68	-2.198	9.154	10.082
0.11374890	10,589.44	26,948.76	-2.174	9.268	10.202
0.15479117	10,565.72	26,885.35	-1.866	9.265	10.199
0.30036837	10,506.45	26,726.96	-1.203	9.260	10.193
0.30369119	10,518.53	26,759.24	-1.192	9.261	10.195

N = 61

Table C-1-3. 1980 Refinery Data (Con’t.)

------------------- Equipment Type=P_CS_PRV SERVICE=LL_G_TPS -------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00004237	3,392.48	8,151.87	-10.069	8.129	9.006
0.00006298	136.58	279.12	-9.673	4.917	5.632
0.00006364	1,886.21	4,400.25	-9.662	7.542	8.389
0.00006397	1,534.24	3,542.06	-9.657	7.336	8.172
0.00010622	170.88	353.17	-9.150	5.141	5.867
0.00016673	3,408.70	8,192.83	-8.699	8.134	9.011
0.00017201	594.94	1,309.46	-8.668	6.388	7.177
0.00041408	374.65	805.59	-7.789	5.926	6.692
0.00041408	374.65	805.59	-7.789	5.926	6.692
0.00042163	1,089.97	2,473.39	-7.771	6.994	7.813
0.00043552	35.08	66.94	-7.739	3.558	4.204
0.00068080	268.97	568.78	-7.292	5.595	6.343
0.00068243	193.58	402.61	-7.290	5.266	5.998
0.00104082	3,463.88	8,332.20	-6.868	8.150	9.028
0.00105002	1,716.27	3,984.79	-6.859	7.448	8.290
0.00105273	1,205.32	2,749.04	-6.856	7.094	7.919
0.00105947	3,814.46	9,220.20	-6.850	8.247	9.129
0.00106711	24.55	46.02	-6.843	3.201	3.829
0.00107106	24.55	46.02	-6.839	3.201	3.829
0.00108841	431.13	933.64	-6.823	6.066	6.839
0.00108885	245.52	516.81	-6.823	5.503	6.248
0.00167903	970.51	2,189.47	-6.390	6.878	7.691
0.00170760	1,207.89	2,755.21	-6.373	7.097	7.921
0.00173961	431.38	934.21	-6.354	6.067	6.840
0.00254547	685.07	1,518.60	-5.973	6.530	7.326
0.00259400	4,915.33	12,034.08	-5.955	8.500	9.395
0.00259443	1,742.04	4,047.66	-5.954	7.463	8.306
0.00263011	15,437.18	40,039.38	-5.941	9.645	10.598
0.00264161	3,073.11	7,347.73	-5.936	8.030	8.902
0.00268912	1,216.00	2,774.64	-5.919	7.103	7.928
0.00271908	1,216.01	2,774.68	-5.907	7.103	7.928
0.00272186	383.07	824.63	-5.906	5.948	6.715
0.00399588	13,479.04	34,722.28	-5.522	9.509	10.455
0.00405129	1,224.09	2,794.03	-5.509	7.110	7.935
0.00406909	3,070.07	7,340.09	-5.504	8.029	8.901
0.00416407	34,171.65	92,254.02	-5.481	10.439	11.432
0.00423609	1,952.06	4,561.75	-5.464	7.577	8.425
0.00423609	1,952.06	4,561.75	-5.464	7.577	8.425
0.00641761	549.40	1,204.39	-5.049	6.309	7.094
0.00646354	11,933.39	30,552.46	-5.042	9.387	10.327
0.00655481	1,738.73	4,039.58	-5.028	7.461	8.304
0.00656223	2,472.04	5,846.08	-5.026	7.813	8.674
0.00656741	6,115.18	15,137.41	-5.026	8.719	9.625
0.00658649	6,816.89	16,967.08	-5.023	8.827	9.739
0.00665525	34,348.91	92,756.76	-5.012	10.444	11.438

Table C-1-3. 1980 Refinery Data (Con’t.)

------------------- Equipment Type=P_CS_PRV SERVICE=LL_G_TPS -------------------
(continued)

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00672364	3,057.93	7,309.60	-5.002	8.025	8.897
0.00673458	18,598.42	48,693.93	-5.001	9.831	10.793
0.00679853	3,057.97	7,309.71	-4.991	8.026	8.897
0.00684900	3,053.32	7,298.03	-4.984	8.024	8.895
0.00690833	1,550.34	3,581.13	-4.975	7.346	8.183
0.01031255	158.23	325.77	-4.574	5.064	5.786
0.01036867	11,977.05	30,669.89	-4.569	9.391	10.331
0.01058991	3,017.82	7,208.93	-4.548	8.012	8.883
0.01085059	17,055.40	44,459.47	-4.524	9.744	10.702
0.01088011	1,544.12	3,566.03	-4.521	7.342	8.179
0.01088011	1,544.12	3,566.03	-4.521	7.342	8.179
0.01580135	18,934.25	49,617.93	-4.148	9.849	10.812
0.01593600	776.04	1,731.11	-4.139	6.654	7.457
0.01650647	34,388.01	92,867.66	-4.104	10.445	11.439
0.01656751	34,388.09	92,867.88	-4.100	10.445	11.439
0.01689730	3,810.16	9,209.28	-4.081	8.245	9.128
0.01692011	24,077.03	63,863.87	-4.079	10.089	11.065
0.01719892	1,535.57	3,545.31	-4.063	7.337	8.173
0.01719892	1,535.57	3,545.31	-4.063	7.337	8.173
0.02585373	3,477.82	8,367.42	-3.655	8.154	9.032
0.02593482	17,205.09	44,869.44	-3.652	9.753	10.712
0.02608028	60,696.69	168,680.19	-3.647	11.014	12.036
0.02608058	60,603.82	168,409.10	-3.647	11.012	12.034
0.02627388	60,604.52	168,411.13	-3.639	11.012	12.034
0.02639205	1,560.08	3,604.77	-3.635	7.352	8.190
0.02646313	4,937.17	12,090.24	-3.632	8.505	9.400
0.02686162	1,747.13	4,060.09	-3.617	7.466	8.309
0.02686725	21,446.53	56,555.63	-3.617	9.973	10.943
0.02690520	305.39	649.94	-3.615	5.722	6.477
0.02699393	2,453.79	5,800.75	-3.612	7.805	8.666
0.02749516	6,829.08	16,998.96	-3.594	8.829	9.741
0.02757885	34,200.07	92,334.61	-3.591	10.440	11.433
0.02757885	34,200.07	92,334.61	-3.591	10.440	11.433
0.02768154	34,095.81	92,038.95	-3.587	10.437	11.430
0.02778396	34,095.89	92,039.17	-3.583	10.437	11.430
0.02780143	6,829.17	16,999.20	-3.583	8.829	9.741
0.02813742	6,005.66	14,852.78	-3.571	8.700	9.606
0.02824146	6,005.69	14,852.85	-3.567	8.700	9.606
0.03877057	30,226.79	81,100.81	-3.250	10.316	11.303
0.03927627	8,464.05	21,297.97	-3.237	9.044	9.966
0.03996025	6,008.29	14,859.61	-3.220	8.701	9.606
0.03999937	690.59	1,531.47	-3.219	6.538	7.334
0.04005716	54,394.88	150,333.83	-3.217	10.904	11.921
0.04060862	38,084.57	103,381.36	-3.204	10.548	11.546

Table C-1-3. 1980 Refinery Data (Con’t.)

------------------- Equipment Type=P_CS_PRV SERVICE=LL_G_TPS -------------------
(continued)

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.04060908	38,026.29	103,215.21	-3.204	10.546	11.545
0.04187031	11,943.02	30,578.34	-3.173	9.388	10.328
0.04256917	9,349.99	23,645.64	-3.157	9.143	10.071
0.04256917	9,349.99	23,645.64	-3.157	9.143	10.071
0.04283001	2,432.76	5,748.56	-3.151	7.797	8.657
0.04283051	2,429.05	5,739.33	-3.151	7.795	8.655
0.06487572	24,414.57	64,804.64	-2.735	10.103	11.079
0.06532933	42,937.13	117,260.65	-2.728	10.667	11.672
0.06538471	38,223.99	103,778.94	-2.727	10.551	11.550
0.06581353	42,937.52	117,261.79	-2.721	10.668	11.672
0.06772129	3,881.55	9,390.62	-2.692	8.264	9.147
0.06798752	494.31	1,077.85	-2.688	6.203	6.983
0.06842301	4,313.78	10,492.02	-2.682	8.370	9.258
0.06849158	494.31	1,077.86	-2.681	6.203	6.983
0.06997327	2,509.90	5,940.16	-2.660	7.828	8.689
0.06997569	2,498.40	5,911.58	-2.660	7.823	8.685
0.09915559	42,959.58	117,325.05	-2.311	10.668	11.673
0.10025896	43,025.90	117,515.33	-2.300	10.670	11.674
0.10120459	4,296.13	10,446.92	-2.291	8.365	9.254
0.10206861	77,307.92	217,480.42	-2.282	11.256	12.290
0.10232039	1,581.97	3,657.91	-2.280	7.366	8.205
0.10262666	60,707.73	168,712.42	-2.277	11.014	12.036
0.10331044	1,930.11	4,507.88	-2.270	7.565	8.414
0.10338849	60,615.54	168,443.32	-2.269	11.012	12.034
0.10383965	12,085.32	30,961.16	-2.265	9.400	10.340
0.10462156	54,460.17	150,523.39	-2.257	10.905	11.922
0.10462397	54,293.77	150,040.32	-2.257	10.902	11.919
0.10699986	6,851.16	17,056.70	-2.235	8.832	9.744
0.10931033	7,637.50	19,118.82	-2.214	8.941	9.858
0.15847552	43,182.52	117,964.71	-1.842	10.673	11.678
0.15898465	76,643.97	215,518.87	-1.839	11.247	12.281
0.16951073	3,042.23	7,270.20	-1.775	8.020	8.892
0.25840755	7,645.71	19,140.43	-1.353	8.942	9.860
0.26302874	3,067.28	7,333.09	-1.335	8.029	8.900
0.26527004	12,081.00	30,949.56	-1.327	9.399	10.340
0.42981364	3,073.86	7,349.62	-0.844	8.031	8.902
1.10801132	30,774.57	82,645.36	0.103	10.334	11.322
1.10801132	30,774.57	82,645.36	0.103	10.334	11.322
1.12449932	30,775.07	82,646.76	0.117	10.334	11.322

N = 128

Table C-1-3. 1980 Refinery Data (Con't.)

------------------------ Equipment Type=VALVE SERVICE=G ------------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00001331	88.91	177.82	-11.227	4.488	5.181
0.00004011	6,639.19	16,502.81	-10.124	8.801	9.711
0.00005873	1,100.81	2,499.23	-9.743	7.004	7.824
0.00008684	28,723.41	76,869.15	-9.351	10.265	11.250
0.00008847	273.72	579.32	-9.333	5.612	6.362
0.00008852	82.39	164.13	-9.332	4.411	5.101
0.00012745	2,159.55	5,072.40	-8.968	7.678	8.532
0.00026556	4,000.01	9,691.89	-8.234	8.294	9.179
0.00037361	4,327.05	10,525.93	-7.892	8.373	9.262
0.00053159	2,786.15	6,628.77	-7.540	7.932	8.799
0.00056183	9,364.08	23,683.07	-7.484	9.145	10.073
0.00056516	9,364.16	23,683.30	-7.478	9.145	10.073
0.00077033	9,401.02	23,781.23	-7.169	9.149	10.077
0.00079547	3,094.87	7,402.39	-7.137	8.038	8.910
0.00111849	2,001.89	4,684.16	-6.796	7.602	8.452
0.00163767	10,341.06	26,285.19	-6.414	9.244	10.177
0.00164080	8,596.21	21,647.44	-6.413	9.059	9.983
0.00164247	10,364.87	26,348.78	-6.412	9.246	10.179
0.00230073	40,320.51	109,766.16	-6.075	10.605	11.606
0.00230829	3,972.31	9,621.40	-6.071	8.287	9.172
0.00329738	17,115.36	44,623.65	-5.715	9.748	10.706
0.00335895	87,956.92	249,053.14	-5.696	11.385	12.425
0.00339793	67,782.41	189,423.49	-5.685	11.124	12.152
0.00479241	4,409.66	10,737.12	-5.341	8.392	9.281
0.00525603	22,456.91	59,357.68	-5.248	10.019	10.991
0.00740749	48,426.60	133,057.03	-4.905	10.788	11.799
0.01034094	62,802.08	174,831.53	-4.572	11.048	12.072
0.01097916	57,627.00	159,730.80	-4.512	10.962	11.981
0.01099118	29,275.75	78,422.59	-4.511	10.285	11.270
0.01504923	44,686.05	122,282.85	-4.196	10.707	11.714
0.01514346	57,523.86	159,430.51	-4.190	10.960	11.979
0.01518837	57,458.07	159,238.97	-4.187	10.959	11.978
0.03115510	15,704.60	40,768.29	-3.469	9.662	10.616
0.04884917	10,348.47	26,304.97	-3.019	9.245	10.178
0.09161977	17,363.25	45,302.80	-2.390	9.762	10.721
0.09853946	44,817.44	122,660.53	-2.317	10.710	11.717
0.13483362	41,140.73	112,112.87	-2.004	10.625	11.627
0.13594593	10,484.70	26,668.84	-1.995	9.258	10.191

N = 38

Table C-1-3. 1980 Refinery Data (Con't.)

--------------------- Equipment Type=VALVE SERVICE=LL_TPS ----------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00000225	4.59	7.91	-13.007	1.525	2.068
0.00001410	44.59	86.11	-11.170	3.797	4.456
0.00005956	62.56	122.91	-9.729	4.136	4.811
0.00008638	156.77	322.62	-9.357	5.055	5.776
0.00012792	21.47	39.97	-8.964	3.067	3.688
0.00012930	209.02	436.41	-8.953	5.342	6.079
0.00013197	305.66	650.53	-8.933	5.722	6.478
0.00018238	620.52	1,368.68	-8.609	6.431	7.222
0.00018238	620.52	1,368.68	-8.609	6.431	7.222
0.00018799	22.13	41.25	-8.579	3.097	3.720
0.00019149	84.34	168.23	-8.561	4.435	5.125
0.00026364	64.62	127.17	-8.241	4.169	4.846
0.00027025	976.13	2,202.77	-8.216	6.884	7.697
0.00027125	5,330.54	13,104.08	-8.212	8.581	9.481
0.00039603	484.14	1,054.57	-7.834	6.182	6.961
0.00056453	1,162.25	2,645.96	-7.480	7.058	7.881
0.00060409	9,829.56	24,921.22	-7.412	9.193	10.123
0.00075854	8,440.85	21,236.66	-7.184	9.041	9.963
0.00082319	10.05	18.01	-7.102	2.308	2.891
0.00083585	984.52	2,222.66	-7.087	6.892	7.706
0.00085249	3,206.69	7,683.59	-7.067	8.073	8.947
0.00113007	1,153.61	2,625.30	-6.785	7.051	7.873
0.00118193	10.03	17.96	-6.741	2.305	2.888
0.00120220	3,324.54	7,980.47	-6.724	8.109	8.985
0.00123419	9,979.00	25,319.36	-6.697	9.208	10.139
0.00163290	4,540.59	11,072.23	-6.417	8.421	9.312
0.00168838	1,363.36	3,128.89	-6.384	7.218	8.048
0.00170950	1,796.41	4,180.46	-6.372	7.494	8.338
0.00179606	3,953.18	9,572.75	-6.322	8.282	9.167
0.00241099	5,398.93	13,280.75	-6.028	8.594	9.494
0.00241192	860.44	1,929.39	-6.027	6.757	7.565
0.00243467	3,361.20	8,072.96	-6.018	8.120	8.996
0.00247077	3,354.55	8,056.16	-6.003	8.118	8.994
0.00247366	8,515.22	21,433.26	-6.002	9.050	9.973
0.00248176	3,998.89	9,689.06	-5.999	8.294	9.179
0.00249558	8,515.54	21,434.09	-5.993	9.050	9.973
0.00255458	1,013.43	2,291.28	-5.970	6.921	7.737
0.00341580	39,058.18	106,159.28	-5.679	10.573	11.573
0.00348074	33,787.34	91,164.47	-5.661	10.428	11.420
0.00349794	54,274.02	149,982.99	-5.656	10.902	11.918
0.00353072	8,527.25	21,465.06	-5.646	9.051	9.974
0.00353574	30,014.01	80,501.23	-5.645	10.309	11.296
0.00355244	1,381.43	3,172.46	-5.640	7.231	8.062
0.00357339	1,381.46	3,172.54	-5.634	7.231	8.062
0.00357551	15,739.47	40,863.36	-5.634	9.664	10.618

Table C-1-3. 1980 Refinery Data (Con't.)

--------------------- Equipment Type=VALVE SERVICE=LL_TPS ----------------------
(continued)

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00485006	8,625.65	21,725.33	-5.329	9.062	9.986
0.00491615	3,398.24	8,166.42	-5.315	8.131	9.008
0.00491615	3,398.24	8,166.42	-5.315	8.131	9.008
0.00493071	3,391.35	8,149.01	-5.312	8.129	9.006
0.00495259	1,383.25	3,176.85	-5.308	7.232	8.064
0.00516794	9,994.91	25,361.77	-5.265	9.210	10.141
0.00729950	8,551.85	21,530.11	-4.920	9.054	9.977
0.00736431	8,534.69	21,484.75	-4.911	9.052	9.975
0.00739766	1,176.57	2,680.21	-4.907	7.070	7.894
0.00755167	86,029.82	243,324.55	-4.886	11.362	12.402
0.00758374	2,932.48	6,994.95	-4.882	7.984	8.853
0.00758440	24,845.17	66,005.77	-4.882	10.120	11.097
0.00759940	13,655.17	35,199.01	-4.880	9.522	10.469
0.00772423	5,502.03	13,547.27	-4.863	8.613	9.514
0.01046618	86,317.33	244,178.82	-4.560	11.366	12.406
0.01047971	73,754.07	206,991.10	-4.558	11.208	12.240
0.01060438	8,547.05	21,517.41	-4.546	9.053	9.977
0.01066692	8,547.24	21,517.93	-4.541	9.053	9.977
0.01079315	8,547.64	21,518.97	-4.529	9.053	9.977
0.01127245	6,475.35	16,075.28	-4.485	8.776	9.685
0.01166120	5,355.65	13,168.93	-4.451	8.586	9.486
0.01474084	8,540.75	21,500.76	-4.217	9.053	9.976
0.01570609	29,161.44	78,100.99	-4.154	10.281	11.266
0.01605400	24,817.50	65,928.55	-4.132	10.119	11.096
0.02334577	7,507.70	18,777.67	-3.757	8.924	9.840
0.02368390	5,459.20	13,436.52	-3.743	8.605	9.506
0.02368390	5,459.20	13,436.52	-3.743	8.605	9.506
0.03207526	21,746.78	57,387.63	-3.440	9.987	10.958
0.04684899	47,238.27	129,629.48	-3.061	10.763	11.772
0.06870371	62,845.47	174,958.43	-2.678	11.048	12.072
0.10218383	62,944.53	175,248.12	-2.281	11.050	12.074
0.13512360	62,501.44	173,952.50	-2.002	11.043	12.067

N = 77

Table C-1-3. 1980 Refinery Data (Con't.)

---------------------- Equipment Type=V_CS SERVICE=HYDRO -----------------------

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.00000026	499.50	1,089.76	-15.164	6.214	6.994
0.00001464	33,440.21	90,180.89	-11.132	10.418	11.410
0.00002100	354.70	760.60	-10.771	5.871	6.634
0.00002104	1,197.44	2,730.17	-10.769	7.088	7.912
0.00002118	1,974.09	4,615.83	-10.762	7.588	8.437
0.00002933	33,494.85	90,335.66	-10.437	10.419	11.411
0.00003021	7,191.76	17,948.51	-10.407	8.881	9.795
0.00004536	253.47	534.39	-10.001	5.535	6.281
0.00012180	28,416.27	76,005.97	-9.013	10.255	11.239
0.00012180	28,416.27	76,005.97	-9.013	10.255	11.239
0.00012252	28,416.66	76,007.07	-9.007	10.255	11.239
0.00018123	95,583.08	271,783.91	-8.616	11.468	12.513
0.00025613	95,116.75	270,391.26	-8.270	11.463	12.508
0.00026043	4,052.53	9,825.60	-8.253	8.307	9.193
0.00041109	141.22	289.09	-7.797	4.950	5.667
0.00054874	95,287.08	270,899.89	-7.508	11.465	12.510
0.00056055	3,638.51	8,773.98	-7.487	8.199	9.080
0.00110337	28,727.31	76,880.12	-6.809	10.266	11.250
0.00110661	28,727.51	76,880.68	-6.806	10.266	11.250
0.00111311	28,727.91	76,881.80	-6.801	10.266	11.250
0.00118994	1,204.72	2,747.61	-6.734	7.094	7.918
0.00170959	10,318.68	26,225.43	-6.371	9.242	10.174
0.00235967	8,602.88	21,665.09	-6.049	9.060	9.983
0.00509039	94,269.02	267,860.46	-5.280	11.454	12.498
0.00706640	95,751.81	272,287.91	-4.952	11.470	12.515
0.00710793	95,753.13	272,291.86	-4.947	11.470	12.515
0.00712880	95,753.80	272,293.84	-4.944	11.470	12.515
0.01037369	95,729.11	272,220.09	-4.568	11.469	12.514
0.01040414	95,729.77	272,222.06	-4.566	11.469	12.514
0.01046548	95,621.82	271,899.63	-4.560	11.468	12.513
0.01049601	95,731.75	272,227.99	-4.557	11.469	12.514
0.01559018	95,711.47	272,167.42	-4.161	11.469	12.514
0.02089894	95,777.39	272,364.32	-3.868	11.470	12.515
0.02102181	95,778.71	272,368.27	-3.862	11.470	12.515
0.02114537	95,780.04	272,372.22	-3.856	11.470	12.515
0.02120783	95,671.37	272,047.64	-3.853	11.469	12.514
0.02133247	95,672.91	272,052.24	-3.848	11.469	12.514
0.03262723	95,877.79	272,664.22	-3.423	11.471	12.516
0.03337807	10,367.31	26,355.28	-3.400	9.246	10.179
0.04530855	95,188.17	270,604.54	-3.094	11.464	12.508
0.04570873	95,190.15	270,610.43	-3.085	11.464	12.508
0.04584365	95,082.37	270,288.60	-3.083	11.462	12.507
0.06482435	29,370.14	78,688.21	-2.736	10.288	11.273
0.06483958	74,453.14	209,052.45	-2.736	11.218	12.250
0.06535400	95,270.18	270,849.44	-2.728	11.464	12.509

Table C-1-3. 1980 Refinery Data (Con't.)

---------------------- Equipment Type=V_CS SERVICE=HYDRO -----------------------
(continued)

Measured Emission Rate(kg/hr)	Original TLV Screening Value (ppmv)	OVA Adjusted Screening Value (ppmv)	Natural Log of Emission Rate (kg/hr)	Natural Log of TLV Screening Value (ppmv	Natural Log of OVA Screening Value (ppmv
0.06612569	95,164.29	270,533.21	-2.716	11.463	12.508
0.06612569	95,164.29	270,533.21	-2.716	11.463	12.508

N = 47

Table C-1-4. REGRESSION STATISTICS FOR THE 1980 AND 1993 REFINERY DATA

Equipment		**Facility Type**[a]	**Sample Size**	**Intercept (b_0)**	**Slope (b_1)**	**Root Mean Square Error (RMSE)**	**Coefficient of Simple Determination (R^2)**	**Scale Bias Correction Factor (SBCF)**	**Mean ln Screening Value**	**Sum of Squared Deviations from the Mean ln Screening Value**
Type	**Service**									
Connector	All	REF80	38	-12.07497	0.759	1.011	0.5333	1.6334	6.69239	72.8674
		REF93	28	-17.45599	1.007	1.851	0.7233	4.7774	7.04812	229.6503
Pump	Light Liquid[b]	REF80	128	-10.02998	0.676	1.726	0.3371	4.3133	8.36906	417.3760
		REF93	30	-10.07607	0.419	1.579	0.3281	3.1882	6.71261	194.3916
Valve	Gas	REF80	38	-14.93176	0.960	1.751	0.4788	4.2109	9.15822	109.8584
		REF93	50	-13.94624	0.675	1.245	0.5725	2.1124	6.22836	218.6160
Valve	Light Liquid[c]	REF80	77	-11.46481	0.678	1.230	0.6145	2.0935	7.98760	393.2046
		REF93	82	-14.17854	0.783	1.453	0.6340	2.7995	6.56265	476.8908

[a] Facility types are: REF80=1980 refinery data and REF93=1993 refinery data

[b] For light liquid pumps, the 1980 refinery data include two-phase stream pumps, gas compressors, gas pressure relief valves, and light liquid pumps.

[c] For light liquid valves, the 1980 refinery data include two-phase stream valves and light liquid valves.

APPENDIX C: ATTACHMENT 2

This attachment lists the bagging data used to develop the pegged emission rates for the combined 1993 petroleum industry data in table C-2-1. Table C-2-2 lists summary statistics for the 10,000 ppmv pegged emission rates and Table C-2-3 lists summary statistics for the 100,000 ppmv pegged emission rates.

TABLE C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
--------- Equipment Type=COMPRESSOR SERVICE=G ----------				
ONOFF	100000	100000	0.02448289939	-3.710
ONOFF	100000	100000	0.03493150685	-3.354
		N = 2		
---------- Equipment Type=COMPRESSOR SERVICE=LL -----------				
ONOFF	100000	100000	0.00101197496	-6.896
		N = 1		
----------- Equipment Type=CONNECTOR SERVICE=G -----------				
ONOFF	5000	10000	0.00001270072	-11.274
ONOFF	70000	70000	0.00009344099	-9.278
ONOFF	10000	10000	0.00015104781	-8.798
REF	100000	100000	0.00019804046	-8.527
ONOFF	100000	100000	0.00031933231	-8.049
MT	100000	100000	0.00035811031	-7.935
ONOFF	100000	100000	0.00045858659	-7.687
ONOFF	100000	100000	0.00081556745	-7.112
REF	11000	11000	0.00094198494	-6.968
REF	91000	91000	0.00125365146	-6.682
REF	100000	100000	0.00199886601	-6.215
REF	48000	40000	0.00220312075	-6.118
MT	100000	100000	0.00277519731	-5.887
ONOFF	10000	10000	0.00287262996	-5.853
ONOFF	10000	10000	0.00291935045	-5.836
ONOFF	100000	45000	0.00297922526	-5.816
ONOFF	100000	100000	0.00371632042	-5.595
ONOFF	10000	100000	0.00515513018	-5.268
ONOFF	10000	10000	0.00559920167	-5.185
ONOFF	100000	100000	0.00675269890	-4.998
ONOFF	100000	100000	0.00760364692	-4.879
ONOFF	100000	100000	0.00877029847	-4.736
ONOFF	100000	100000	0.01064229339	-4.543
ONOFF	100000	100000	0.01651047809	-4.104
REF	100000	100000	0.02005624603	-3.909
ONOFF	10000	10000	0.03374716502	-3.389
REF	100000	100000	0.03482899392	-3.357
REF	12500	29000	0.03548852400	-3.339
REF	55000	55000	0.05391454232	-2.920

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	100000	0.06664383562	-2.708
ONOFF	100000	100000	0.10322462125	-2.271
N = 31				
----------- Equipment Type=CONNECTOR SERVICE=HL -----------				
REF	76650	21900	0.01362968339	-4.296
REF	1700	1200	0.03207475279	-3.440
N = 2				
----------- Equipment Type=CONNECTOR SERVICE=LL -----------				
ONOFF	100000	100000	0.00000408237	-12.409
ONOFF	10000	5000	0.00001859748	-10.892
REF	21060	17550	0.00001880613	-10.881
ONOFF	10000	10000	0.00002494784	-10.599
REF	16500	27500	0.00006329946	-9.668
ONOFF	10000	10000	0.00006441078	-9.650
ONOFF	100000	100000	0.00010977048	-9.117
ONOFF	10000	10000	0.00027215821	-8.209
ONOFF	100000	100000	0.00038328949	-7.867
ONOFF	100000	100000	0.00040143337	-7.820
REF	48000	100000	0.00062002177	-7.386
ONOFF	10000	10000	0.00063594303	-7.360
REF	90000	90000	0.00082713417	-7.098
ONOFF	100000	100000	0.00088768938	-7.027
ONOFF	10000	10000	0.00092760591	-6.983
REF	72000	80000	0.00117463485	-6.747
REF	117000	117000	0.00119817654	-6.727
ONOFF	4000	10000	0.00153451873	-6.480
ONOFF	10000	10000	0.00185475823	-6.290
ONOFF	100000	100000	0.00198267259	-6.223
ONOFF	10000	10000	0.00259548217	-5.954
REF	100000	100000	0.00275909462	-5.893
REF	47000	47000	0.00283806586	-5.865
REF	117000	117000	0.00303991654	-5.796
REF	49700	56000	0.00337970607	-5.690
ONOFF	10000	10000	0.00383470924	-5.564
ONOFF	5000	10000	0.00396035562	-5.531
ONOFF	100000	50000	0.00445613717	-5.413
ONOFF	100000	100000	0.00489748707	-5.319
ONOFF	100000	100000	0.00597387281	-5.120
REF	90000	90000	0.00711648372	-4.945
ONOFF	10000	10000	0.01034019777	-4.572
ONOFF	100000	100000	0.01055701715	-4.551

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	10000	10000	0.01699718770	-4.075
REF	20000	35000	0.02082463939	-3.872
ONOFF	100000	100000	0.02084550485	-3.871
ONOFF	100000	100000	0.02378708156	-3.739
REF	66000	66000	0.02872992833	-3.550
ONOFF	100000	100000	0.05975551120	-2.817
ONOFF	100000	100000	0.07526807584	-2.587
ONOFF	40000	50000	0.15713462760	-1.851
N = 41				
----------- Equipment Type=DUMP LEVER ARM SERVICE=G -----------				
ONOFF	100000	100000	0.39765218180	-0.922
N = 1				
----------- Equipment Type=FLANGE SERVICE=G -----------				
ONOFF	10000	10000	0.00000544316	-12.121
REF	86000	86000	0.00007830899	-9.455
ONOFF	10000	8000	0.00030254922	-8.103
ONOFF	4000	10000	0.00045722580	-7.690
ONOFF	100000	100000	0.00241857933	-6.025
ONOFF	10000	9000	0.00292252563	-5.835
REF	86000	86000	0.00374639390	-5.587
ONOFF	100000	90000	0.00613217817	-5.094
ONOFF	100000	100000	0.01279370407	-4.359
ONOFF	100000	100000	0.01363467296	-4.295
ONOFF	100000	100000	0.01780277601	-4.028
ONOFF	100000	100000	0.01851673773	-3.989
REF	100000	100000	0.02487798240	-3.694
ONOFF	100000	100000	0.03357615894	-3.394
ONOFF	100000	20000	0.04434137712	-3.116
ONOFF	100000	100000	0.06712600925	-2.701
ONOFF	100000	100000	0.09028894130	-2.405
ONOFF	100000	100000	0.10636124467	-2.241
N = 18				
----------- Equipment Type=FLANGE SERVICE=LL -----------				
ONOFF	100000	100000	0.00015603738	-8.765
REF	18000	22500	0.00095309807	-6.956
REF	30000	40000	0.00125641840	-6.679
REF	13200	9900	0.00344683843	-5.670

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	60000	0.02859657081	-3.554
ONOFF	100000	100000	0.17639481085	-1.735
N = 6				
----------- Equipment Type=INSTRUMENT SERVICE=G -----------				
ONOFF	30000	30000	0.00028259095	-8.172
ONOFF	100000	100000	0.01809307811	-4.012
N = 2				
----------- Equipment Type=INSTRUMENT SERVICE=LL -----------				
ONOFF	100000	100000	0.00345005897	-5.669
N = 1				
----------- Equipment Type=LOADARM SERVICE=G -----------				
MT	100000	100000	0.00021052799	-8.466
MT	400000	400000	0.04320148780	-3.142
MT	310000	310000	0.04397804590	-3.124
MT	7200	24000	0.04716501860	-3.054
N = 4				
----------- Equipment Type=OEL SERVICE=G -----------				
ONOFF	100000	100000	0.00000272158	-12.814
ONOFF	3000	10000	0.00001360791	-11.205
ONOFF	200	10000	0.00001769028	-10.942
ONOFF	10000	10000	0.00001814388	-10.917
ONOFF	10000	10000	0.00003039100	-10.401
REF	13400	16750	0.00004146875	-10.091
ONOFF	20000	15000	0.00004853488	-9.933
ONOFF	10000	10000	0.00005080287	-9.888
ONOFF	3000	10000	0.00007983308	-9.436
ONOFF	10000	10000	0.00008935861	-9.323
ONOFF	10000	10000	0.00009026581	-9.313
REF	100000	100000	0.00013893677	-8.881
ONOFF	9000	10000	0.00014877982	-8.813
ONOFF	10000	100000	0.00020547945	-8.490
REF	6000	10000	0.00023758051	-8.345
ONOFF	12000	15000	0.00029257008	-8.137

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	100000	0.00046901932	-7.665
ONOFF	35000	20000	0.00057652182	-7.458
ONOFF	10000	10000	0.00059194412	-7.432
ONOFF	100000	100000	0.00072167287	-7.234
REF	50000	40000	0.00087367323	-7.043
ONOFF	100000	100000	0.00094847138	-6.961
ONOFF	100000	100000	0.00100244942	-6.905
ONOFF	10000	10000	0.00142610904	-6.553
ONOFF	10000	9000	0.00148326227	-6.514
ONOFF	70000	70000	0.00203392906	-6.198
ONOFF	15000	15000	0.00229792253	-6.076
REF	119000	119000	0.00267976050	-5.922
ONOFF	100000	100000	0.00350403701	-5.654
ONOFF	40000	100000	0.00398666425	-5.525
REF	89000	89000	0.00412528350	-5.491
ONOFF	100000	100000	0.00440850948	-5.424
ONOFF	100000	100000	0.00509843055	-5.279
ONOFF	10000	10000	0.00556200671	-5.192
REF	110000	110000	0.00582781457	-5.145
ONOFF	10000	10000	0.00610314796	-5.099
ONOFF	100000	100000	0.00673001905	-5.001
ONOFF	100000	100000	0.00783997097	-4.849
ONOFF	100000	80000	0.00808309897	-4.818
ONOFF	100000	100000	0.00899074662	-4.712
REF	140000	140000	0.01182844961	-4.437
ONOFF	100000	100000	0.01357071578	-4.300
REF	140000	140000	0.01958495872	-3.933
ONOFF	100000	100000	0.02699718770	-3.612
ONOFF	100000	100000	0.04810033566	-3.034
ONOFF	100000	100000	0.05125374218	-2.971
ONOFF	100000	100000	0.05756735916	-2.855
ONOFF	100000	100000	0.06938129366	-2.668
ONOFF	100000	100000	0.15146738637	-1.887
ONOFF	100000	100000	0.19622017600	-1.629
ONOFF	100000	100000	0.72652136442	-0.319

N = 51

----------- Equipment Type=OEL SERVICE=HL -----------

ONOFF	10000	8000	0.00003991654	-10.129
REF	15000	16000	0.00018571169	-8.591
ONOFF	10000	10000	0.00264628504	-5.935
REF	700	700	0.00467341014	-5.366

N = 4

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
----------- Equipment Type=OEL SERVICE=LL -----------				
ONOFF	20000	100000	0.00003538057	-10.249
REF	13200	16500	0.00009666606	-9.244
ONOFF	20000	3000	0.00011385285	-9.081
ONOFF	30000	40000	0.00013063594	-8.943
ONOFF	2000	10000	0.00043000998	-7.752
ONOFF	10000	8000	0.00043499955	-7.740
REF	12000	13000	0.00056373038	-7.481
ONOFF	6000	20000	0.00085366960	-7.066
REF	100000	100000	0.00085947564	-7.059
REF	14000	12000	0.00092007620	-6.991
REF	95000	100000	0.00101356255	-6.894
ONOFF	10000	1000	0.00117753788	-6.744
ONOFF	40000	35000	0.00120112492	-6.724
MT	300000	300000	0.00217168647	-6.132
ONOFF	20000	20000	0.00219268802	-6.123
MT	136000	119000	0.00292179987	-5.836
ONOFF	50000	35000	0.00361471469	-5.623
ONOFF	100000	100000	0.00493286764	-5.312
ONOFF	80000	60000	0.00594257462	-5.126
ONOFF	100000	100000	0.00672366869	-5.002
ONOFF	50000	100000	0.00678853307	-4.993
ONOFF	100000	30000	0.00804363603	-4.823
ONOFF	100000	100000	0.00847319242	-4.771
REF	20000	33600	0.00883470924	-4.729
ONOFF	10000	10000	0.00924929692	-4.683
ONOFF	10000	10000	0.01178853307	-4.441
ONOFF	100000	100000	0.01185702622	-4.435
REF	73000	73000	0.01350811939	-4.304
ONOFF	100000	100000	0.01985711694	-3.919
ONOFF	100000	100000	0.02174907013	-3.828
REF	140000	140000	0.04261680123	-3.156
ONOFF	100000	100000	0.07331080468	-2.613
N = 32				
----------- Equipment Type=OTHER SERVICE=G -----------				
MT	100000	100000	0.01708926789	-4.069
MT	100000	100000	0.01809353171	-4.012
N = 2				
----------- Equipment Type=PRV SERVICE=G -----------				
ONOFF	100000	100000	0.02052209018	-3.886

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	100000	0.36418670054	-1.010
N = 2				
----------- Equipment Type=PUMP SERVICE=LL -----------				
REF	35000	21000	0.00082055702	-7.106
REF	40500	27000	0.00086514560	-7.053
REF	109000	98100	0.00105651819	-6.853
REF	76500	90000	0.00106527261	-6.845
REF	21000	25000	0.00119445704	-6.730
MT	10000	12000	0.00176567178	-6.339
REF	56000	28000	0.00958087635	-4.648
REF	12000	16000	0.00968248208	-4.637
REF	18000	17400	0.03439081920	-3.370
REF	77000	47000	0.03876077293	-3.250
REF	100000	100000	0.16085911276	-1.827
REF	100000	100000	1.25088451420	0.224
N = 12				
----------- Equipment Type=STUFFING BOX SERVICE=LL -----------				
ONOFF	10000	500	0.00035698086	-7.938
ONOFF	10000	10000	0.00215186428	-6.141
N = 2				
----------- Equipment Type=VALVE SERVICE=G -----------				
ONOFF	100000	100000	0.00000725755	-11.833
ONOFF	1000	10000	0.00001814388	-10.917
ONOFF	10000	10000	0.00002585503	-10.563
ONOFF	60000	10000	0.00002585503	-10.563
ONOFF	100000	100000	0.00002676222	-10.529
ONOFF	100000	100000	0.00004127733	-10.095
ONOFF	10000	10000	0.00005171006	-9.870
ONOFF	100000	100000	0.00005488524	-9.810
ONOFF	100000	3000	0.00008754423	-9.343
REF	20000	2000	0.00023997097	-8.335
ONOFF	100000	100000	0.00026399347	-8.240
ONOFF	10000	10000	0.00026852944	-8.223
ONOFF	15000	15000	0.00029257008	-8.137
ONOFF	100000	100000	0.00031706432	-8.056
REF	22500	22500	0.00035323415	-7.948
ONOFF	10000	10000	0.00038555747	-7.861
REF	18000	15000	0.00038567541	-7.861

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
REF	65700	65700	0.00060437268	-7.411
REF	100000	100000	0.00060967976	-7.403
ONOFF	10000	10000	0.00064002540	-7.354
ONOFF	100000	100000	0.00068946748	-7.280
ONOFF	100000	20000	0.00069717863	-7.268
REF	80000	48000	0.00085747981	-7.062
ONOFF	70000	70000	0.00090220448	-7.011
ONOFF	30000	10000	0.00094166742	-6.968
ONOFF	15000	15000	0.00094484260	-6.964
ONOFF	10000	10000	0.00095799692	-6.951
ONOFF	100000	100000	0.00104644834	-6.862
ONOFF	50000	40000	0.00109815840	-6.814
ONOFF	10000	10000	0.00121291844	-6.715
ONOFF	7500	10000	0.00122335117	-6.706
REF	100000	100000	0.00128871451	-6.654
ONOFF	100000	100000	0.00128957634	-6.653
ONOFF	100000	100000	0.00133085367	-6.622
REF	100000	100000	0.00160963440	-6.432
ONOFF	40000	40000	0.00171278236	-6.370
REF	109000	109000	0.00178594756	-6.328
ONOFF	10000	10000	0.00181348090	-6.313
ONOFF	10000	10000	0.00199129094	-6.219
REF	100000	100000	0.00205130182	-6.189
ONOFF	60000	100000	0.00206341286	-6.183
ONOFF	100000	100000	0.00208563912	-6.173
ONOFF	25000	40000	0.00233194230	-6.061
ONOFF	50000	40000	0.00269255194	-5.917
MT	300000	300000	0.00277487980	-5.887
ONOFF	100000	100000	0.00287081557	-5.853
REF	67000	100000	0.00287548762	-5.852
ONOFF	100000	100000	0.00300553388	-5.807
ONOFF	100000	100000	0.00333167014	-5.704
ONOFF	100000	100000	0.00336795791	-5.693
REF	77000	77000	0.00341059603	-5.681
REF	80000	80000	0.00349872993	-5.655
ONOFF	100000	100000	0.00377438084	-5.580
REF	58000	35000	0.00417118752	-5.480
REF	100000	100000	0.00479905652	-5.339
REF	100000	100000	0.00497732015	-5.303
ONOFF	100000	100000	0.00498639209	-5.301
REF	78000	78000	0.00514197587	-5.270
ONOFF	100000	100000	0.00520366506	-5.258
ONOFF	100000	100000	0.00543227796	-5.215
ONOFF	10000	10000	0.00546720494	-5.209
REF	100000	100000	0.00554839880	-5.194
ONOFF	100000	100000	0.00594393541	-5.125
ONOFF	10000	10000	0.00630545224	-5.066
ONOFF	100000	100000	0.00660664066	-5.020
REF	70000	63000	0.00672094711	-5.003

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	80000	100000	0.00687607729	-4.980
ONOFF	100000	100000	0.00845640933	-4.773
ONOFF	80000	100000	0.00850403701	-4.767
REF	100000	100000	0.00879071033	-4.734
REF	90000	90000	0.00915767033	-4.693
ONOFF	100000	100000	0.00999909281	-4.605
REF	100000	100000	0.01077791890	-4.530
ONOFF	100000	100000	0.01084051529	-4.524
ONOFF	10000	10000	0.01150231334	-4.465
ONOFF	100000	100000	0.01338700898	-4.313
REF	50000	100000	0.01343826544	-4.310
REF	16000	80000	0.01372947473	-4.288
ONOFF	100000	100000	0.01451056881	-4.233
ONOFF	50000	50000	0.01612628141	-4.127
ONOFF	30000	100000	0.01659711512	-4.099
ONOFF	100000	100000	0.01664837159	-4.095
REF	58000	58000	0.01690556110	-4.080
REF	120000	120000	0.01879887508	-3.974
ONOFF	100000	100000	0.01883380205	-3.972
ONOFF	100000	100000	0.02038374308	-3.893
ONOFF	100000	100000	0.02074389912	-3.876
ONOFF	100000	100000	0.02144924249	-3.842
ONOFF	100000	100000	0.02216048263	-3.809
ONOFF	100000	100000	0.02497323778	-3.690
REF	71400	71400	0.02521500499	-3.680
ONOFF	100000	100000	0.02522135535	-3.680
ONOFF	100000	100000	0.02819150866	-3.569
ONOFF	100000	100000	0.03083597932	-3.479
ONOFF	100000	100000	0.03347137803	-3.397
ONOFF	100000	100000	0.03378118480	-3.388
ONOFF	100000	100000	0.03389685204	-3.384
ONOFF	100000	100000	0.03527669418	-3.345
ONOFF	100000	100000	0.03595482174	-3.325
ONOFF	100000	100000	0.03649097342	-3.311
ONOFF	100000	100000	0.03771114941	-3.278
ONOFF	100000	100000	0.03832713417	-3.262
ONOFF	5000	10000	0.04127914361	-3.187
ONOFF	100000	100000	0.04416220630	-3.120
ONOFF	100000	100000	0.04438764402	-3.115
ONOFF	60000	70000	0.04505624603	-3.100
ONOFF	100000	100000	0.04937176812	-3.008
ONOFF	10000	10000	0.05139208927	-2.968
ONOFF	100000	100000	0.05296924612	-2.938
ONOFF	100000	100000	0.05525764311	-2.896
ONOFF	100000	100000	0.06018007802	-2.810
MT	90000	300000	0.06055973873	-2.804
ONOFF	10000	10000	0.06589585412	-2.720
ONOFF	10000	10000	0.06919123651	-2.671
ONOFF	10000	100000	0.06986891046	-2.661

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	100000	0.07176086365	-2.634
REF	100000	100000	0.07735190057	-2.559
ONOFF	100000	100000	0.08639118207	-2.449
ONOFF	10000	10000	0.08908826998	-2.418
ONOFF	100000	100000	0.09582463939	-2.345
ONOFF	100000	100000	0.15789757779	-1.846
ONOFF	100000	100000	0.18449242493	-1.690
ONOFF	100000	100000	0.18958677311	-1.663
ONOFF	100000	100000	0.19712873084	-1.624
ONOFF	100000	100000	0.21433094439	-1.540
ONOFF	100000	100000	0.22602739726	-1.487
ONOFF	100000	100000	0.27724439808	-1.283
ONOFF	10000	10000	0.28369636215	-1.260
ONOFF	100000	100000	0.28827360973	-1.244
ONOFF	100000	100000	0.38205751610	-0.962
ONOFF	100000	100000	0.44049986392	-0.820
ONOFF	100000	100000	0.81931597569	-0.199
ONOFF	100000	100000	1.13625011340	0.128
N = 133				
----------- Equipment Type=VALVE SERVICE=HL -----------				
REF	10000	16000	0.00043354350	-7.744
REF	11000	12000	0.00223700445	-6.103
N = 2				
----------- Equipment Type=VALVE SERVICE=LL -----------				
ONOFF	10000	10000	0.00002404064	-10.636
ONOFF	10000	10000	0.00002449424	-10.617
ONOFF	100000	100000	0.00003447337	-10.275
REF	80000	32000	0.00009142702	-9.300
ONOFF	15000	20000	0.00010342012	-9.177
REF	16000	32000	0.00013744443	-8.892
ONOFF	10000	4000	0.00018279960	-8.607
MT	19800	22000	0.00023388370	-8.361
REF	13500	10800	0.00025930781	-8.257
REF	42000	28000	0.00035377846	-7.947
MT	17600	26400	0.00043848771	-7.732
REF	49500	36000	0.00044372675	-7.720
REF	70000	35000	0.00045913091	-7.686
REF	18000	22500	0.00046035562	-7.684
ONOFF	10000	10000	0.00050122471	-7.598
ONOFF	20000	20000	0.00052617255	-7.550
ONOFF	10000	10000	0.00056563549	-7.478
REF	2000	10000	0.00056713236	-7.475

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
REF	10000	24000	0.00059525538	-7.427
REF	24000	24000	0.00060782001	-7.406
ONOFF	100000	60000	0.00065091173	-7.337
ONOFF	30000	4000	0.00068220992	-7.290
ONOFF	20000	20000	0.00070443618	-7.258
ONOFF	10000	10000	0.00070488978	-7.257
ONOFF	70000	40000	0.00075932142	-7.183
REF	50000	30000	0.00095572893	-6.953
ONOFF	60000	50000	0.00102558287	-6.882
REF	11000	11000	0.00113353896	-6.782
REF	80000	80000	0.00134786356	-6.609
ONOFF	80000	100000	0.00135625510	-6.603
MT	10000	11984	0.00142805951	-6.551
REF	25000	18000	0.00153742175	-6.478
ONOFF	10000	10000	0.00168647374	-6.385
ONOFF	350	10000	0.00185929420	-6.288
ONOFF	20000	15000	0.00211829810	-6.157
ONOFF	40000	70000	0.00223351175	-6.104
ONOFF	10000	10000	0.00225936678	-6.093
ONOFF	10000	10000	0.00226753152	-6.089
ONOFF	100000	100000	0.00230064411	-6.075
ONOFF	50000	35000	0.00247028939	-6.003
REF	58000	58000	0.00307012610	-5.786
ONOFF	10000	9000	0.00325773383	-5.727
REF	70000	70000	0.00345051256	-5.669
ONOFF	9000	10000	0.00417490701	-5.479
ONOFF	90000	100000	0.00426290484	-5.458
ONOFF	100000	100000	0.00436587136	-5.434
ONOFF	10000	10000	0.00454277420	-5.394
ONOFF	100000	100000	0.00488886873	-5.321
REF	5000	40000	0.00500408237	-5.298
REF	70000	70000	0.00507983308	-5.282
ONOFF	100000	100000	0.00518234600	-5.262
ONOFF	100000	100000	0.00592896671	-5.128
ONOFF	10000	10000	0.00596117209	-5.122
REF	24500	27300	0.00601378935	-5.114
ONOFF	100000	100000	0.00647010796	-5.041
REF	131400	146000	0.00666334029	-5.011
REF	30000	70000	0.00844506940	-4.774
REF	55000	100000	0.00920847319	-4.688
ONOFF	100000	100000	0.01027941577	-4.578
ONOFF	100000	100000	0.01037285675	-4.569
ONOFF	10000	10000	0.01041458768	-4.565
ONOFF	10000	10000	0.01133221446	-4.480
ONOFF	10000	10000	0.01256146240	-4.377
REF	67000	67000	0.01319241586	-4.328
REF	140000	140000	0.01378798875	-4.284
ONOFF	10000	10000	0.01564138619	-4.158
REF	17000	34000	0.01730744806	-4.057

Table C-2-1. BAGGING DATA USED TO DEVELOP PEGGED EMISSION RATES (CONTINUED)

Plant Type	Initial Screening Value (ppmv)	Final Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
ONOFF	100000	100000	0.01835979316	-3.998
REF	100000	100000	0.01882427651	-3.973
ONOFF	45000	45000	0.01897986029	-3.964
REF	76000	69850	0.02037603193	-3.893
REF	100000	100000	0.02065272612	-3.880
ONOFF	10000	10000	0.02356890139	-3.748
REF	87500	87500	0.02427696634	-3.718
REF	100000	100000	0.02519096435	-3.681
REF	39000	39000	0.02586999909	-3.655
ONOFF	100000	100000	0.02691508664	-3.615
REF	70000	70000	0.03012791436	-3.502
ONOFF	10000	10000	0.03019504672	-3.500
ONOFF	10000	10000	0.03919486528	-3.239
ONOFF	10000	10000	0.08274879797	-2.492
ONOFF	100000	100000	0.08523224168	-2.462
ONOFF	10000	10000	0.08567948834	-2.457
ONOFF	100000	100000	0.08933548036	-2.415
ONOFF	100000	100000	0.09434591309	-2.361
ONOFF	100000	100000	0.10369500136	-2.266
REF	70000	70000	0.18793885512	-1.672
ONOFF	100000	100000	0.38088768938	-0.965

N = 88

----------- Equipment Type=VENT SERVICE=G -----------

ONOFF	100000	100000	0.00012972875	-8.950
ONOFF	100000	100000	0.00851719133	-4.766
ONOFF	100000	100000	0.00923206024	-4.685
ONOFF	100000	100000	0.02947428105	-3.524

N = 4

----------- Equipment Type=VENT SERVICE=LL -----------

ONOFF	100000	100000	0.00005443164	-9.819
ONOFF	100000	100000	0.00027714778	-8.191
ONOFF	10000	10000	0.00117844507	-6.744
ONOFF	10000	10000	0.00200762043	-6.211

N = 4

TABLE C-2-2. PEGGED VOC MASS EMISSION RATES AND 95 PERCENT CONFIDENCE INTERVALS FOR READINGS PEGGED AT 10,000 PPMV DEVELOPED FROM THE COMBINED 1993 REFINERY, MARKETING TERMINAL, AND OIL AND GAS PRODUCTION OPERATIONS DATA

Equipment Type/Service	**Sample Size**	**Normal Statistic[a] (Probability of a Larger Normal Statistic)**		**Mean Natural Log Mass Emission Rate**	**Scale Bias Correction Factor**	**Lower 95 Percent Confidence Bound for Pegged Emission Rate (kg/hr)**	**Pegged Emission Rate (kg/hr)**	**Upper 95 Percent Confidence Bound for Pegged Emission Rate (kg/hr)**
		Mass Emission Rate	**ln Mass Emission Rate**					
Connector/All	74	0.5569 (0.0000)	0.9631 (0.0945)	-6.067	12.24	0.01668	0.02836	0.04821
Flange/All	24	0.6790 (0.0000)	0.9424 (0.1899)	-5.312	17.25	0.02877	0.08504	0.25141
Open-Ended Line/All	87	0.2597 (0.0000)	0.9819 (0.6620)	-6.374	17.78	0.01797	0.03031	0.05110
Pump/All	12	0.3985 (0.0000)	0.8640 (0.0519)	-4.869	9.63	0.01609	0.07395	0.33989
Valve/All	223	0.3740 (0.000)	0.9774 (0.1524)	-5.301	12.84	0.04741	0.06403	0.08648
Other[b]/All	25	0.4359 (0.0000)	0.9506 (0.2710)	-5.219	13.46	0.02665	0.07285	0.19914

[a] The Normal Statistic is generated by default from SAS--by default the Shapiro-Wilk statistic is calculated for sample sizes less than 2,000. Probabilities greater than 0.05 indicate a normal distribution.

[b] The "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment other than connectors, flanges, open-ended lines, pumps, or valves.

TABLE C-2-3. PEGGED VOC MASS EMISSION RATES AND 95 PERCENT CONFIDENCE INTERVALS FOR READINGS PEGGED AT 100,000 PPMV DEVELOPED FROM THE COMBINED 1993 REFINERY, MARKETING TERMINAL, AND OIL AND GAS PRODUCTION OPERATIONS DATA

Equipment Type/Service	Sample Size	Normal Statistic[a] (Probability of a Larger Normal Statistic)		Mean Natural Log Mass Emission Rate	Scale Bias Correction Factor	Lower 95 Percent Confidence Bound for Pegged Emission Rate (kg/hr)	Pegged Emission Rate (kg/hr)	Upper 95 Percent Confidence Bound for Pegged Emission Rate (kg/hr)
		Mass Emission Rate	ln Mass Emission Rate					
Connector/All	33	0.6405 (0.0000)	0.9579 (0.2747)	-5.739	9.25	0.01359	0.02974	0.06509
Flange/All	12	0.8101 (0.0106)	0.8653 (0.0539)	-3.969	4.47	0.02515	0.08439	0.28317
Open-Ended Line/All	36	0.3759 (0.0000)	0.9444 (0.0918)	-4.893	10.55	0.03672	0.07911	0.17046
Pump/All[b]	-	-	-	-	-	-	0.16000	-
Valve/All	99	0.4680 (0.0000)	0.9519 (0.0042)	-4.388	11.30	0.08984	0.14043	0.21952
Other/All[c]	19	0.4759 (0.0000)	0.9140 (0.0900)	-4.853	14.61	0.03374	0.11406	0.38554

[a] The Normal Statistic is generated by default from SAS--by default the Shapiro-Wilk statistic is calculated for sample sizes less than 2,000. Probabilities greater than 0.05 indicate a normal distribution.

[b] Only 2 data points were available for the pump emission factor; therefore the ratio of the pump/overall 10,000 ppmv emission factor was multiplied by the overall 100,000 ppmv emission factor to approximate the pump 100,000 ppmv emission factor

[c] The "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment other than connectors, flanges, open-ended lines, pumps, or valves.

APPENDIX C: ATTACHEMENT 3

This attachment lists the bagging data used to develop the default zero emission rates for the combined 1993 petroleum industry data in table C-3-1. Table C-3-2 lists summary statistics for the default zero emission rates.

TABLE C-3-1. BAGGING DATA USED TO DEVELOP DEFAULT ZERO EMISSION RATES

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
----------- Equipment Type=CONNECTOR SERVICE=G -----------			
REF	0.00	0.00000000476	-19.163
REF	0.00	0.00000000636	-18.873
REF	0.00	0.00000002555	-17.483
REF	0.00	0.00000023605	-15.259
REF	0.00	0.00000038635	-14.767
REF	0.00	0.00000362959	-12.526
		N = 6	
----------- Equipment Type=CONNECTOR SERVICE=LL -----------			
REF	0.00	0.00000000501	-19.112
REF	0.00	0.00000000544	-19.030
REF	0.00	0.00000000739	-18.723
REF	0.00	0.00000000763	-18.691
REF	0.00	0.00000000777	-18.673
MT	0.00	0.00000137993	-13.493
MT	0.00	0.00000177942	-13.239
MT	0.00	0.00000258886	-12.864
MT	0.00	0.00000332328	-12.615
REF	0.00	0.00000470743	-12.266
MT	0.00	0.00000863240	-11.660
MT	0.00	0.00001050395	-11.464
		N = 12	
----------- Equipment Type=FLANGE SERVICE=G -----------			
REF	0.00	0.00000000642	-18.863
REF	0.00	0.00000000709	-18.764
REF	0.00	0.00000007912	-16.352
REF	0.00	0.00000080155	-14.037
		N = 4	
----------- Equipment Type=FLANGE SERVICE=LL -----------			
REF	0.00	0.00000000958	-18.464
REF	0.00	0.00000019031	-15.475
REF	0.00	0.00000021919	-15.333
REF	0.00	0.00000021930	-15.333
REF	0.00	0.00000047102	-14.568
		N = 5	
----------- Equipment Type=LOADARM SERVICE=LL -----------			
MT	0.00	0.00005125646	-9.879

TABLE C-3-1. BAGGING DATA USED TO DEVELOP DEFAULT ZERO EMISSION RATES (CONTINUED)

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
		N = 1	
----------- Equipment Type=OEL SERVICE=G -----------			
REF	0.00	0.00000000693	-18.788
REF	0.00	0.00000140955	-13.472
MT	0.00	0.00000303602	-12.705
MT	0.00	0.00000334319	-12.609
		N = 4	
----------- Equipment Type=OEL SERVICE=HL -----------			
REF	0.00	0.00000000575	-18.975
REF	0.00	0.00000000583	-18.960
REF	0.00	0.00000001096	-18.329
REF	0.00	0.00000009800	-16.138
		N = 4	
----------- Equipment Type=OEL SERVICE=LL -----------			
REF	0.00	0.00000000511	-19.093
REF	0.00	0.00000000540	-19.036
REF	0.00	0.00000076594	-14.082
MT	0.00	0.00000288878	-12.755
		N = 4	
----------- Equipment Type=PRV SERVICE=G -----------			
REF	0.00	0.00000000710	-18.763
REF	0.00	0.00000000807	-18.635
REF	0.00	0.00000001125	-18.303
		N = 3	
----------- Equipment Type=PUMP SERVICE=HL -----------			
REF	0.00	0.00000002008	-17.723
REF	0.00	0.00000002256	-17.607
REF	0.00	0.00000002315	-17.581
REF	0.00	0.00000002586	-17.471
REF	0.00	0.00000089186	-13.930
		N = 5	

TABLE C-3-1. BAGGING DATA USED TO DEVELOP DEFAULT ZERO EMISSION RATES
(CONTINUED)

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
----------- Equipment Type=PUMP SERVICE=LL -----------			
REF	0.00	0.00000002503	-17.503
REF	0.00	0.00000002714	-17.422
REF	0.00	0.00000005485	-16.719
REF	0.00	0.00000006666	-16.524
REF	0.00	0.00000053647	-14.438
REF	0.00	0.00000186896	-13.190
MT	0.00	0.00000480541	-12.246
MT	0.00	0.00000775832	-11.767
MT	0.00	0.00000998821	-11.514
MT	0.00	0.00001319922	-11.235
MT	0.00	0.00001436632	-11.151
MT	0.00	0.00001653679	-11.010
REF	0.00	0.00002058968	-10.791
MT	0.00	0.00006269164	-9.677
		N = 14	
----------- Equipment Type=VALVE SERVICE=G -----------			
REF	0.00	0.00000000775	-18.676
REF	0.00	0.00000000865	-18.565
REF	0.00	0.00000000940	-18.482
REF	0.00	0.00000000990	-18.431
REF	0.00	0.00000001019	-18.402
REF	0.00	0.00000001420	-18.070
REF	0.00	0.00000002762	-17.405
REF	0.00	0.00000003664	-17.122
REF	0.00	0.00000003966	-17.043
REF	0.00	0.00000004455	-16.927
REF	0.00	0.00000020591	-15.396
REF	0.00	0.00000032682	-14.934
REF	0.00	0.00000032845	-14.929
REF	0.00	0.00000061449	-14.302
REF	0.00	0.00000083416	-13.997
MT	0.00	0.00000125837	-13.586
MT	0.00	0.00000196249	-13.141
MT	0.00	0.00000201696	-13.114
MT	0.00	0.00000208210	-13.082
REF	0.00	0.00000218398	-13.034
MT	0.00	0.00000238633	-12.946
MT	0.00	0.00000798694	-11.738
REF	0.00	0.00000893314	-11.626
REF	0.00	0.00001171097	-11.355
REF	0.00	0.00001563050	-11.066
		N = 25	

TABLE C-3-1. BAGGING DATA USED TO DEVELOP DEFAULT ZERO EMISSION RATES (CONTINUED)

----------- Equipment Type=VALVE SERVICE=HL -----------

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
REF	0.00	0.00000000660	-18.836
REF	0.00	0.00000000665	-18.828
REF	0.00	0.00000001034	-18.387
REF	0.00	0.00000001058	-18.364
REF	0.00	0.00000001345	-18.124
REF	0.00	0.00000001638	-17.927
REF	0.00	0.00000004990	-16.813
REF	0.00	0.00000005393	-16.736
REF	0.00	0.00000005530	-16.710
REF	0.00	0.00000240865	-12.936
REF	0.00	0.00001479770	-11.121
REF	0.00	0.00002881475	-10.455
REF	0.00	0.00003605008	-10.231

N = 13

----------- Equipment Type=VALVE SERVICE=LL -----------

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
REF	0.00	0.00000000467	-19.182
REF	0.00	0.00000000637	-18.871
REF	0.00	0.00000000664	-18.830
REF	0.00	0.00000000691	-18.791
REF	0.00	0.00000000834	-18.602
REF	0.00	0.00000000976	-18.445
REF	0.00	0.00000000997	-18.423
REF	0.00	0.00000001104	-18.322
REF	0.00	0.00000001198	-18.240
REF	0.00	0.00000002004	-17.725
REF	0.00	0.00000002139	-17.660
REF	0.00	0.00000002191	-17.636
REF	0.00	0.00000002793	-17.394
REF	0.00	0.00000005696	-16.681
REF	0.00	0.00000007503	-16.405
REF	0.00	0.00000048449	-14.540
REF	0.00	0.00000053602	-14.439
MT	0.00	0.00000103293	-13.783
MT	0.00	0.00000112977	-13.693
REF	0.00	0.00000192842	-13.159
MT	0.00	0.00000195101	-13.147
MT	0.00	0.00000195727	-13.144
MT	0.00	0.00000220253	-13.026
REF	0.00	0.00000233299	-12.968
REF	0.00	0.00000234795	-12.962
REF	0.00	0.00000312302	-12.677
REF	0.00	0.00000683117	-11.894

TABLE C-3-1. BAGGING DATA USED TO DEVELOP DEFAULT ZERO EMISSION RATES (CONTINUED)

Plant Type	Screening Value (ppmv)	Measured Emission Rate(kg/hr)	Natural Log of Emission Rate (kg/hr)
REF	0.00	0.00000696181	-11.875
REF	0.00	0.00000698812	-11.871
REF	0.00	0.00001664883	-11.003

N = 30

TABLE C-3-2. DEFAULT ZERO VOC MASS EMISSION RATES AND 95 PERCENT CONFIDENCE INTERVALS DEVELOPED FROM THE COMBINED 1993 REFINERY AND MARKETING TERMINAL DATA[a]

Equipment Type/Service	**Sample Size**	**Normal Statistic[b] (Probability of a Larger Normal Statistic)**		**Mean ln Mass Emission Rate**	**Scale Bias Correction Factor**	**Lower 95 Percent Confidence Bound for Default Zero Emission Rate (kg/hr)**	**Default Zero Emission Rate (kg/hr)**	**Upper 95 Percent Confidence Bound for Default Zero Emission Rate (kg/hr)**
		Mass Emission Rate	**ln Mass Emission Rate**					
Connector/All	18	0.7177 (0.0001)	0.8302 (0.0034)	-15.550	42.72	1.64E-06	7.54E-06	3.47E-05
Flange/All	9	0.8137 (0.0296)	0.8687 (0.1173)	-16.354	3.94	7.39E-08	3.11E-07	1.31E-06
Open-Ended Line/All	12	0.7232 (0.0009)	0.7909 (0.0061)	-16.245	22.70	3.19E-07	2.00E-06	1.25E-05
Pump/All	19	0.5942 (0.0000)	0.8532 (0.0065)	-14.184	34.97	5.81E-06	2.42E-05	1.01E-04
Valve/All	68	0.5178 (0.0000)	0.8764 (0.0000)	-15.415	38.38	3.95E-06	7.75E-06	1.52E-05
Other[c]/All	4	0.6297 (0.0000)	0.6691 (0.0045)	-16.395	52.16	3.91E-09	3.95E-06	4.00E-03

[a] No default zero data were collected from oil and gas production facilities

[b] The Normal Statistic is generated by default from SAS--by default the Shapiro-Wilk statistic is calculated for sample sizes less than 2,000. Probabilities greater than 0.05 indicate a normal distribution.

[c] The "other" equipment type were developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment other than connectors, flanges, open-ended lines, pumps, or valves.

APPENDIX C: ATTACHMENT 4

Because it would be impractical to list all of the screening data used to develop emission factors, this attachment summarizes the 1993 marketing terminal and oil and gas production operations screening data sets. Figures C-4-1 through C-4-4 are plots of the distribution of screening values for marketing terminals and figures C-5-5 through C-5-10 are plots of the distribution of screening valves for oil and gas production operations.

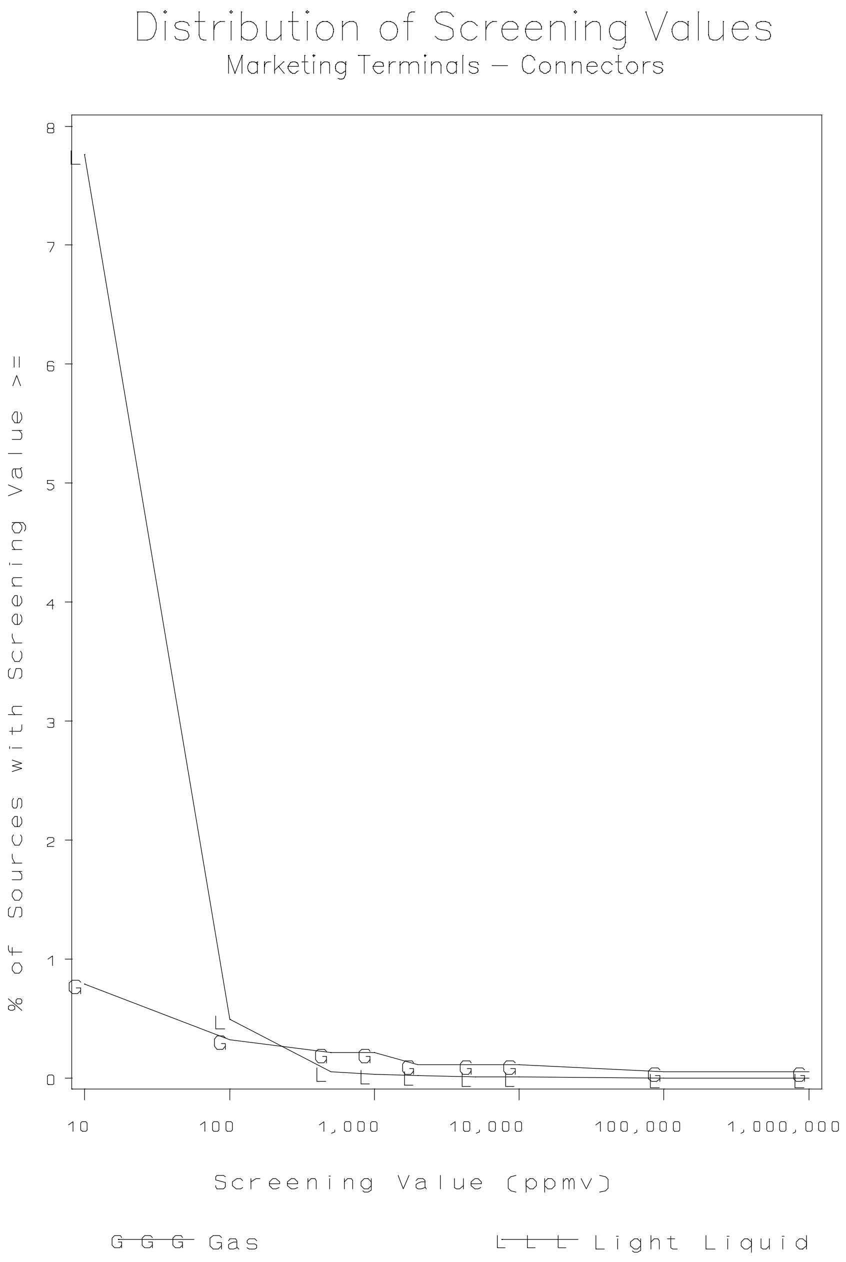

Figure C-4-1. Distribution of Connector Screening Values for Marketing Terminals

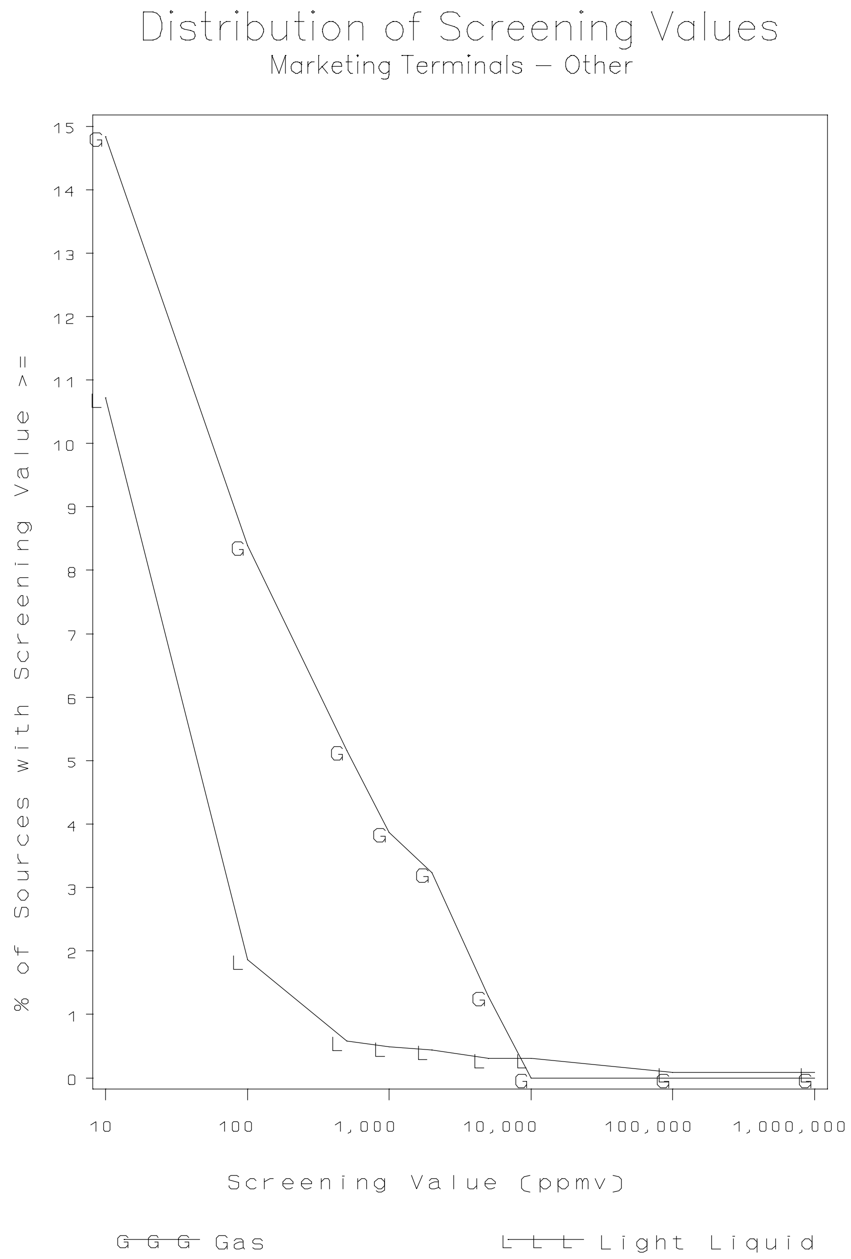

Figure C-4-2. Distribution of Other Screening Values for Marketing Terminals

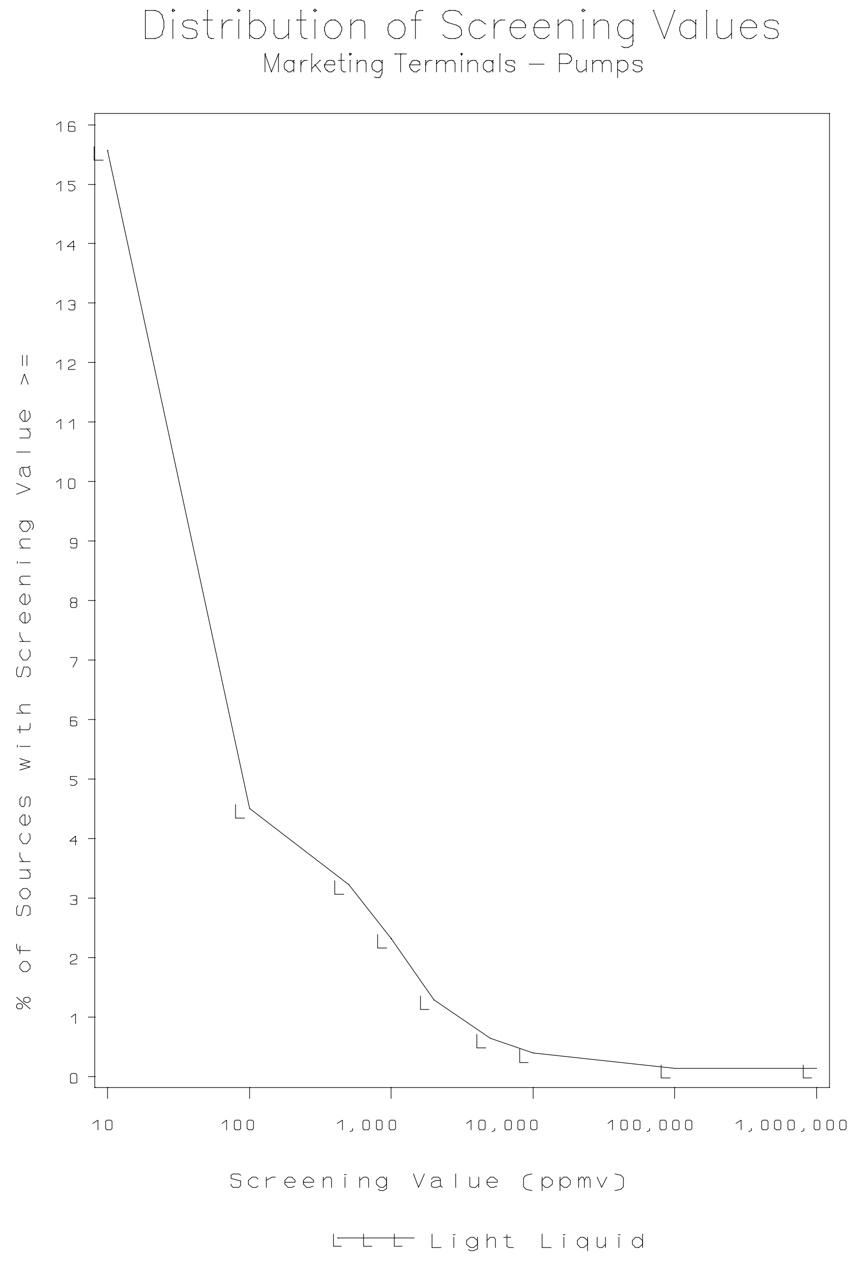

Figure C-4-3. Distribution of Pump Screening Values for Marketing Terminals

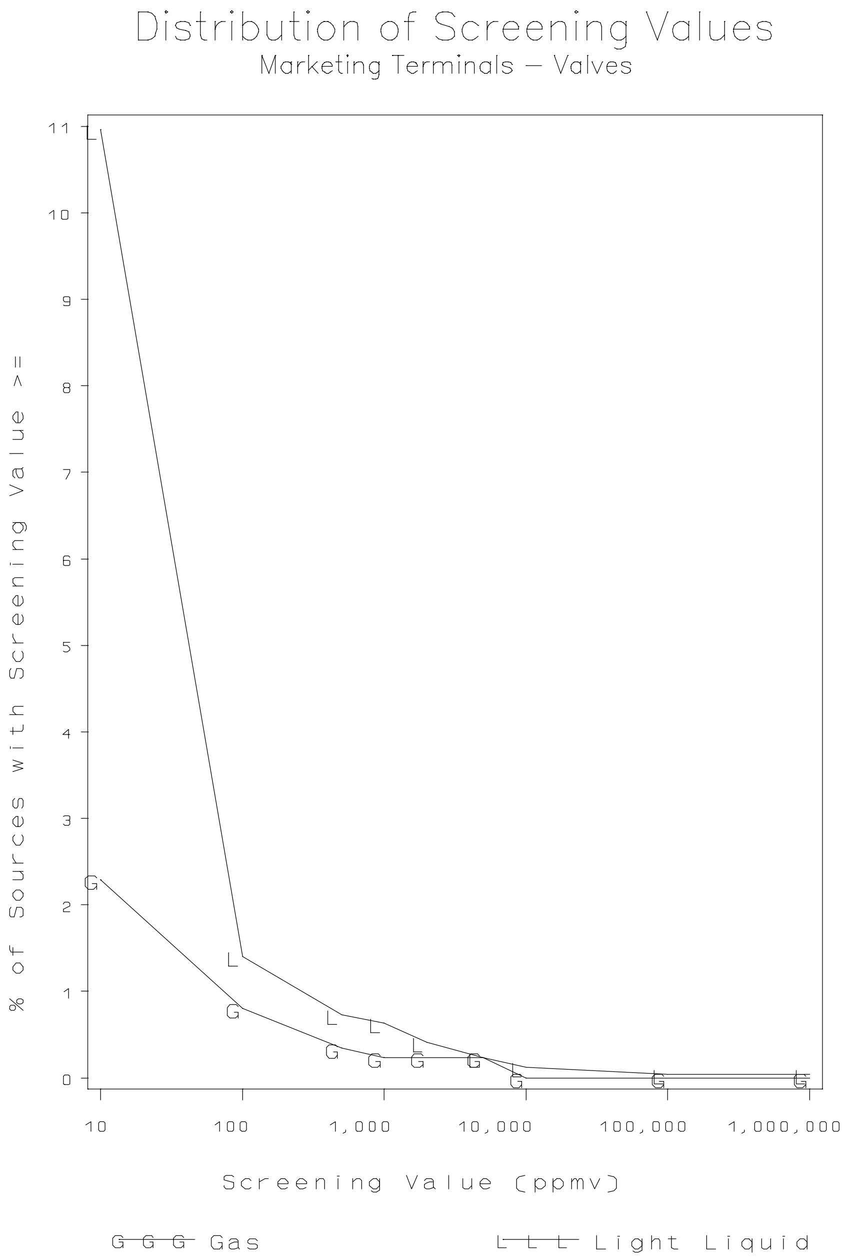

Figure C-4-4. Distribution of Valve Screening Values for Marketing Terminals

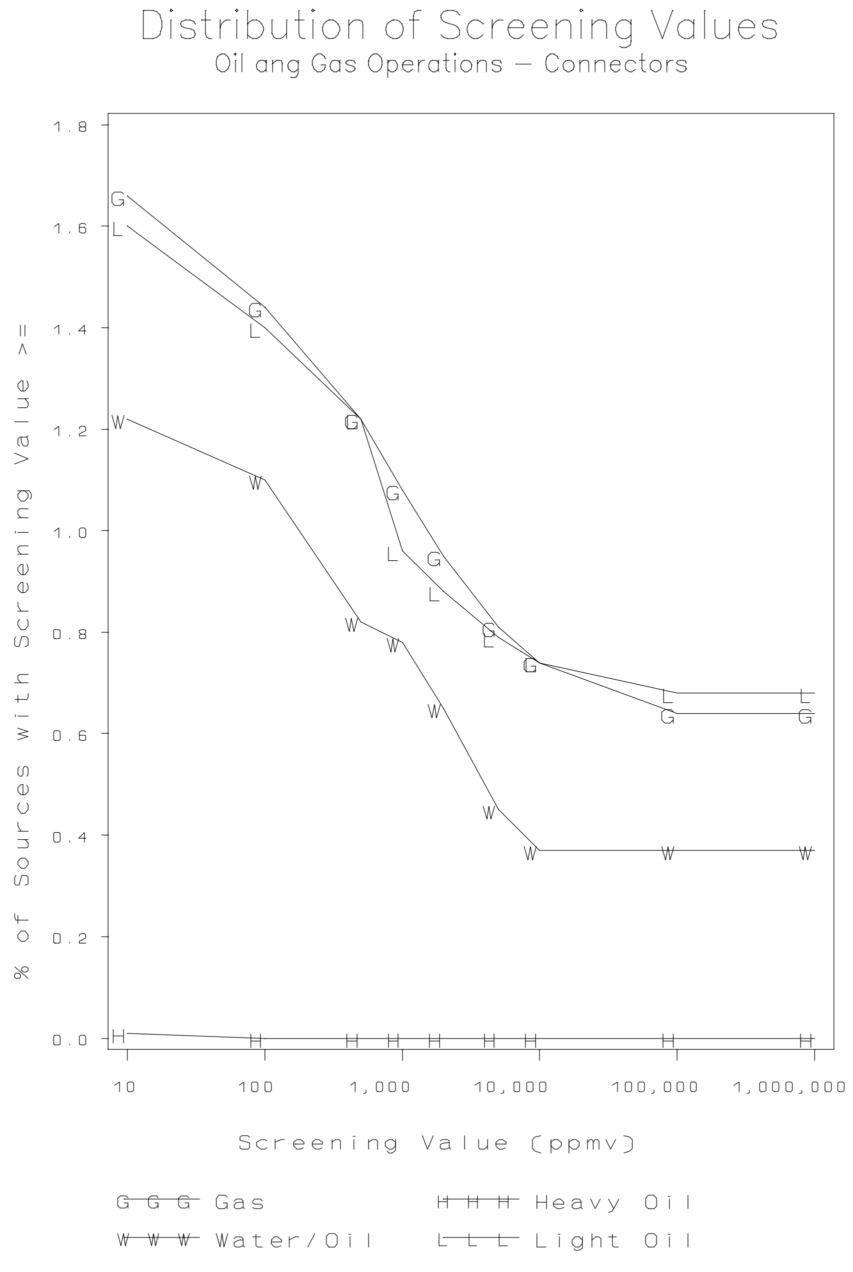

Figure C-4-5. Distribution of Connector Screening Values for Oil and Gas Operations

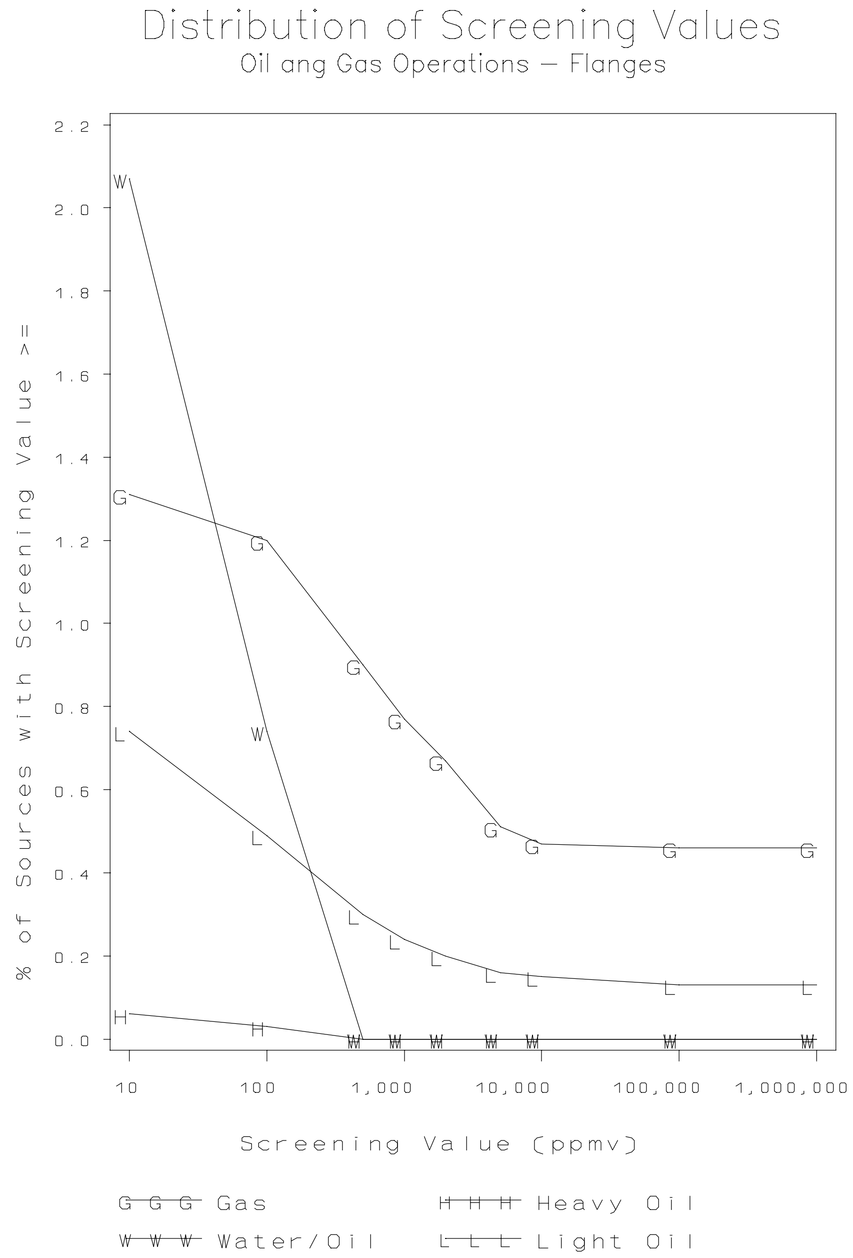

Figure C-4-6. Distribution of Flange Screening Values for Oil and Gas Operations

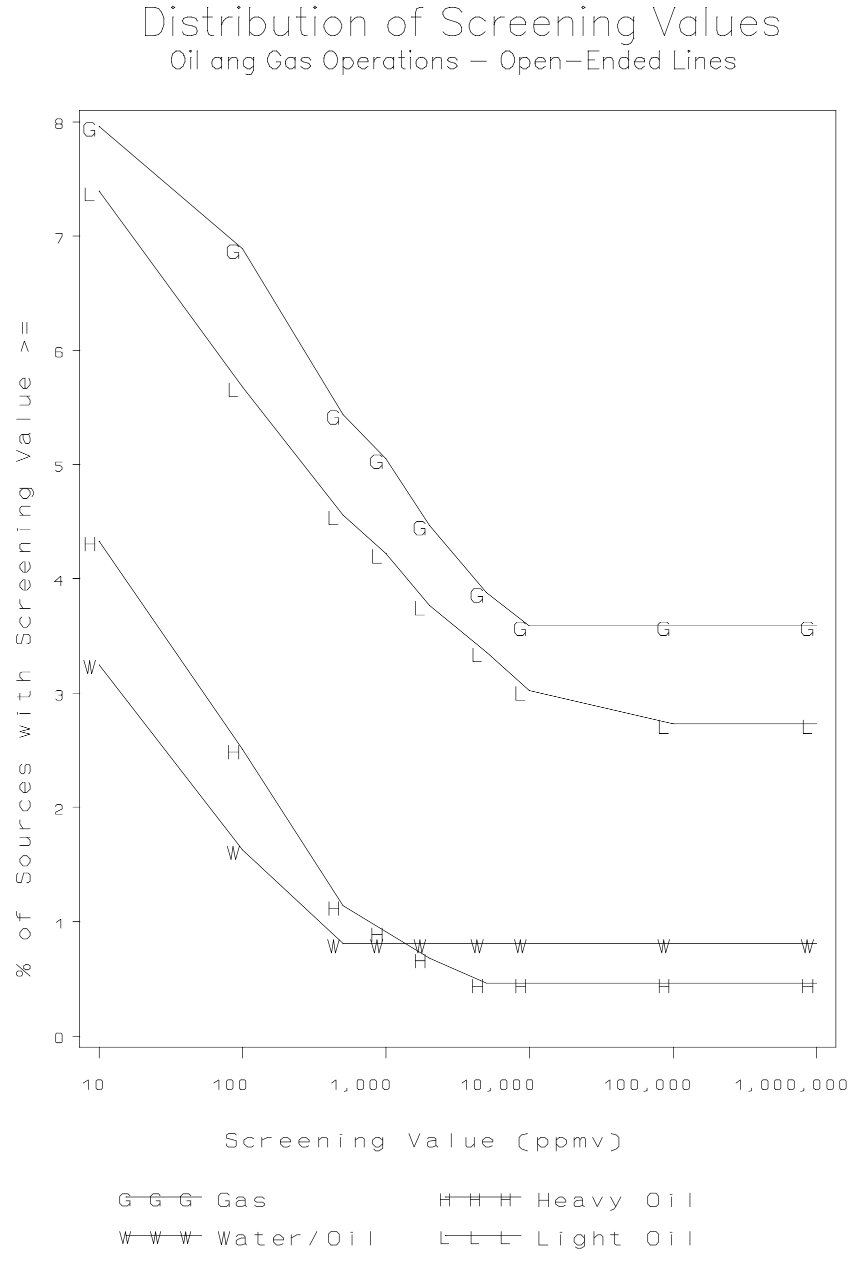

Figure C-4-7. Distribution of Open-Ended Line Screening Values for Oil and Gas Operations

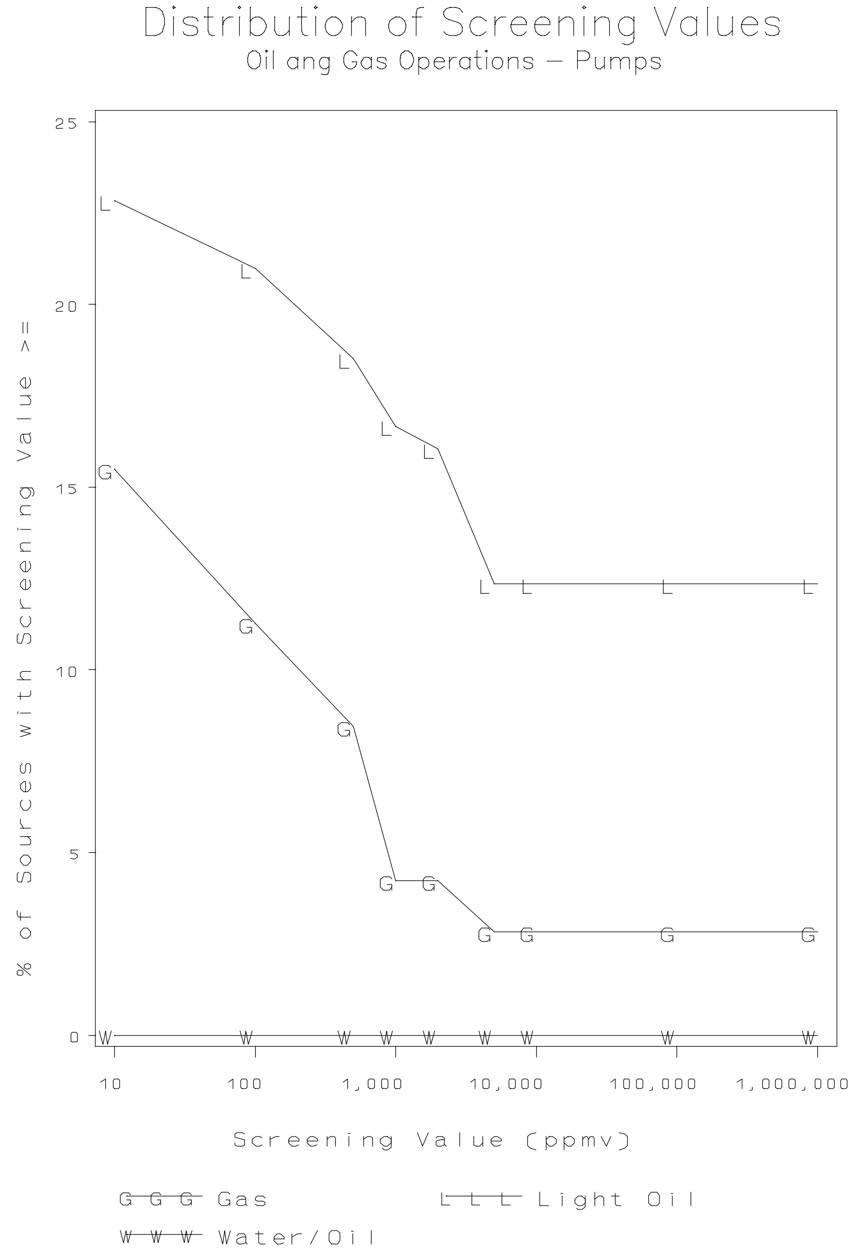

Figure C-4-8. Distribution of Pump Screening Values for Oil and Gas Operations

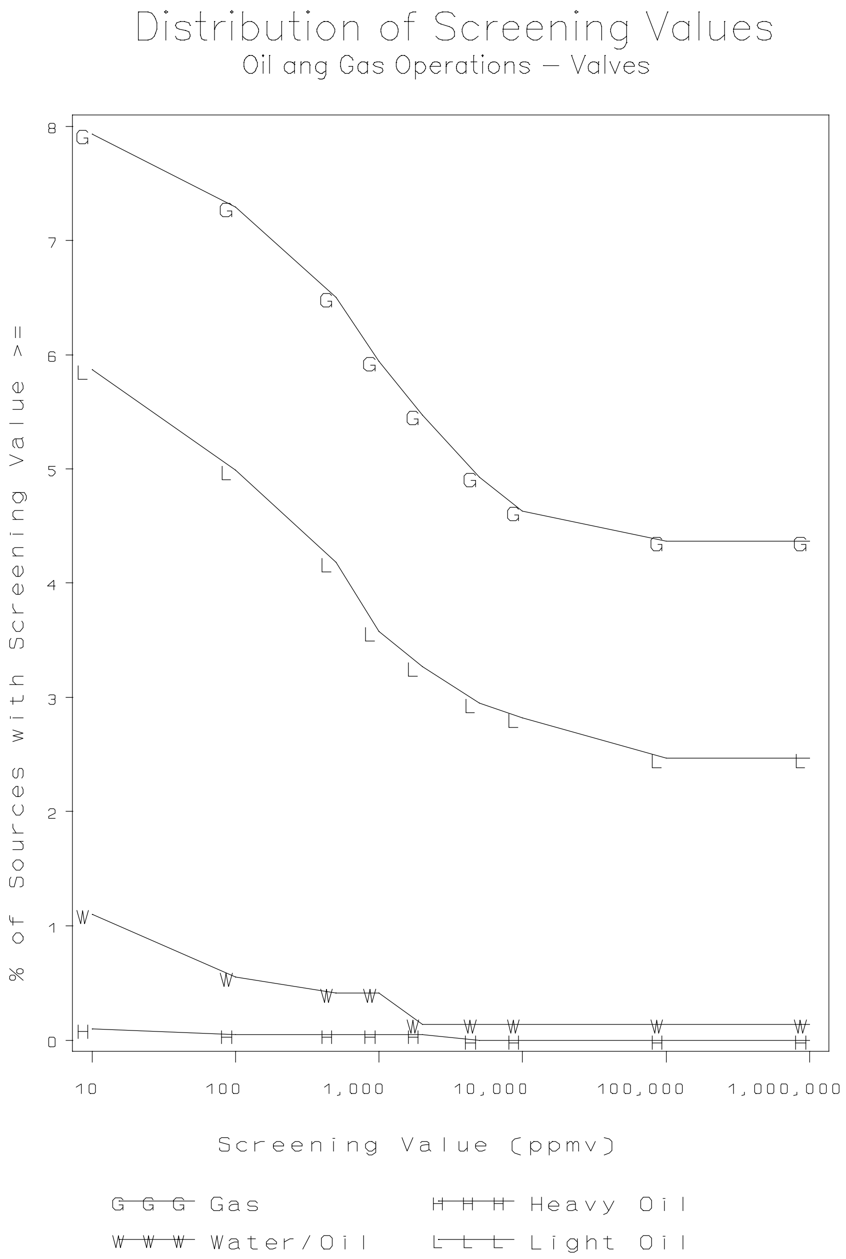

Figure C-4-9. Distribution of Valve Screening Values for Oil and Gas Operations

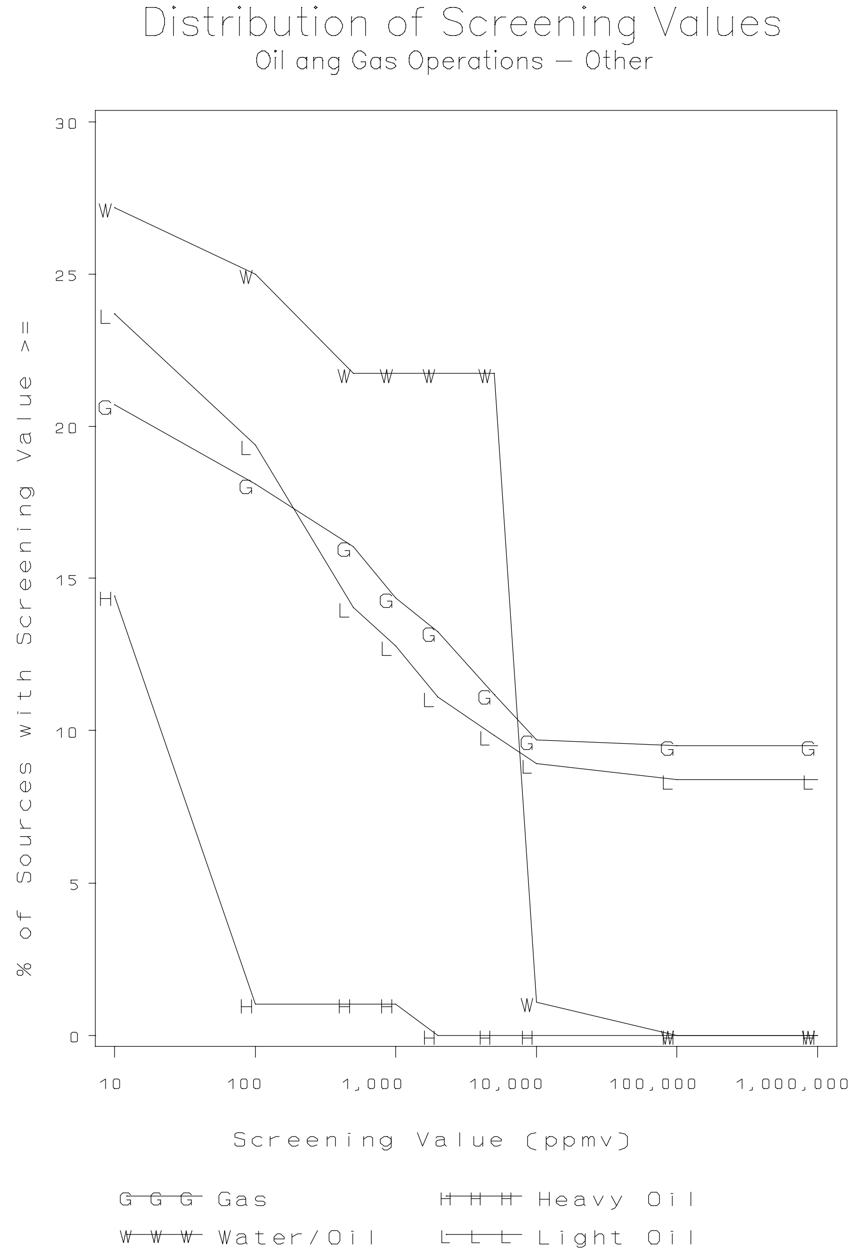

Figure C-4-10. Distribution of Other Screening Values for Oil and Gas Operations

APPENDIX D: RESPONSE FACTORS

APPENDIX D

RESPONSE FACTORS

The response factors presented in table D-1 were taken from two separate sources. The response factors at an actual concentration of 10,000 ppmv are from the EPA document entitled, "Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Chemicals," EPA-600/2-81-002 (September 1980). The document presents results of analytical tests performed to determine the response factors at 10,000 ppmv of two portable monitoring instruments--the Foxboro OVA-108 and the Bacharach TLV-108. Both instruments were calibrated with methane.

The response factors at a concentration of 500 ppmv are from the document entitled "Method 21 Evaluation for the HON, "90-ME-07)" (March 1991) prepared for the Emission Measurement Branch of the U.S. Environmental Protection Agency. This document presents the results of analytical tests performed to determine the response factors at an actual concentration of 500 ppmv of several emission monitors including the Foxboro OVA-108, two of Foxboro OVA-128 units, the Heath Detecto-PAK III, and the HNU Systems HW-101. The two Foxboro OVA-128 instrument response factors are presented in the table to indicate the variability of individual instruments. To determine the response factor for the OVA-128, the average of the two instrument response factors should be used. All of the instruments except the HNU HW-101 were calibrated with methane. The HNU HW-101 was calibrated with benzene.

A dashed line in table D-1 indicates that the study did not test that particular chemical. If the emission monitor did not respond to a chemical, N/R was recorded to indicate no response.

Operators of portable leak detection devices should be thoroughly familiar with their instrumentation. Even under the best of circumstances, no two analyzers will perform exactly the same and the effect of changes in instrument parameters upon accuracy can be significant. Other external quality controls, such as a checklist for periodically noting battery condition, fuel pressure, post-survey calibration checks, etc., will support the validity of the data. An audit program testing both the operator and the analyzer should be a requirement whenever a situation warranting an exacting determination of a fugitive emission is encountered.

In general, the response factors follow the pattern which would be predicted for increasing flame ionization detector response with increasing hydrocarbon character for the molecule. The sequence of compounds methyl chloride, methylene chloride, chloroform, and carbon tetrachloride exhibits progressively decreasing response on the OVA detectors (response factors ranging from 2 to 12) as the substitution on the methyl carbon atom increases (i.e., decreasing hydrocarbon character for the molecule). In general, increasing electronegativity of the substituent decreases the system response: methyl chloride, response factor approximately 2; methyl bromide, response factor approximately 5; iodomethane, response factor approximately 8. Carbon tetrachloride exhibits a response factor of 12 or more, but tetrachloroethylene has a response factor of 2 or less. The lack of carbon-hydrogen bonds in tetrachloroethylene is apparently compensated by the presence of a site of unsaturation in the molecule (chlorobenzene, response factor 0.60 vs. trichlorobenzene, response factor of 12 or greater). The difficulty of obtaining a reproducible and useful response factor for compounds of insufficient volatility such as nitrobenzene, m-cresol, and oxygenated compounds such as acrylic acid demonstrates that there is a point dictated by vapor pressure or possibly boiling point where an accurate measurement cannot be made using the portable field analyzers. With compounds which are not very volatile, the portable field analyzers can be usedonly qualitatively, at best; if a large amount of the compound is present in the air, the compound will be observed but not with a proportionate quantitative response.

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
75-07-0	Acetaldehyde	LL	--	--	8.41	9.96	7.95	5.36	6.07
64-19-7	Acetic Acid	LL	1.83	5.70	--	--	--	--	--
108-24-7	Acetic anhydride	LL	1.36	2.89	--	--	--	--	--
67-64-1	Acetone	LL	0.79	1.22	--	--	--	--	--
75-86-5	Acetone cyanohydrin	HL	3.42	7.84	--	--	--	--	--
75-05-08	Acetonitrile	LL	0.94	1.17	1.20	1.24	1.27	1.27	N/R
98-86-2	Acetophenone	HL	10.98	54.86	2.71	2.62	2.43	2.92	3.07
75-36-5	Acetyl chloride	LL	1.99	2.59	--	--	--	--	--
74-86-2	Acetylene	G	0.37	11.95	--	--	--	--	--
107-02-8	Acrolein	LL	--	--	6.25	6.69	5.64	3.71	2.73
79-10-7	Acrylic acid	LL	4.65	36.95	10.51[c]	10.81[c]	9.63[c]	8.61[c]	8.91[c]
107-13-1	Acrylonitrile	LL	0.96	2.70	1.55	1.58	1.56	1.47	3.04
	Allene	G	0.55	5.78	--	--	--	--	--
107-18-6	Allyl alcohol	LL	0.94		--	--	--	--	--
107-5-1	Allyl chloride	LL	--	--	2.77	2.73	2.51	1.56	1.46
71-41-0c	Amyl alcohol, N-	HL	0.69	1.78	--	--	--	--	--
	Amylene	LL	0.31	1.03	--	--	--	--	--
62-53-3	Aniline	HL	--	--	14.44[c]	20.45[c]	22.68[c]	14.71[c]	15.23[c]
100-66-3	Anisole	LL	0.92	2.69	--	--	--	--	--
100-52-7	Benzaldehyde	HL	2.36	6.30	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
71-43-2	Benzene	LL	0.21	1.07	0.56	0.54	0.50	0.38	1.00
100-47-0	Benzonitrile	HL	2.24	9.13	--	--	--	--	--
98-88-4	Benzoyl Chloride	HL	6.40	6.60	--	--	--	--	--
100-44-7	Benzyl Chloride	HL	4.20	4.87	1.43	1.42	1.21	0.95	1.34
10-86-0	Bromobenzene	LL	0.36	1.16	--	--	--	--	--
75-25-2	Bromoform	LL	--	--	5.90	6.71	5.68	5.12	0.62
106-99-0	Butadiene, 1,3-	G	0.37	6.00	2.41	2.69	2.37	1.68	2.15
106-97-8	Butane, N-	G	0.38	0.68	--	--	--	--	--
71-36-3	Butanol, N-	LL	1.43	2.80	--	--	--	--	--
78-92-2	Butanol, Sec-	LL	0.70	1.26	--	--	--	--	--
75-65-0	Butanol, Tert-	S	0.44	2.19	--	--	--	--	--
106-98-9	Butene, 1-	G	0.51	2.97	--	--	--	--	--
111-76-2	Butoxyethanol, 2-[c]		--	--	19.37[c]	26.11[c]	24.69[c]	13.93[c]	9.23[c]
123-86-4	Butyl acetate	LL	0.60	1.30	--	--	--	--	--
141-32-2	Butyl acrylate, N-	LL	0.64	1.98	--	--	--	--	--
142-96-1	Butyl ether, N-	LL	2.70	2.66	--	--	--	--	--
	Butyl ether, Sec-	LL	0.26	1.13	--	--	--	--	--
109-73-9	Butylamine, N-	LL	0.63	1.91	--	--	--	--	--
13952-84-6	Butylamine, Sec-	LL	0.67	1.50	--	--	--	--	--
75-64-9	Butylamine, Tert-	LL	0.58	1.80	--	--	--	--	--
98-06-6	Butylbenzene, Tert-	HL	1.27	6.42	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
123-72-8	Butyraldehyde, N-	LL	1.39	1.89	--	--	--	--	--
107-92-6	Butyric acid	HL	0.74	4.58	--	--	--	--	--
109-74-0	Butyronitrile	LL	0.46	1.33	--	--	--	--	--
75-1-50	Carbon disulfide	LL	--	2.96	33.87	53.06	N/R	57.06	0.71
56-23-5	Carbon tetrachloride	LL	--	--	12.07	15.99	13.72	11.11	3.06
463-58-1	Carbonyl Sulfide	G	--	--	103.95	N/R	N/R	N/R	3.14
107-20-0	Chloroacetaldehyde	LL	13.40	5.07	--	--	--	--	--
79-04-9	Chloroacetyl chloride	LL	--	--	1.86	1.93	1.66	1.28	3.21
108-90-7	Chlorobenzene	LL	0.36	0.88	0.62	0.60	0.54	0.38	1.06
75-00-3	Chloroethane	G	0.67	2.16	--	--	--	--	--
67-66-3	Chloroform	L	4.48	8.77	2.06	2.38	1.91	1.38	3.35
	Chloromethyl methyl ether		--	--	7.77	9.76	7.52	4.28	1.65
25167-80-0	Chlorophenol, 0-	HL	3.33	5.87	--	--	--	--	--
	50% Chloroprene/xylene		--	--	1.46	1.47	1.27	0.77	1.37
	Chloropropene, 1-	LL	0.59	0.86	--	--	--	--	--
	Chloropropene, 3-	LL	0.75	1.24	--	--	--	--	--
108-41-8	Chlorotoluene, M-	LL	0.43	0.92	--	--	--	--	--
95-49-9	Chlorotoluene, O-	LL	0.45	1.05	--	--	--	--	--
106-43-4	Chlorotoluene, P-	LL	0.52	1.15	--	--	--	--	--
95-48-7	Cresol, O-	S	0.95	3.98	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
108-39-4	Cresol, M-	LL	--	--	75.60[c]	115.20[c]	N/R	N/R	N/R
106-44-5	Cresol, P-	S	--	--	N/R	N/R	N/R	N/R	N/R
4170-30-0	Crotonaldehyde	LL	1.32	8.54	--	--	--	--	--
98-82-8	Cumene	LL	1.92	12.49	2.05	1.82	1.55	0.79	1.87
110-82-7	Cyclohexane	LL	0.36	0.72	--	--	--	--	--
108-93-0	Cyclohexanol	HL	0.82	4.92	--	--	--	--	--
108-94-1	Cyclohexanone	LL	1.50	3.99	--	--	--	--	--
110-83-8	Cyclohexene	LL	0.40	1.84	--	--	--	--	--
108-91-8	Cyclohexylamine	LL	0.47	1.38	--	--	--	--	--
124-18-5	Decane	HL	0.00	0.20	--	--	--	--	--
123-42-2	Diacetone alcohol	HL	1.53	0.98	--	--	--	--	--
431-03-8	Diacetyl	LL	1.61	2.81	--	--	--	--	--
	Dichloro-1-propene, 2,3-	LL	61.51	34.34	--	--	--	--	--
541-73-1	Dichlorobenzene, M-	HL	0.66	1.89	--	--	--	--	--
95-50-1	Dichlorobenzene, O-	HL	0.70	1.22	--	--	--	--	--
75-34-3	Dichloroethane, 1,1-	LL	0.77	1.80	--	--	--	--	--
107-06-2	Dichloroethane, 1,2-	LL	0.95	2.08	--	--	--	--	--
540-59-0	Dichloroethylene, 2-	LL	1.31	1.93	--	--	--	--	--
540-59-0	Dichloroethylene, TRANS, 1,2	LL	1.13	1.86	--	--	--	--	--
111-44-4	Dichloroethyl ether[c]		--	--	22.12[c]	25.10[c]	24.48[c]	16.88[c]	8.79[c]

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
	Dichloromethane	LL	2.26	3.63	--	--	--	--	--
	Dichloropropane, 1,2-	LL	1.03	1.80	--	--	--	--	--
542-75-6	Dichloropropene, 1,3-		--	--	2.03	2.08	1.93	1.23	1.18
25167-70-8	Diisobutylene	LL	0.24	1.39	--	--	--	--	--
	Dimethoxy ethane, 1,2-	LL	1.28	1.43	--	--	--	--	--
68-12-2	Dimethylformamide, N,N-	LL	3.89	2.95	6.42	6.38	7.20	7.09	5.73
57-14-7	Dimethylhydrazine, 1,1-	LL	1.04	2.74	2.68	2.84	3.00	2.89	2.29
67-68-5	Dimethylsulfoxide	HL	0.00	4.88	--	--	--	--	--
123-91-1	Dioxane, 1,4-	LL	1.58	1.23	3.74	4.27	3.60	3.21	1.66
106-89-8	Epichlorohydrin	LL	1.72	2.02	2.30	2.41	2.07	1.27	1.95
106-88-7	Epoxybutane, 1,2-		--	--	2.67	2.54	2.16	1.89	2.68
74-84-0	Ethane	G	0.57	0.73	--	--	--	--	--
64-17-5	Ethanol	LL	2.04	--	--	--	--	--	--
110-80-5	Ethoxy ethanol, 2-	LL	1.68	1.61	3.55	4.09	3.50	2.02	1.70
141078-6	Ethyl acetate	LL	0.84	3.13	--	--	--	--	--
141-97-9	Ethyl acetoacetate	HL	3.02	3.13	--	--	--	--	--
140-88-5	Ethyl acrylate	LL	0.72	--	2.49	2.64	2.18	1.16	1.09
75-00-3	Ethyl chloride	G	--	--	1.68	1.84	1.65	1.10	2.38
105-39-5	Ethyl chloroacetate	LL	1.97	1.47	--	--	--	--	--
60-29-7	Ethyl Ether	LL	0.97	1.11	--	--	--	--	--
100-41-4	Ethylbenzene	LL	0.70	3.14	0.77	0.76	0.66	0.51	1.08

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
74-85-1	Ethylene	G	0.52	4.49	--	--	--	--	--
106-93-4	Ethylene dibromide		--	--	2.03	2.22	2.03	1.36	0.98
107-06-2	Ethylene dichloride	LL	--	--	1.37	1.59	1.41	1.19	1.42
107-21-1	Ethylene glycol[c]		--	--	24.81	39.39	N/R	33.13	10.91
75-21-8	Ethylene oxide	G	2.72	2.43	2.40	2.77	2.40	1.81	6.61
107-15-3	Ethylenediamine	LL	1.78	2.46	--	--	--	--	--
64-18-6	Formic Acid	LL	34.87	33.21	--	--	--	--	--
	Formalin (37% formaldehyde/H_2O)		--	--	18.83	31.39	27.66	16.50	4.04
556-52-5	Glycidol	LL	8.42	5.23	--	--	--	--	--
142-82-5	Heptane	LL	0.30	0.75	--	--	--	--	--
87-68-3	Hexachlorobutadiene[c]		--	--	16.28[c]	22.99[c]	18.06[c]	14.56[c]	19.34[c]
100-54-3	Hexane, N-	LL	0.31	0.72	1.42	1.49	1.33	0.93	1.49
592-41-6	Hexene, 1-	LL	0.39	2.92	--	--	--	--	--
	Hydroxyacetone	LL	8.70	9.34	--	--	--	--	--
74-88-4	Iodomethane		--	--	8.06	8.76	7.35	4.59	0.72
75-28-5	Isobutane	G	0.30	0.61	--	--	--	--	--
115-11-7	Isobutylene	G	2.42	6.33	--	--	--	--	--
540-84-1	Isooctane	LL	--	--	1.05	1.05	0.89	0.56	0.98
78-79-5	Isoprene	LL	0.38	--	--	--	--	--	--
78-59-1	Isophorone[c]		--	--	28.80	40.71	N/R	29.69	17.76

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
67-63-0	Isopropanol	LL	0.90	1.35	--	--	--	--	--
108-21-4	Isopropyl acetate	LL	0.68	1.25	--	--	--	--	--
75-29-6	Isopropyl chloride	LL	0.62	0.99	--	--	--	--	--
590-86-3	Isovaleraldehyde	LL	0.55	2.04	--	--	--	--	--
141-79-7	Mesityl oxide	LL	1.12	3.12	--	--	--	--	--
78-85-3	Methacrolein	LL	1.27	3.10	--	--	--	--	--
79-41-4	Methacrylic acid	HL	0.71	6.61	--	--	--	--	--
67-56-1	Methanol	LL	5.69	1.88	13.24	17.34	N/R	21.73	4.59
111-90-0	Methoxy-ethanol, 2-	LL	2.70	2.19	9.61[c]	9.87[c]	N/R	7.91[c]	2.80[c]
79-20-9	Methyl acetate	LL	1.80	1.76	--	--	--	--	--
74-99-7	Methyl acetylene	G	0.53	3.92	--	--	--	--	--
74-83-9	Methyl bromide	G	--	--	3.71	3.83	3.46	2.43	1.47
74-87-3	Methyl chloride	G	1.75	2.45	1.97	2.38	1.97	1.27	1.77
78-93-3	Methyl ethyl ketone	LL	0.57	1.12	1.78	1.84	1.59	1.19	2.92
107-31-3	Methyl formate	LL	3.47	1.93	--	--	--	--	--
60-34-4	Methyl hydrazine	LL	--	--	5.47	5.50	5.74	5.44	3.93
108-10-1	Methyl isobutyl ketone	LL	--	--	1.65	1.69	1.40	0.98	1.46
80-62-6	Methyl methacrylate	LL	0.99	2.36	2.02	2.16	1.81	0.92	1.84
	Methyl tert-butyl ketone		--	--	1.23	1.25	1.03	0.72	1.69
108-11-2	Methyl-2-pentanol, 4-	LL	1.70	1.94	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
	Methyl-2-pentanone, 4-	LL	0.49	1.54	--	--	--	--	--
	Methyl-3-butyn-2-OL, 2-	LL	0.51	--	--	--	--	--	--
109-87-5	Methylal	LL	1.46	1.41	--	--	--	--	--
100-61-8	Methylaniline, N-	HL	4.13	5.25	--	--	--	--	--
108-87-2	Methylcyclohexane	LL	0.38	0.85	--	--	--	--	--
	Methylcyclohexene, 1-	LL	0.33	2.22	--	--	--	--	--
75-09-2	Methylene chloride	LL	2.26	3.63	1.67	1.72	1.41	0.84	2.06
77-75-8	Methylpentynol	LL	1.17	2.82	--	--	--	--	--
98-83-9	Methylstyrene, A-	LL	10.24	31.46	--	--	--	--	--
110-91-8	Morpholine	LL	0.92	1.93	--	--	--	--	--
98-95-3	Nitrobenzene	HL	29.77	40.61	16.41[c]	16.52[c]	N/R	26.01[c]	19.98[c]
79-24-3	Nitroethane	LL	1.40	2.54	--	--	--	--	--
75-52-5	Nitromethane	LL	3.32	5.25	--	--	--	--	--
24332-01-4	Nitropropane, 2-	LL	1.06	1.77	1.86	1.91	1.60	1.06	3.29
111-84-2	Nonane-N	LL	1.62	5.54	--	--	--	--	--
111-65-9	Octane	LL	1.04	2.06	--	--	--	--	--
	Phenol (90% carboxylic acid)	LL	--	--	16.38	44.89	47.01	N/R	71.06
109-66-0	Pentane	LL	0.42	0.62	--	--	--	--	--
109-06-8	Picoline, 2-	LL	0.34	1.17	--	--	--	--	--
74-98-6	Propane	G	0.88	0.63	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
123-38-6	Propionaldehyde	LL	1.19	1.65	4.01	4.27	3.95	2.53	4.79
79-09-4	Propionic acid	LL	1.34	3.51	--	--	--	--	--
71-23-8	Propyl alcohol	LL	0.91	1.55	--	--	--	--	--
103-65-1	Propylbenzene, N-	LL	0.44	5.97	--	--	--	--	--
115-07-1	Propylene	G	0.79	2.80	--	--	--	--	--
78-87-5	Propylene dichloride	LL	--	--	1.49	1.48	1.26	0.84	1.37
75-56-0	Propylene oxide	LL	0.80	1.15	2.02	2.14	1.78	1.26	3.09
75-55-8	Propyleneimine, 1,2-		--	--	1.75	1.52	1.53	1.33	2.31
110-86-1	Pyridine	LL	0.41	1.17	--	--	--	--	--
100-42-5	Styrene	LL	4.16	36.83	1.10	1.08	0.93	0.57	1.36
96-09-3	Styrene Oxide	L	--	--	2.61	2.49	2.06	2.61	3.03
79-34-5C	Tetrachloroethane, 1,1,1,2-	LL	3.00	6.52	--	--	--	--	--
	Tetrachloroethane, 1,1,2,2-	LL	6.06	14.14	1.64	1.69	1.66	1.14	1.52
127-18-4	Tetrachloroethylene	LL	3.16	11.46	1.77	2.09	1.72	1.20	0.74
108-88-3	Toluene	LL	0.33	2.32	0.87	0.87	0.76	0.57	1.25
120-82-1	Trichlorobenzene, 1,2,4		1.35	0.39	12.55	16.71	N/R	18.66	16.58
71-55-6	Trichloroethane, 1,1,1-	LL	0.79	2.41	1.09	1.16	1.03	0.70	1.85
79-00-5	Trichloroethane, 1,1,2-	LL	1.26	3.68	1.19	1.27	1.11	0.79	1.33
79-01-6	Trichloroethylene	LL	0.94	3.35	2.26	2.60	2.14	1.25	1.09
96-18-4	Trichloropropane, 1,2,3-	LL	0.95	2.23	--	--	--	--	--

TABLE D-1. RESPONSE FACTORS AT ACTUAL CONCENTRATIONS OF 10,000 PPMV AND 500 PPMV (Cont.)

			Actual Concentration: 10,000 ppmV		Actual Concentration: 500 ppmV				
CAS No.#	Compound Name	Volatility Class	Foxboro OVA - 108[a]	Bacharach TLV[a]	Foxboro OVA - 108[a]	Foxboro OVA - 128[a]	Foxboro OVA - 128[a]	Heath DP III[a]	HNU HW - 101[b]
121-44-8	Triethylamine	LL	0.46	1.41	0.47	0.49	0.48	0.35	0.73
108-05-4	Vinyl acetate	LL	1.31	3.99	3.63	3.36	2.80	1.48	2.07
593-60-2	Vinyl bromide	G	--	--	2.14	2.41	2.33	1.68	1.37
75-01-4	Vinyl chloride	G	0.65	1.10	2.03	2.11	2.11	1.76	2.18
	Vinyl propionate	LL	0.94	0.70	--	--	--	--	--
75-35-4	Vinylidene chloride	LL	1.15	2.38	2.73	2.97	2.61	1.79	1.70
106-42-3	Xylene, P-	LL	2.27	5.35	0.89	0.88	0.74	0.54	0.93
108-38-3	Xylene, M-	LL	0.30	3.56	0.89	0.89	0.75	0.54	0.96
95-47-6	Xylene, O-	LL	0.36	1.40	0.95	0.95	0.80	0.60	1.09

N/R = No response
[a] = Calibrated with methane in air.
[b] = Calibrated with benzene in air.
[c] = Volatility problem with compound.

APPENDIX E

SELECTION OF SAMPLE SIZE FOR SCREENING CONNECTORS

APPENDIX E

SELECTION OF SAMPLE SIZE FOR SCREENING CONNECTORS

In estimating emissions for a given process unit, all equipment components must be surveyed for each class of components. The one exception to this "total component screening" criterion is the category of connectors. Note however, that if the process unit is subject to a standard which requires the screening of connectors, then all connectors must be screened. In typical process units, connectors represent the largest count of individual equipment components, making it costly to screen all components. The purpose of this appendix is to present a methodology for determining how many connectors must be screened to constitute a large enough sample size to identify the actual screening value distribution of connectors in the entire process unit. Please note that the sampling is to be a random sampling throughout the process unit.

The basis for selecting the sample population to be screened is the probability that at least one "leaking" connector will be in the screened population. The "leaker" is used as a representation of the complete distribution of screening values for the entire class of sources. The following binomial distribution was developed to approximate the number of connectors that must be screened to ensure that the entire distribution of screening values for these components is represented in the sample:

$$n \geq N \times \{1 - (1 - p)^{1/D}] \qquad \text{(E-1)}$$

where:

N = Number of connectors;

D = (fraction of leaking connectors) × N; and

$p \geq 0.95$.

Refer to figure E-1, which shows the fraction of leaking connectors at several leak definitions based on currently available data. Since the fraction of leaking connectors will most likely not be known prior to screening, the leaking fraction at the intersection of the SOCMI average emission factor line and applicable leak definition line on figure F-1 can be used to estimate what the fraction of leaking connectors will be. Entering this value into equation E-1 for at least a 95 percent confidence interval (p = 0.95) will give the minimum number of connectors that need to be screened. A larger sample size will be required for units exhibiting a lower fraction of leaking connectors.

After ’n’ connectors have been screened, an actual leak frequency should be calculated as follows:

$$\text{Leaking frequency} = \frac{\text{Number of leaking connectors}}{n} \qquad \text{(E-2)}$$

Then, the confidence level of the sample size can be calculated using the following equation, based upon a hypergeometric distribution:

$$P = 1 - \frac{(N-D')!\ (N-n)!}{N!\ (N-D'-n)!} \qquad \text{(E-3)}$$

where:

N = Total population of connectors;

n = Sample size; and

$D' = \frac{\text{Number of leaking connectors}}{n} \times N$

If ’p’ calculated in this manner is less than 0.95, then a less than 95 percent confidence exists that the screening value distribution has been properly identified. Therefore, additional connectors must be screened to achieve a 95 percent confidence level. The number of additional connectors required to satisfy the requirement for a 95 percent confidence level can be calculated by solving Equation (E-1) again, using the leak frequency calculated in Equation (E-2), and subtracting the

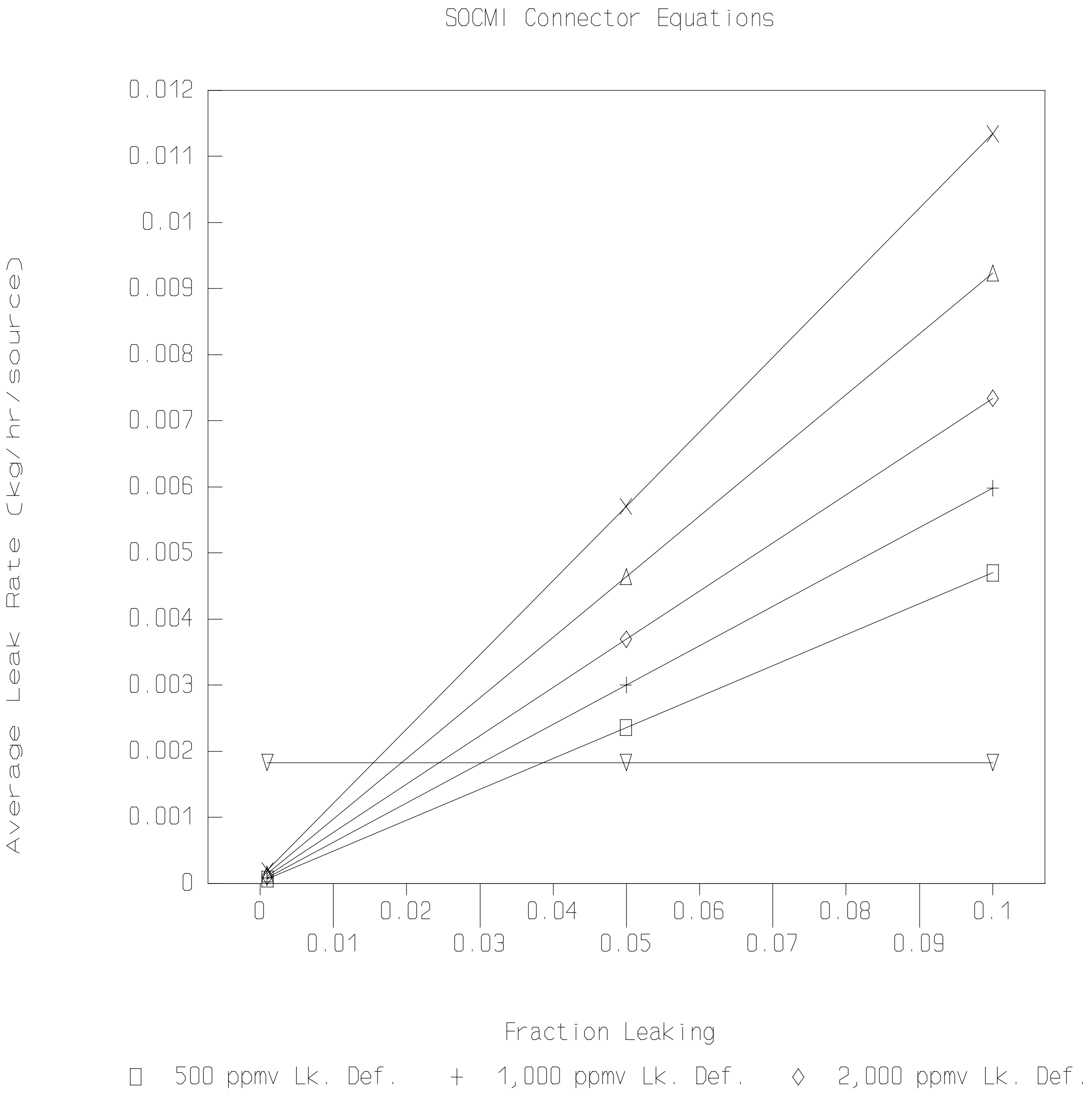

Figure E-1. Fraction of Leaking Connectors at Several Leak Definitions original sample size. After this additional number of connectors have been screened, the revised fraction of leaking components and the confidence level of the new sample size (i.e., the original sample size plus the additional connectors screened) should be recalculated using Equation (E-3). The Agency requires sufficient screening to achieve a 95 percent confidence level, until a maximum of 50 percent of the total number of connectors in the process unit have been screened. The EPA believes that 50 percent of the total connector population is a reasonable upper limit for a sample size. If half of the total number of connectors are screened, no further connector screening is necessary, even if a 95 percent confidence level has not been achieved.

APPENDIX F

REFERENCE METHOD 21

(Code of Federal Regulations, Title 40, Part 60, Appendix A. Reference Method 21, Determination of Volatile Organic Compound Leaks. Washington, D.C., U.S. Government Printing Office. Revised June 22, 1990.)

EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER
NSPS TEST METHOD

(EMTIC M-21, 2/9/93)

Method 21 - Determination of Volatile Organic Compound Leaks

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This method applies to the determination of volatile organic compound (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.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

2. DEFINITIONS

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present, The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppm, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. The total VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is not present. Since background VOC concentrations may exist, and to account for instrument drift and imperfect reproducibility, a difference between the source surface concentration and the local ambient concentration is determined. A difference based on the meter readings of less than a concentration corresponding to the minimum readability specification indicates that a VOC emission (leak) is not present. (For example, if the leak definition in a regulation is 10,000 ppm, then the allowable increase is surface concentration versus local ambient concentration would be 500 ppm based on the instrument meter readings.)

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 Response Time. The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. APPARATUS

3.1 Monitoring Instrument.

3.1.1 Specifications

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

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

c. The scale of the instrument meter shall be readable to + or - 5 percent of the specified leak definition concentration.

d. The instrument shall be equipped with a pump so that a continuous sample is provided to the detector. The nominal sample flow rate shall be 0.1 to 3.0 liters per minute.

e. The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the applicable U.S.A. standards (e.g., National Electrical Code by the National Fire Prevention Association).

f. The instrument shall be equipped with a probe or probe extension for sampling not to exceed 1/4 in. in outside diameter, with a single end opening for admission of sample.

3.1.2 Performance Criteria.

a. The instrument response factors for the individual compounds to be measured must be less than 10.

b. The instrument response time must be equal to or less than 30 seconds. The response time must be determined for the instrument configuration to be used during testing.

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

d. The evaluation procedure for each parameter is given in section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

b. 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.

c. 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.

3.2 Calibration Gases.

The monitoring instrument is calibrated in terms of parts per million by volume (ppm) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppm VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within + or - 2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternatively, calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within + or - 2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. PROCEDURES

4.1 Pretest Preparations. Perform the instrument evaluation procedure given in section 4.4 if the evaluation requirement of section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup 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.)

4.3 Individual Source Surveys.

4.3.1 Type I - Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves - Leaks usually occur at the seal between the stem and the housing. Place the probe at the interface where the stem exits the packing and sample the stem circumference and the flange periphery. Survey valves of multipart assemblies where a leak could occur.

b. Flanges and Other Connections - Place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange.

c. Pump or Compressor Seals - If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described above.

d. Pressure Relief Devices - For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

e. Process Drains - For open drains, place the probe inlet as near as possible to the center of the area open to the atmosphere. For covered drains, locate probe at the surface of the cover and traverse the periphery.

f. Open-ended Lines or Valves - Place the probe inlet at approximately the center of the opening of the atmosphere.

g. Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices - If applicable, observe whether the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur before the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere before the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in this section shall be used to determine if detectable emissions exist.

h. Access door seals - Place the probe inlet at the surface of the door seal interface and traverse the periphery.

4.3.2 Type II - "No Detectable Emission". Determine the ambient concentration around the source by moving the probe randomly upwind and downwind around one to two meters from the source. In case of interferences, this determination may be made closer to the source down to no closer than 25 centimeters. Then move the probe to the surface of the source and measure as in 4.3.1. The difference in these concentrations determines whether there are no detectable emissions. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are: (a) Pump or Compressor Seals - Survey the local area ambient VOC concentration and determine if detectable emissions exist. (b) Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices - Determine if any VOC sources exist upstream of the device. If such ducting exists and emissions cannot be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If venting is possible sample to determine if detectable emissions are present.

4.3.3 Alternative Screening Procedure.

4.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of section 4.3.1 or 4.3.2.

4.3.3.2 Spray a soap solution over all potential leak sources. The soap Solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water.

A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of section 4.3.1 or 4.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

4.4 Instrument Evaluation Procedures. At the beginning of the instrument performance evaluation test, assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

4.4.1 Response Factor.

4.4.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration of approximately 80 percent of the applicable leak definition unless limited by volatility or explosivity. In these cases, prepare a standard at 90 percent of the standard saturation concentration, or 70 percent of the lower explosive limit, respectively. Introduce this mixture to the analyzer and record the observed meter reading. Introduce zero air until a stable reading is obtained. Make a total of three measurements by alternating between the known mixture and zero air. Calculate the response factor for each repetition and the average response factor.

4.4.1.2 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in the Bibliography.

4.4.2 Calibration Precision. 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.

4.4.3 Response Time. Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. Measure the time from switching to when 90 percent of the final stable reading is attained. Perform this test sequence three times and record the results. Calculate the average response time.

5. BIBLIOGRAPHY

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APPENDIX G

DEVELOPMENT OF LEAK RATE VERSUS FRACTION LEAKING EQUATIONS AND DETERMINATION OF LDAR CONTROL EFFECTIVENESS

APPENDIX G

The purpose of this appendix is to provide additional information on the approach used to develop the average leak rate versus fraction leaking equations presented in chapter 5.0. Also, background information is presented on the determination of control effectiveness of LDAR programs at SOCMI process units and refinery process units.

G.1 DEVELOPMENT OF AVERAGE LEAK RATE VERSUS FRACTION LEAKING EQUATIONS

In chapter 5.0, tables 5-4 and 5-5 present equations that predict average leak rate based on the fraction leaking at SOCMI process units and refinery process units, respectively. Equations are presented for gas valves, light liquid valves, light liquid pumps, and connectors, and each of the equations are plotted in figures 5-1 through 5-8.

The equations are expressed in the following format:

$$\text{Average Leak Rate} = (\text{Slope} \times \text{Fraction Leaking}) + \text{Intercept}$$

The average leak rate has units of kilograms per hour per source. The fraction leaking is the fraction of sources that screen greater than or equal to the applicable leak definition. The leak definition is the screening value at which a leak is indicated. (For example an equipment leak regulation may have a leak definition of 10,000 ppmv.) Equations were developed for several possible leak definitions.

Using the applicable equation, if it is known what percentage of sources screen greater than or equal to the leak definition, then an overall average leak rate for all sources can be estimated. If the fraction leaking before and after an LDAR program is implemented are known, then the average leak rates before and after the program can be determined. These average leak rates before and after the program are used to calculate the control efficiency of the program.

The leak rate versus fraction leaking equations were developed using the following procedure:

STEP 1: Determine average emission factors for (1) screening values greater than or equal to the applicable leak definition, and (2) screening values less than the applicable definition.

STEP 2: The average emission factor for screening values less than the leak definition is the intercept in the equation.

STEP 3: The average emission factor for screening values greater than or equal to the leak definition minus the average emission factor for screening values less than the leak definition is the slope in the equation.

An example of the above steps is presented for gas valves in a SOCMI process units for a leak definition of 10,000 ppmv. From table 2-4 the gas valve $\geq$10,000 ppmv emission factor is 0.0782 kg/hr and the <10,000 ppmv factor is 0.000131 kg/hr. Thus, the equation relating average leak rate to fraction leaking for SOCMI gas valves with a leak definition of 10,000 ppmv is as follows:

$$\begin{aligned} \text{Avg Leak Rate (kg/hr)} &= [(0.0782-0.000131) \times FL] + 0.000131 \\ &= (0.0781 \times FL) + 0.000131 \end{aligned}$$

where:

FL = Fraction leaking.

Notice that when applying the above equation if 100 percent of the gas valves screened less than 10,000 ppmv, the equation predicts an average leak rate equal to the <10,000 ppmv factor. Similarly, if 100 percent of sources screened greater than or equal to 10,000 ppmv, the equation predicts an average leak rate equal to the $\geq$10,000 ppmv factor.

For SOCMI process units, equations were developed for each of the equipment types for leak definitions of 500 ppmv, 1,000 ppmv, 2,000 ppmv, 5,000 ppmv, and 10,000 ppmv. For each of the leak definitions, the greater than or equal to factors and the less than factors were developed by entering the applicable screening data from the combined screening data set into the applicable revised SOCMI correlation equation (see appendix B). For example, the <500 ppmv factor for connectors was estimated by entering all connector screening data with values less than 500 ppmv from the combined screening dataset into the revised SOCMI connector correlation equation. The sum of total emissions divided by the number of screening values gives the <500 ppmv connector average emission factor.

For refinery process units, equations were developed for each of the equipment types for leak definitions of 500 ppmv, 1,000 ppmv and 10,000 ppmv. The refinery ≥10,000 ppmv and <10,000 ppmv emission factors had previously been developed and are presented in table 2-5. The same approach used to develop the ≥10,000/<10,000 ppmv refinery factors was used to develop the factors for leak definitions of 500 ppmv and 1,000 ppmv. This approach involves using information from the Refinery Assessment Study (EPA-600/2-80-075c) on the cumulative distribution of emissions and screening values.

G.2 CONTROL EFFECTIVENESS CALCULATIONS

In addition to the equations described in section G.1, chapter 5.0 presents estimated control effectiveness values at SOCMI and refinery process units for control equivalent to:

(1) Monthly LDAR program with a leak definition of 10,000 ppmv;

(2) Quarterly LDAR program with a leak definition of 10,000 ppmv; and

(3) Control equivalent to the LDAR program required by the proposed hazardous organic NESHAP equipment leaks negotiated regulation.

Tables G-1 and G-2 summarize how the control effectiveness values of the above LDAR programs were determined for SOCMI and refinery process units, respectively.

The approach for calculating the control effectiveness of a LDAR program is discussed in detail in chapter 5.0. The approach involves determining the average leak rate before and after the LDAR program is implemented. The average leak rates before and

TABLE G-1. DETERMINATION OF LDAR CONTROL EFFECTIVENESS AT SOCMI PROCESS UNITS

					Steady-state leak fraction after LDAR implemented (percent)				
Equipment type	Control program	Leak definition (ppmv)	Initial leak fraction (percent)	Initial leak rate (kg/hr)	Immediately after LDAR monit.	Immediately prior to LDAR monit.	Cycle average	Final leak rate (kg/hr)	LDAR control effectiveness (percent)
LL Valves	Monthly	10000	4.3	0.0040	0.20	0.88	0.54	0.00064	84
	Quarterly	10000	4.3	0.0040	0.59	2.61	1.60	0.00159	61
	HON reg neg	500	8.5	0.0040	0.00	2.00	1.00	0.00050	88
Gas Valves	Monthly	10000	7.5	0.0060	0.29	1.29	0.79	0.00075	87
	Quarterly	10000	7.5	0.0060	0.86	3.80	2.33	0.00195	67
	HON reg neg	500	13.6	0.0060	0.00	2.00	1.00	0.00045	92
LL Pumps	Monthly	10000	7.5	0.0199	0.00	3.53	1.77	0.00613	69
	Quarterly	10000	7.5	0.0199	0.00	7.50	3.75	0.01092	45
	HON reg neg	1000	17.1	0.0199	0.00	8.04	4.02	0.00501	75
Connectors	HON reg neg	500	3.9	0.0018	0.00	0.50	0.25	0.00013	93

TABLE G-2. DETERMINATION OF LDAR CONTROL EFFECTIVENESS AT REFINERY PROCESS UNITS

Equipment type	Control program	Leak definition (ppmv)	Initial leak fraction (percent)	Initial leak rate (kg/hr)	Immediately after LDAR monit.	Immediately prior to LDAR monit.	Cycle average	Final leak rate (kg/hr)	LDAR control effectiveness (percent)
LL Valves	Monthly	10000	11.0	0.0109	0.39	1.72	1.06	0.00258	76
	Quarterly	10000	11.0	0.0109	1.15	5.07	3.11	0.00430	61
	HON reg neg	500	28.5	0.0109	0.00	2.00	1.00	0.00057	95
Gas Valves	Monthly	10000	10.0	0.0268	0.36	1.60	0.98	0.00317	88
	Quarterly	10000	10.0	0.0268	1.06	4.69	2.88	0.00813	70
	HON reg neg	500	24.0	0.0268	0.00	2.00	1.00	0.00120	96
LL Pumps	Monthly	10000	24.0	0.1140	0.00	11.28	5.64	0.03597	68
	Quarterly	10000	24.0	0.1140	0.00	24.00	12.00	0.06300	45
	HON reg neg	1000	48.0	0.1140	0.00	10.00	5.00	0.01365	88
Connectors	HON reg neg	500	1.7	0.00025	0.00	0.50	0.25	0.00005	81

after implementing the LDAR program are estimated by entering the fraction leaking before and after implementing the program into the equations described in section G.1.

For SOCMI process units, the fraction leaking before implementing the LDAR program was based on the percentage of equipment screening above the applicable leak definition in the combined SOCMI screening dataset. (See appendix B.) Similarly, the initial fraction leaking for refinery process units was based on data from the Refinery Assessment Study on the percentage of equipment screening above the applicable leak definition. Note that each of the initial leak fractions predict leak rates equal to the applicable SOCMI or refinery average emission factors (tables 2-1 and 2-2) when entered into the applicable equation described in section G.1. In other words, when estimating the control effectiveness for the SOCMI and refinery LDAR programs, it has been assumed that prior to implementing the program equipment leak emissions are equivalent to emissions that would be predicted by the average emission factors.

The fraction leaking after implementing the LDAR program is assumed to be the average of the "steady-state" fraction leaking immediately before and after a monitoring cycle (see discussion in chapter 5.0). The following parameters are used to estimate the steady-state leak fractions:

- recurrence rate,
- unsuccessful repair rate, and
- occurrence rate.

The values used for these parameters are summarized in table G-3 for both SOCMI and refinery process units.

The paragraphs below summarize the approach used to determine the above parameters. First, the approach used to determine the parameters in a program with a leak definition of 10,000 ppmv is described. Then, the approach used to determine the parameters in a program equivalent to the proposed hazardous organic NESHAP equipment leaks negotiated regulation is described.

TABLE G-3. PARAMETERS USED TO CALCULATE STEADY-STATE LEAK FRACTION AFTER LDAR PROGRAM IS IMPLEMENTED

Equipment type	Control program	Leak definition (ppmv)	Recurrence rate[a] (percent)	Unsuccessful repair rate[a] (percent)	Initial leak fraction[b] (percent)	Occurrence rate[c] (percent)
PARAMETER VALUES FOR SOCMI PROCESS UNITS						
LL Valves	Monthly	10000	14	10	4.3	0.68
	Quarterly	10000	14	10	4.3	2.03
	HON reg neg	500	0	0	8.5	2.00
Gas Valves	Monthly	10000	14	10	7.5	1.00
	Quarterly	10000	14	10	7.5	2.97
	HON reg neg	500	0	0	13.6	2.00
LL Pumps	Monthly	10000	0	0	7.5	3.53
	Quarterly	10000	0	0	7.5	7.50
	HON reg neg	1000	0	0	17.1	8.04
Connectors	HON reg neg	500	0	0	3.9	0.50
PARAMETER VALUES FOR REFINERY PROCESS UNITS						
LL Valves	Monthly	10000	14	10	11.0	1.34
	Quarterly	10000	14	10	11.0	3.97
	HON reg neg	500	0	0	28.5	2.00
Gas Valves	Monthly	10000	14	10	10.0	1.24
	Quarterly	10000	14	10	10.0	3.67
	HON reg neg	500	0	0	24.0	2.00
LL Pumps	Monthly	10000	0	0	24.0	11.28
	Quarterly	10000	0	0	24.0	24.00
	HON reg neg	1000	0	0	48.0	10.00
Connectors	HON reg neg	500	0	0	1.7	0.50

[a] The recurrence rate and unsuccessful repair rate for valves and pumps in LDAR programs with a leak definition of 10,000 ppmv was obtained from the SOCMI Fugitives AID (EPA-450/3-82-010). For the HON reg neg, a simplifying assumption was made that the recurrence rate and unsuccessful repair rate equal zero percent for all equipment types.

[b] The initial leak fraction for SOCMI process units is based on the combined screening dataset. The initial leak fraction for refinery process units is based on data collected in the Refinery Assessment Study (EPA-600/2-8--075c).

[c] The occurrence rate for LDAR programs with a leak definition of 10,000 ppmv is calculated as a function of the initial leak fraction. The relationship is based on data collected in the Six Unit Maintenance Study (EPA-600/S2-081-080). The equations for valves and pumps are as follows:

Valve 30 Day Occurrence rate = 0.0976 * leak fraction + 0.264.
Pump 30 Day Occurrence rate = 0.47 * leak fraction.

The quarterly occurrence rate is approximately 3 times the 30-day occurrence rate. In cases where the quarterly occurrence rate exceeded the initial leak fraction, it was set equal to the initial leak fraction. The occurrence rate for the HON reg neg LDAR programs is set equal to the performance level, except for pumps in SOCMI process units. For pumps in SOCMI process units the occurrence rate is calculated using the equation above.

G.2.1 LDAR Program with Leak Definition of 10,000 ppmv.

Estimates for the recurrence rate and unsuccessful repair rate were obtained from the Fugitive Emissions Additional Information document (EPA-450/3-82-010). In this document, data collected for LDAR programs with a leak definition of 10,000 ppmv were summarized. It was concluded that the recurrence rate for valves was 14 percent and the unsuccessful repair rate for valves 10 percent. It was assumed that all pumps are replaced with a new seal and for that reason the recurrence rate and unsuccessful repair rate for pumps were both assumed equal to zero percent (i.e., all pumps are successfully repaired and leaks do not recur). Data were unavailable for connectors for an LDAR program with a leak definition of 10,000 ppmv, and, for this reason, control efficiency for connectors in an LDAR program with a leak definition of 10,000 ppmv have not been estimated.

Estimates for the occurrence rate were based on data collected in the Six Unit Maintenance Study (EPA-600/S2-081-080). Data from this study indicated that the occurrence rate is a function of the initial leak fraction. For valves this relationship was expressed by the following equation:

$$OCC_{valve} = 0.0976\ (LF) + 0.264$$

where:

OCC_{valve} = Monthly occurrence rate for valves; and

LF = Initial leak fraction.

For pumps, the relationship was as follows:

$$OCC_{pump} = 0.47 \times LF$$

where:

OCC_{pump} = Monthly occurrence rate for pumps; and

LF = Initial leak fraction.

For both pumps and valves, the monthly occurrence rate was used to estimate the quarterly occurrence rate using the following equation:

$$Q = M + M\,(1 - M) + M\,\{1 - [M + M\,(1 - M)]\}$$

where:

M = Monthly occurrence rate; and
Q = Quarterly occurrence rate.

Note that in cases where the estimated quarterly occurrence rate exceeded the initial leak fraction, it was set equal to the initial leak fraction.

G.2.2 Control Equivalent to the LDAR Program Required by the Proposed Hazardous Organic NESHAP Equipment Leaks Negotiated Regulation

For each of the equipment types, the proposed hazardous organic NESHAP LDAR program requirements include a performance level requirement. This performance level specifies the allowable leak fraction once the program is in place. For example, the performance level for valves is 2 percent. Because the proposed hazardous organic NESHAP rule contains the performance level requirement and because limited data are available on LDAR programs with the leak definitions of the proposed hazardous organic NESHAP rule, simplifying assumptions were made when estimating the recurrence rate, unsuccessful repair rate, and occurrence rate.

For each of the equipment types, it was assumed that the recurrence rate and unsuccessful repair rate were equal to zero percent. These two parameters have the least impact on the predicted control efficiency.

For valves and connectors, the proposed hazardous organic NESHAP rule allows for reduced monitoring frequency if the leak fraction remains below the performance level. For this reason, it was assumed that process units would monitor valves and connectors at whatever monitoring frequency (i.e., monthly, quarterly, annually, etc.) that allows them to meet the performance level. Thus, for valves and connectors the occurrence rate was set equal to the performance level. Note that in cases where process units remain below the performance level this may overestimate the occurrence rate. However, this is offset by the assumption that the recurrence rate and unsuccessful repair rate are equal to zero percent.

For pumps the proposed hazardous organic NESHAP rule requires monthly monitoring. For this reason the occurrence rate was calculated using the same equation for pumps as presented in section G.2.1 for LDAR programs with a leak definition of 10,000 ppmv. Note, however, that the initial leak fraction used in the equation was the leak fraction associated with the leak definition of the proposed hazardous organic NESHAP rule (1,000 ppmv). For refineries, the predicted occurrence rate for pumps exceeded the performance level, and for this reason the occurrence rate was set equal to the performance level.

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16. ABSTRACT

The report presents standard protocols for estimating mass emissions from equipment leaks. Different approaches for estimating equipment leak emissions are described and several topics relevant to estimating equipment leak emissions (such as speciating emissions) are addressed. Information on how to perform a screening survey at a process unit is presented. Information on how a process unit can collect equipment leak rate data by enclosing individual equipment pieces and measuring mass emissions is provided. Also, information if provided that can be used to estimate the control efficiency of equipment leak control techniques. The document will help facilities generate accurate plant-specific equipment leak emission estimates.

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Guide **38**

Noise Control Directive User Guide

November 1999

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1 Introduction

1.1 What's New

Guide 38: Noise Control Directive User Guide has been revised in 1999 to assist in the interpretation and application of *Interim Directive (ID) 99-8: Noise Control Directive*. This 1999 edition of *Guide 38*, which replaces earlier editions, integrates the section formerly identified as "Supplement to the Interim Directive" into the guide itself.

Although the technical requirements in this edition of the directive and *Guide 38* have not changed, many enhancements have been made to help users better understand the complexities of this policy. Some of the more significant areas of interest are as follows:

- Construction Noise (Section 5.1)—Industrial operators must consider construction noise. This guide provides a number of suggestions that operators can implement to help minimize the noise impact on nearby residents.

- Complaint Investigation Process (Section 6)—The directive and guide now provide tools to assist operators and their neighbours in determining the conditions when industrial noise is a problem so that noise surveys can be performed under similar representative conditions.

- Noise Impact Assessments (Section 7)—The improved section on noise impact assessments enables operators to better understand EUB expectations and carry out assessments as part of their facility applications.

- Measurement Instrumentation and Techniques (Appendix 2)—Calibration requirements have been added for sound level meters in accordance with the appropriate American Noise Standards Institute requirements.

1.2 What *Guide 38* Includes

Composed of nine sections and four appendices, the guide introduces the 1999 interim directive on noise control and provides details for its implementation.

- Section 2 is an overview of the 1999 noise control directive.

- Section 3 gives a description of the Leq concept and some other basic acoustics, including how to add sound levels and extrapolate sound levels to different distances. For those not familiar with noise and related terminology, reviewing this section before applying the directive is especially useful.

- Section 4 defines sound levels and adjustments and explains how they are determined.

- The three flowcharts in Section 5 identify the different appropriate responses when designing a new facility, modifying an existing facility, or responding to a public complaint. Reference numbers in the bottom right corner of each flowchart box correspond to a matching explanatory note in Section 5.1. Each note gives more detail as to what is required for that step or background on the rationale behind the directive.

- Responding to noise complaints is one of the events that trigger *ID 99-8*. Section 6 outlines some basic expectations for complaint investigation. A sample Complaint Investigation Form is included to help concerned parties understand the technical aspects of the noise and handle any complaints.

- As stated in *ID 99-8*, a noise impact assessment is required to be completed for applications for new permanent facilities or for modifications to existing permanent facilities where there is a reasonable expectation of a continuous noise source. Section 7 has information on what should be included in a noise impact assessment.

- Section 8 explains compliance and EUB enforcement processes.

- Section 9 provides example problems that demonstrate how the flowcharts in Section 5 are used in applying *ID 99-8*.

- There are four appendices:

  1) Glossary of noise-related technical terms

  2) Minimum requirements for measurement instrumentation and techniques that must be used to conduct appropriate sound surveys

  3) Sound levels of familiar noise sources

  4) *ID 99-8: Noise Control Directive*

2 Overview of *ID 99-8: Noise Control Directive*

2.1 Background

With the continued widespread growth of energy operations throughout the province, additional sources of sound related to the energy industry are appearing. While residents, particularly in rural areas, would generally prefer no increase in sound levels resulting from energy-related developments, it is sometimes not possible to completely eliminate these increases. However, if proper sound control features are incorporated into facility design in the planning stages, increases in sound levels can be kept to acceptable minimums.

Interim Directive (ID) 99-8 views noise from a receptor viewpoint, rather than considering sound levels at the property line. Criteria based on property line measurements were considered to be too restrictive in rural settings, since a natural buffer often exists between operating facilities and any occupied dwellings.

The directive applies to all facilities under the EUB’s jurisdiction or where the EUB will issue or has issued a permit to operate. Facilities approved prior to April 1988 will be dealt with on a case-by-case basis, while post-April 1988 facilities will be designed to meet this directive. Although the directive is comprehensive, it is expected some cases will need to be dealt with on a site-specific, issues-oriented basis. For example, while the directive is not applicable to construction activity, these activities must be conducted with some consideration for noise. Any related complaints must be dealt with by the facility operator.

2.2 Sound Levels and Measurements

2.2.1 Permissible Sound Level

The permissible sound level (PSL) is the maximum integrated (averaged) sound level that a facility must not exceed at the nearest or most impacted residence. Even for remote facilities where there are no impacted dwellings, uncontrolled sound generation is not allowed, particularly since retrofit may be required if a residence is built and the facility is no longer remote. New facilities planned for remote areas should be designed to meet a target sound level of 40 dBA Leq at a distance of 1.5 km, although this is not a mandatory requirement. (Using the rule of 6 dBA loss per doubling of distance from the source, the facility would generate a sound level of approximately 70 dBA at 50 m.) As a target, this does not establish compliance should infringement occur.

2.2.2 Comprehensive Sound Level

In most noise-related complaint situations, the comprehensive sound level (CSL) must be measured and compared to the PSL. (See Appendix 2 for the requirements for measurement instrumentation and techniques.) Modelling of the industrial noise source component can be used as a diagnostic tool to assist in the timely resolution of noise concerns but not to demonstrate compliance.

The CSL for the facility must not exceed the PSL. The CSL is determined by conducting a continuous sound-monitoring survey, which must encompass a representative portion of the times of day or night on typical days when the noise causing the complaints occurs over a minimum 6-hour to maximum 24-hour period. The maximum survey time may exceed 24 hours where warranted. These exceptional circumstances should be discussed with the EUB before proceeding. If the required survey period straddles the daytime/nighttime periods, then a minimum of three survey hours must be conducted within each of the daytime and nighttime periods. The measurements are to be conducted 15 m from the complainant’s dwelling in the direction of the noise source. The 15 m requirement may be altered if it is physically impossible or acoustically illogical.

If a complainant has highlighted specific weather conditions, plant operating conditions, or seasons, the monitoring should take place under these representative conditions. Representative conditions do not constitute absolute worst-case conditions or the exact conditions the complainant has highlighted if those conditions are not easily duplicated. In order to expedite complaint resolution, sound measurements should be conducted at the earliest opportunity when sound propagation towards the impacted dwelling is likely and representative conditions might exist. An extended duration survey (greater than 24 hours) may be considered to ensure representative conditions have been met if they are frequent but difficult to predict.

The local EUB field centre can be consulted to help establish criteria for determining when favourable conditions exist.

When the measured CSL exceeds the PSL but noise from the facility and its related activities is not considered to be responsible for the accedence, then a further assessment using an appropriate isolation analysis technique to separate the facility noise contribution from the measured CSL may be carried out. This will, in effect, separate noises not related to the facility. This isolated facility contribution can then be compared to the PSL for compliance.

Invalid data, such as those collected during periods with unacceptable meteorological conditions or nonrepresentative ground cover, and abnormal data, such as those from nontypical noise events, should be extracted from the measured CSL. The extraction of data from the measured CSL must be justified and supported by an appropriate reference, such as high-fidelity video cassette recorder (VCR) recording, digital analogue tape (DAT) recording, operational log, event log, etc. The accumulated isolated facility contribution data must encompass the previously stipulated minimum time period.

2.2.3 Responsibility for Sound Control

For drilling and servicing rigs, the responsibility for sound control belongs to the well licensee. The EUB believes it is the responsibility of the well licensee to contract an appropriately equipped rig for sensitive situations and that the rig contractor is responsible for suitably equipping and maintaining rigs contracted for sensitive situations. Compliance for drilling and servicing rigs is on a complaint basis only. All parties are expected to act quickly to remedy any complaints.

While noise impact from facility-related heavy truck traffic and vibration impact from energy facility operations are not specifically addressed in this directive, it should be noted that receipt of a public complaint with regard to these impacts may require corrective action from the operator. The EUB acknowledges the special nature of these impacts and is prepared to consider these on a site-specific basis. Industry is expected to take every reasonable measure to avoid or minimize the impact of heavy truck traffic or vibration concerns in an area.

Compliance with the noise control directive for pre-1988 facilities occurs when a valid comprehensive sound survey indicates the energy facility contribution is equal to or less than the PSL. When a facility is found to be noncompliant, the operator is allowed reasonable time to undertake corrective action (see Section 5.1, note 10.2). However, if in the opinion of the EUB the operator is not working in the spirit of this directive to resolve the issue, the EUB will intervene. Consequences may include curtailing production to reduce sound generation and possible shutdown of the facility. Communication with the complainant through all phases of corrective action is required.

2.2.4 Resolution of Disagreements

The PSLs set out in this directive are receptor oriented. However, the EUB does not believe that industry has the right to arbitrarily reduce a landowner’s right to the use of his own property. This approach allows industry to take maximum advantage of the normally substantial distance in rural areas between a facility and any residences. The receptor-oriented approach does not protect industry against eventual infringement; therefore, industry is advised to consider the magnitude of this risk when choosing sites, designing facilities, and negotiating leases. Operators are strongly encouraged to communicate with their neighbours to identify potential developments that may infringe upon their facility. Once identified, industry representatives are expected to work proactively to minimize potential impacts.

If there is disagreement, the EUB considers each case of infringement on its own merits before requiring compliance. Furthermore, EUB staff are available to work with both parties in the event of a dispute. Developers (anyone building a dwelling) knowingly infringing upon existing energy facilities by ignoring the obvious impacts may not be eligible for redress under this directive. If redress is deemed appropriate, the EUB expects an operator to be prepared to comply expeditiously with the requirements of this directive once aware that infringing developments resulted in the facility exceeding the PSL.

In certain situations when it is difficult for both sides to agree on an acceptable course of action, the EUB should be contacted to mediate and, if necessary, make recommendations or give specific direction.

Overall, public benefit and impacts of energy development are taken into consideration by the EUB when resolving complaints. The public desire for a no-impact (zero industry noise) solution is essentially unattainable. Sometimes the benefits are not as apparent as the detractions to those living near energy facilities. Should a successful resolution not be achieved through mediation, both the facility owner and the landowner continue to have the right to request a hearing before the EUB under the appropriate sections of the Energy Resources Conservation Act.

2.2.5 Special Cases

The EUB recognizes that there will be situations that do not fit into the categories in this policy; it will judge such cases on an individual basis.

Under special circumstances the PSLs calculated using this directive may need to be reviewed. A higher or lower sound emission from a resource facility may be deemed appropriate in such exceptional circumstances. One such exception is Alberta’s Industrial Heartland area in the Fort Saskatchewan region. The PSL for the Industrial Heartland area is based in part on ambient sound level data dating back as far as 1980, when there were few EUB-regulated facilities. New or existing operators contemplating expansion and required to comply with this directive should consult the Fort Saskatchewan Regional Industrial Association office, the local municipal noise bylaw, and the EUB for information relevant in determining the PSL for the area.

ID 99-8 will be reviewed in November 2001 or as required and revised if necessary.

3 The Leq Concept and Basic Acoustics

3.1 dB and dBA

The human ear is capable of hearing a large range of levels of sound pressure from 2 x 10^{-5} pascals (Pa) (just audible, 0 dB) to 2 x 10^{2} Pa (sensation of pain, 140 dB) — a difference of seven orders of magnitude. Because of this large range, the decibel (dB) is used to compress the range into a more meaningful scale. The symbol used to represent the linear decibel scale is dB(lin), or simply dB.

The A-weighted decibel scale is represented by dB(A), or dBA. The A-weighting network approximates the way the human ear hears different frequency sounds. Low frequency sounds (hum) are harder for the human ear to hear than higher frequency sounds (whine). This means a low frequency sound would have a higher sound level on the linear scale (dB) than a high frequency sound and yet would sound equally loud to the ear. These two sounds would have the same dBA rating on the A-weighting scale because they sound equally loud.

3.2 Leq Concept

This guide uses Leq measurements, which represent energy equivalent sound levels. The Leq is the average A-weighted sound level over a specified period of time—a single-number representation of the cumulative acoustical energy measured over the interval. The time interval used should be specified in brackets following the Leq (e.g., Leq (9) is a 9-hour Leq). If a sound level is constant over the measurement period, the Leq will equal the constant sound level. Figure 1 illustrates this concept.

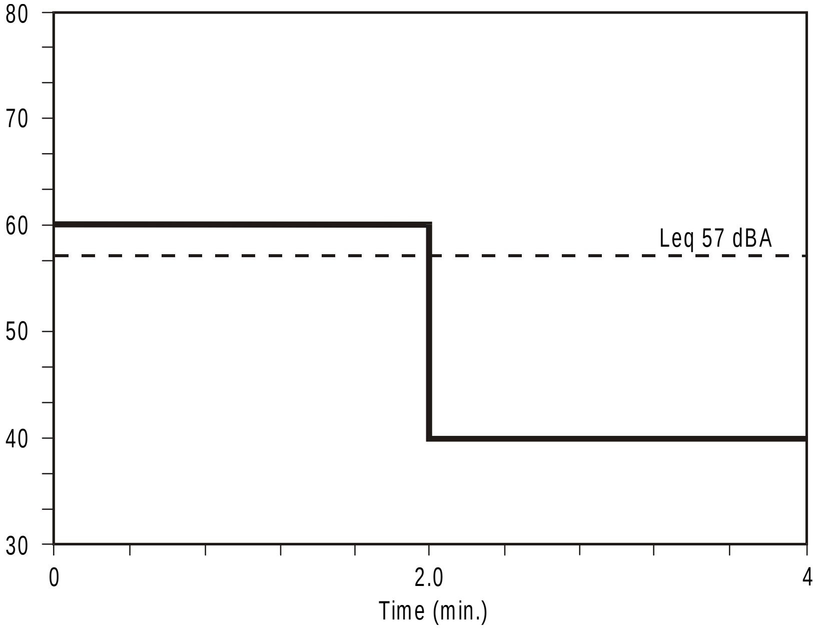


Figure 1. Illustration of Leq concept

In Figure 1, the equivalent energy during the 4-minute period is not 50 dBA, as one might expect, but 57 dBA. This is due to the way in which sound energies are added, which is logarithmical rather than arithmetic. A quick look at the mathematics shows this:

$$\text{Leq} = 10 \log\left(\sum_{i=1}^{n} f_i \times 10^{L_i/10} \right)$$

where:

f_i = fraction of total time the constant level L_i is present

L_i = sound level in dBA

For Figure 1, which has 4 minutes of 1-second Leq values:

$$\begin{aligned} \text{Leq} &= 10 \log\left(\sum_{i=1}^{n} f_i \times 10^{L_i/10} \right) \\ &= 10 \log\left(\sum_{1}^{240} f_i \times 10^{L_i/10} \right) \\ &= 10 \log\left(\frac{120}{240} \times 10^{60/10} + \frac{120}{240} \times 10^{40/10} \right) \\ &= 10 \log (505\,000) \\ &= 57 \text{ dBA Leq (4 min)} \end{aligned}$$

In these calculations, we are adding numbers that are proportional to the corresponding sound energies. For example, the energy associated with the 60 dBA level is 100 times greater than the energy associated with the 50 dBA level (10^6 versus 10^4).

Another example of a Leq calculation is useful to demonstrate how a loud noise event, such as a train passing by, can alter the Leq value. Assume we measure the sound level for 1 hour. For 59 minutes, the sound level is 40 dBA (fairly quiet), and for 1 minute it is 90 dBA while a train passes:

$$\begin{aligned} \text{Leq} &= 10 \log\left(f_1 \times 10^{L_1/10} + f_2 \text{ x } 10^{L_2/10} \right) \\ &= 10 \log\left(\frac{59}{60} \times 10^{40/10} + \frac{1}{60} \times 10^{90/10} \right) \\ &= 10 \log (0.98 \times 10^4 + 0.02 \times 10^9) \\ &= 73 \text{ dBA Leq (1 hour)} \end{aligned}$$

This example demonstrates how loud noise events, such as train passings, can dominate the Leq values.

3.3 Sound Power and Sound Pressure Levels

Sound power is a physical property of the source alone and is an important absolute parameter used for rating and comparing sound sources. Sound power levels for specific equipment may be obtained from the manufacturer or by modelling the source using near-field sound pressure level measurements.

Sound pressure levels can be calculated using sound power levels. The formula for a free field is

$$L_{pressure} = L_{power} + 10 \log_{10} Q - 20 \log_{10} r - 10.8 - A_{NC} - A_{air} - A_{ground} - ....$$

where r = distance, in metres

Q = directivity factor of source, composed of inherent directivity of the source, Q_s, and the geometry of location, Q_g

A = attenuation from noise control, air absorption, ground effects, etc.

For simplicity with an exposed source in a free field (i.e., the distance, r, is greater than 5 times the size of the source and there are no significant reflections of sound) where additional attenuation factors are to be neglected, this calculation can be done using A-weighted power and pressure levels. This gives a conservative estimate of the sound pressure level at a distance, but not necessarily the “worst-case” level that may occur under weather conditions favouring noise propagation in a given direction, which can be considered as a negative attenuation.

Where any noise control measures are to be added to the source (such as a silencer or a building that will enclose the source), or where environmental conditions (such as the barrier effect of the topography) are to be included, the calculations must be done using octave or ⅓-octave frequency bands and the sound pressure levels added together and A-weighted afterwards. Noise controls and environmental effects are strongly frequency dependent, and a calculation using A-weighted data is not adequate.

The directivity factor, Q, can be thought of as the portion of a sphere into which the source radiates its sound energy. Some sources radiate uniformly in all directions, while others, notably fans, are very directional. For example, a fan in a vertical plane radiates most of the sound energy in a narrow beam to the front ($Q_s \approx 5 - 8$).

The directionality of the source is also affected by the geometry of its immediate surroundings, largely due to the presence of reflecting surfaces. The directivity of the location may or may not be significant due to the inherent directivity of the source. How the directivity factors Q_s and Q_g combine depends on the layout of the equipment and its surroundings. Table 1 below gives examples of values of Q for a variety of location geometries.

Table 1. Q Values

Q	Radiation pattern	Examples
1	Spherical	Elevated sources, flares, aircraft
2	Hemispherical	Source near or on ground surface
4	¼-spherical	Source on ground beside taller building
8	⅛-spherical	In a corner of three surfaces

3.4 Addition of Sound Power or Sound Pressure Levels

A similar formula to the one used in Section 3.3 can be used to add sound levels together both for the A-weighted levels and in frequency bands. This formula is useful for adding together sound power or sound pressure levels from different components of a plant, for example, to arrive at a composite sound level for the plant.

Sound pressure levels can be added together in this way only if they are measured or calculated for the same location.

Sound power levels can be added together and the composite source can be thought of as being at the acoustic centre of the individual sources (similar to the concept of the centre of mass of an object).

The formula for the addition of sound levels is

$$L_{TOTAL} = 10 \log_{10} \left(\sum_{i=1}^{n} f_i \times 10^{L_i/10} \right)$$

where L_i = individual component sound levels (power or pressure)**.**

Example Calculation of Addition of Sound Power Levels

You are building a compressor station. You are told by the manufacturer that the A-weighted sound power levels (referred to as 10^{-12} watts, also written 1 picowatt, or 1 pW) for the different components are as follows:

Engine exhaust, with muffler	106 dBA
Aerial cooler (nondirectional)	113 dBA
Piping noise	79 dBA

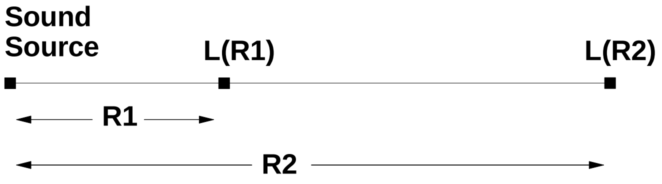
$$
\begin{aligned}
L_{\mathrm{POWER,\ TOTAL}} &= 10 \log_{10} \left(\sum_{i=1}^{n} f_i \times 10^{L_i/10} \right) \\
&= 10 \log_{10} (10^{106/10} + 10^{113/10} + 10^{79/10}) \\
&= 10 \log_{10} (10^{10.6} + 10^{11.3} + 10^{7.9}) \\
&= 10 \log_{10} (2.394 \times 10^{11}) \\
&= 10\ 11.38 \\
&= 113.8 \text{ dBA (ref 1 pW)}
\end{aligned}
$$

When adding sound pressure levels, note that these levels are only valid for the specific location. To add the sound pressure levels, they must all be calculated or measured at the same location.

3.5 Calculation of Sound Levels for Different Distances

This calculation assumes hemispherical spreading of the sound waves and equates to a 6 dBA loss per doubling of distance from the sound source. The calculation does not account for any attenuation (or loss) due to atmospheric or ground absorption. The basic equation is

$$L(R_2) = L(R_1) - 20 \log_{10} \left(\frac{R_2}{R_1} \right)$$



with: R_1 = distance R_1 in metres
R_2 = distance R_2 in metres
L = sound level in dBA

Note that if R_2 is less than R_1, the second term in the equation is negative and $L(R_2)$ is higher than $L(R_1)$. Also, under certain source-receiver configurations, the loss per doubling of distance can be less than 6 dBA.

The inverse square law (6 dBA loss per doubling of distance) for sound dissipation over distance does not apply for "near-field" measurements. The near field is the area where the dimensions of the source are significant; it applies to sound pressure levels measured at distances less than about five times the size of the source object.

The data supplied by manufacturers are often provided as sound pressure levels measured very close to the equipment (i.e., in the near field) and are intended for use under occupational hearing requirements rather than for environmental assessment. Note that such measurements are often conducted using conditions that may not reflect field or operational conditions. Therefore, this type of measurement cannot be used in the equation above. However, given additional information about the dimensions of the equipment and the conditions of the measurement, an expert can determine the sound power level of the equipment, and the equation from Section 3.3 can be used instead.

An acceptable distance for applying the inverse square law depends on the sound source dimensions and the wavelength of the sound. The formula is usually safe to use as long as R_1 and R_2 are about five times the size of the source. Alternately, a minimum distance of 50 m can be used as a rule of thumb.

Example Calculation of Determining the Sound Level at a Different Distance

The sound level specification you are given is 75 dBA for the compressor package at 50 m away. You have a residence 800 m away from your facility. What is the compressor sound level as measured at the residence?

You know L (50 m) = 75 dBA.

$$L(R_2) = L(R_1) - 20 \log\left(\frac{R_2}{R_1}\right)$$

$$L(800\text{ m}) = L(50\text{ m}) - 20 \log\left(\frac{800}{50}\right)$$

$$L(800\text{ m}) = 75\text{ dBA} - 20 \log\left(\frac{800}{50}\right)$$

$$L(800\text{ m}) = 75\text{ dBA} - 24\text{ dBA}$$

$$L(800\text{ m}) = 51\text{ dBA}$$

So the sound level contribution due to the compressor is 51 dBA at 800 m.

A simpler, more intuitive way to do the calculation is illustrated below.

Alternate Method of Determining the Sound Level at a Different Distance—Simple Table Approach

A simplified way to estimate the sound level is based upon using the rule of 6 dBA lost per doubling of distance. With this method, you simply make a table and subtract 6 dBA for each time you double the distance from the noise source.

If we use the 75 dBA at 50 m specification:

Distance (m)	Sound level (dBA)
50	75
100	69
200	63
400	57
800	51
1600	45

From this simple method, you get 51 dBA at 800 m. This matches the calculation above. The table method only allows you to get sound values at discrete distance points. If sound values between the distance points are required, use the calculation method.

3.5.1 Line Sources

Where a long, narrow source radiates noise, the radiation pattern is that of a cylinder, not a sphere. Examples include pipes, conveyor belts, and transportation corridors such as roads. Calculations using the spherical spreading of sound from point like sources would involve a final step of integration over the length of the sound. It is more convenient to treat the sound as a line radiating into a cylinder. The pressure level at distance r is considered below. If the length, L, of the line source is limited, once the distance, r, exceeds three to five times the length, the source can be considered as a point source, and the equations in Sections 3.3 and 3.5 above can be used.

For a line source, the sound spread equates to a 3 dBA loss per doubling of distance. The formula for noise levels at different distances from a line source is as follows:

$$L(R_2) = L(R_1) - 10 \log_{10}\left(\frac{R_2}{R_1}\right)$$

with: R_1 = distance R_1 in metres
R_2 = distance R_2 in metres, and
L = sound level in dB (for octave bands) or dBA

Note that if $R_2 < R_1$, the second term in the equation is negative, and $L(R_2)$ is higher than $L(R_1)$.

4 Determining Sound Levels and Adjustments

This section provides insight into the tables to be used to determine PSLs, basic sound levels (BSL), and adjustments. (See Appendix 1: Glossary for an explanation of related terminology.)

4.1 Permissible Sound Level

The PSL is derived from a base value (the BSL) that includes a 5 dBA Leq allowance for industrial presence plus adjustments intended to more accurately reflect specific aspects of the facility and the environment. The minimum PSL for rural Alberta would not be expected to be less than 40 dBA Leq during nighttime. However, there may be pristine (pure natural) areas where an ambient adjustment may result in a lower PSL, while more developed areas may result in a higher PSL. The PSL is calculated as follows:

Permissible sound level = Basic sound level (Table 2) + Daytime adjustment + Class A adjustment (Table 3) + Class B adjustment (Table 4)

The PSLs do not apply in emergency situations. An emergency is defined as an unplanned event requiring immediate action to prevent loss of life or property. Events occurring more than four times a year are not considered unplanned. Planned maintenance or operational events (e.g., blowdowns, catalyst changes) may be considered temporary activities and thus qualify for a Class B adjustment. Prior to such events, operators should inform nearby residents of the potential for increased sound levels and should attempt to schedule the events during daytime hours to reduce the noise impact on neighbours.

4.2 Basic Sound Level

Nighttime BSLs are determined from Table 2 below. See 4.3.1 for the adjustment used for daytime values. The average rural ambient sound level in Alberta is approximately 35 dBA Leq at night. By adding 5 dBA Leq for industrial presence, the EUB arrives at the minimum PSL. Moving down each column, 5 dBA is added for closer proximity to transportation noise sources. Moving across each row, 3 dBA is added for higher population density.

Table 2. Basic sound levels for nighttime

	Dwelling unit density per quarter section of land		
Proximity to transportation	1 - 8 dwellings; 22:00 - 07:00 (nighttime) dBA Leq	9 - 160 dwellings; 22:00 - 07:00 (nighttime) dBA Leq	>160 dwellings; 22:-00 - 07:00 (nighttime) dBA Leq
Category 1	40	43	46
Category 2	45	48	51
Category 3	50	53	56

Terms Used in Table 2

Category 1	Dwelling units more than 500 m from heavily travelled roads and/or rail lines and not subject to frequent aircraft flyovers.
Category 2	Dwelling units more than 30 m but less than 500 m from heavily travelled roads and/or rail lines and not subject to frequent aircraft flyovers.
Category 3	Dwelling units less than 30 m from heavily travelled roads and/or rail lines and/or subject to frequent aircraft flyovers.
Dwelling Unit	Any permanently or seasonally occupied dwelling with the exception of an employee or worker residence, dormitory, or construction camp located within an industrial plant boundary. In the latter cases, occupational noise standards may be applicable.
Seasonally Occupied Dwelling*	A fixed residence with a conventional foundation that, while not being occupied full time, is occupied on a regular basis (approximately six weeks per year or more).
Density per Quarter Section	Refers to a quarter section with the affected dwelling at the centre (a quarter mile/400 m radius). For quarter sections with various land uses or with mixed densities, the density chosen is then averaged for the area under consideration.
Heavily Travelled Roads	Generally includes primary and secondary highways and any other road where the average traffic count is at least 10 vehicles/hour over the nighttime period.
Rail Lines	Includes any rail line where there is a minimum of one 25-car train passage during every nighttime period.
Frequent Aircraft Flyovers*	Dwellings that lie within a noise exposure forecast (NEF) 25 or greater contour, as designated by Transport Canada, require a site-specific analysis. In the absence of NEF contours for a local airport, Transport Canada is referenced for current air traffic statistics. To qualify for this adjustment, a dwelling must be within 5 km of an airport that has a minimum of nine aircraft takeoffs or landings over the nighttime period. See Noise Exposure Forecast in the Glossary (Appendix 1).

*Note: For more detailed explanation of these definitions, see Appendix 1: Glossary.

4.3 Adjustments to Basic Sound Level

4.3.1 Daytime Adjustment

This adjustment recognizes that daytime ambient sound levels are commonly 10 dBA higher than nighttime levels and that nighttime noise disturbances are generally considered less acceptable. The daytime period is 07:00 to 22:00, and the daytime adjustment is +10 dBA.

4.3.2 Class A Adjustment

These adjustment values permit adjustment of the BSLs based upon the nature of the activity and/or the actual ambient sound level (ASL) in an area. Technical verification must be supplied to use any of these adjustments. More than one Class A adjustment can be claimed if applicable to a maximum of 10 dBA.

Table 3. Class A adjustments*

Class	Reason for adjustment	Value (dBA Leq)
A1	Seasonal adjustment (1 November - 31 March)	+ 5
A2	Absence of both tonal and impulse/impact components	+ 5
A3	Ambient monitoring adjustment	- 10 to + 10

*Class A adjustment = Sum of A1, A2, and A3 (as applicable), but not to exceed a maximum of 10 dBA Leq

A1 — Seasonal Adjustment

This adjustment is applicable for facilities operating during the 1 November to 31 March period. Facilities that operate year round should not add this adjustment when determining the sound level to design for. If a complaint were limited to only the winter period, the use of this adjustment would be allowed at year-round facilities to determine the PSL.

A2 — Absence of Both Tonal and Impulse/Impact Components

This adjustment is applicable only to existing facilities and cannot be used in the design of new facilities, because most energy industry facilities typically exhibit either a tonal or an impulse/impact component. Sound measurements to determine if the facility meets the test must be conducted 15 m from the nearest or most impacted dwelling unit. These measurements must be conducted at appropriate intervals during the comprehensive survey when sound propagation from the facility is representative of the conditions causing the complaint. A minimum of three measurements must be obtained.

The test for the absence of tonal components consists of two parts:

- The first must demonstrate that the sound pressure level of any one of the slow-response, A-weighted, ⅓ octave bands between 20 and 16 000 Hz is 10 dBA or more than the sound pressure level of at least one of the adjacent bands within ⅓ octave bandwidths. In addition, there must be a minimum of a 5 dBA drop from the band containing the tone within 2 bandwidths on the opposite side.

- The second part is that the tonal component peak must be a pronounced peak clearly obvious within the spectrum.

There is considered to be an absence of impulse/impact components when the difference between the A-weighted impulse response sound level measurement and the A-weighted slow-response sound level measurement is 10 dBA or less (see Section 5, note 4.0, for further clarification).

A3 — Ambient Monitoring Adjustment

The ASL is considered to be the average sound environment in a given area. An adjustment for an incremental change to the basic sound level is applicable only when BSLs (Table 2) are thought not to be representative of the actual sound environment and when ASLs have been measured (i.e., without any energy-related industrial component).

An ambient sound monitoring survey consists of a 24-hour continuous sound monitoring survey, with measured ASLs presented for the daytime and nighttime periods, conducted 15 m from the nearest or most impacted dwelling unit and under representative conditions. The 15-m requirement may be altered if it is physically impossible or acoustically illogical. Recall that an ambient sound survey must be conducted without any energy-related industrial component. Another measurement location may be chosen if the affected dwelling unit is not an appropriate location. Refer to Figure 2 to determine the appropriate adjustment value A3, which will be added to any other applicable Class A adjustment factors.

4.3.3 Class B Adjustment

These adjustment values are intended to permit adjustment of the BSLs based upon people’s responses to temporary activities. If it is known that an activity will only be of a temporary duration, there may be some additional tolerance of it. However, in order to utilize this additional tolerance, it is important to fully inform the potentially impacted residents of the duration and character of the noise. Note that, for the purposes of this directive, any activity lasting longer than two months is not considered temporary.

Table 4. Class B adjustment*

Class	Duration of activity	Value (dBA Leq)
B1	1 day	+ 15
B2	1 week	+ 10
B3	≤ 2 months	+ 5
B4	> 2 months	0

*Class B adjustment = one only of B1, B2, B3, or B4

To use Figure 2:

1. Determine the difference between the BSL (Table 2) for the appropriate dwelling density and transportation proximity and the measured ASL to the nearest whole number.

2. Look up this difference on the x-axis of Figure 2.

3. Move up on the figure until the plotted line is intersected.

4. Move left on the figure and read off the applicable A3 adjustment factor. This number can be either positive or negative.

5. Add this adjustment factor to any other applicable Class A adjustment factors to arrive at the Class A adjustment. Note that if the sign of A3 is negative, you will be adding a negative number to arrive at the Class A adjustment.

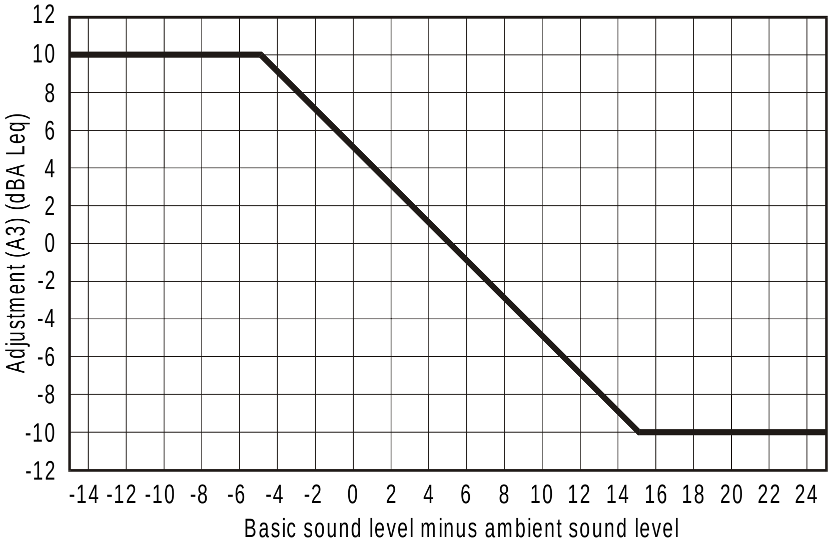
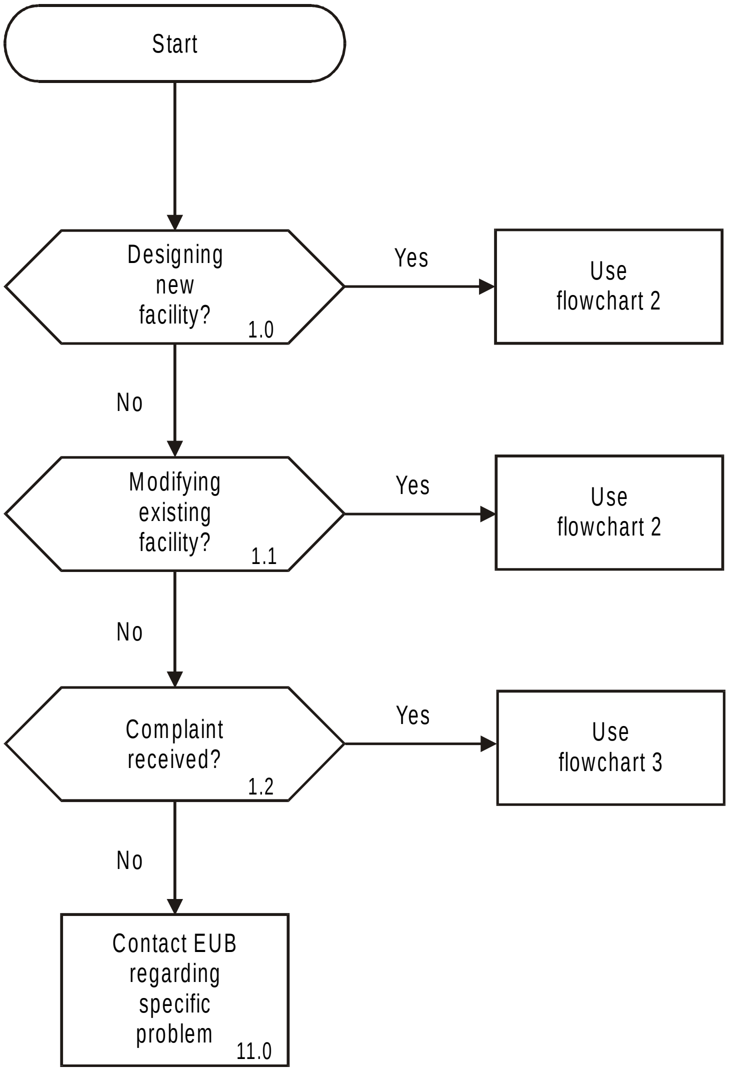


Figure 2. Ambient monitoring adjustment - A3

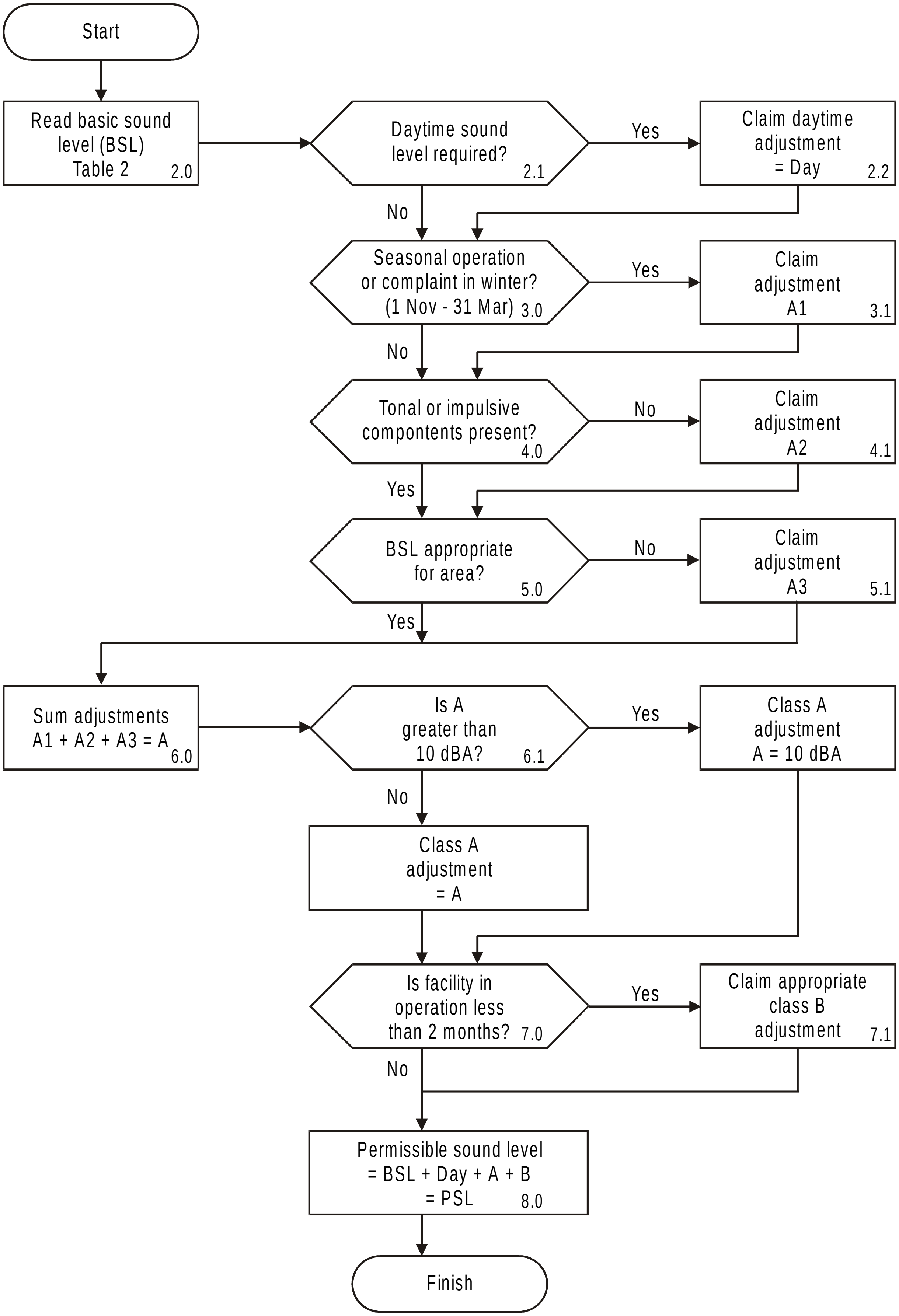
5 Flowcharts for Facility Design and Modification

The following flowcharts identify the different appropriate responses when designing a new facility, modifying an existing facility, or responding to a public complaint.

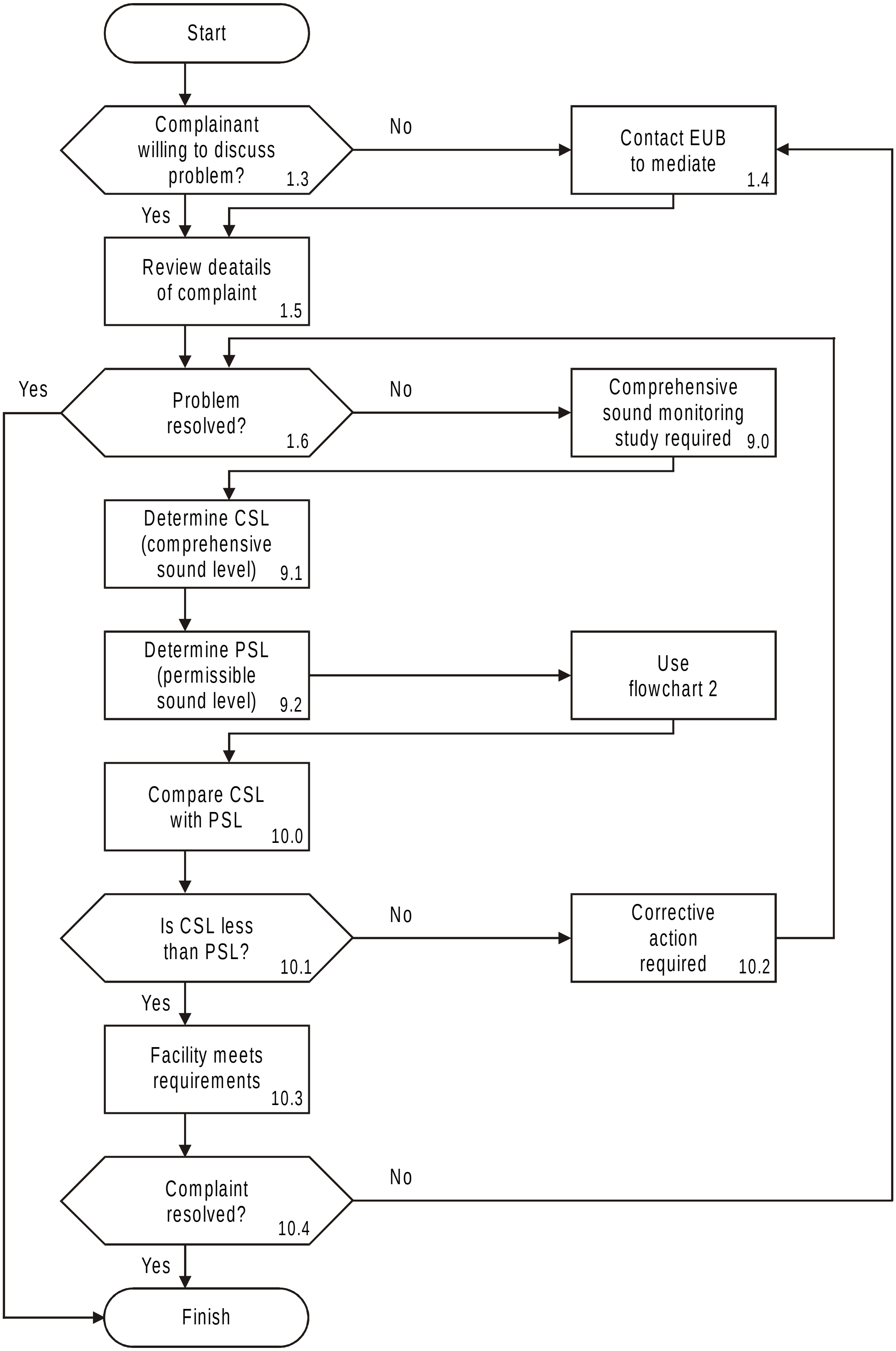
Note that numbers appearing in the lower portion of each box in the flowcharts refer to corresponding notes in Section 5.1: Explanatory Notes.



Flowchart 1. Initial flowchart



Flowchart 2. Permissible sound levels



Flowchart 3. Compliance

5.1 Explanatory Notes

These explanatory notes correspond to the reference numbers in the bottom right corners of the boxes in the preceding flowcharts. Each note gives more detail as to what is required for that step or background on the rationale behind the directive.

1.0 For the purposes of *ID 99-8*, a new facility is any new operation in the exploration for and the processing, development, and transportation of energy resources and energy-related functions. A new facility does not include the drilling and completion of wells. Other operations or facilities that do not require applications should nevertheless be designed to comply with this directive.

A primary objective of *ID 99-8* is to encourage the consideration of noise in the design stage of facility development. Modest levels of noise control introduced at the design stage are often a small portion of the capital cost, while retrofit solutions can be very expensive. Operators should discuss noise matters with residents during the design, construction, and operation phases of a facility.

Best practical technology (accounting for cost versus benefit) should be considered to minimize the potential for noise impacts to existing dwellings and future infringement. Operators should discuss noise matters with area residents during the design, construction, and operating phases of an energy facility. Should a valid complaint be registered after the facility is constructed and in operation, the operator must meet the PSL referenced in the noise impact assessment.

While *ID 99-8* is not applicable to construction noise, operators should attempt to take the following reasonable mitigative measures to reduce the impact of construction noise at nearby residences from new facilities or modifications to existing facilities:

- Limit construction activity between the hours of 07:00 and 22:00 to reduce the potential impact of construction noise.
- Advise nearby residents of significant noise-causing activities and schedule these to create the least disruption to neighbours.
- Ensure all internal combustion engines are fitted with appropriate muffler systems.
- Take advantage of acoustical screening from existing on-site buildings to shield residential locations from construction equipment noise.

1.1 As 1.0, except that a facility already exists and some modification, expansion, repair, or servicing operation is to take place. Applications for modifications to existing facilities where there is a reasonable expectation of a continuous noise source require a noise impact assessment. See 1.0 and Section 7 for further information on noise impact assessments. Regardless of whether an application is required, it is advised that the *Noise Control Directive* be adhered to.

In reviewing *ID 99-8* sound requirements at existing facilities, the EUB considers the ASLs of the area if necessary (recall that ASLs in rural Alberta are approximately 35 dBA at night and do not include the existing facility), as well as the technical difficulty involved in meeting the requirements. Reasonable time for modifications is allowed when necessary. It is acknowledged that under special circumstances the PSLs calculated using *ID 99-8* may need to be reviewed. A higher or lower sound emission from a resource facility may be deemed appropriate in exceptional circumstances.

1.2 A complainant may register a complaint in a number of ways. Once the operator of the facility is aware of the complaint, the operator must make direct contact with the complainant in order to understand the concerns and to establish a dialogue to set reasonable expectations and a time frame for action to resolve the issue.

While the EUB does review and assess information on noise control as part of energy facility application processing, investigation of compliance with this directive will only be done on a complaint basis or when an audit is conducted on the facility application, which includes the noise impact assessment.

1.3 In certain situations when it is difficult for both sides to agree on an acceptable course of action, the EUB should be contacted to mediate and, if necessary, make recommendations or give specific direction.

Overall public benefits and impacts of energy development are considered when resolving complaints. The public desire for a no-impact (zero industry noise) solution is essentially unattainable. Sometimes the benefits are not as apparent as the detractions to those living near energy facilities. See Section 6 for more information about complaint investigation.

1.4 The EUB is willing to act as a mediator in situations where a resolution satisfactory to both parties is not possible.

1.5 Such factors as the time of the complaint, direction, duration, and character of the noise, weather conditions, facility operating conditions, and unrelated activities should all be recorded and reviewed to determine the cause of the complaint.

1.6 A mutual agreement between facility and complainant is far preferable to an imposed solution. Every effort should be made to come to an equitable solution. For temporary facilities, the option of conducting detailed sound surveys may not be feasible. Should a successful resolution not be achieved through mediation, the facility owner or landowner continues to have the right to request a hearing before the EUB under the appropriate sections of the Energy Resources Conservation Act.

2.0 Table 2 gives typical ambient (Leq) sound levels for various types of areas based on population density and nearness to busy transportation routes, plus an additional 5 dBA (Leq) for the presence of industry. Thus, using Table 2 alone, industry is permitted 5 dBA (Leq) over and above the Leq values observed in the various types of areas.

For the majority of the cases the EUB deals with, the BSLs are 40 dBA Leq during nighttime and 50 dBA Leq during daytime, i.e., Category 1 and low dwelling unit density. These sound levels would be used in a typical rural setting not close to any major roads. Typically, for the vast majority of rural Alberta areas, the minimum PSL would not be expected to be less than 40 dBA Leq during nighttime; however, there may be pristine (pure natural) areas where an ambient adjustment may result in a lower PSL, while more developed areas may result in a higher PSL.

In order to use Table 2, the dwelling unit density per quarter section of land affected by the potential or existing sound source must be determined. A dwelling unit is any permanently or seasonally occupied dwelling. The quarter section of land to be considered is not the location where the sound source is or will be located; it is the quarter section with the affected dwelling at the centre (a quarter mile/400 m radius). The quarter section chosen must surround the nearest or most impacted dwelling in the area. If the quarter section under consideration has various land uses or mixed densities, the appropriate density will be factored. Once again, the most sensitive density will be the one selected. (See Example Problem 1 in Section 9.)

Next, the appropriate transportation proximity category must be selected. The key here is determining the type of area and whether the road is heavily travelled. Obviously, a quieter area will be more easily affected by traffic than a noisier area. The daytime category may also vary from the nighttime category. If a road has been designated as a primary or secondary highway by Alberta Transportation or is one where the average traffic count is at least 10 vehicles/hour over the nighttime period, it may be designated as heavily travelled. If the road is not heavily travelled, use Category 1. Since primary and secondary highways are sometimes lightly travelled during the nighttime period, which is usually the period of greatest concern, the EUB uses the 10-vehicles/hour criterion to determine whether primary and secondary highways qualify as heavily travelled during the nighttime period.

Finally, the appropriate nighttime BSL is found in Table 2 using the dwelling unit density per quarter section and transportation proximity category determined previously.

2.1 In this directive, the time spans are those between the hours of 07:00 and 22:00 (daytime Leq) and between 22:00 and 07:00 (nighttime Leq).

3.0 If the facility in question operates only during the period 1 November through 31 March, a +5 dBA Leq adjustment may be claimed. If a complaint is received during the applicable period for any facility (permanent or temporary, year-round or seasonal operation), this adjustment can be claimed in determining the PSL the facility must be below. For permanent facilities that operate year round, this adjustment cannot be used in the design stage to determine what PSL to design for, as this would not be a representative scenario. For permanent facilities that operate only during this winter period (e.g., compressors used only for high nominations in the winter), this adjustment could be used for design.

The rationale behind this adjustment is that people generally have their windows closed during this period and outdoor activities are greatly reduced. Therefore, a slightly higher sound level is tolerable. If it is demonstrated that the facility may impact a winter recreation area in which a quiet environment is a key aspect, the seasonal adjustment may be disallowed.

3.1 See 3.0, above. Claim +5 dBA Leq for adjustment A1. This adjustment is added to the other applicable A adjustments (see 4.0 and 5.0 below), and a maximum Class A adjustment of 10 dBA Leq is permitted.

4.0 An adjustment of +5 dBA Leq is permitted if it can be demonstrated that both tonal and impulse/impact sound components are not present. This adjustment is applicable only to existing facilities and cannot be used in the design of new facilities, because most energy industry facilities typically exhibit either a tonal or impulse/impact component. Sound measurements can be made to determine if the facility meets the test; they are to be conducted 15 m from the nearest or most-impacted dwelling unit. These measurements must be conducted at appropriate intervals during the comprehensive survey when sound propagation from the facility is representative of the conditions causing the complaint. A minimum of three measurements must be obtained.

The test for the absence of tonal components consists of two parts. The first must demonstrate that the sound pressure level of any one of the slow-response, A-weighted, ⅓ octave bands between 20 and 16 000 Hz is 10 dBA or more than the sound pressure level of at least one of the adjacent bands within two ⅓ octave bandwidths. In addition, there must be a minimum of a 5 dBA drop from the band containing the tone within 2 bandwidths on the opposite side.

The second part is that the tonal component must be a pronounced peak clearly obvious within the spectrum.

Figure 3 shows some examples of tonal components and Table 5 shows how the presence of tonal components was determined. There are qualifying tonals at 250 Hz (≥10 dBA within 2 bandwidths on one side and ≥5 dBA drop within

2 bandwidths on the other side, in addition to being pronounced within the spectrum) and at 2000 Hz (≥10 dBA within 1 bandwidth on one side and ≥5 dBA drop within 1 bandwidth on the other side, in addition to being pronounced within the spectrum). Note that the 630 Hz component meets part of the test (≥5 dBA difference within 2 bandwidths in addition to being pronounced within the spectrum), but it does not meet the full test of having a drop of 10 dBA or more within two bandwidths on at least one side. A facility causing a frequency spectrum with tones such as those in the 250 and 2000 Hz bands would not qualify for the A2 adjustment.

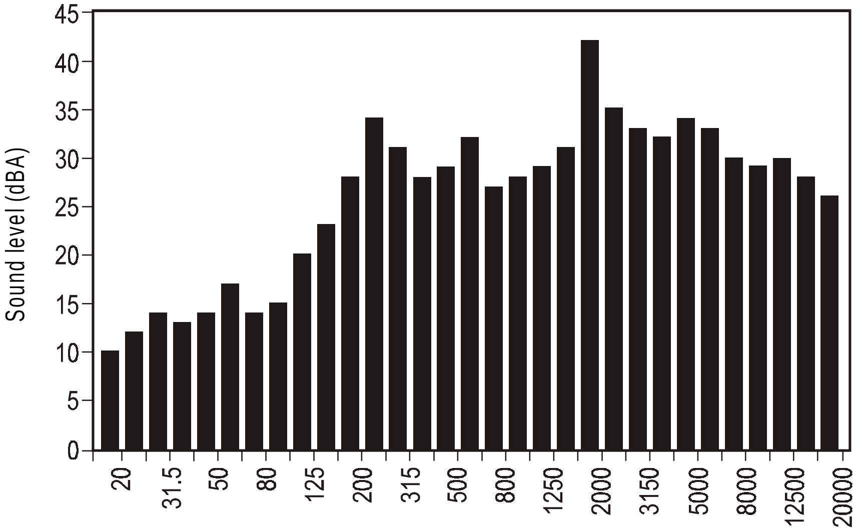


Figure 3. 1/3 octave band centre frequency (Hz)

There is considered to be an absence of impulse/impact components when the difference between the A-weighted impulse response sound level measurement and the A-weighted slow-response sound level measurement is 10 dBA or less.

Note that adjustment A2 applies to existing permanent facilities only.

Operators planning facilities in an area where there is already an energy industry presence are responsible for ensuring that their facility will either not cause the overall sound levels to exceed the PSL or, in situations where the existing sound levels are acceptable to residents even though it may be higher than the PSL, that it will not cause an increase in overall sound levels. The applicant may wish to discuss the proposed project with adjacent operators to examine potential sound attenuation measures that are both effective and economical. For example, it may be more cost effective to install silencers on existing equipment rather than design additional sound attenuation measures into the proposed facility.

Table 5. 1/3 octave band frequency spectrum analysis for tonal components

		Part 1		Part 2			Part 1		Part 2
Band (Hz)	Sound level (dBA)	Maximum Δ dBA within 2 bandwidths	≥5 dBA on other side?	Pronounced within the spectrum	Band (Hz)	Sound level (dBA)	Maximum Δ dBA within 2 bandwidths	≥5 dBA on other side?	Pronounced within the spectrum
20	10	-4	n/a	n/a	800	27	-5	n/a	n/a
25	12	-2	n/a	n/a	1000	28	-3	n/a	n/a
31.5	14	4	n/a	n/a	1250	29	-13	n/a	n/a
40	13	-4	n/a	n/a	1600	31	-11	n/a	n/a
50	14	-3	n/a	n/a	2000	42	13	**yes**	**yes**
63	17	4	n/a	n/a	2500	35	-7	n/a	n/a
80	14	-6	n/a	n/a	3150	33	-9	n/a	n/a
100	15	-8	n/a	n/a	4000	32	-3	n/a	n/a
125	20	-8	n/a	n/a	5000	34	4	n/a	n/a
160	23	-11	n/a	n/a	6300	33	4	n/a	n/a
200	28	8	n/a	n/a	8000	30	-4	n/a	n/a
250	34	11	**yes**	**yes**	10000	29	-4	n/a	n/a
315	31	3	n/a	n/a	12500	30	4	n/a	n/a
400	28	-6	n/a	n/a	16000	28	-2	n/a	n/a
500	29	-3	n/a	n/a	20000	26	-4	n/a	n/a
630	32	5	n/a	**yes**					

For operators proposing projects in an area with established energy facilities, a comprehensive sound survey or modelling using measurements from similar existing sources should be considered to determine the existing sound environment. For areas with no energy industry presence, operators may want to conduct an ambient sound survey to identify existing sound levels. However, for either case a sound survey is not required to conduct a noise impact assessment.

The noise impact assessment should indicate what the predicted design sound level from the facility will be at the nearest or most impacted permanently or seasonally occupied dwelling. The EUB would not automatically require detailed calculations to prove the validity of the predictions, but it does expect a reasonable technical basis for the values presented. Modelling and manufacturers' specifications, with an appropriate allowance for sound attenuation with distance from source, may be used as tools to predict CSLs. The design sound level should be compared to the calculated PSL to determine the possible impact of the facility.

For the purposes of this directive, a permanent facility is defined as any facility at a location longer than two months. However, drilling and servicing rigs fall into the temporary facility category even if they are expected to be at a location more than two months. Temporary activities generally do not require a noise impact assessment and are handled on a complaint basis. Nevertheless, when considering equipment such as rigs for these temporary activities, operators should be aware of the EUB's expectation of expeditious compliance if complaints occur.

Potentially impacted residents must be approached regarding the proposed facility and informed of any short-term and long-term noise impacts from construction and operation activities.

4.1 If both tonal and impulse/impact components are absent (see 4.0), adjustment A2 may be claimed. This adjustment is added to the other applicable A adjustments (see 3.0 and 5.0) and a maximum Class A adjustment of 10 dBA is permitted.

5.0 In some cases, the BSL given in Table 2 may be felt to be either too high or too low owing to special circumstances unique to the area under consideration. In such cases, it is permissible to perform a 24-hour ambient sound monitoring study to determine a more appropriate ASL in order to adjust Table 2 accordingly.

5.1 The opportunity to perform a 24-hour ambient sound monitoring study exists both prior to the approval of an application or once a facility is in place. Note that the intent of this sound study is to determine what the ASLs are, which does not include any energy-related industrial component. Therefore, for existing facilities, the sound survey must be conducted with all the facilities shut down so that the ASL is measured. See 9.1 below for an explanation of comprehensive sound surveys used for complaint cases.

The survey should be conducted 15 m from the nearest or most-impacted dwelling unit. For various reasons, such as topography or intervening barriers, the nearest dwelling unit may not be the most impacted unit. Even for remote facilities where there are no impacted dwellings, uncontrolled sound generation will not be allowed, particularly since retrofit may be required if a residence is built and the facility is no longer remote.

Although this is not a mandatory requirement, new facilities planned for remote areas should be designed to meet a target sound level of 40 dBA Leq at a distance of 1.5 km. (Note that using the rule of 6 dBA lost per doubling of distance from the source, the facility would generate a sound level of approximately 70 dBA at 50 m.) As a target, this does not establish the criterion for compliance should infringement occur.

The survey should be conducted during periods representative of typical days and nights for the area. What is typical depends upon the area being surveyed and should include such tests as

- What is the frequency of this type of activity?
- Do these types of activities normally occur in this area?

For example, the question might be whether to monitor at a location where fall harvesting (expected to run 24 hours a day for the next week) is taking place. The answer is no, because harvesting does not typically take place year round.

One of the first tests any sound survey is subjected to is whether it is representative for the area being measured. Consideration must be given to determining when an appropriate time to measure is so that the sound survey passes the test of “being representative.”

The results of the 24-hour monitoring study should be reported in terms of a 15-hour daytime Leq and a 9-hour nighttime Leq. The results are known as the ambient sound level (ASL).

See Appendix 2 for instrumentation and measurement requirements.

Appropriate references, such as VHS recordings, DAT recordings, operational logs, or event logs, should be kept to verify any unusual noise levels or any noise events that may be deleted from the survey results. A log of vehicle pass-bys, for example, would be useful.

Figure 2 allows for an adjustment of between -10 and +10 dBA Leq. If the ASLs are more than 5 dBA lower than the BSLs, the adjustment factor will be negative, indicating that the BSLs in the directive are too high in this case and should be lowered by the factor A3. If A3 is negative, it is possible for the Class A adjustment to be negative as well.

Adjustment A3 is added to the remaining Class A adjustments if applicable (see 3.0 and 4.0), and a maximum permissible adjustment of 10 dBA Leq is permitted.

6.0 Adjustments A1, A2, and A3 (if claimed) are added together. Call the sum A.

6.1 If A is greater than 10 dBA, the maximum Class A adjustment is 10 dBA. If the sum of A is less than 10 dBA, the maximum Class A adjustment is equal to A.

7.0 If it is known that a noise will only be temporary, there may be some additional tolerance of it. However, in order to utilize this additional tolerance, it is important to fully inform the potentially impacted residents of the anticipated duration and character of the noise.

ID 99-8 provides for an increasing adjustment as the duration of the sound becomes shorter. The Class B adjustment is based on four increments of sound duration, namely, one day, one week, two months, and more than two months.

Permanent facilities (defined here as being in operation more than two months at a location) do not qualify for the Class B adjustment. The Class B adjustment is therefore set to zero. For temporary activities at permanent facilities, such as turnarounds or repairs, the EUB will consider the use of the temporary activity adjustment. For most of these types of activities, it is not expected an application would have to be made to the EUB, so this adjustment would apply only if a complaint were received.

7.1 The number of days of the full duration of the operation must be determined. This is the duration of the sound as heard by an observer, not necessarily the duration of sound at one location. For example, a service rig operating on a multi well drilling pad may spend only three days at each well, but it may spend well over a month in total at the pad. Each well operation took only three days, but to the observer the sound was present for over a month. The duration is calculated to the nearest day.

Based on the number of days calculated above, the appropriate Class B adjustment is selected from Table 4. Note that only one of B1, B2, B3, or B4 may be chosen. The adjustment selected is known as the Class B adjustment, or B.

8.0 The BSL obtained from Table 2 in note 2.0 above is added to the daytime adjustment and the Class A and Class B adjustments. If no adjustments are claimed, the BSL obtained from Table 2 is used. The total is known as the permissible sound level (PSL).

9.0 In certain situations when it is difficult for both sides to agree on an acceptable course of action, the EUB should be contacted to mediate and if necessary make recommendations or give specific direction. For permanent facilities, a comprehensive sound monitoring study based on representative conditions (see 9.1 for further clarification of representative conditions) is required to determine if a violation has occurred. For temporary facilities, the option of conducting comprehensive sound surveys may not be feasible. The EUB is required to outline a suitable course of action in this situation.

Should a successful resolution not be achieved through mediation, the facility owner or landowner continues to have the right to request a hearing before the EUB under the appropriate sections of the Energy Resources Conservation Act.

9.1 A comprehensive sound monitoring study is not the same as an ambient sound monitoring study. The comprehensive sound study incorporates all sounds in the area, including the contribution of the facility. An ambient sound study does not include the contribution of the facility. For more information on ambient sound surveys, see 5.1 above. Because of the difference, a facility requires a separate sound survey from the comprehensive sound survey to claim adjustment A3. If a previous ambient monitoring survey has been conducted, that is acceptable to use to determine the ASLs.

The monitoring period may vary between 6 and 24 hours depending on the type, time, and duration of the noise. For example, if the sound is steady and not fluctuating, 6 hours of monitoring may be sufficient. On the other hand, if it varies and fluctuates and complaints are scattered in time, a longer term would be appropriate. The maximum survey time may exceed 24 hours where warranted. Exceptional circumstances should be discussed with the EUB before proceeding. If the complaint occurs very near to or straddles the day-night boundary, then a minimum of 3 hours must be performed during each of the day and night periods.

The comprehensive sound level (CSL) survey must encompass a representative portion of the times of day or night on typical days when the noise causing the complaints occurs. If a complainant has highlighted specific weather conditions, plant operating conditions, or seasons, the monitoring should take place under representative conditions. “Representative conditions” does not constitute absolute worst-case conditions or the exact conditions the complainant has highlighted if those conditions are not easily duplicated. In order to expedite complaint resolution, sound measurements may be conducted at the earliest opportunity when sound propagation towards the impacted dwelling is favourable. The local EUB field office can be consulted to help in establishing favourable conditions criteria.

The survey results are known as the CSL and are reported for the daytime and/or nighttime period involved. For example, if 6 hours of monitoring were carried out in the night, the results would be reported as a nighttime 6-hour Leq. For time periods less than the full 9 hours or 15 hours, it is assumed that the shorter time period is representative of the full time period unless results of the sound survey indicate otherwise.

The monitoring must be carried out at a point 15 m from the complainant’s dwelling towards the noise source. The 15-m requirement may be altered if it is physically impossible or acoustically illogical.

Instrumentation and measurement requirements are set out in Appendix 2.

A log or record of unusual noises such as vehicle passings, animal and bird sounds, and other non-industry-related sound, should be kept to verify any unusual short-term noise levels or any noise events that may be isolated from the survey results. The use of VHS recording, DAT recording, operational logs, event logs, etc., is acceptable to support any extraction of data from a CSL.

The daytime and/or nighttime CSLs are examined and a decision made as to whether they are to be used. If it is suspected that the facility is not the major contributor to the CSL or if it is thought that the facility's sound contribution is below the PSL, then facility isolation techniques may be applicable. These techniques may require the help of acoustical specialists.

Facility isolation techniques are used to determine the contribution of a single facility to the overall CSL at a particular location. These techniques could involve taking sound measurements near various sound sources to determine the equipment sound power levels and then determining the attenuation over the distance to the receiver. If possible, they may involve the selective shutting off of various facilities and determining the resulting decrease in CSL. These techniques are generally employed when several sources of sound are present and the contribution of each to the sound environment is being sought. Alternatively, it may be desired to demonstrate that the facility in question does not significantly contribute to the CSL or is below the PSL.

Where several facilities contribute to a CSL that exceeds the recommended levels, the EUB would favourably view the formation of a joint committee to solve the problem. Facilities not under EUB jurisdiction would have to be approached through the appropriate jurisdiction.

9.2 The PSL is obtained from flowchart 2. Any applicable adjustment factors may be claimed. If a noise assessment was completed for this facility, the PSL stated in that assessment must be used.

10.0 The PSL is the number that the CSL (or the isolated sound level) must be compared to.

10.1 Compliance with *ID 99-8* occurs when a valid comprehensive sound survey indicates the energy-related facility contribution is equal to or less than the PSL.

10.2 Corrective action to reduce the sound level of the facility at the complainant's dwelling is necessary. This may take the form of reducing the sound at the source, placing intervening barriers between the source and the receiver, or treating the receiver. In certain cases acoustical improvements to the receiver may be an economically attractive solution. The advice of a specialist in acoustics is recommended at this stage. When a facility is found to be noncompliant, the operator is allowed reasonable time to undertake corrective action. This time allows for any sound monitoring, analysis, evaluation, budgeting, equipment procurement, and installation on a schedule agreed upon by all parties. However, if in the opinion of the EUB, the operator is not working in the spirit of the directive to resolve the issue, the EUB will intervene. Consequences may include curtailing production to reduce sound generation and possible shutdown of the facility. Communication with the complainant through all phases of corrective action is required.

For temporary facilities such as rigs, the suggested solution that the facility will be moving on soon and will not be causing a problem anymore is generally not accepted. If the resident does accept that solution, then it is acceptable to the EUB.

Once corrective action has been taken, complainants should be approached to see if they are satisfied. If they are, the problem is resolved. If the complainants are not satisfied, another comprehensive sound survey should be done to determine if the facility is now complying with the directive. In special circumstances where both parties agree or the EUB dictates, an ambient sound survey may be conducted to determine the incremental impact of the facility. Based upon the results of this survey, a decision will be made by the EUB as to whether to recommend further action.

10.3 The facility satisfies the requirements of *ID 99-8.* The results of the comprehensive sound survey must be made available to the complainants, so that they understand why the facility is in compliance and no corrective action is required.

If a situation occurs where an operator is either unable or unwilling to meet a required reduction in noise level, it may apply to the EUB for a hearing under the appropriate section of the Energy Resources Conservation Act. A similar option is available to an impacted landowner.

10.4 In situations where a facility is in compliance, yet the complainant's concerns have not been resolved, the EUB should be contacted to mediate.

11.0 If you have any questions about *ID 99-8: Noise Control Directive* and how it relates to your particular situation, call the EUB's Regulatory Support Branch at (403) 297-3642.

6 Noise Complaint Investigations

The EUB expects operators to make every reasonable attempt to resolve any noise-related complaint brought to their attention in a timely manner. It is critical when investigating a noise complaint that operators first attempt to resolve the issue through direct contact with the complainant to understand their concerns and establish a dialogue. In doing so, the operator must carefully explain the requirements of this directive and clearly outline the process, including time lines they intend to follow in addressing the matter. If a comprehensive sound survey is to be performed, the operator or its consultant must determine the representative conditions that exist when noise would impact a residence for a survey to be technically valid.

A sample complaint investigation form that can be used by industry in responding to a noise concern follows on the next two pages.

On part 1 of the form the operator gathers necessary information about the quality and characterization of the noise from the resident(s) to help determine the source of the noise. This part also examines the weather and ground cover conditions that exist when the noise is most annoying to the residents. From this information the operator, or its representative, can establish the typical representative conditions that exist under which sound level monitoring should take place. Representative conditions do not necessarily constitute absolute worst-case conditions or the exact conditions the residents have described if those conditions are not easily duplicated.

Part 2 of the form, the event log, is designed for use by the residents concerned about the noise. They should enter details about the noise when it becomes annoying to them. The event log can then be used by the operator to further pinpoint the source of the noise or the representative conditions needed to conduct a sound level survey.

Sound level surveys should be conducted at the first available opportunity when the representative conditions can be reasonably met. Operators should provide a copy of the completed complaint investigation form to the residents in question and should consider including a copy in any sound level survey reports to demonstrate that the representative conditions were met.

NOISE COMPLAINT INVESTIGATION

PART 1

Date (D/M/Y):______________________________

Resident:______________________________________	Respondent:________________________________
Legal location:__________________________________	Company:__________________________________
Address:_______________________________________	Address:___________________________________
_______________________________________	___________________________________
Telephone:_____________________________________	Telephone:_________________________________

Noise Characterization

Identify the quality and characteristics of the noise.

Distance to source:_________________ (m) When is noise a problem (day/night)?____________________

Pitch (high/low): ___________________ Where is noise most annoying (inside/outside)?____________________

Is there a noticeable tone? __________ Describe: ____

Is noise steady/intermittent/pulsing? ____________ Describe: ____

What is noise comparable to? ____

Other comments: ____

Weather Conditions

Identify the weather conditions under which the noise is most noticeable.

Temperature: _________________ Direction wind is coming from:________________________________

Wind speed (km/h): ___________ Cloud cover:____________ Precipitation: _________________

Ground cover between residence and facility (snow, water, grass, crop, trees, ice, etc.):

____

Other comments: ____

Representative Conditions

From the above, identify the conditions that should exist as closely as possible during a comprehensive sound survey.

____

____

____

____

EVENT LOG

PART 2

Resident: ____________________________

Company contact: ___________________________________

Telephone: ___________________________

Telephone: ____

List any details related to the sound from the industrial facility that is annoying you. Refer to the descriptions at the bottom for assistance in providing information.

Date (D/M/Y)	**Time a.m./p.m.**	**Noise characteristics**	**Weather conditions**	**Ground cover**	**Receiver location**

Noise characteristics:	Describe the sound as a high or low tone, steady or pulsing. What would you compare the sound to?
Weather conditions:	If possible, provide details on temperature, wind direction and speed, cloud conditions (clear or cloudy), and existence of precipitation when the sound is a problem.
Ground cover:	Describe what is covering the ground between you and the facility; for example, is it snow, water, grass, crop, trees, ice?
Receiver location:	Note where you were when the sound was annoying (outdoors, such as on the deck or in the yard or corrals, or indoors, such as in the bedroom or living room).

7 Noise Impact Assessments

A noise impact assessment (NIA) must be completed for any new permanent facilities or for modifications to existing permanent facilities where there is a reasonable expectation of a continuous noise source. Compressor stations, pumping stations, electric power plants, coal mines, industrial development permit facilities, gas processing plants, and batteries with compressors are examples of facilities where an NIA is required. The EUB may require an NIA for any facility it deems necessary.

While an NIA must be conducted for all facilities identified above, the assessment need not be included with the facility application if the analysis indicates compliance. In cases where the assessment indicates noncompliance, further attenuation measures must be considered. Where these are not practical, the assessment can be included with the application, along with the mitigative measures proposed to reduce the impacts. If the applicant is unsure of the requirements for an assessment, a knowledgeable consultant or the EUB should be contacted.

The intent of an NIA is to ensure that applicants consider possible noise impacts before a facility is constructed or operated, since the cost to retrofit may be significantly more than if noise mitigation measures are incorporated into the design of a facility. Best practical technology (accounting for cost versus benefit) should be considered to minimize the potential noise impacts to existing dwellings and future infringement. Operators should discuss noise matters with area residents during the design, construction, and operating phases of an energy facility. Should a valid complaint be registered after the facility is constructed and in operation, the operator must meet the permissible sound level (PSL) referenced in the NIA. It is in an operator’s best interest to get as accurate a predicted sound level as possible, in order to avoid the expense and embarrassment of having a facility’s operations affected or shut down because of noncompliance.

Operators planning facilities in an area where there is already an energy-industry presence are responsible for ensuring that their facility will not cause the overall sound levels to exceed the PSL or, where the existing noise levels are acceptable to residents even though they may be higher than the PSL, will not cause an increase in overall sound levels. The applicant may wish to discuss the proposed project with adjacent operators to examine potential sound attenuation measures that are both effective and economical. For example, it may be more cost effective to install silencers on existing equipment rather than design additional sound attenuation measures into the proposed facility.

No matter what sound level is predicted before a facility is built, if a valid complaint is received after the facility is operating and the measured CSL does not comply with *ID 99-8*, remedial action may be required. The EUB is less likely to grant operating concessions (i.e., higher sound emissions) to new facilities, since operators will have had the opportunity to identify and design proper noise control features into their facilities.

For operators proposing projects in an area with established energy facilities, a comprehensive sound survey or modelling using measurements from similar existing sound sources should be considered to determine the existing sound environment. For areas with no energy industry presence where noise may be an issue with local residents, operators may want to conduct an ambient sound survey to identify existing sound levels. However, a sound survey is not mandatory for conducting an assessment. In all cases, the NIA should address construction noise and any mitigation that may be required as a result.

As part of a facility application, the operator must indicate that the facility meets the requirements in *ID 99-8*. It must also keep corroborating information on hand. The EUB conducts audits of facilities that require proof that NIAs have been completed.

An acceptable NIA must do the following:

1. Identify what the PSL is at the nearest or most impacted dwelling. This includes all details on how the PSL was calculated and any adjustments claimed. Flowchart 2 in Section 5 can be used to calculate the PSL.

2. Identify major sources of noise from the facility and their associated sound power/pressure levels. Indicate whether the sound data are from vendors, field measurements, theoretical estimates, etc. Such items as cooler fans, exhaust noise, and pump noise are examples of major noise sources. When using manufacturer’s data for expected performance, it may be necessary to modify the data to account for actual design conditions. Note that use of any theoretical data or extrapolation techniques can lead to inaccuracies and therefore is less reliable than actual field measurements made once the equipment is in place.

3. Identify what the predicted overall sound level at the nearest or most impacted residence will be. Normally only the nighttime sound level is necessary, as it will often not change from daytime to nighttime. But if there are differences between day and night operations, both levels must be calculated.

4. Identify how the predicted overall sound level at the nearest or most impacted residence was calculated. Models or hand calculations can be used to obtain the predicted sound levels. All inputs and assumptions (e.g., weather, ground conditions, wind speeds, wind direction) should be clearly stated within the assessment, so that if the EUB audits a facility and requests the NIA, the assessment can be understood.

5. Identify whether the assessment indicates the facility is in compliance with the requirements of *ID 99-8.*

6. Consider further attenuation measures in cases where the assessment indicates noncompliance. Where further attenuation measures are not practical, the assessment can be included with the application, along with the measures proposed to reduce the impacts.

7. Identify the person conducting the assessment.

A sample form has been developed to assist in conducting an NIA (see next page). It includes the major types of information that must be included in an assessment.

Direct questions regarding NIAs to the EUB's Regulatory Support Branch at (403) 297-3642.

NOISE IMPACT ASSESSMENT

Company: ____

Facility name: ______________________ Type: ________________

Legal location: ______________________________________

Contact: ______________________ Telephone: ________________

1. Permissible Sound Level (PSL) Determination

(Note that the PSL for a pre-1988 facility undergoing modifications may be the sound pressure level (SPL) that currently exists at the residence if no complaint exists.)

Distance to nearest or most impacted residence: ______________________ (m)

Basic sound level (nighttime): __________ (dBA) Class A adjustment: __________ (dBA)

Daytime adjustment: __________ (dBA) Class B adjustment: __________ (dBA)

Permissible sound level, nighttime: __________ (dBA) Daytime: __________ (dBA)

2. Sound Source Identification

Distance (far or free field) at which the SPL was calculated or measured: ______________ (m)

List all new and existing equipment that are sound sources. For each, give its predicted sound pressure level (SPL) and the source of the SPL prediction data.

New equipment	Predicted SPL	SPL prediction data source

Existing equipment/facility	Predicted SPL	SPL prediction data source

3. Predicted Sound Level

Predicted sound level to the nearest or most impacted residence from new facility (including any existing facilities):______________ dBA (night/day) Permissible sound level: _______________ dBA (night/day)

4. Predicted Sound Level Calculation

Name of computer model (if used): ____

Distance at which manufacturers' data was referred: ____________________________________(m)

Describe any considerations and assumptions used in conducting engineering estimates:_____________________

____

____

5. Compliance Determination

Is the predicted sound level less than the permissible sound level? Yes _____________ No __________________

If **YES**, the facility is expected to be in compliance with guidelines and the NIA is complete.

6. Attenuation Measures

If **NO** (the facility is not in compliance), what attenuation measures are planned to reduce noise impacts?

____

____

____

____

____

Explain what measures have been taken to address construction noise. ___________________________________

____

____

____

____

7. Analyst's Name:____

Title: ____

Telephone: _________________________________ Date: ___________________________________

8 Compliance and Enforcement

A noise impact assessment must be conducted for any new permanent facilities or for modifications to existing permanent facilities where there is a reasonable expectation of a continuous noise source (see Section 7). However, you do not have to include the assessment with the facility application if the analysis indicates compliance (see EUB *Guide 56: Energy Development Application Guide*). In cases where the assessment indicates noncompliance, you must consider further attenuation measures. Where such measures are not practical, you can include the assessment with the application, along with reasons why the measures proposed to reduce the impacts are not practical.

The EUB conducts random comprehensive sound surveys and audits on facilities and facility applications and expects sound levels to be in compliance and NIAs to be complete and understandable. Upon audit, failure to have an appropriate or complete NIA is considered a noncompliance event. If you are unsure of the requirements for an NIA, contact an appropriate consultant or the EUB’s Regulatory Support Branch (403-297-3642).

The EUB considers the following to be “major” noncompliance events:

- Submission of an NIA that is inappropriate, incomplete, and contains significant errors or omissions

- Failure of a new facility to meet the permissible sound levels at the nearest or most impacted residence as determined by a post-construction/start-up comprehensive survey

- Failure to respond expeditiously to a legitimate noise complaint regarding an existing facility

Noncompliance with other requirements of *ID 99-8* or *Guide 38* are considered “minor” events.

The EUB reserves the right to escalate noncompliance issue(s) to any level should conditions warrant.

If in the opinion of the EUB a noncompliance event causes noise levels greater than the permissible sound level or unacceptable impacts on nearby residents, it may suspend operations if the impacts cannot be resolved.

Where possible, the EUB intends to utilize existing audit and enforcement processes. For example, Field Surveillance Group enforcement ladders may be used to provide consistent consequences with other similar field facility noncompliance events. For more information on this, contact the appropriate EUB field centre office.

9 Example Problems

The example problems below, when used in combination with the flowcharts in Section 5, show a step-by-step process to determine compliance or noncompliance for any new or existing facility.

Example Problem 1

A new compressor station is proposed for the area shown below. What sound levels should the facility be designed for?

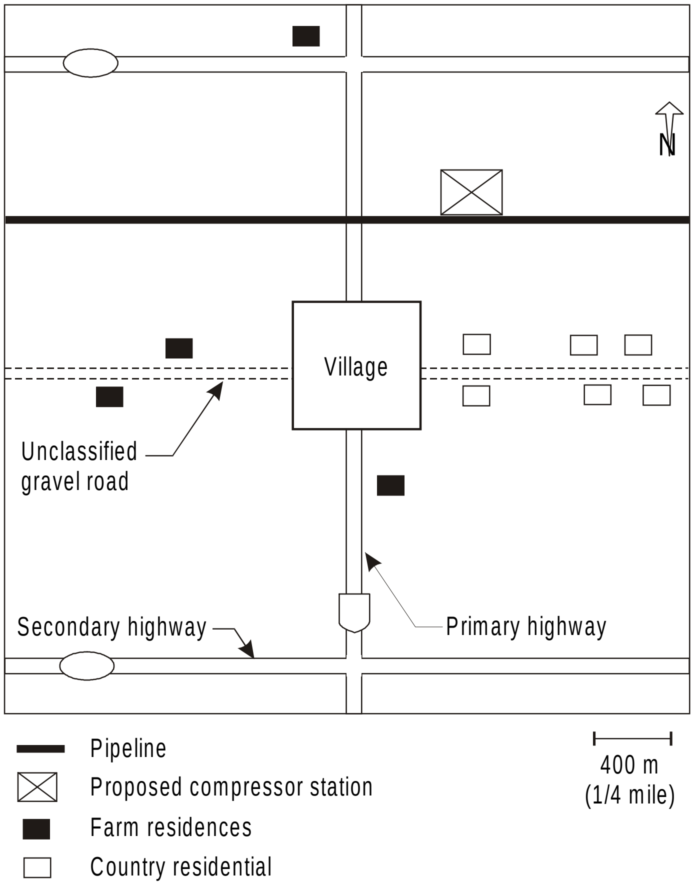


Figure 4. Area sketch for problem 1

Problem 1 - Solution

Using the flowcharts in Section 5, take the following steps in sequence to determine the appropriate PSL.

Step 1 Go to flowchart 1.
Designing new facility?
Yes. Use flowchart 2.

Step 2 Go to flowchart 2.
Read BSL from Table 2.

All three possible dwelling unit densities are represented in this area. The four 8.1-ha (20-acre) country residential dwellings factored over a quarter section fall into the 1-8 dwellings range, as do the farmhouses. The two country residential dwellings closest to the village and a portion of the village are in the 9-160 dwellings range, while the body of the village is in the greater than 160 dwellings range.

Regarding the transportation proximity category: the presence of the primary highway causes the adjacent farmhouses to fall into category 2, while the dwellings in the village fall into category 2 or 3, depending on the distance from the highway. Some of the country residences fall into category 2 (those closest to the highway), while others fall into category 1 (farther along the gravel road).The farmhouses on the gravel road are category 1.

It appears that the country residences to the south of the proposed facility are probably the most sensitive, being category 1 units. This gives a nighttime BSL of 40 dBA Leq, from Table 2.

Some preliminary calculation of expected sound levels and attenuation may be useful in determining the worst impacted residence. For instance, the nearest dwelling unit may be a category 2, while a more distant dwelling unit may be category 1. Some elementary calculations may be necessary to determine the worst case.

Step 3 Are daytime sound levels required?
No, as the lower sound level is the one that must be designed for and the nighttime level is usually lower.

Step 4 Seasonal operation?
No, because this facility will be running all year. Again, the lower level is the one that must be designed for, so including this adjustment in the design stage is not appropriate.

Step 5 Are tonal or impulse/impact components present?
This adjustment is applicable only to existing facilities and cannot be used in the design of new facilities. Therefore adjustment A2 is not applicable.

Step 6 Is the BSL appropriate for this area?
Assume no. The operators of this proposed facility have taken some spot measurements with a hand-held sound meter. The levels recorded ranged from 35 dBA at night to 55 dBA during the day.

Step 7 A 24-hour ambient sound monitoring study 15 m from the nearest acreage dwelling unit prior to construction of the facility must be conducted to claim adjustment A3. The results of the survey are

Daytime ASL: 53 dBA Leq
Nighttime ASL: 37 dBA Leq

Claim adjustment A3 from Figure 2. First, subtract the ASL measured in this step from the BSL in step 2.

Daytime BSL - daytime ASL = 50 - 53 = - 3
Nighttime BSL - nightime ASL = 40 - 37 = +3

For each in turn, locate this difference on the horizontal axis of Figure 2, read upward until the adjustment line is intersected, and read to the left to find the applicable adjustment A3.

Daytime adjustment: A3 = +8 dBA Leq
Nighttime adjustment: A3 = + 2 dBA Leq

Step 8 Sum of adjustments: A1 + A2 + A3 (call it A)
Daytime: 0 + 0 + 8 = 8 dBA Leq
Nighttime: 0 + 0 + 2 = 2 dBA Leq

Step 9 Is A greater than 10 dBA Leq?
In either case, no.
Class A adjustment = 8 dBA daytime
Class A adjustment = 2 dBA nighttime

Step 10 Is noise temporary in nature?
No; the facility will operate all year.
Class B adjustment: B = 0 dBA

Step 11 Determine the PSL.

Daytime	Nighttime
PSL = BSL + Day + A + B	PSL = BSL + Day + A + B
PSL = 40 + 10 + 8 + 0	PSL = + 40 + 0 + 2 + 0
PSL1 = 58 dBA Leq	PSL = 42 dBA Leq

Step 12 Daytime PSL = 58 dBA Leq
Nighttime PSL = 42 dBA Leq

as measured 15 m from the nearest acreage dwelling unit.

Using these PSLs, the designer must calculate the maximum sound output of the facility. In this case, for example, the dwelling unit is about 600 m from the facility. Assuming a theoretical 6 dBA drop in sound level per doubling of distance, the facility must have a sound level of no more than 60 dBA Leq measured 75 m from the facility in order to have a sound level of 42 dBA at 600 m. This can be seen from the following table:

Distance (m)	Sound Level (dBA)
600	42
300	48
150	54
75	60

This 6 dBA loss per doubling of distance is a very rough estimate, and more site-specific methods should be used if possible. A more accurate way to determine the sound attenuation with distance is to measure similar equipment at a topographically similar location. This is done by measuring the sound levels at specified distances away from the facility (for example, 100 m, 200 m, 400 m, etc.) to determine the actual attenuation with distance. It is not uncommon for this attenuation to vary between 5 and 10 dBA for each doubling of distance.

For a design situation, notice how it is the nighttime sound level that must be met. Most permanent facilities create the same amount of noise whether it is day or night, and so the most stringent criterion is the nighttime sound level.

The NIA developed from these findings would include the following:

Problem 1 - Noise Impact Assessment

Note that this NIA is slightly more detailed than some because of claiming adjustment A3. Other than that, it is typical of the type of information and level of detail required.

1. The major sources of noise in this facility include cooler fans, exhaust noise, and possibly noise. The manufacturer of this equipment has stated that the maximum sound level from all the equipment is 60 dBA measured at 50 m in front of the cooler fan.

2. The sound levels at the nearest residence have been predicted using only the theoretical 6 dBA loss per doubling of distance. No additional losses for air absorption, excess ground attenuation, or facing the cooler fan away from the dwelling have been calculated. The only input is the 60 dBA criterion at 50 m.

3. The distance to the most impacted residence is 600 m to the south. This also happens to be the closest residence. If we extrapolate the 60 dBA value out to 600 m, using the theoretical 6 dBA loss per doubling of distance:

$$L(R_2) = L(R_1) - 20 \log\left(\frac{R_2}{R_1}\right)$$

$$L(600\text{ m}) = 60 - 20 \log\left(\frac{600}{50}\right)$$

$$L(600\text{ m}) = 60 - 21.6$$

$$L(600\text{ m}) = 38.4\text{ dBA}$$

   So the predicted sound level at the residence is 38.4 dBA.

   As well, we have measurements at a similar facility with similar topography to the one being applied for. Those measurements indicate short-term sound levels of 55-60 dBA at a distance of 75 m. These measurements indicate that the 6 dBA loss per doubling of distance may be conservative. As another measure to ensure compliance of the facility, the cooler fan will be faced in a northeasterly direction, so that residences are not located in front of it.

4. The most impacted residence is along an unclassified gravel road, so it is a category 1 proximity to transportation. There are four residences along this road, each consisting of 81 ha (20 acres). When factored over the quarter section, these residences fall into the 1-8 dwellings range. Based upon these two factors, the BSL is 40 dBA at night, from Table 2.

The only adjustments to the BSL being claimed are the daytime adjustment and the ambient monitoring adjustment.

Some spot measurements with a hand-held sound meter have been taken. The levels recorded ranged from 35 dBA at night to 55 dBA during the day. As a result, a 24-hour ambient monitoring survey was conducted at the most impacted residence.

The results of the survey are 53 dBA Leq (15 h) during the daytime period and 37 dBa Leq (9 h) during the nighttime period. The report detailing the ambient monitoring survey is contained in an attachment to this NIA.

Claiming adjustment A3 from Figure 2, the ASL measured is subtracted from the BSL:

Daytime BSL - Daytime ASL = 50 - 53 = -3
Nighttime BSL - Nighttime ASL = 40 - 37 = +3

Using Figure 2, the applicable A3 adjustments are

Daytime adjustment A3 = +8 dBA Leq
Nighttime adjustment A3 = +2 dBA Leq

The PSLs are

Daytime						Nighttime					
PSL	=	BSL	+ Day	+ A	+ B	PSL	=	BSL	+ Day	+ A	+ B
PSL	=	40	+ 10	+ 8	+ 0	PSL	=	+ 40	+ 0	+ 2	+ 0
PSL = 58 dBA Leq						PSL = 42 dBA Leq					

5. The assessment indicates the predicted sound level is 38.4 dBA. This is less than the PSL of 42 dBA during the nighttime, calculated above. The assesssment indicates the facility will meet the noise directive. If the facility receives any complaints, they will be investigated promptly, and if the facility is not meeting the directive, remedial action will be undertaken to rectify the situation and bring the facility into compliance with the noise directive.

6. No further attenuation measures need to be considered at this time.

7. This NIA was conducted by A. Tech-Engineer, of XYZ Company.

Example Problem 2

A drilling rig is drilling a multiwell pad and averages one well every 1.5 days. Including rigging up and tearing down, the rig will be at the site for 25 days.

A residence exists 500 m south of the drill pad and is 50 m from a secondary highway. The company receives a complaint that noise during the early morning is unacceptable during typical drilling operations. The problem is not resolved by private negotiation.

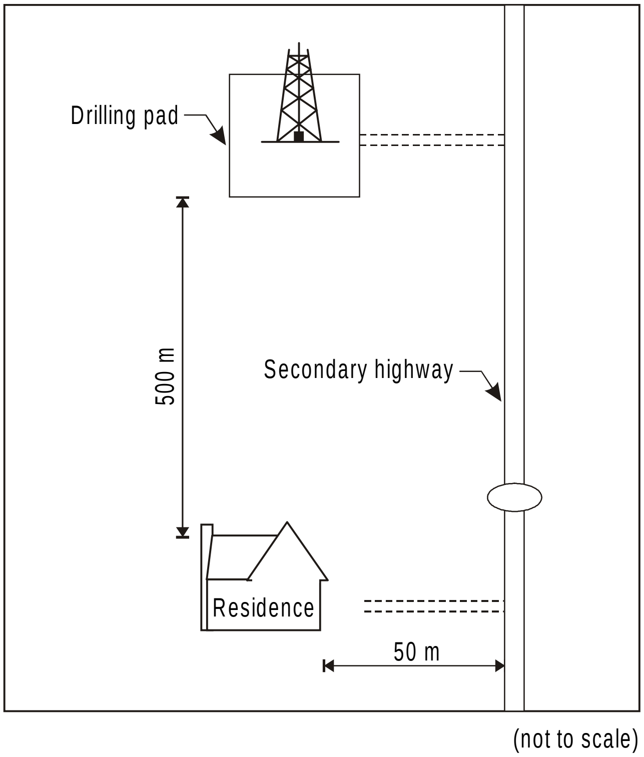


Figure 5. Area sketch for problem 2

Problem 2 - Solution

Step 1 Go to flowchart 1.
Complaint received?
Yes. Use flowchart 3.

Step 2 Go to flowchart 3.
Complainant willing to discuss problem?
Yes.

Step 3 Review details of complaint.
Normal drilling operations (tripping), 04:00, calm summer morning.

Step 4 Problem privately resolved?
No.
A comprehensive sound monitoring study is required. Because the rig will be at this location for 25 days, it is feasible to conduct a sound survey. The sound survey will be conducted as soon as possible in order to determine if a problem exists.

Step 5 The comprehensive sound survey must be performed under similar conditions to those during the complaint. The operator decides to monitor for the full nighttime period (22:00-07:00), while the rig is drilling ahead, instead of the minimum 6 hours required. The results of the comprehensive sound survey are

Comprehensive sound level (CSL) = 53 dBA Leq nighttime.

Since the drilling rig is the only source of sound apart from unrelated traffic, it is felt the CSL measured should be representative.

Step 6 Determine PSL.
Use flowchart 2.
The approach is similar to that taken in example problem 1.

Step 6A The BSL in this case is 45 dBA at night, because the dwelling is in the 1-8 dwellings per section and category 2 transportation proximity. The dwelling fits into category 2 because the residence is 50 m from a secondary highway.

Step 6B None of the Class A adjustments are applicable because
- A1 - complaint not received during the winter season,
- A2 - the adjustment for tonal or impulsive component absence applies only for permanent facilities,
- A3 - we will assume the BSL is appropriate.

Therefore A is 0.

Step 6C The rig is in operation less than two months, so one of the Class B adjustments would be applicable. Each well is drilled in 1.5 days and drilling operations are expected to last 25 days. The duration of the activity is 25 days.

From Table 4, the class B adjustment = B3 = 5 dBA.

Step 6D The PSL is
PSL = BSL + Day + A + B
PSL = 45 + 0 + 0 + 5

PSL = 50 dBA Leq nighttime

Step 7 Compare CSL with PSL:

CSL = 53 dBA Leq nighttime
PSL = 50 dBA Leq nighttime

Step 8 CSL is not less than PSL.
Some sort of corrective action is required.

Step 9 The *ID 99-8* requirements are exceeded by 3 dBA Leq. The cause has not yet been identified. A simple solution may be to apply upgraded mufflers to the rig or reschedule some nighttime activities, such as tripping or unloading pipe, to daytime hours if possible.

The statement that “The rig is only going to be here for a few more days; let’s just get the job done and then we won’t be causing a problem anymore” will not generally be accepted as a solution. However, if the resident will accept that solution, it would be acceptable to the EUB.

Step 10 Once corrective action has been taken, the complainants should be approached to see if they are satisfied. If they are, the dispute has been resolved. If not, other simple solutions should be pursued. If nothing more can be accomplished, another comprehensive sound survey should be done to determine if the rig is now complying with the directive.

Based upon the results of this new survey, a decision will be made by the EUB whether to recommend further action. Should a successful resolution not be achieved through mediation, the facility owner or landowner continues to have the right to request a hearing before the EUB under the appropriate sections of the Energy Resources Conservation Act.

Appendix 1 Glossary

Some of the terms used in *ID 99-8* and *Guide 38* are defined for this particular context; these definitions are not necessarily the same as the generally accepted broader definitions of these terms. Explanations used in this section should not be used for other noise legislation, as the meanings for some terms may not be identical.

Abnormal noise events	Noises that are sufficiently infrequent as to be uncharacteristic of an area or that occur so close to the microphone as to dominate the measurements in an unrealistic manner. Consideration must be given to deleting occurrences of abnormal noise from the measurements to obtain a reasonably accurate representation of the sound environment. Examples of abnormal noises include a dog barking close to the microphone, a vehicle passing nearby, people talking in the vicinity of the microphone in a quiet environment, or a passing road grader.
Ambient noise	All noises that exist in an area and are not related to a facility covered by *ID 99-8.* Ambient noise includes sound from other industrial noise not subject to this directive, transportation sources, animals, and nature.
Ambient sound level (ASL)	The sound level that is a composite of different airborne sounds from many sources far away from and near the point of measurement. The ASL does not include any energy-related industrial component and must be measured without it. The ASL can be measured when the sound level in an area is not felt to be represented by the basic sound levels in Table 2. The ASL must be measured under representative conditions. As with comprehensive sound levels, representative conditions do not constitute absolute worst-case conditions (i.e., the most quiet day in this case) but conditions that portray typical conditions for the area. Also see entry for Representative conditions.
A-weighted sound level	The sound level as measured on a sound level meter using a setting that emphasizes the middle frequency components similar to the frequency response of the human ear.

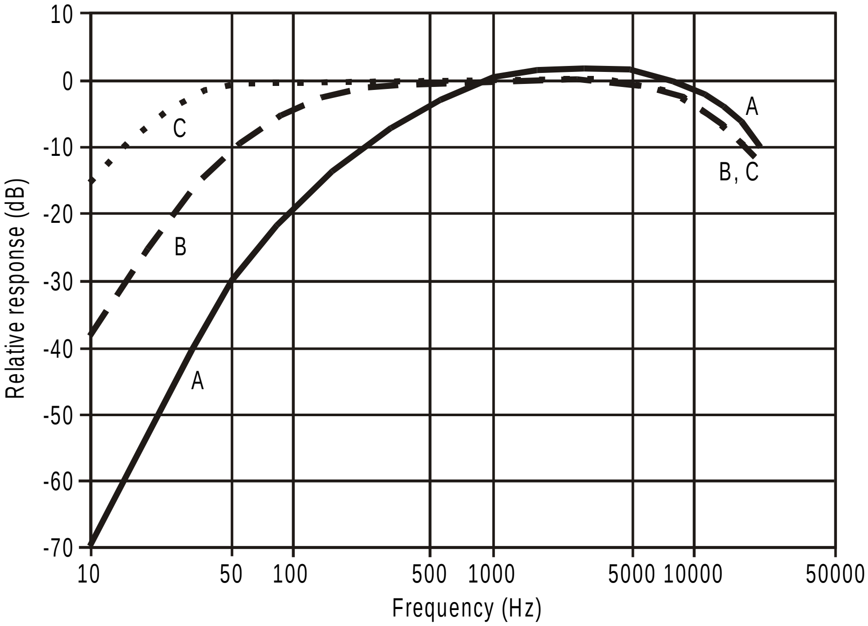


Figure 6. Weighting network curves

Bands (octave, ⅓ octave)	A series of electronic filters separate sound into discrete frequency bands, making it possible to know how sound energy is distributed as a function of frequency. The octave band has a centre frequency that is double the centre frequency of the octave band preceding it. The ⅓ octave band analysis provides a finer breakdown of sound distribution as a function of frequency.
Basic sound level (BSL)	The A-weighted Leq sound level commonly observed to occur in the designated land-use categories with industrial presence. The BSL is assumed to be 5 dBA above the ASL and is set out in Table 2.
Calibration	The procedure used for the adjustment of a sound level meter using a reference source of a known sound pressure level and frequency. Calibration must take place before and after the sound level measurements.
Category	A classification of a dwelling unit in relation to transportation routes used to arrive at a BSL.
Category 1	Dwelling units more than 500 m from heavily travelled roads and/or rail lines and not subject to frequent aircraft flyovers. Also see entry for Category.

Category 2	Dwelling units more than 30 m but less than 500 m from heavily travelled roads and/or rail lines and not subject to frequent aircraft flyovers. Also see entry for Category.
Category 3	Dwelling units less than 30 m from heavily travelled roads and/or rail lines and/or subject to frequent aircraft flyovers. Also see entry for Category.
Class A adjustment	Consists of the sum of adjustments that account for the adjustment seasonal nature of the noise source, absence of both tonal and impulse/impact components, and the actual ambient sound level in an area. It cannot exceed +10 dBA. The Class A adjustment is added to the BSL, the daytime adjustment, and the Class B adjustment to arrive at a permissible sound level.
Class B adjustment	An adjustment based on the duration of a noisy activity that recognizes that additional noise can be tolerated if it is known that the duration will be limited. An adjustment of B1, B2, B3, or B4 may be selected as applicable.
Comprehensive sound level (CSL)	The sound level that is a composite of different airborne sounds from many sources far away from and near the point of measurement. The CSL does include industrial components and must be measured with them, but it should exclude abnormal noise events. The CSL is used to determine whether a facility is complying with *ID 99-8*. Also see entry for Representative conditions.
Daytime	Defined as the hours from 07:00 to 22:00.
Daytime adjustment	An adjustment that allows a 10 dBA increase because daytime sound levels are generally about 10 dBA higher than nighttime values.
Density per quarter section	Refers to a quarter section with the affected dwelling at the centre (a quarter-mile/400-m radius). For quarter sections with various land uses or with mixed densities, the density chosen must be factored for the area under consideration.

dB (decibel)	A unit of measure of sound pressure that compresses a large range of numbers into a more meaningful scale. Hearing tests indicate that the lowest audible pressure is approximately 2 x 10^{-5} Pa (0 dB), while the sensation of pain is approximately 2 x $\mathbf{10^{2}}$ Pa (140 dB). Generally, an increase of 10 dB is perceived as twice as loud. $\text{Sound pressure level (dB)} = 10 \log \left(\frac{p^2}{p_o^2} \right) = 20 \log \left(\frac{p}{p_o} \right)$ p = root-mean-square sound pressure (Pa) p_o = reference root-mean-square-sound pressure, generally 2 x 10^{-5} Pa
dBA	The decibel (dB) sound pressure level filtered through the A filtering network to approximate human hearing response at low frequencies. Also see entries for dB and A-weighted sound level.
Dwelling unit	Any permanently or seasonally occupied residence with the exception of an employee or worker residence, dormitory, or construction camp located within an industrial plant boundary. Trailer parks and campgrounds may qualify as a dwelling unit if it can be demonstrated that they are in regular and consistent use during the applicable season.
Dwelling unit (most impacted)	The nearest dwelling unit may not necessarily be the one most adversely affected because of factors such as topography or man-made features. For example, the nearest dwelling unit to a facility may be located behind an intervening ridge, while a more distant dwelling unit may be in direct line of sight with the facility. Care must be taken in determining the most impacted dwelling unit. Also see entry for Dwelling unit.

Emergency	An unplanned event requiring immediate action to prevent loss of life or property. Events occurring more than four times a year are not considered unplanned.
Energy equivalent sound level (Leq)	The Leq is the average A-weighted sound level over a specified period of time. It is a single-number representation of the cumulative acoustical energy measured over a time interval. The time interval used should be specified in brackets following the Leq (e.g., Leq (9) is a 9-hour Leq). If a sound level is constant over the measurement period, the Leq will equal the constant sound level where f_i is the fraction of time the constant level $L_{i,}$ is present. $\mathrm{Leq} = 10 \log \left(\sum_{i=1}^{n} f_i \times 10^{L_i/10} \right)$ See Section 3 for more detail on the Leq concept.
Facility	A facility is any operation used in exploration, processing, development, and transportation of energy resources. A new facility is one that was not in operation prior to the effective date of *ID 99-8.* An existing facility is one that was in operation prior to the effective date of this directive.
Far field	The far field may consist of two parts, the free part and the reverberant part. In the free part, the sound pressure level obeys the inverse-square law (6 dBA loss per doubling of distance). See Section 3.5 for examples. The reverberant part exists for enclosed situations where there are many reflected sound waves from all directions. An example of a reverberant field is the case of industrial equipment enclosed in a room.
Fast response	Fast response has a time constant of 125 milliseconds on a sound level meter. Also see entry for Slow response.
Filter	A device separating the components of an incoming signal by its frequencies.

Frequent aircraft flyovers	Used in the assessment of categories as part of a site-specific analysis for dwellings that lie within a contour area with a noise exposure forecast (NEF) 25 or greater, as designated by Transport Canada. In the absence of any NEF contours for a local airport, Transport Canada will be referenced for current air traffic statistics. In this case, to qualify for the BSL adjustment, a dwelling must be within 5 km of an airport that has a minimum of nine aircraft takeoffs or landings over the nighttime period. Also see entry for Noise exposure forecast.
Heavy industrial area	Usually an area zoned by the appropriate municipality containing or meant to contain a concentration of large industrial complexes, thereby helping operators avoid multiplicity of industrial effects on surrounding residents. A buffer zone is generally established between the industrial facilities and where people live so that there are no residences situated among industrial facilities.
Heavy truck	Any truck having a gross vehicle weight of 12 000 kg or more and having three or more axles.
Heavily travelled road	Generally includes primary and secondary highways and any other road where the average traffic count is at least 10 vehicles/hour over the nighttime period. It is acknowledged that primary and secondary highways are sometimes lightly travelled during the nighttime period, which is usually the period of greatest concern. The EUB will use the 10 vehicles/hour criterion to determine whether primary and secondary highways qualify as heavily travelled during the nighttime period.
Industrial development permit facility	Typically a large industrial facility such as a chemical production plant or oil refinery that uses large amounts of energy and has received an approval to operate from the EUB.
Impulse/impact component	A sound that quickly rises to a peak value and falls off over a short period of time. The absence of impulse/impact components is determined when the difference between the A-weighted impulse response setting sound level measurement and the A-weighted slow-response setting sound level measurement is 10 dBA or less. Some examples of an impulse/impact sound are a hammer striking a nail, the firing of a gun, pipe-on-pipe impacts due to unloading pipe at a well site, and pile driving.

Infringement	Defined as when a residence is newly located within the existing noise footprint (boundary) of a facility, such that the facility could be seen as being in contravention of *ID 99-8*.
Isolation analysis techniques	Various sound measurements and analytical skills used to separate out various sound sources and obtain the sound level from the source of interest alone.
Leq	See Energy equivalent sound level.
Near field	The region close to the source where the inverse-square law (6 dBA loss per doubling of distance) does not apply. Usually this region is located within a few wavelengths of the source and is also controlled by the dimensions of the source.
Nighttime	Defined as the hours from 22:00 to 07:00.
Noise	Generally associated with the unwanted portion of sound.
Noise exposure forecast (NEF)	The NEF contours are site specific to each airport and take into account such factors as traffic levels, proximity to runways, flight paths, and aircraft type and size. NEF contours are available from Transport Canada.
Noise impact assessment (NIA)	An NIA identifies the expected sound level emanating from a facility as measured 15 m from the nearest or most impacted permanently or seasonally occupied dwelling. It also identifies what the permissible sound level is and how it was calculated. Also see Section 6: Noise Complaint Investigations.
Pass-by	The movement of a vehicle past the point of measurement and observed as an increase in sound level to a peak, followed by a decrease as the vehicle moves away from the microphone.
Permanent facility	Any existing or proposed facility that will be at a location longer than two months.
Permanently occupied dwelling	A fixed residence occupied on a full-time basis.

Permissible sound level (PSL)	The maximum sound level that a facility should not exceed at a point 15 m from the nearest or most impacted dwelling unit. The PSL is the sum of the BSL, daytime adjustment, Class A adjustment, and Class B adjustment.
Pristine area	A pure, natural area that might have a residence but no industrial presence, including energy, agricultural, forestry, manufacturing, recreational, or other industries that could make noise generation a consideration.
Rail lines	Includes any rail line where there is a minimum of one 25-car train passage during every nighttime period.
Representative conditions	Those conditions typical for an area and/or the nature of a complaint. For ASLs, these are conditions that portray the typical activities for the area, not the quietest time. For CSLs, these do not constitute absolute worst-case conditions or the exact conditions the complainant has highlighted if those conditions are not easily duplicated. Sound levels must be taken only when representative conditions exist; this may necessitate a survey of extensive duration (two or more consecutive nights).
Seasonally occupied dwelling	A fixed residence that, while not being occupied on a full-time basis, is occupied on a regular basis. A regular basis does not imply a scheduled occupancy but implies use of six weeks per year or more. The residence must not be mobile and should have some sort of foundation or features of permanence (e.g., electrical power, domestic water supply, septic system) associated with it. Summer cottages or mobile homes are examples of seasonally occupied dwellings, while a holiday trailer simply pulled onto a site is not.
Slow response	A standardized detector response on a sound level meter that dampens the movement of displays so that rapidly fluctuating sound levels may be read. Slow response has a time constant of 1 second, which helps average out the display fluctuations. Fast response has a time constant of 125 milliseconds.

Sound level meter	An instrument designed and calibrated to respond to sound and to give objective, reproducible measurements of sound pressure level. It normally has several features that would enable its frequency response and averaging times to be changed to make it suitable to simulate the response of the human ear.
Sound monitoring survey	The measurement and recording of sound levels and pertinent related information over a given time period. *Guide 38* sets out two types of monitoring surveys. The first helps determine the PSL and consists of a 24-hour continuous sound monitoring survey conducted 15 m from the nearest or most impacted dwelling unit without any energy-related industrial presence. This type of sound survey can be used to determine an ASL. Also see entry for Ambient sound level. The second sound monitoring survey is required to determine a facility's compliance with *ID 99-8*. The CSL is determined by conducting a continuous sound monitoring survey over a minimum 6-hour period to a maximum 24-hour period. The need for extended sound monitoring surveys (greater than 24 hours) may exist and should be discussed with the EUB prior to proceeding. Also see entry for Comprehensive sound level.
Spectrum	A wide range or sequence of frequencies.
Temporary facility	Any facility that will be at a location less than two months.
Tonal components	This adjustment is applicable only to existing facilities and cannot be used in design of new facilities. Most energy industry facilities typically exhibit either a tonal or impulse/impact component. Examples of tonal components are transformer hum, sirens, and piping noise. *ID 99-8* specifies that the absence of a tonal component may be demonstrated by performing a ⅓ octave band analysis. The test for the presence of tonal components consists of two parts. The first must demonstrate that the sound pressure level of any one of the slow-response, A-weighted, ⅓ octave bands between 20 and 16 000 Hz is 10 dBA or more than the sound pressure level of at least one of the adjacent bands within two ⅓ octave bandwidths. In addition, there must be a minimum of a 5 dBA drop from the band containing the tone within 2 bandwidths on the opposite side.

	The second part is that the tonal component must be a pronounced peak clearly obvious within the spectrum. An example of tonal component determination is shown in Section 5.1, note 4.0**.**
Windscreen	A specialized piece of porous sponge that fits over the microphone in order to reduce the noise generated by the wind blowing around the microphone. Useful in moderately low wind speeds. Generally, outdoor measurements are not recommended when wind speeds exceed 15 km/h, as the wind-induced noise on the microphone becomes of the same magnitude as the levels of noise being measured.

Appendix 2 Measurement Instrumentation and Techniques

Measurement Instrumentation

Instrumentation used to conduct sound monitoring surveys must be able to measure the A-weighted (dBA) continuous energy equivalent sound level (Leq) of steady, intermittent, and fluctuating sounds. It must be able to accumulate the data and calculate the Leqs over the time periods required herein and must meet the minimum technical specifications in International Electrotechnical Commission (IEC) publication 804 for Type II sound level meters.

Sound Level Meter Calibration Requirements

It is important that the sound level meters used for noise surveys be properly calibrated and functioning. The sound level meters used for noise measurements made under this directive must

1) meet the requirements as indicated in American National Standards Institute (ANSI) S1.4-1983 and S1.4A-1985 or latest revision;

2) be calibrated immediately prior to the measurement with a sound calibrator meeting the requirements of ANSI S1.40-1984 or latest revision;

3) have their calibration confirmed immediately after the measurement using the same calibrator; a record of calibration results must be included in the report;

4) be calibrated by the instrument manufacturer, by an authorized instrument calibration facility, or by another agency acceptable to the EUB within a two-year period immediately preceding the measurements; records of calibration and the procedures used in the reciprocal calibration must be maintained, although formal calibration certificates are not necessary.

Calibrator Certification Requirements

Calibrators must be recertified in accordance with ANSI publication SI.40-1984, which requires that a calibrator be recalibrated at least once a year.

The sound measurement instrumentation necessary to conduct the ⅓ octave band sound pressure level measurements to characterize the presence of tonal components must meet the minimum technical specification in IEC publication 225-1966 or ANSI publication S1.11-1966 for Class II filter sets used in conjunction with conventional sound level meters that meet the minimum technical specifications in IEC publication 651-1979 or ANSI publication S1.4-1983 for Type II sound level meters.

The sound measurement instrumentation necessary to conduct the impulse sound level measurements to characterize the presence of impulse/impact components must meet the minimum technical specifications in IEC publication 651-1979 or ANSI publication S1.4-1983 for Type II sound level meters.

Better-quality instrumentation may meet many or all of the specifications mentioned herein.

Measurement Techniques

The sound measurement techniques employed must be carefully chosen and controlled to obtain valid and consistent results. Factors to take into account include the effects of meteorological factors, activities in the vicinity of the sound meter, suitability of the monitoring location, and topographical features.

General guidelines for sound measurement techniques are found in the following publications: *A Method for Conducting and Reporting Noise Surveys at Industrial Plants*, March 1978, Alberta Environment; *Model Municipal Noise Control By-Law*, 1978, Ontario Ministry of the Environment; *Methods for the Measurement of Sound Pressure Levels*, ANSI publication S1.13-1971; and *Assessment of Noise with Respect to Community Response*, International Organization for Standardization (ISO) publication 1996.

Users must also ensure that the instrumentation is working within manufacturers' recommended specifications and limitations.

The major considerations requiring attention include the following:

- Calibration—acoustic calibration must be performed before and after each survey.

- Microphone position and orientation—the microphone must be a minimum of 1.2 m above the ground. Use of a tripod is recommended. The microphone must be a minimum of 3 m away from significant sound-reflecting surfaces and oriented as per instrumentation manufacturer's instructions. Use of a windscreen recommended by the manufacturer is required.

- Steady precipitation—invalid for monitoring.

- Wind effects—invalid noise data may occur with wind speeds greater than those shown in Table 1 below. This table shows that wind gradients can greatly affect the sound levels measured. The table is less applicable in situations where hills exist between the facility and the measurement location. Appropriate judgement must be used in determining the applicability of the table. Short-term wind gusts less than five minutes in duration and up to 20 km/h may be acceptable.

- Abnormal noise events, including excessive winds, are potentially invalid for monitoring; however, the use of an appropriate isolation analysis technique may correct for any such events.

Table 1. Suggested wind speed limits for obtaining reasonable data

	Distance from noise source to measurement location		
	< 500 m	**500-1000 m**	**> 1000 m**
Upwind*	10 km/h	5 km/h	<5 km/h
Crosswind	15 km/h	10 km/h	5 km/h
Downwind	15 km/h	10 km/h	5 km/h

* The wind is blowing from the measurement location towards the noise source.

Note that the limits for wind speed and precipitation apply at the measurement position, not at some remote sensing position many kilometres away. While data from a location nearby (within 10 km) may serve as an indicator, that does not guarantee the same conditions at the measurement position.

In cases where a discrepancy occurs between measurement techniques mentioned herein and those presented in the cited references, *ID 99-8* prevails. The EUB reserves the right to pass judgement regarding the suitability of any sound measurement techniques employed.

Appendix 3 Sound Levels of Familiar Noise Sources

Source[1]	Sound Level (dBA)
Bedroom of a country home	30
Soft whisper at 1.5 m	30
Quiet office or living room	40
Moderate rainfall	50
Inside average urban home	50
Quiet street	50
Normal conversation at 1 m	60
Noisy office	60
Noisy restaurant	70
Highway traffic at 15 m	75
Loud singing at 1 m	75
Tractor at 15 m	78-95
Busy traffic intersection	80
Electric typewriter	80
Bus or heavy truck at 15 m	88-94
Jackhammer	88-98
Loud shout	90
Freight train at 15 m	95
Modified motorcycle	95
Jet taking off at 600 m	100
Amplified rock music	110
Jet taking off at 60 m	120
Air-raid siren	130

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[1] Cottrell, Tom, 1980, *Noise in Alberta*, Table 1, p.8, ECA80 - 16/1B4 (Edmonton: Environment Council of Alberta).

Sound Levels Generated by Common Appliances

Source[2]	Sound level at 3 feet (dBA)
Freezer	38-45
Refrigerator	34-53
Electric heater	47
Hair clipper	50
Electric toothbrush	48-57
Humidifier	41-54
Clothes dryer	51-65
Air conditioner	50-67
Electric shaver	47-68
Water faucet	62
Hair dryer	58-64
Clothes washer	48-73
Dishwasher	59-71
Electric can opener	60-70
Food mixer	59-75
Electric knife	65-75
Electric knife sharpener	72
Sewing machine	70-74
Vacuum cleaner	65-80
Food blender	65-85
Coffee mill	75-79
Food waste disposer	69-90
Edger and trimmer	81
Home shop tools	64-95
Hedge clippers	85
Electric lawn mower	80-90

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[2] Reif, Z. F., and Vermeulen, P. J., 1979, "Noise from domestic appliances, construction, and industry," Table 1, p.166, in Jones, H. W., ed., *Noise in the Human Environment*, vol. 2, ECA79-SP/1 (Edmonton: Environment Council of Alberta).

Appendix 4 *ID 99-8: Noise Control Directive*

1 November 1999

TO: All Energy Industry and Industrial Development Permit Facility Operators and Drilling and Servicing Rig Contractors

NOISE CONTROL DIRECTIVE

Introduction

This directive supersedes *Interim Directive (ID) 94-4.* It is effective immediately and will be reviewed after a two-year period, in November 2001, or as required.

With the continued widespread growth of energy operations throughout the province, additional sources of energy industry-related sound are appearing. While residents, particularly in rural areas, would generally prefer no increase in sound levels resulting from energy-related developments, it is sometimes not possible to completely eliminate these increases. However, if proper sound control features are incorporated into facility design in the planning stages, increases in sound levels can be kept to acceptable minimums.

This directive views noise from a receptor viewpoint, rather than considering sound levels at the property line. Criteria based on property line measurements were considered to be too restrictive in rural settings, since a natural buffer often exists between operating facilities and any occupied dwellings.

This directive applies to all facilities under the EUB's jurisdiction or where the EUB has issued a permit to operate. Facilities approved prior to April 1988 will be dealt with on a case-by-case basis, while new facilities will be designed to meet this directive. Although the directive is comprehensive, it is expected some cases will need to be dealt with on a site-specific, issues-oriented basis. For example, while the directive is not applicable to construction activity, these activities must be conducted with some consideration for noise. Any related complaints must be dealt with by the facility operator. For details about construction noise, see *Guide 38: Noise Control Directive User Guide*, Section 5.1, note 1.0.

This directive takes into consideration the existing ambient sound level, character of the sound, temporary or permanent nature of the source, and seasonal sensitivity to sound in order to establish reasonable sound levels. It was developed by a committee composed of members from the acoustical consulting community, industry, universities, rural landowners, governmental agencies, and EUB staff.

The directive attempts to take a balanced viewpoint by considering the interests of both the nearby residents and the facility owner/operator. The directive does not guarantee that a resident will not hear sounds from a facility even if it is in compliance; rather it aims for a situation where sound level increases will be kept to acceptable minimums and overall quality of life and indoor sound levels for neighbours to a facility will not be adversely affected. For example, the attenuation of sound through the walls of a dwelling should decrease indoor sound levels to a point where normal sleep patterns are not disturbed.

Guide 38

Guide 38: Noise Control Directive User Guide has been revised to help you better understand this directive. It presents the rationale for the directive, provides background information, and outlines an approach to dealing with noise problems. Those not familiar with noise and related terminology used in this directive are encouraged to review Section 3: The Leq Concept and Appendix 1: Glossary in *Guide 38.*

What's New in *Guide 38*: This 1999 edition of *Guide 38*, which replaces earlier editions, integrates the section formerly identified as "Supplement to the Interim Directive" into the guide itself.

Although the technical requirements in this edition of the directive and *Guide 38* have not changed, many enhancements have been made to help users better understand the complexities of this policy. Some of the more significant areas of interest are as follows:

- Construction Noise (Section 5.1)—Industrial operators must consider construction noise. This guide provides a number of suggestions that operators can implement to help minimize the noise impact on nearby residents.

- Complaint Investigation Process (Section 6)—The directive and guide now provide tools to assist operators and their neighbours in determining the conditions when industrial noise is a problem so that noise surveys can be performed under similar representative conditions.

- Noise Impact Assessments (Section 7)—The improved section on noise impact assessments enables operators to better understand EUB expectations and carry out assessments as part of their facility applications.

- Measurement Instrumentation and Techniques (Appendix 2)—Calibration requirements have been added for sound level meters in accordance with the appropriate American Noise Standards Institute requirements.

Complaint Investigation

The EUB expects operators to deal expeditiously with any noise-related complaint brought to their attention. When attempting to resolve a noise complaint, it is critical that operators first establish direct contact with the complainant to understand their concerns and create a dialogue. At this point, the operator should explain the requirements of this directive and clearly outline the process, including time lines, it intends to follow in addressing the matter. If a comprehensive sound survey is to be performed, to be technically valid the operator or its consultant must determine the representative conditions that exist when noise would impact a residence. For more information on complaint investigation, see *Guide 38*, Sections 2 and 6. Section 6 includes a sample Complaint Investigation and Event Log form to assist in resolving the concern.

Noise Impact Assessment

Intent and Objective: The intent of a noise impact assessment (NIA) is to ensure that applicants consider possible noise impacts before a facility is constructed or operated, since the cost to retrofit may be significantly more than if noise mitigation measures are incorporated into the design of a facility. The objective of an NIA is to predict what the expected design sound level from the facility is at the nearest or most impacted permanently or seasonally occupied dwelling. Best practical technology (accounting for cost versus benefit) should be considered to minimize the potential noise impacts to existing dwellings and future infringement. Operators should discuss noise matters with area residents during the design, construction, and operating phases of a facility. Should a valid complaint be registered after the facility is constructed and in operation, the operator must meet the permissible sound level (PSL) referenced in the NIA.

Eligible Facilities: An NIA must be completed as part of the facility application process for any new permanent facilities or for modifications to existing permanent facilities where there is a reasonable expectation of a continuous or intermittent noise source. For the purposes of this directive, a permanent facility is defined as any facility that will be at a location longer than two months. Compressor stations, pumping stations, electric power plants, coal mines, gas processing plants, industrial development permit facilities, and batteries with compressors are examples of facilities where an NIA is required.

Drilling and servicing rigs fall into the temporary facility category even if they are expected to be at a location more than two months. Temporary activities will generally not require an NIA and will be handled on a complaint basis. Nevertheless, when selecting equipment, such as rigs, for these temporary activities, operators should bear in mind the EUB’s expectation of expeditious compliance if complaints occur. The EUB may require an NIA for any facility it deems necessary.

Compliance and Enforcement: An NIA must be conducted for any new permanent facilities or for modifications to existing permanent facilities where there is a reasonable expectation of a continuous noise source (see Section 7 in *Guide 38*). However, you do not have to include the assessment with the facility application if the analysis indicates compliance (see EUB *Guide 56: Energy Development Application Guide*). In cases where the assessment indicates noncompliance, you must consider further attenuation measures. Where such measures are not practical, you can include the assessment with the application, along with reasons why the measures proposed to reduce the impacts are not practical.

The EUB conducts random comprehensive sound surveys and audits on facilities and facility applications and expects sound levels to be in compliance and NIAs to be complete and understandable. Upon audit, failure to have an appropriate or complete NIA is considered a noncompliance event. If you are unsure of the requirements for an NIA, contact an appropriate consultant or the EUB's Regulatory Support Branch (403-297-3642).

The EUB considers the following to be "major" noncompliance events:

- Submission of an NIA that is inappropriate, incomplete, and contains significant errors or omissions
- Failure of a new facility to meet the permissible sound levels at the nearest or most impacted residence as determined by a post-construction/start-up comprehensive survey
- Failure to respond expeditiously to a legitimate noise complaint regarding an existing facility

Noncompliance with other requirements of *ID 99-8* or *Guide 38* are considered "minor" events.

The EUB reserves the right to escalate noncompliance issue(s) to any level should conditions warrant.

If in the opinion of the EUB a noncompliance event causes noise levels greater than the permissible sound level or unacceptable impacts on nearby residents, it may suspend operations if the impacts cannot be resolved.

Where possible, the EUB intends to utilize existing audit and enforcement processes. For example, Field Surveillance Group enforcement ladders may be used to provide consistent consequences with other similar field facility noncompliance events. For more information on this, contact the appropriate EUB Field Centre office.

Technical Methodology: The EUB does not automatically require detailed calculations to prove the validity of the predictions, but it does expect a reasonable technical basis for the values presented in the NIA. Computer modelling, field measurements of similar equipment, accepted acoustical engineering examples from literature, or calculations may be used as tools to predict comprehensive sound levels (CSL).

Legitimate manufacturers' specifications rated for the type of service expected are also acceptable, but applicants are cautioned to use only manufacturers' data that indicate sound levels in the acoustic far or free fields. Manufacturers' data are often provided as the sound pressure level in the near or reverberant field (e.g., sound pressure levels measured at 1 m from the source), which are not indicative of those expected in the far or free field. Using near or reverberant sound pressure levels results in inaccurate noise impact assessment predictions. A sound pressure level value measured at 1 m is not applicable for inverse square law calculations and therefore does not qualify for the 6 dB reduction in sound level for each doubling of distance from the source. Once the predicted CSL has been established, it should be compared to the calculated PSL to determine the possible impact of the facility on any permanent or seasonal residents.

Special Considerations: Operators planning facilities in an area where there is already an energy industry presence are responsible for ensuring that their facility either will not cause the overall sound levels to exceed the PSL or, in situations where the existing noise levels are acceptable to residents even though they may be higher than the PSL, will not cause an increase in overall sound levels. In the latter case, the existing sound levels become the new PSL. Applicants may wish to discuss their proposed projects with adjacent operators to examine potential sound attenuation measures that are both effective and economical. For example, it may be more cost effective to install silencers on existing equipment, rather than design additional sound attenuation measures into the proposed facility.

For operators proposing projects in an area with established energy facilities, a comprehensive sound survey or modelling using measurements from similar existing sources should be considered to determine the sound environment. For areas with no energy industry presence where noise may be an issue with local residents, operators may want to conduct an ambient sound survey to identify existing sound levels. However, neither sound survey is required to conduct an NIA.

For more information on the requirements of an NIA, refer to *Guide 38*, Section 7, which includes a worksheet form to assist in completing an assessment.

Grandfathering

It is the EUB's view that noise impacts are either acceptable or unacceptable, irrespective of the age of the facility, and that a separate formula based on facility age would be inappropriate. However, the EUB remains willing to address individual cases on their own merits, since a vast number of variables may affect the level of noise impacts and an operator's ability to respond effectively. The EUB is also aware that each decision by an operator with regard to noise attenuation may affect its ability to provide overall net public benefits in other areas (e.g., facility consolidation). The EUB is willing to consider noise as one component of an overall public benefit/cost assessment for a facility and to consider a range of options in assessing project acceptability. Further information regarding this interim directive may be obtained from the EUB's Regulatory Support Branch (403-297-3642) or from the appropriate Field Centre.

Brad McManus, QC
Board Member

CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) CODE

1998

Alberta Environmental Protection
Environmental Service

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1.0 INTRODUCTION

1.1 General

This code establishes requirements for the installation, operation, maintenance, and certification of continuous emission monitoring systems. These requirements will ensure effective measurement, recording, and standardized reporting of specified emissions and other parameters. In addition, the code establishes requirements for alternative monitoring systems and for the quality assurance and quality control of continuous emission monitoring data.

1.2 Purpose and Intent

Approvals issued under the Environmental Protection and Enhancement Act (EPEA) may require continuous emissions monitoring on an effluent source. The Alberta Continuous Emission Monitoring System (CEMS) Code, hereafter referred to as the "CEMS Code," identifies acceptable methods and specifications for the installation and operation of such monitoring systems.

The Alberta CEMS Code is largely based on methodology developed and used by both the U.S. Environmental Protection Agency and Environment Canada.

The CEMS Code contains performance specifications for the majority of CEM system requirements that are referenced in facility approvals. For those CEM systems for which specifications are not included in this code, new methods will be incorporated into the CEMS Code as they are developed.

The final decision on any matter dealing with the CEMS Code rests with the Director of Air and Water Approvals, hereafter referred to as the "Director," in Alberta Environmental Protection.

1.3 CEMS Data Use

All data generated by a CEMS (where the use of that CEMS is linked to the EPEA approval for its associated facility) can be used as a basis for enforcement. Exceptions include in-stack opacity data except as noted otherwise or data specified in the approval as not useable for compliance. These other CEMS data would be used only to fulfil performance assessment requirements. For the purposes of this Code, opacity and in-stack opacity are defined differently and are not equivalent.

Within the thermal electric power generating industry, in-stack opacity limits for start-up and shutdown have been established and CEMS generated data for this industry can be used as a basis for compliance.

For opacity, the "visible emissions reader" will continue to be the only official compliance method for determining opacity levels as currently referenced in the Substance Release Regulation. In the event that this compliance requirement changes, the "Director," will provide a minimum advance notice of at least two years of the intent to implement in-stack opacity CEMS as compliance monitors (except as already noted above). This transition period would allow sufficient lead time for implementation of any required equipment changes to in-stack opacity monitors.

1.4 Implementation

The CEMS Code applies to all facilities where continuous emission monitoring is a condition of an EPEA approval.

The requirements in the CEMS Code come into effect on January 1, 1999.

1.5 Application of CEMS Code to Existing and New CEMS Installations

1.5.1 Code Requirements for Existing Installations

A number of facilities, approved prior to the issuance of this CEMS Code, may have CEMS that do not fully comply with the CEMS Code with respect to either of the following, namely: (a) installation requirements; or (b) equipment required to conduct various quality control procedures (for example, calibration gas may not be introducible at the proper location in some of the older designs, etc.).

Each facility shall assess (within 6 months of this code coming into effect or alternatively according to a schedule agreed to by the Director), on the basis of technical merit, whether CEMS operational and performance specification requirements (as specified in Section 4) can be achieved with the existing configuration. This assessment is to ensure that the facility's CEMS can meet CEMS Code performance specification requirements. If the CEMS can meet these requirements, then no further action would be required; if not, then the facility shall establish a program, acceptable to Alberta Environmental Protection, to upgrade the CEMS installation so it meets performance specification requirements.

Replacement of the existing data handling system associated with a CEMS will not require that initial performance specification testing requirements be conducted; however, the Quality Assurance Plan (QAP) for the facility should detail the appropriate quality control procedures to ensure data quality of the new data acquisition system.

Facilities for which installation received approval prior to the effective date of the CEMS Code are still required to meet ongoing Quality Assurance/Quality Control (QA/QC) requirements as specified in the code.

1.5.2 Code Requirements for New Installations

All new CEMS required after the issuance of this Code must comply with all design, installation, performance, and quality control requirements of this Code. All new CEMS will be required to conduct the initial performance specification testing as contained in this CEMS Code and be certified in accordance with Section 4.0 of this code.

1.6 CEMS Technology

In general, monitoring techniques are based on the direct measurement of both physical and chemical properties of the component of interest. The method selected for the gas analysis depends primarily upon the characteristics of the subject gas, but it can also be affected by other parameters such as regulatory requirements and stack conditions. Commonly used analytical techniques include those of spectroscopic absorption, luminescence, electroanalysis, electro-chemical analysis and paramagnetism.

The specifications of this Code address the use of independent, certified gases for calibration and audit for CEMS that accept calibration gases. The Director reserves the right to review

CEMS that do not accept independent, certified gases for calibration or audit. Alternative methods of calibration will be authorized if equivalent performance to gas calibrated systems can be demonstrated.

The Director also reserves the right to review proposed indirect monitoring systems that use operating parameters correlated to emissions. Such "parameter" or "predictive" emission monitoring systems must be validated initially for the range of operating and control conditions likely to occur at the facility. Parameter and predictive emission monitoring systems must also provide for a method of daily validation that results in continuous performance equivalent to that of gas calibrated CEMS.

1.7 Endorsement

Alberta Environmental Protection does not endorse specific CEMS equipment, alternative methods, or equipment suppliers. No list of approved equipment will be maintained by Alberta Environmental Protection.

1.8 CEMS Data Retention Requirements

Each facility shall maintain "raw" data for a period of at least 3 years and "summary" data for a period of at least 10 years. "Raw" data must be consistent with the definition of continuous as defined in Appendix A and should provide for "satisfactory demonstration" of quality control activities as defined in the CEMS Code and the facility Quality Assurance Plan (QAP). The media for storage of "raw" data shall be designated by the facility and documented in the facility QAP. Raw data shall be made available for inspection if requested by Alberta Environmental Protection.

1.9 Monitoring Plan

For new installations, the following information regarding the CEM system must be submitted to the Director at least sixty (60) days prior to system installation : [1]

A. Describe in general terms the process(es) and pollution control equipment, along with all factors that may affect the operation of the monitoring system.

B. Describe the location of the monitoring system/sample acquisition point(s) or path(s) in relation to flow disturbances (fans, elbows, inlets, outlets), pollution control equipment, flue walls, and emission point of the monitored effluent streams to the atmosphere. Explain any deviations from the location criteria that are specified in Section 3.0.

C. List the following system information:

- pollutant(s) or parameters to be monitored,
- the operating principles of the analyzer(s),
- the number of analyzers, and the number of acquisition point(s) or path(s) for a analyzer, or bank of analysers sharing multiple ducts (time sharing systems),
- the equipment manufacturer and model number(s),
- a copy of the checklist to be used by the instrument technician for periodic checking of the analyzer(s), and
- the expected normal and maximum analyzer or flow rate readings.

D. Describe the process and pollution control equipment operating parameters that affect the emission levels of the pollutants being monitored or the parameters being monitored, and also explain the method to be used to record these parameters.

---

[1] The listed information requirements may be included as part of the QAP. It is not necessary to duplicate this information elsewhere.

E. Describe calibration, operational and maintenance procedures, along with recommended schedules.

F. Explain procedures to be used to satisfy the requirements for record keeping as defined by the Director.

2.0 DESIGN SPECIFICATIONS

Continuous Emission Monitoring Systems for monitoring gases consists of the following four subsystems:

- Sample Interface/Conditioning;
- Gas Analyzers;
- Data Acquisition;
- Flow monitor (where applicable).

The acceptability of emission monitoring systems is in general, performance based; however minimal design specifications are specified for gas analyzers, in-stack opacity monitors, and flow monitoring systems. These specifications have been established either to ensure the overall stability of the CEMS once the analyzers are incorporated into the system, or to ensure that accurate readings will be obtained for the parameter being measured. Procedures for the verification of design specifications are given in Section 4.0.

Unless otherwise authorized by the Director, the chosen range of each monitor is specified in Tables 1 to 4. If the average monthly parameter of any analyzer should fall outside these limits, the analyzer span should be adjusted so that the average is brought back within these limits. If emission values vary widely, the use of multi-range analyzers is encouraged. Data that fall outside the range of an analyzer are considered to be missing.

2.1 Design Specifications for Gas Analyzers

Design specifications for gas analyzers for monitoring sulphur dioxide, oxides of nitrogen, and carbon monoxide are given in Table 1.

Table 1 Design Specifications for CEM system gas analyzers

Design Specifications	Sulphur Dioxide Analyzers	Oxides of Nitrogen Analyzers	Carbon Monoxide Analyzers
Lower detection limit	≤ 2% of span	≤ 2% of span	≤ 2% of span
Interference rejection (sum total)	≤ ± 4% of span	≤ ± 4% of span	≤ ± 4% of span
Response time (95%)	200 s (Max.)	200 s (Max.)	200 s (Max.)
Analyzer range	1.5 times approval limit		
Temperature-responsive zero drift[a]	≤ ± 2% of span	≤ ± 2% of span	≤ ± 2% of span
Temperature-responsive span drift[a]	≤ ± 3% of span	≤ ± 4% of span	≤ ± 3% of span

[a] for every 10°C change in analyzer operating temperature.

Table 2 Design Specifications for Total Reduced Sulfur analyzers

Design Specification	TRS Analyzer
Lower detection limit	≤ 2% of span
Interference rejection (sum total)	≤ ± 4% of span
Response time (95%) and cycle time	15 minutes (Max.)
Analyzer range	1.5 times approval limit or 30 ppm whichever is the greater

Design specifications for oxygen and carbon dioxide (diluent) monitors are given in Table 3.

Table 3 Design Specifications for diluent monitors

Design Specification	0_2 Analyzers	CO_2 Analyzers
Lower detection limit	≤ 0.5% 0_2	≤ 0.5% $C0_2$
Interference rejection	≤ ± 1.0% 0_2	≤ ± 1.0% $C0_2$
Response time (95%)	200s (Max.)	200s (Max.)
Analyzer range	0 - 21%	0 - 25%
Temperature-responsive zero drift[a]	≤ ± 0.5% 0_2	≤ ± 0.5% 0_2
Temperature-responsive span drift[a]	≤ ± 0.5% 0_2	≤ ± 0.5% 0_2

[a] for every 10°C change in analyzer operating temperature.

2.1.1 Interference Rejection

Each analyzer shall exhibit a response of less than that specified in Tables 1 to 3 for the sum of all interferences due to other gas constituents as measured by the procedures given in Section 4.0.

2.1.2 Temperature-Responsive Drifts

Each pollutant or diluent gas analyzer used in the system must exhibit a zero drift less than 2% of the full-scale setting for any 10°C change over the temperature range of 5° to 35°C. Additionally, each analyzer must exhibit a span drift of less than 3 or 4% of the full-scale setting for any 10°C change in temperature from 5° to 35°C. Both the zero and span drift tests are to be carried out within the acceptable temperature operating range of the analyzer, as specified by the manufacturer. Follow the procedures outlined in Section 4.4.2 or alternatively confirm that Section 4.4.3 has been complied with to determine the temperature-responsive drift.

2.1.3 Cycle-time/Response Time

The cycle-time/response-time specification applies to systems, as opposed to analyzers. One complete measurement or cycle of measurements of all effluent streams must be completed in 15 minutes or less.

2.2 Design Specifications for In-Stack Opacity Monitors

Design Specifications for in-stack opacity monitors are given in Table 4.
These specifications establish specific design criteria for the in-stack opacity monitoring system.

Table 4 In-Stack Opacity Monitor Design specifications

Design Specification	In-Stack Opacity Monitors
Spectral response	Photopic
Angle to view	≤ 5°
Angle of projection	≤ 5°
Response time	10 sec (Max.)
Range	0 - 100%
Temperature-Responsive zero drift[a]	2% opacity
Temperature-Responsive span drift[a]	2% opacity
Physical design	a. Simulated zero and upscale calibration system b. Access to external optics c. Automatic zero compensation d. External calibration filter access e. Optical alignment sight

[a] for every 10°C change in analyzer operating temperature

Alternatively, a certificate of conformance stating that the in-stack opacity monitor meets the design specifications of the U.S. EPA given in 40 CFR 60 Appendix B - Performance Specification 1, obtained from the manufacturer would be acceptable to the Director.

Then, the in-stack opacity monitor is calibrated, installed, and operated for a specified length of time. During this specified time period, the system is evaluated to determine conformance with the established performance specifications given in Section 4.0 of this Code.

2.2.1 Peak and Mean Spectral Responses

The peak and mean spectral responses must occur between 500 nm and 600 nm. The response at any wavelength below 400 nm or above 700 nm shall be less than 10% of the peak spectral response.

2.2.2 Angle of View

The total angle of view shall be no greater than 5 degrees.

2.2.3 Angle of Projection

The total angle of projection shall be no greater than 5 degrees.

2.2.4 Simulated zero and upscale calibration system

Each analyzer must include a calibration system for simulating a zero in-stack opacity and an upscale in-stack opacity value for the purpose of performing periodic checks of the monitor calibration while on an operating stack or duct. This calibration system will provide, as a minimum, a system check of the analyzer internal optics and all electronic circuitry including the lamp and photodetector assembly.

2.2.5 Access to external optics

Each analyzer must provide a means of access to the optical surfaces exposed to the effluent stream in order to permit the surfaces to be cleaned without requiring removal of the unit from the source mounting or without requiring optical realignment of the unit.

2.2.6 Automatic zero compensation

If the system has a feature that provides automatic zero compensation for dust accumulation on exposed optical surfaces, the system must also provide some means of indicating when a compensation of 4% in-stack opacity has been exceeded.

2.2.7 External calibration filter access

The monitor must provide a design that accommodates the use of an external calibration filter to assess monitor operation.

2.2.8 Optical Alignment sight

Each analyzer must provide some method for visually determining that the instrument is optically aligned. The method provided must be capable of indicating that the unit is misaligned when an error of ± 2 percent in-stack opacity occurs due to misalignment at a monitor pathlength of 8 metres.

2.3 Design Specifications for Flow Monitors

Design specifications for flow monitors are given in Table 5.

Table 5 Flow Monitor Design specifications

Design Specification	**Flow Monitors**
Lower detection limit	1.0 m/sec
Range	1.5 times expected max. value
Response time (95%)	10 sec (Max.)
Physical design	a. Means of cleaning flow element b. No interference from moisture

2.3.1 Cleaning

If necessary, differential pressure flow monitors shall provide an automatic, timed period of backpurging or equivalent method of sufficient force and frequency to keep the sample port and probe and lines free of obstructions. Differential pressure flow monitors shall provide a method (either manual or automated) for detecting leaks or plugging throughout the system. Thermal flow monitors and ultrasonic monitors shall provide a method for detecting probe fouling and a means of cleaning the transducer surface in situ or by removal and cleaning.

2.3.2 Calibration

The entire flow monitoring system including the flow probe or equivalent and including the data acquisition and handling system shall be calibrated as per the requirements contained in Table 16.

2.4 Design Specifications for Temperature Sensors

Table 6. Temperature sensor design specifications.

Design Specification	Temperature Sensors
Response time (95%)	60 sec (Max.)
Range	1.5 times approval limit

2.5 Specifications for the Data Acquisition System

2.5.1 General

The CEMS shall include a data acquisition system that accepts the output of the analyzers and flow monitors (where applicable) and converts these to emission rates of the gaseous pollutants in appropriate units as specified in the facility approval. These systems shall be capable of interpreting and converting the individual output signals from each monitor to produce a continuous readout in appropriate units as specified in the facility approval. Where diluent emissions are measured with a CEMS, the data acquisition system shall also be capable of producing a readout in appropriate units as specified in the facility approval.

The system shall maintain a permanent record of all parameters in a format acceptable to the Director.

The system must also record and compute daily zero and span drifts (as specified in Table 16), and provide for backfilling and substitution for missing data, if required by an approval.

Automated data acquisition and handling systems shall:

1. read and record the full range of pollutant concentrations from zero through to span, and
2. provide a continuous, permanent record.

Data shall be reduced to valid one-hour averages and shall be computed from four (4) or more values equally spaced or averaged over each one-hour period and in accordance with the definition of a “valid hour” as defined in Appendix A.

During each 24 hour period, one, one-hour average may consist of a minimum of two (2) data points (representing 30 minutes of data) to allow for calibration, quality assurance activities, maintenance, or repairs. If this minimum data accumulation is not achieved, the hour will be counted as missing data for the purposes of calculating availability.

2.5.2 Data Recorder Resolution

Data recorder hard copy resolution for system response shall be ±0.5% of full scale or better. Data recorder hard copy time resolution shall be 1 minute or less.

2.5.3 Availability

The percentage availability for the system and each analyzer shall be calculated monthly either by the data acquisition system or manually, using the following equation:

$$\text{\% Availability (System or Analyzer)} = \frac{T_a}{T} \times 100$$

where:

T_a = the time in hours during which the system or analyzer was generating quality assured data (as defined in Appendix A) during the time the source operated during the month.

T = the total time in hours the source operated during the month and is defined as those hours during which the fuel is burned***** (for combustion-related processes) or those hours during which effluent is being discharged from an effluent source as described in an approval (for noncombustion-related sources).

***** for combustion sources, the operational time also includes any time period(s) attributable to "cool down" or "purge" modes.

Time periods necessary for CEMS calibration, quality control checks or backpurging, shall not be considered as downtime when calculating T_a.

2.5.4 Backfilling and Substitution for Missing Data

Upon the authorization of the Director, emissions data that are missing due to a malfunction of the CEMS may be substituted for a period of up to 120 hours for any single episode using data derived from operational parameter correlation or predictive modelling techniques. Reference Method test data or data obtained from a monitor previously certified for the application may also be used for substituting data. The technique used to obtain substitute data must be fully described in the QAP developed for each CEMS, and must be authorized in writing by the Director prior to implementation.

For sources authorized to backfill or substitute data, when a CEMS malfunction extends beyond 120 hours for any single episode, data must be generated by another authorized CEMS or valid Reference Method.

Other CEMS used for this purpose must meet all design and performance specifications given in this Code. When using another system, the effluent stream sample shall be extracted from the sample port used for the Reference method during certification of the installed CEMS.

Data that are substituted using the correlation technique cannot be credited towards meeting the CEMS availability criteria. Data generated by an acceptable alternate CEMS may be credited to the availability requirement.

Data substitution shall be limited to a maximum of 120 hours per calendar month for each CEMS, unless specified otherwise by the Director.

3.0 INSTALLATION SPECIFICATIONS

This Section contains guidelines for selecting a suitable sampling site on the flue, duct, or stack and determining the representativeness of the desired location with respect to the homogeneity of the effluent stream.

3.1 Location of the Sampling Site

The frequency and quality of maintenance on the CEMS have been shown to be directly related to the accessibility of the stack-mounted portion of the CEMS.

The stack-mounted analyzing equipment generally must be installed in a location that is accessible at all times and during any normal weather conditions. Overshadowing this criterion is the over-riding concern for personal safety; it is not expected that individuals place themselves at risk to service the CEMS equipment under conditions of severe thunderstorms, or during high wind or heavy icing/snow/rain events.

To achieve the required up-time, the CEMS equipment must be able to operate in any environmental condition under which the plant will be operating. For example: a thermal power plant will require stack-mounted equipment to operate and be maintainable over the full range of ambient temperatures experienced (at least -40^{o} to $+40^{o}$C). Such performance may be accomplished by enclosing the instruments in heated/air conditioned shelters, enclosed stack annulus, etc., and ensuring that provisions are in place for conducting adequate maintenance procedures on schedule as per the QAP.

Gaseous pollutant monitors, in-stack opacity monitors, volumetric flow monitors and temperature sensors shall be sited in accordance with the requirements specified in Method 1 of the Alberta Stack Sampling Code as amended from time to time.

3.1.1 Measurement Locations

The measurement location shall be (1) at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur, and (2) at least a half equivalent diameter upstream from the effluent exhaust or control device.

3.1.2 Point CEM Systems

The measurement point shall be (1) no less than 1.0 m from the stack or duct wall, or (2) within or centrally located over the centroidal area of the stack or duct cross section.

3.1.3 Flow Monitors

The installation of a flow monitor is acceptable if the location satisfies the siting criteria of Method 1 of the Alberta Stack Sampling Code. Check for non-cyclonic or non-swirling flow conditions shall be made to ensure the suitability of the sampling site.

3.2 Representativeness

The sampling probe or in-situ analyzer must be installed in a location where effluent gases are completely mixed or at a location authorized by the Director. Flowing gases are generally well mixed, but stratification can occur when there are differing temperatures or when dissimilar gas streams intersect or where the duct/flue geometry changes. The degree of stratification in a duct or stack can be quantified. One method of quantification has been proposed (U.S. EPA 1979) that involves traversing the stack or duct and obtaining gas concentrations and comparing those concentrations to the target gas at a fixed concentration. To verify that the effluent stream is not stratified, the procedure outlined in Section 3.2.1 of this code is recommended or an alternative method as authorized by the Director, may be used.

3.2.1 Stratification Test Procedure

A minimum of nine (9) traverse points are required for this test. Locate the points in a balanced matrix of equal area on the stack or duct, using the procedures of Method 1 of the Alberta Stack Sampling Code. Using two automated systems with similar response characteristics, the concentration of a target gas is measured at each of the sampling points in the matrix with one system (traversing system), while simultaneously measuring the target gas concentration at a fixed location, usually at the centre of the flue, duct or stack.

For determining flow stratification, a pitot tube may be used (instead of automated gas monitoring systems) following the procedures of Method 2 of the Alberta Stack Sampling Code.

If the concentration of the gas measured or the velocity of the effluent stream at the fixed location varies by more than ±10% of the average concentration for longer than one minute during this test, retest for stratification when more stable conditions prevail.

Alternately, if the stability of the emission source has been demonstrated at a chosen load, using the output of a chosen automated analyzer withdrawing a sample from a fixed point, the single automated analyzer may be used to measure the degree of stratification.

The concentration of a target gas or the velocity of the effluent stream shall be measured at each of the sampling points in the matrix. At the conclusion of the traverses, repeat the measurement of the concentration at the initial measurement point. If the concentrations differ by more than 10% for the pre- and post-test values at this point, retest for stratification when more stable conditions prevail.

The degree of stratification at each sampling point can be calculated as:

$$\text{\% of stratification at point i} = \frac{(c_i - c_{ave})}{c_{ave}} \times 100$$

where:

c_i = concentration of target gas at point i
c_{ave} = average of target gas concentration

The sampling plane across the stack or duct is considered stratified if any of the calculated values are greater than ±10%.

4.0 PERFORMANCE SPECIFICATIONS and TEST PROCEDURES

4.1 General

This section addresses how to evaluate the acceptability of a CEMS at the time of installation and whenever specified in the CEMS Code. The specifications are not designed to evaluate CEMS performance over an extended period of time, nor do they identify detailed calibration procedures to assess CEMS performance. It is the responsibility of the source owner or operator to properly calibrate, maintain, and operate the CEMS.

Performance specifications and test procedure requirements for each specific CEMS are detailed in this section.

4.1.1 Initial Certification Requirements and Test Procedures

Subject to Section 1.5.1, the owner or operator of the facility shall demonstrate that the CEMS meets all the applicable system performance specifications within six (6) months of the installation of a new CEMS, upon recertification, or as specified otherwise by the Director. The satisfactory demonstration by the approval holder of meeting all of these performance specifications, along with notice of such to the Director, shall constitute certification of the CEMS.

4.2 Performance Specifications

Performance specifications for continuous emission monitoring systems are given in Tables 7 to 12.

4.2.1 Performance Specifications for Sulphur Dioxide, Oxides of Nitrogen, and Carbon Monoxide Emission Monitoring Systems.

Any owner or operator, subject to the provisions of an applicable approval, shall install, calibrate, maintain, and operate sulphur dioxide, oxides of nitrogen, and/or carbon monoxide monitoring systems and record the output of the systems.

Table 7 provides a summary of the general performance specifications of sulphur dioxide, oxides of nitrogen, and carbon monoxide emission monitoring systems. These specifications are not meant to limit the types of technologies that can be used or prevent the use of equivalent methods. Both technologies and methods can be varied upon authorization of the Director.

Table 7. Performance specifications for sulphur dioxide, oxides of nitrogen, and carbon monoxide emission monitoring systems.

Performance Specifications	Sulphur Dioxide Systems	Oxides of Nitrogen Systems	Carbon Monoxide Systems
Analyzer linearity	≤ ± 2% of span from cal. curve	≤ ± 2% of span from cal. curve	≤ ± 2% of span from cal. curve
Relative accuracy[a]	≤ ± 10% of RM	≤ ± 10% of RM	≤ ± 10% of RM
Zero drift - 24 hr	≤ ± 2% of span	≤ ± 2% of span	≤ ± 2% of span
Span drift - 24 hr	≤ ± 4% of span	≤ ± 4% of span	≤ ± 4% of span

[a] If the reference method value is less than 50% of the analyzer full scale, then use 10% of full scale for relative accuracy for SO_2, NO_x, and CO.

4.2.2 Performance Specifications for Oxygen and Carbon Dioxide Monitors

Any owner or operator, subject to the provisions of an applicable approval, shall install, calibrate, maintain, and operate oxygen and/or carbon dioxide monitoring systems and record the output of the systems.

Table 8 provides a summary of the general performance specifications for oxygen and carbon dioxide monitors. These specifications are not meant to limit the types of technologies that can be used or prevent the use of equivalent methods. Both technologies and methods can be varied upon the written authorization of the Director.

Table 8. Performance Specifications for oxygen and carbon dioxide monitors.

Performance Specifications	Oxygen Monitors	Carbon Dioxide Monitors
Relative accuracy	≤ ± 10% of RM or within 1% of O_2 (whichever is greater)	≤ ± 10% of RM or within 1% CO_2 (whichever is greater)
Analyzer linearity	≤ ± 0.5% O_2	≤ ± 0.5% CO_2
Zero drift - 24 hr	≤ ± 0.5% O_2	≤ ± 0.5% CO_2
Span drift - 24 hr	≤ ± 0.5% O_2	≤ ± 0.5% CO_2

4.2.3 Performance Specifications for Total Reduced Sulphur Monitoring Systems

Any owner or operator, subject to the provisions of an applicable approval, shall install, calibrate, maintain, and operate a Total Reduced Sulphur (TRS) monitoring system and a data acquisition system for the continuous measurement and recording of the TRS emissions from the affected facility.

A summary of the performance specifications for operation of TRS Monitors are provided in Table 9. These specifications are not meant to limit the use of alternative technology and may be varied upon the written authorization of the Director to accommodate the use of alternative technology.

Table 9. Performance specifications for Total Reduced Sulphur monitoring systems.

Performance Specifications	Total Reduced Sulphur Systems
Analyzer linearity	≤ 5% of span
Relative accuracy	≤ ± 20% of RM or within ± 2 ppm (whichever is greater)
Zero drift - 24 hr	≤ ± 5.0% of span
Span drift - 24 hr	≤ ± 5.0% of span

4.2.4 Performance Specifications for In-Stack Opacity Monitoring Systems.

The specifications given in Table 10 shall be adhered to until final requirements for in-stack opacity monitors are specified at a later date. As required in the approval, the approval holder shall install, operate, and maintain each continuous in-stack opacity monitoring system in accordance with the specifications and procedures as contained in Table 10.

Certain design requirements and test procedures established in this specification may not apply to all instrument designs. In such instances, equivalent design requirements and test procedures may be used with prior written authorization of the Director.

Laboratory and field verification procedures have been established for in-stack opacity monitors by the U.S. Environmental Protection Agency and are found in the reference USEPA 1996c. These specifications are to be used to evaluate the acceptability of continuous in-stack opacity monitoring systems.

Table 10. Performance Specifications for In-Stack Opacity Monitors

Performance Specifications	In-Stack Opacity Monitors
Zero drift - 24 hr	≤ ± 2% In-Stack Opacity
Span drift - 24 hr	≤ ± 2% In-Stack Opacity

4.2.5 Performance Specifications for Volumetric Flow/Velocity Monitoring Systems.

Table 11 provides a summary of the general performance specifications of flow monitors. These specifications are not meant to limit the types of technologies to be used or prevent the use of equivalent methods (such as the use of F-factors). Both technologies and methods can be varied upon written authorization of the Director.

Table 11. Performance specifications for volumetric flow/velocity monitors.

Performance Specifications	Volumetric Flow/Velocity Monitors
System Relative Accuracy for velocity ≥ 3 m/sec	≤ ± 15% of Reference Method
System Relative Accuracy for velocity < 3 m/sec	within 0.5 m/sec of Reference Method
Orientation Sensitivity	≤ ± 4% of span
Zero drift - 24 hr	≤ ± 3% of span
Span drift - 24 hr	≤ ± 3% of span

4.2.6 Performance Specifications for Temperature Sensors

The approval holder shall install, operate, and maintain a continuous temperature sensing system on each stack or source, and record the output of the system, for effluent streams released to the atmosphere, as specified in an EPEA approval.

Table 12 provides a summary of the general performance specifications of temperature sensors. These specifications are not meant to limit the types of technologies to be used or prevent the use of equivalent methods. Both technologies and methods can be varied upon the written authorization of the Director.

Table 12. Performance specifications for temperature sensors.

Performance Specification	Temperature Sensors
System Accuracy	± 10°C of the reference method

The response time should also be verified in "small" step changes in the process, as the opportunity presents itself (i.e., internal audits).

4.2.7 Performance Specifications for other Pollutant Monitoring Systems

The following requirements shall be adhered to until final requirements for other categories of pollutant monitors are specified.

Design requirements and test procedures established in these specifications may not apply to all emission monitoring system designs. Approval holders, who are required to continuously monitor other pollutant parameters that are not specified in the CEMS Code, shall install, operate, and maintain those CEMS in a manner satisfactory to the Director.

Each owner or operator shall develop and implement a Quality Assurance Plan (QAP) for the overall CEMS (See Section 5.0). As a minimum, each QAP must include a written plan that describes in detail complete, step-by-step procedures and operations for each of the activities. Quality control procedures for the calibration of the CEMS may require some variance from the procedures in Section 4.5.3 (e.g., how gases are injected, adjustments of flow rates and pressure). These variances must be documented in the QAP.

The details of what is required for the QAP are outlined in Section 5.0 as quality assurance and quality control. This section provides a description of the procedures required for a QAP.

Sixty (60) days before the CEMS is installed and begins operation, the approval holder must submit a Monitoring Plan that provides the information specified in Section 1.9.

4.3 Test Procedures - Administrative

The test procedures needed to demonstrate compliance with the relevant performance specifications are given here for each CEMS. Test procedures for determining compliance with the applicable performance specifications include the following:

- Conditioning and Performance Evaluation Periods
- Relative Accuracy Test Audit and Bias Calculation
- Zero Drift (24 hour)
- Span Drift (24 hour)
- Linearity
- Response Time
- Interference Rejection

The Director must be advised in writing (or facsimile) of the intent to test (complete with tentative test schedule[s]) at least two weeks before the performance testing is to occur. This notice enables the Director or his/her designate to have the opportunity to observe any or all testing.

The owner or operator of the facility shall retain on file at the facility, and make available for inspection or audit, the performance test results on which the certification was based.

Recertification is required following any major change in the CEMS (e.g., addition of components or replacement of components with different makes/models, change in gas cells, path length, probe or system optics, relocation) that could impair the system from meeting the applicable performance specifications for that system. Recertification should be conducted at the earliest possible opportunity or as agreed to in writing by the Director.

The comparison of CEMS measurements to the reference method values during certification or recertification shall be based only on the output as recorded by the data acquisition system.

4.4 Test Procedures for Verifying Design Specifications

4.4.1 Analyzer Interference Rejection

This test may be carried out after the analyzers have been installed in the CEMS or in a laboratory or other suitable location before the analyzers are installed. Sufficient time must be allowed for the analyzer under test to warm up, then the analyzer must be calibrated by introducing appropriate low- and high-range gases directly to the analyzer sample inlet. After the initial calibration, test gases shall be introduced, each containing a single interfering gas at a concentration representative of that species in the gas flow to be monitored. The magnitude of the interference of each potential interfering species on the target gas shall then be determined.

The analyzer is acceptable if the summed response of all interfering gases is less than 4% of the full-scale value.

4.4.2 Analyzer Temperature-Responsive Zero and Calibration Drifts

Place the analyzer in a climate chamber in which the temperature can be varied from 5 to 35°C. Allow sufficient time to warm up, then calibrate the analyzer at 25°C using appropriate zero and span gases. Adjust the temperature of the chamber to 35, 15, and 5°C, respectively. Ensure that the analyzer temperature has stabilized. Do not turn off the power to the analyzer over the duration of this test.

When the analyzer has stabilized at each climate chamber temperature, introduce the calibration gases at the same flow or pressure conditions, and note the response of the analyzer. Calculate the temperature-responsive zero drift from the difference in the indicated zero reading and the next higher or lower temperature. The analyzer is acceptable if the difference between all adjacent (i.e. 5/15, 15/25, and 25/35°C) zero responses is less than 2% of the full-scale setting.

Calculate the temperature-responsive span drift from the differences between adjacent span responses. An analyzer is acceptable if the difference between all adjacent span responses is less than 4% of the full-scale setting.

4.4.3 Manufacturer's Certificate of Conformance

It may be considered that specifications for both interference rejection and temperature-responsive drift have been met if the analyzer manufacturer certifies that an identical, randomly selected analyzer, manufactured in the same quarter as the delivered unit, was tested according to the procedures given above in Subsections 4.4.1 and 4.4.2, and the parameters were found to meet or exceed the specifications.

4.5 Performance Specification Test Procedures

4.5.1 Conditioning Test Period

After the CEMS has been installed according to the manufacturer's written instructions, the entire CEMS shall be operated for a period of not less than 168 hours, during which the emission source must be operating. During this period, the entire CEMS must operate normally, which means all processes of the entire system must work, including the analyzing of both the concentrations of the pollutant and diluent gases, and the effluent stream flow rate (where applicable). The only exceptions are for periods during which calibration procedures are being carried out, or other procedures as indicated in the QAP. Note that the data acquisition system forms an integral part of the overall system and must be fully operational during this period.

The system must output emission rates of the pollutants in units as specified in the facility approval.

System modifications may be carried out, along with fine-tuning of the overall system, in preparation for the Operational Test Period.

Daily calibration checks shall be conducted, and when the accumulated drift exceeds the daily control limits, the analyzers shall be adjusted using the procedures defined in the CEMS QAP. The data acquisition system must reflect any calibration adjustments. Any automatic adjustments made in response to the daily zero and span checks must also be indicated in the data acquisition system. If the Conditioning Test Period is interrupted as a result of a process shutdown, the times and dates of the shutdown period shall be recorded and the 168-hour test period shall be continued, after the emission source has resumed operation.

4.5.2 Operational Test Period

When the Conditioning Test Period has been successfully completed, the CEMS must be operated for an additional 168-hour period during which the emission source is operating under typical conditions. The Operational Test Period need not immediately follow the Conditioning Test Period.

During the Operational Test Period, the CEMS must continue to analyze the gases without interruption and produce a permanent record, using the data acquisition system, of the emission data. Sampling may be interrupted during this test period only to carry out system calibration checks and specified procedures as contained in the QAP.

During this period, no unscheduled maintenance, repairs, or adjustments should be carried out. Calibration adjustments may be performed at 24-hour intervals or more frequently, if specified by the manufacturer and stated in the QAP. Automatic zero and calibration adjustments made without operator intervention may be carried out at any time, but these adjustments must be documented by the data acquisition system.

If the test period is interrupted because of process shutdown, the times and dates of this period should be recorded, and the test period continued when the process continues operation. If the test period is interrupted as a result of CEMS failure, the entire test period must be restarted after the problem has been rectified.

The Performance Specifications tests outlined in Section 4.5 are carried out during the Operational Test Period, with the exception of the relative accuracy tests, which may be conducted during the Operational Test Period or during the 168-hour period immediately following the Operational Test Period. These tests are to be carried under conditions that typify the day-to-day operation of the CEMS and should be described in the QAP.

4.5.3 Calibration Drift Test Protocol for Gas and Flow Monitoring Systems

(a) General - For those systems that are not designed (and authorized as such by the Director) for the dynamic use of calibration gases, alternative protocols (as authorized by the Director) may be used in place of the following. These alternative procedures shall be included and detailed in the facility QAP.

Measure the zero and span drift of the CEMS once each day at 24-hour intervals (to the extent possible) for 7 consecutive operating days according to the following procedures. Units using dual span monitors must perform the calibration drift test on both high- and low-end scales of the pollutant concentration monitor.

(b) Calibration Adjustments - Automatic or manual calibration adjustments may be carried out each day. The Calibration Drift Test must be conducted immediately before these adjustments, or in such a manner that the magnitude of the drifts can be determined. A zero drift adjustment may be made prior to the span drift determinations.

(c) Test Procedures - At approximately 24-hour intervals for seven (7) consecutive days, perform the calibration drift tests at two concentration ranges:

low-level range (0-20% of full scale)
high-level range (80-100% of full scale)

Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in situ-type monitors, perform calibration by checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the CEMS once with each gas. Record the monitor response from the data acquisition system.

(d) Calculations - Determine the calibration drift, at each concentration, once each day (at 24-hour intervals) for 7 consecutive days according to the following calculation:

$$\text{Calibration Drift (\%)} = \frac{(R - A)}{FS} \times 100$$

where:

R = the true value of the reference standard (ppm or % for gas analyzers, kPa for pressure transducers, ^{o}C for temperature transducers, m^3/d or tonnes/d for flow elements).

A = the CEM component value (in same units as R).

FS = the full scale reading of the CEM system component (in the same units as R).

With dual span CEMS, the above procedure must be conducted on both concentration ranges. Use only NIST (National Institute of Standards and Technology) -traceable reference material, standard reference material, Protocol 1 calibration gases (certified by the vendor to be within 2% of the label value, or where applicable, zero air material).

Calibration drift test results are acceptable for CEMS certification, if none of these daily calibration system test results exceed the applicable CEMS specifications in Section 4.2.

4.5.4 Linearity

Perform a linearity test using the following test gases and procedures:

(a) General - For those systems that are not designed (and authorized as such by the Director) for the dynamic use of calibration gases, alternative protocols (as authorized by the Director) may be used in place of the following. These alternative procedures shall be included and detailed in the facility QAP.

(b) Test Gases - Use Protocol 1 gases at low (0 to 20% FS (full scale)), mid-(40 to 60% FS), and high-level (80 to 100% FS) for each pollutant and diluent gas analyzer. Dynamic or static dilution of a test gas to generate lower concentration standards is acceptable provided that the corresponding QA/QC plan/procedures are established and followed for the use of dynamic or static dilution systems.

(c) Calibration Gas Injection Port -Test gases may be injected immediately before each analyzer.

(d) Procedures - The system must operate normally during the test, with all pressures, temperatures, and flows at nominal values. Introduce each test gas and allow the system response to stabilize, then record the concentration of the pollutant or diluent gas indicated by the data acquisition system output. Challenge the system three (3) times with each gas, but not in succession. To do this, alternate the gases presented to the system.

Calculate the average response of the system as indicated by the data acquisition system to the three (3) challenges of each gas for each pollutant or diluent gas analyzer at low-, mid-, and high-level.

(e) Calculations and Acceptable Results - Determine the linearity, at each concentration, according to the following calculation:

$$\text{Linearity (\%)} = \frac{(R - A)}{FS} \times 100$$

R = the true value of the test gas (% or ppm).

A = the average of the three system response to the low-, mid-, or high-range calibration gas, (% or ppm).

FS = the full scale value of the monitoring system (% or ppm).

With dual span CEMS, the above procedure must be conducted on both concentration ranges. Use only NIST-traceable reference material, standard reference material, Protocol 1 calibration gases (certified by the vendor to be within ±2 % of the label value, or where applicable, zero ambient air material).

The system is acceptable if each of the three values of the linearity do not exceed the value for linearity, specified in Table 7, 8, or 9, as applicable.

4.5.5 Flow Monitor Calibration Drift

Use the zero and span reference signals generated by the system for this test, following the procedures given in 4.5.3 above (where, instead of calibration gas, read reference signal).

Once a day over the 168-hour Operational Test Period, introduce the flow monitors reference signals to the sensor, corresponding to low (0 to 20% FS) and high (80 - 100%) flow rates, and record the response of the monitor to each signal, as reported by the data acquisition system.

The unit is acceptable if the drift does not exceed 3% of the corresponding input signal for any day during the 168-hour test period.

4.5.6 Flow Monitor Orientation Sensitivity

This test is intended as a test for flow rate monitors that are sensitive to the orientation of the sensor in the gas flow, such as differential pressure flow sensors. Where possible, it is recommended that this test is carried out at three loads (rates):

a) minimum safe and stable operating load (rate);
b) approximately mid-load (rate) (40 to 60%); and
c) full load (rate) (90 -100%).

During a period of steady flow conditions at each load (rate), rotate the sensor in the gas flow a total of 10 degrees on each side of the zero degree position (directly into the gas flow, with no cyclonic flow patterns) in increments of 5 degrees, noting the response of the sensor at each angle. A total of five (5) flows will be generated for each load (rate) condition, at -10, -5, 0, +5, +10 degrees relative to the zero-degree position.

The sensor is acceptable if the flow measurements do not exceed a difference of 4% from the zero-degree orientation.

4.5.7 System Cycle Time/Response Time Test

Perform a response time test for each CEMS according to the following procedures.

Use a low-level and a high-level calibration gas as used in the calibration drift assessment alternately. While the CEMS is measuring and recording the concentration, inject either a low-level or a high-level concentration calibration gas into the injection port. Continue injecting the gas until a stable response is reached. Record the amount of time required for the monitor or monitoring system to complete 95.0% of the concentration step change using the data acquisition system output. Then repeat the procedure with the other gas. For CEMS that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible response time. (Note: for some CEMS, such as TRS/H_2S and CO_2/O_2 CEMS, it will be necessary to simultaneously inject calibration gases into the pollutant and diluent monitors, in order to measure the step change in the emission rate.)

Cycle time/response time test results are acceptable for monitoring or monitoring system certification, if none of the response times exceeds the applicable specifications in Section 4.2.

4.5.8 Relative Accuracy and Bias Tests for Gas Monitoring Systems

Perform a Relative Accuracy Test audit (RATA) for each CEMS. Record the CEMS output from the data acquisition system. For each CEMS, calculate bias as well as relative accuracy for each test.

(a) Plant Operating Conditions - For new CEMS installations, complete the RATA test during the operational test period or within 168 hours after the completed operational test period has been completed or when the unit is combusting its primary fuel or producing its primary product (as applicable). Perform the test for each CEMS at a normal rate for the unit.

For existing CEMS installations, RATA tests shall be conducted at a frequency as specified in Table 16.

When the test is performed on a CEMS or component(s) installed on bypass stacks/ducts or combined units exhausting into a common stack, perform the test for each CEMS installed to monitor the individual units when the units are operating. Use the fuels normally combusted by the units or operate the unit in a normal manner (as the case may be for combustion related or non combustion sources).

(b) CEMS Operating Conditions - Do not perform corrective maintenance, repairs, replacements or adjustments on the CEMS during the RATA other than as required in the operation and maintenance portion of the QAP.

(c) Reference Method Sampling Points - When the absence of stratified flow has not been verified, or if the gas flow has been found to be stratified, the Reference Method samples must be collected at a number of points in the effluent stream. Establish a "measurement line" that passes through the centroidal area of the flue or duct. This line should be located within 30 cm of the CEM sampling system cross section. Locate three (3) sampling points at 16.7, 50, and 83.3% along the length of the measurement line. Other sample points may be selected if it can be demonstrated that they will provide a representative sample of the effluent flow over the period of the test. A tip of the Reference Method probe must be within 3 cm of each indicated traverse point, but no closer than 7.5 cm to the wall of the stack or duct.

Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling.

(d) Reference Method Sampling Conditions - Conduct the Reference Method tests in accordance with the Alberta Stack Sampling Code, and in such a manner that they will yield results representative of the pollutant concentration, emission rate, moisture content, temperature, and effluent flow rate from the unit and can be correlated with the CEMS measurements. Conduct the diluent (O_2 or CO_2) measurements and any moisture measurements that may be needed simultaneously with the pollutant concentration measurements. To properly correlate individual CEMS data, with the Reference Method data, mark the beginning and end of each Reference Method test run (including the exact time of day) on the data acquisition system, individual chart recorder(s) or other permanent recording device(s).

(e) Consistency - Confirm that the CEMS and Reference Method test results are based on consistent moisture, pressure, temperature, and diluent concentration and in the same units. In addition, consider the response times of the CEMS to ensure comparison of simultaneous measurements.

For each RATA conducted, compare the measurements obtained from the monitor via the data acquisition system (in ppm, % CO_2, lb./M Btu, or other units as appropriate) against the corresponding Reference Method values. Display the paired data in a table.

(f) Sampling Strategy - Perform a minimum of nine sets of paired monitor (or monitoring system) and Reference Method test data for every required (i.e., certification, semiannual, or annual) relative accuracy or Bias Test audit. Each test shall take a minimum duration of thirty (30) minutes, sampling for equal periods at the three (3) sampling points for stratified flow testing, or at the single point for nonstratified flow.

NOTE: the tester may choose to perform more than nine sets of Reference Method tests up to a total of 12 tests. If this option is chosen, the tester may reject a maximum of three sets of the test results, if an appropriate statistical test applied to the data demonstrates that these results are outliers, and as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. All data must be reported, including the outliers, along with all calculations.

(g) Calculations - Analyze the test data from the Reference Method and CEMS tests for the applicable CEMS.

Summarize the results on a data sheet. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the Reference Method values. Using data from the automated data acquisition system, calculate the arithmetic differences between the Reference Method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the % confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

The absolute value of the average difference, | |, is calculated using the equation:

$$|\bar{d}| = \frac{1}{n} \sum_{i=1}^{n} (X_i - Y_i)$$

Where: n = number of data points

X_i = concentration from the Reference Method

Y_i = concentration from the CEMS

The standard deviation, S_d, is calculated using the equation:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \frac{1}{n}\left(\sum_{i=1}^{n} d_i\right)^2}{n - 1}}$$

Where: d_i = difference between individual pairs

The 2.5% error confidence coefficient, |cc|, is calculated using the equation:

$$|cc| = t_{0.025} \frac{S_d}{\sqrt{n}}$$

Where: $t_{0.025}$ = t - table value from Table 13.

Table 13. Range of t-values applicable for calculating confidence coefficients in Relative Accuracy Tests of CEMS.

t-VALUES

n	$t_{0.025}$	n	$t_{0.025}$
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

The Relative Accuracy (RA) is calculated using the equation:

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} X\ 100$$

Where:

$|\bar{d}|$ = Absolute value of the mean difference

$|cc|$ = Absolute value of the confidence coefficient

RM = Average Reference Method value

(h) The Bias Test

A bias, or systematic error is considered to be present if:

$|d| \geq |cc|$

(i) Acceptance Criteria for Analyzer Bias-

For each pollutant and diluent gas analyzer in the CEMS, calculate $|d|$ and $|cc|$, in the units of the analyzer. If

$|d| - |cc| \geq$ 4% of FS

the analyzer has significant bias. The cause of the bias must be determined and rectified. After corrections have been made, the Relative Accuracy Tests must be repeated to determine if the systematic error has been eliminated or reduced to an acceptable level.

4.5.9 Relative Accuracy Test for Flow Monitors

For new systems, carry out this test during the Operational Test Period, or during the week immediately following. It is recommended, if possible, that the testing be carried out at the three (3) loads (rates) as per section 4.5.6. For existing systems, conduct this test in accordance with the frequency specified in Table 16.

Carry out a minimum of nine (9) manual velocity traverse measurements at each load condition. Calculate the Relative Accuracy for each load (rate) condition as shown in 4.5.8.

The flow monitor is satisfactory if it meets the performance specifications given in Table 11.

4.5.10 Relative Accuracy Test for Temperature Sensors

Temperature sensors shall be verified using a certified reference thermometer or certified resistance temperature device (RTD)/readout or thermocouple/readout combination when conducting the RATA test.

5.0 QUALITY ASSURANCE AND QUALITY CONTROL

The Quality Assurance (QA) procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing Quality Control (QC) policies and corrective actions. These two functions form a control loop. When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable.

To provide high-quality data on a continuing basis a good QA program is necessary. The approval holder shall develop a QAP for each installed CEMS to ensure the quality of the CEMS measurements.

A "Quality Assurance" program is defined as a management program to ensure that the necessary quality control activities are being adequately performed, whereas "Quality Control" activities are those that detail the day-to-day operation of the system. The program shall be fully described in a Quality Assurance Plan (QAP) that is specific to the CEMS.

5.1 Quality Assurance Plan (QAP) for CEMS

The QAP must include and describe a complete program of activities to be implemented to ensure that the data generated by the CEMS will be complete, accurate, and precise. As a minimum, the manual must include QA/QC procedures specified in this code. The recommended Table of Contents for a QAP is shown in Table 14.

5.1.1 Section 1 - Quality Assurance Activities

This section of the manual describes the CEM system QAP, and describes how the QA program is managed, provide personnel qualifications, and describe the QA reporting system. It must describe the CEMS, how it operates, and the procedures for calibration and inspection. It must also include preventative maintenance and performance evaluation procedures.

5.1.2 Section 2 - Quality Control Activities

This section of the manual provides the detailed descriptions of the step-by-step procedures, the standard operating procedures required to operate and evaluate the system, including details about daily calibration procedures, CGAs, Relative Accuracy Tests, and tests for system bias. Minimum criteria and procedures for these activities are provided in Section 4.2, Section 4.4, and Section 4.5.

Table 14. Example Table of Contents for facility CEMS QAP.

SECTION	SUBSECTION	CONTENTS
		The Quality Assurance Plan
I	1	Assurance Policy and Objectives
	2	Document Control System
	3	CEMS Description
	4	Organization and Responsibilities
	5	Facilities, Equipment and Spare Parts Inventory
	6	Methods and Procedures
	7	Calibration and Quality Control Checks
	8	Preventative Maintenance Schedule
	9	Systems Evaluations
	10	Performance Evaluations
	11	Corrective Action Program
	12	Reports
	13	Data Backfilling Procedures (where authorized)
	14	References
		Quality Control Procedures
II	1	Start-up and Operation
	2	Daily CEMS Operation
	3	Calibration Procedures
	4	Preventative Maintenance Procedures
	5	Corrective Maintenance Procedures
	6	Evaluation Procedures - Cylinder Gas Audits
	7	Evaluation Procedures - Relative Accuracy Tests
	8	System and Subsystem Evaluation Procedures
	9	Data Backup Procedures
	10	Training
	11	CEMS Security
	12	Data Reporting Procedures
		Appendices
III	1	Facility Approval
	2	CEMS Specifications
	3	Reference Method Procedures
	4	Blank Forms

5.1.3 Inspection, Verification, and Calibration

Inspection, verification and calibration (when required) of the CEMS performance are among the most important aspects of the QA/QC program. The following summarizes the requirements for inspection, verification and calibration, all of which must appear in the QAP.

The method of verifying the accuracy of a CEMS component is to compare the value of the reference standard (e.g., reference gas or dead weight tester output) to the value displayed by the data acquisition system.

(a) Frequency - All CEMS components shall be inspected periodically (approval holder shall identify frequency in the QAP) to verify that individual components have not failed and are operating within prescribed guidelines (e.g., sample system flow rates are appropriate). The use of system components with integral fault detection diagnostics is highly desirable.

The minimum verification frequency for individual CEMS components (e.g., analyzers and temperature transmitters) performance shall be as specified in Table 16. The minimum frequency may be reduced (upon the written authorization of the Director) provided the operator can demonstrate (using historical data) that a lower verification frequency will not affect system performance at the 95% confidence level.

(b) Accuracy of Verification/Calibration Equipment and Materials - The minimum accuracy requirement for verification/calibration equipment and materials shall be a factor of two or better than the performance requirement specified for that system component in Section 4.2. (For example, if a performance specification requires an accuracy of ± 2% then the verification/calibration equipment shall be accurate to within ± 1%.)

For analyzers, the use of certified reference gases is acceptable for routine analyzer system performance verifications. Protocol 1 gases are required for a CGA. All other calibration equipment such as test pressure gauges, dead weight testers and multi-meters must be calibrated at least every 2 years in a manner that is traceable either through the Canadian Standards Association (CSA) or the U.S. National Institute of Standards and Technology (NIST).

For parameters for which cylinder gases are not available at reasonable cost, are unstable, or are unavailable, alternative calibration techniques are acceptable, if the Director has given prior written authorization.

(c) Calibration Adjustment - A CEMS component must be calibrated (i.e., output adjusted) whenever the observed inaccuracy exceeds the limits for that system component accuracy as specified in the Performance Specifications. A CEMS component need not be calibrated after each verification, only when it exceeds the specified tolerance.

(d) Out-of-Control Conditions - Only quality assured data may be used to determine CEMS availability. When an analyzer or system is out-of-control, the data generated by the specific analyzer or system are considered missing and does not qualify for meeting the requirement for system availability.

An out-of-control period occurs if either the low level (zero) or high level calibration results exceed twice the applicable Performance Specification. The criteria that pertain to out-of-control periods for specific CEMS are illustrated in Table 15.

Table 15. Criteria for out-of-control periods[e].

Instrument	Acceptable		2X[(a,b)]		4X[(c)]	
	Zero drift	**Span drift**	**Zero drift**	**Span drift**	**Zero drift**	**Span drift**
SO_2 [g]	±2%	±4%	±4%	±8%	±8%	±16%
NO_x[g]	±2%	±4%	±4%	±8%	±8%	±16%
TRS[g]	±5%	±5%	±10%	±10%	±20%	±20%
O_2 [d,f]	±0.5%	±0.5%	±1%	±1%	±2%	±2%
CO_2[d,f]	±0.5%	±0.5%	±1%	±1%	±2%	±2%
In-Stack Opacity[g]	±2%	±2%	±4%	±4%	±8%	±8%
CO[g]	±3%	±4%	±6%	±8%	±12%	±16%

[a] Corrective action must be taken, at a minimum, whenever the daily zero calibration drift or daily span calibration drift exceeds two times the limits stated above.

[b] If either the zero or span calibration drift results exceeds twice the above stated calibration drift for five consecutive daily periods, the CEMS is out-of-control beginning on the fifth day of error.

[c] If either the zero or span calibration drift results exceeds four times the applicable calibration drift, the CEMS is out-of-control back to the previous calibration drift found to be within tolerance unless a decisive point error occurrence can be defined.

[d] If the CO_2/O_2 CEMS is defined as being out-of -control, the TRS/SO_2/NO_x will also be out-of-control, until the CO_2/O_2 CEMS is defined as being within acceptable limits.

[e] If the CEMS is out-of-control, assess and identify the cause of the excessive drift and correct accordingly. Once the appropriate corrective action has been implemented, repeat the calibration drift test in order to demonstrate the CEMS is back within acceptable limits.

[f] Values are given as a % of gas concentration.

[g] Values are given as a % of full scale reading.

In addition, an out-of-control period also occurs if any of the quarterly, semiannual, or annual performance evaluations exceed the applicable performance specification criteria (i.e., Relative Accuracy, Bias, etc.). In this case, the out-of-control period begins with the hour when this condition occurred and ends with the hour after this condition ends.

(e) Verification/Calibration—Data Logging, and Tabulation - The "as found" values for each verification point shall be recorded before any calibration occurs. The "as left" values for each verification point shall also be recorded after any component is calibrated (i.e., adjustment). For systems capable of automated calibrations, the data system shall record the "as found" and "as left" values including a time stamp (date and time). If strip chart recorder data are reported, any automatic calibration adjustments must be noted on the strip chart recorder.

All verification data must be time-stamped and tabulated on a daily (where applicable) and monthly basis. The use of quality control charts is recommended.

The approval holder must retain the results of all performance evaluations including raw test data as well as all maintenance logs, corrective action logs and the QAP (including sample calculations) for a period of at least 3 years for inspection by Alberta Environmental Protection.

(f) Gas Analyzer/ System Verification - For all CEMS, the system is calibrated rather than the analyzer.

System performance shall be verified in accordance with the procedures specified in the facility QAP. For multi-range analyzers, all applicable operating ranges must be verified.

For systems amenable to verification through the use of standard reference gases, the standard reference gas must be introduced at the probe inlet or in the vicinity of the probe inlet. A calibration filter may be used for daily system zero and span verification for path in-situ CEMS only.

Ensure enough time passes to allow the system to attain a steady output, as shown by the data acquisition system, before recording.

For CGAs, the process and analyzer system must be operating at normal conditions (e.g., pressure, temperature, flow rate, pollutant concentration). The analyzer system must be challenged three times with each gas, but not in succession. To do this, alternate the gases presented to the system. Calculate the average response of the system as indicated by the data acquisition system or chart recorder to the three challenges of each concentration of reference gas.

For analyzers not amenable to verification/calibration through the use of reference gases, the operator shall detail verification/calibration procedures in the facility's QAP.

(g) In-Stack Opacity Analyzer Verification - Procedures for verification of in-stack opacity monitors are shown in US EPA 40 CFR 60, Appendix B.

(h) Temperature Measurement Subsystem Verification - The temperature measurement shall be verified using a certified reference thermometer or certified resistance temperature device (RTD)/readout or thermocouple/ readout combination when conducting the RATA test.

(i) Pressure Measurement Subsystem Verification - The static pressure and differential measurement devices shall be verified using a certified manometer, dead weight tester or test gauge when conducting the RATA test.

(j) Flow Element Subsystem Verification - For pitot tube or similar systems visual inspection at turnaround (or at least once per year) and as opportunities present themselves for visible signs of plugging or damage. Wind tunnel calibration of flow-measuring devices should be carried out before initial installation, when visible damage has occurred, or when flow system inaccuracy exceeds acceptable tolerances and inaccuracy cannot be attributed to any component other than the flow element. For pitot tube systems, if, when compared to the stack survey data, $|d| > \pm 15\%$, then pitot tubes must be pulled and recalibrated unless the source of the error is found to be in the transmitter. ($|d|$ refers to absolute difference.)

Backpurging (as necessary) of the primary flow measuring elements at an appropriate frequency is acceptable to ensure accurate data (and remove any build up of materials) but should be done when analyzer is being calibrated (or zeroed) so that actual complete sampling time of both flow and pollutant concentration is maximized.

For other flow methods such as ultrasonic meters, anemometers, etc., the QA/QC procedures and frequency shall be specified in the facility QAP and be followed accordingly.

Table 16. Minimum frequency for CEM system component Quality Assurance/Quality Control (QA/QC) requirements.

CEMS COMPONENT	**Frequency of Performance Verification Parameter**				
	Inspection	**Zero Drift**	**Span Drift**	**Cylinder Gas Audit**[a]	**Relative Accuracy Test Audit**[a]
Analyzers					
Sulphur Dioxide	Daily	Daily	Daily	2/yr.	2/yr.
Oxides of Nitrogen	Daily	Daily	Daily	2/yr.	2/yr.
Carbon Monoxide	Daily	Daily	Daily	2/yr.	2/yr.
Total Reduced Sulphur	Daily	Daily	Daily	2/yr.	2/yr.
In-Stack Opacity	Daily	Daily	Daily	na	na
Oxygen	Daily	Daily	Daily	2/yr.	2/yr.
Carbon Dioxide	Daily	Daily	Daily	2/yr.	2/yr.
Other Monitors	as specified in QAP	as specified in QAP	as specified in QAP	as specified in QAP	as specified in QAP
Rate Measurement Components					
Temperature	Daily	NA	semi-annual	NA	
Diff. Pressure	Daily	semi-annual	semi-annual	NA	
Static Pressure	Daily	semi-annual	semi-annual	NA	
Flow Element	1/yr.	NA	at RATA	NA	
Data Acquisition Components					
Recorder	Daily	See Note b	See Note b		
PLC/DCS	Daily	See Note b	See Note b		

[a] Frequency is subject to requirements in Section 5.2.

[b] The inputs to a PLC/SCADA or DCS must be checked as part of the trouble shooting procedures, only if the analyzer or flow system is found to be out-of-control.

(k) Data Receiver Subsystem Verification

The inputs to the digital data acquisition system (e.g., PLC, DCS, Scada) or chart recorder must be verified at the frequency specified in Table 16 using an appropriate calibrator as identified in the QAP.

5.2 Relative Accuracy Test Audits and Cylinder Gas Audits

5.2.1 General Requirements (applicability)

The approval holder shall conduct Relative Accuracy Tests and Cylinder Gas Audits on each CEMS. For the 1st year of CEMS operation a minimum of two Relative Accuracy Tests and a minimum of two CGAs must be conducted on each CEMS. A RATA may be substituted in place of a CGA; however, a CGA cannot be substituted in place of a Relative Accuracy Test. For the second and succeeding years, the minimum frequency of Relative Accuracy Tests may be decreased to once per year upon the Director being satisfied that the QAP demonstrates compliance with ongoing CEMS performance requirements (as detailed in Section 4.2). In lieu of the decreased RATA frequency, the minimum CGA frequency would be increased to three times per year.

The data obtained during a Relative Accuracy Test may also be used toward fulfilling associated stack survey requirements as provided for in an approval issued under EPEA.

5.2.2 Relative Accuracy Test Procedures

The procedure for carrying out the relative accuracy and bias tests is given in Subsections 4.5.9 of this Code.

5.2.3 Cylinder Gas Audits

The Cylinder Gas Audit procedure and acceptance criteria are the same as the Linearity Procedure of 4.5.4.

For those systems that are not designed for the dynamic use of calibration gases, alternative protocols (as authorized by the Director) may be used in place of the cylinder gas audit. These alternative procedures shall be included and detailed in the facility QAP.

5.2.4 Test Procedure Requirements

The associated QA/QC test procedures applicable to each CEMS and a description of the actual test procedures shall be contained in the facility QAP and adhered to by the facility operator.

During periods of scheduled CEMS quality control procedures, such as Relative Accuracy Test, the facility should be operated at a rate of at least 90 % of "normal" production. Normal production is defined as the average production or throughput for the facility over the previous month. Any exceptions to this would need to be authorized in writing by the Director.

At least one month must elapse between conducting either a CGA or a RATA, unless otherwise authorized by the Director.

5.3 Annual Evaluation

The CEMS and QAP must be evaluated every twelve (12) months.

An auditor, knowledgable in auditing procedures and in CEMS operations, and independent of the CEMS operation, must review the QAP, the CEMS operation, reports, and other associated records to determine if the procedures in the QAP are being followed. The auditor shall also note any changes in the system or the procedures since the last yearly evaluation and ensure that these have been included in the QAP.

The auditor shall report the findings and observations to the facility management. This report may include recommendations for improvements in the CEMS or its operation.

5.4 Minimum System Availability Requirements

The operational time or "availability" for both the CEMS and each individual monitor shall be greater than or equal to 90% based on the calendar month.

For CEMS applications requiring CO_2, O_2, mass or volumetric measurements, whenever these CEM subsystems are out-of-control, the data generated by the entire CEMS are considered missing and do not qualify for meeting the requirement for system availability. For other applications (e.g., in-stack opacity, concentration limit on a specific pollutant), only when that monitoring system is found to be out-of-control (See Table 15) are the data generated by that system considered missing and not qualified for meeting the requirement for system availability.

6.0 REPORTING REQUIREMENTS

6.1 General

All reporting requirements regarding continuous source emission data generated by the CEMS will be specified in the Air Monitoring Directive issued by Alberta Environmental Protection and as amended from time to time.

The approval holder shall make the QAP (and related QC information generated as a result of the QAP) available for inspection and audit to Alberta Environmental Protection upon request.

Detailed reporting requirements for the CEMS will be incorporated through the Air Monitoring Directive. In the interim, Section 6.2 shall apply until such time it can be formally incorporated into the Air Monitoring Directive, at which time Section 6.2 will cease to apply.

6.2 Quality Assurance Reporting Requirements

Within 1 month following the end of each quarter, the CEMS operator must report a summary of the following performance evaluations carried out within the quarter; these include: a) initial certification performance tests, b) Relative Accuracy Test Audits, and c) Cylinder Gas Audits. All other data records for the facility's QAP shall be retained at the facility site and be made available for inspection and audit by Alberta Environmental Protection upon request.

In addition, the CEMS availability for each month must be calculated in a manner as specified in Section 2.5.3 of the CEMS Code and reported in accordance with the reporting frequency as specified in the facility's approval. Section 6.2 ceases to apply upon the amendment of the Air Monitoring Directive to incorporate applicable CEMS reporting requirements.

The annual report shall contain confirmation of whether the annual evaluation (as required in Section 5.3) has been conducted and the date of completion of the evaluation.

APPENDIX A - DEFINITIONS

APPENDIX A - DEFINITIONS

Accuracy means the closeness of the measurement made by a CEMS, a pollutant concentration monitor or a flow monitor, to the true value of the emissions or volumetric flow. It is expressed as the difference between the measurement and a Reference Method value, which is assumed to be equivalent to the true value. Variation among these differences represents the variation in accuracy that could be caused by random or systematic error.

Alberta Stack Sampling Code means Publication No. REF. 89, published by Alberta Environmental Protection and as amended from time to time.

Alternative monitoring system means a system designed to provide direct or indirect determinations of mass per unit time emissions, pollutant concentrations, and/or volumetric flow data that does not use analyzers that accept independent, certified calibration gases. For the purposes of this Code, acceptable alternative monitoring systems are those that meet the same criteria of performance with respect to accuracy, precision, and availability, as CEMS that accept calibration gases.

As found or unadjusted value means the output value of the measurement device that corresponds to the reference value input before a calibration check or adjustment.

As left or adjusted value means the output value of the measurement device corresponding to the reference value input after calibration adjustment.

Available means that the CEMS or continuous in-stack opacity monitoring system is functional and operating within the calibration drift limits and other applicable performance specifications.

Bias means systematic error. The result of bias is that measurements will be either consistently low or high, relative to the true value.

Bypass means any flue, duct, stack, or conduit through which emissions from an unit may or do pass to the atmosphere, which either augments or substitutes for the principal ductwork and stack exhaust system during any portion of the unit's operation.

Calibration adjustment means the procedure to adjust the output of a device to bring it to a desired value (within a specified tolerance) for a particular value of input (typically the value of the reference standard).

Calibration check means the procedure of testing a device against a known reference standard without adjusting its output.

Calibration drift means the difference between (1) the response of a gas monitor to a reference calibration gas and the known concentration of the gas, 2) the response of a flow monitor to a reference signal and the known value of the reference signal, or (3) the response of a continuous in-stack opacity monitoring system to an attenuation filter and the known value of the filter after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Calibration gas means for the purposes of this Code, a known concentration of a gas (1) that is traceable to either a standard reference material (SRM) or a U.S. National Institute of Standards and Technology (NIST), 2) an authorized certified reference gas, or (3) a Protocol 1 gas.

Calibration gas cell or a filter means a device that, when inserted between the transmitter and detector of the analyzer, produces a desired output level on the data recorder.

Centroidal area means a concentric area that is geometrically similar to the flue, duct or stack cross section and is not greater than 1% of the stack or duct cross-sectional area.

Continuous means that a device is capable of making a measurement at least once every 15 minutes and operates with an availability greater than 90% on a monthly basis.

Continuous emission monitoring system (CEMS) means the equipment required to analyze, measure, and provide, on a continuous basis, a permanent record of emission and other parameters as established by this code.

Cylinder gas audit (CGA) means a challenge of the monitoring system with a cylinder gas of a known concentration which is traceable to standard reference materials (SRMs) of the U.S. National Institute of Standards and Technology (NIST) according to Protocol 1 of the US EPA.

Data acquisition system (DAS) means one or more devices used to receive, compute, store, and report CEMS measurement data from single or multiple measurement devices.

Data backfilling means the act of transferring data from one portion of the data acquisition system to another after electronic communications have been restored. For example, delayed transfer of data from a datalogger to the main or central computer normally used for data processing and storage.

Data recorder means a device capable of providing a permanent record of both "raw" and "summary" data.

Data substitution means the procedure using data from a calculation or alternate device as a source of replacement data for periods of time during which a continuous emission monitoring system was "out-of-control," as defined in Table 15. For example, data generated by other means such as a "predictive emissions" program or an alternative monitoring system (or some combination) would be designated as substituted data.

Diluent gas means a major gaseous constituent in a gaseous pollutant mixture or the gas used to dilute the pollutant mixture in dilution type analyzer systems. For combustion sources, carbon dioxide, nitrogen and oxygen are the major diluent gases.

Director means a person designated as a Director for the purposes of the Environmental Protection and Enhancement Act by the Minister of Alberta Environmental Protection.

Drift means an undesired change in output, over a period of time, that is unrelated to input or equipment adjustments.

Dual span system means a pollutant concentration monitor, flow monitor, or in-stack opacity monitor that has two ranges of values over which measurements are made.

Emission standard level means the maximum emission level (either as a concentration or mass) as stated in an approval issued under the Environmental Protection and Enhancement Act.

Equivalent diameter means a calculated value used to determine the upstream and downstream distances for locating flow or pollutant concentration monitors in flues, ducts or stacks with rectangular cross sections.

Extractive monitoring system means one that withdraws a gas sample from the stack and transports the sample to the analyzer.

Flow monitor means an analyzer that measures the velocity and volumetric flow of an effluent stream.

Full scale reading means the upper value of the monitor or analyzer range (as contained in Section 2.0).

In-situ monitor means a monitor that senses the gas concentration in the flue, duct or stack effluent stream and does not extract a sample for analysis.

Inspection means a check for conditions that are likely to affect the reliability of the system. Examples of these conditions could include the following: damage to system components, leaks, a low flow condition in sample transport system, alarms, adequate supply of consumables such as chart paper and calibration gases, etc.

Interference rejection means the ability of a CEMS to measure a gaseous species without responding to other gases or substances, within specified limits.

Invalid data means data that were generated while the measurement device(s) was out-of-control.

Linearity means the degree to which a CEMS exhibits a straight line (first order) response to changes in concentration (or other monitored value), over the range of the system. Nonlinearity is expressed as the percentage difference of the response from a straight line response.

Lower detection limit means the minimum value that a device can measure, which may be a function of the design and materials of construction of the device rather than of its configuration.

Month means a calendar month.

NIST/EPA-approved certified reference material means, a reference material for which one or more of its values are certified by a technically valid procedure, such as Traceability Protocol 1 (U.S. Code of Federal Regulations (40 CFR 75 Appendix H), accompanied by or traceable to a certificate or other documentation that is issued by a certifying body and approved by U.S.-EPA. A current list of certified reference material cylinder gases and certified reference material vendors is available from the Quality Assurance Division (MD-77), Environmental Monitoring Systems Laboratory, U.S.-EPA, Research Triangle Park, NC 27711.

Operational period means a minimum period of time over which a measurement system is expected to operate within certain performance specifications, as set forth in this code, without unscheduled maintenance, repair, or adjustment.

Orientation sensitivity means the degree to which a flow monitoring system is affected by its change in orientation to give an accurate flow measurement.

Path continuous emission monitoring system means a CEMS that measures the pollutant concentration along a path greater than 10% of the equivalent diameter of the flue, duct or stack cross section.

Point continuous emission monitoring system means a CEMS that measures the pollutant concentration either at a single point or along a path equal to or less than 10% of the equivalent diameter of the flue, duct or stack cross section.

Precision means the closeness of a measurement to the actual measured value expressed as the uncertainty associated with repeated measurements of the same sample or of different samples from the same process (e.g., the random error associated with simultaneous measurements of a process made by more than one instrument). A measurement technique is determined to have increasing precision as the variation among the repeated measurements decreases.

Protocol 1 gas means a calibration gas mixture prepared and analyzed according to "Revised Traceability Protocol No. 1," U.S Code of Federal Regulations, 40 CFR 75 Appendix H to Part 75. The certified concentrations for calibration gas mixtures developed using "Revised Traceability Protocol No. 1" are traceable to a standard reference material or an NIST/EPA-approved certified reference material.

Quality assured data means data generated from a CEMS when the CEMS is in control, and meets both the design and performance specifications of this Code.

Range means the algebraic difference between the upper and lower limits of the group of values within which a quantity is measured, received or transmitted.

Raw data means the generation and recording of data at the minimum specified frequency where required in this code and the generation and recording of data associated with quality control activities where required by this code or as a result of a facility's quality assurance plan.

Reference Method means any method of sampling and analyzing for a substance or determining the flow rate as specified in the Alberta Stack Sampling Code (as amended from time to time), or any other such method as authorized by the Director.

Reference value means the known concentration of a verification or calibration gas or the known value of a reference thermometer or output value of a temperature, pressure, current or voltage calibrator.

Relative accuracy is the absolute mean difference between the gas concentration or emission rate determined by a CEMS and the value determined by an appropriate Reference Method plus the 2.5 percent error confidence coefficient of a series of tests, divided by the mean of the Reference Method tests. The relative accuracy provides a measure of the systematic and random errors associated with data from a CEMS.

Response time means the amount of time required for the CEMS to display on the data recorder 95% of a step change in pollutant concentration. This period includes the time from when the sample is first extracted from the flue, duct or stack (if extractive system) to when the concentration is recorded.

Sample interface means that portion of a system used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the monitor from the effects of the flue, duct or stack effluent stream.

Sensitivity means the minimum change of input to which a device is capable responding and is defined as two times the noise level.

Span means the algebraic difference between the upper and lower range values.

Standard absolute pressure means 760 mm Hg (101.325 kpa) at 25^{o}C.

Standard absolute temperature means 25°C, 298°K, 77°F, or 537°R.

Standard reference material means a reference material distributed and certified by the National Institute of Standards and Technology (NIST) or the Canadian Standards Association (CSA).

Temperature-responsive zero drift means the zero drift of an analyzer for any 10° C change in temperature over the temperature range of 5 to 35°C.

Temperature-responsive span drift means the span drift of an analyzer for any 10° C change in temperature over the temperature range of 5 to 35°C.

Valid hour means data for a given hour consisting of at least four equally spaced data points. For example, if scans occur once every 15 minutes, then four 15-minute scans must be collected for the hour to be valid.

Valid in-stack opacity period means data for a given time period consisting of at least 36 equally spaced data points. For example, for a 6-minute time period, a minimum of 36 samples (cycles) must be obtained, based on a standard rate of sampling at no less than 6 samples (cycles) per minute.

Verification means to ascertain the extent of error in a device or system by comparing the output of that device or system to the reference value.

Zero drift means the difference between the CEMS's response to a lower range calibration value and the reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

APPENDIX B - RELATIVE ACCURACY SAMPLE CALCULATIONS

APPENDIX B - RELATIVE ACCURACY SAMPLE CALCULATIONS

Relative Accuracy Test Audit Calculations

Example data from RATA on a $SO_2/0_2$ CEMS are shown in Table B.1.

$$CEMS_{ppm,\ dry} = \frac{CEMS_{ppm,\ wet}}{1 - B_{ws}}$$ **Equation B-1**

where: B_{ws} = moisture fraction of the CEMS gas sampled.

Table B.1 Relative Accuracy Test Audit Data for SO_2 and O_2 CEMS

Run Number	SO_2	SO_2	O_2	O_2	SO_2	SO_2	SO_2
	$Rm_{d'}$ ppm	$CEMS_{d'}$ ppm	$Rm_{d'}$ %	$CEMS_{d'}$ %	$Rm_{d'}$ ng/J	$CEMS_{d'}$ ng/J	Diff ng/J
1	500	475	3.0	3.1	422.4	403.5	18.9
2	505	480	3.0	3.1	426.6	407.7	18.9
3	510	480	3.0	3.0	430.8	405.4	25.4
4	510	480	2.9	2.9	428.4	403.2	25.2
5	500	480	2.9	3.0	420.0	405.4	14.6
6	500	500	3.0	3.1	422.4	424.7	-2.3
7	510	510	3.0	3.1	430.8	433.3	-2.5
8	505	505	2.9	3.0	424.2	426.6	-2.4
9	510	520	2.9	3.0	428.4	439.3	-10.9
Avg	---	---	---	---	426.0	413.1	9.43

$Rm_{d'}$ = reference method data, dry basis
$CEMS_{d'}$ = monitor data, dry basis

The SO_2 and O_2 CEMS and RATA data in Table B.1 were converted to the units of the applicable standard using Equation B-2:

$$E = CF \frac{20.9}{20.9 - \text{percent } 0_2} \qquad \textbf{Equation B-2}$$

where

E = pollutant emission, ng/J (lb/million Btu),

C = pollutant concentration, ng/dsm^3 (lb/dscf),

F = factor representing a ratio of the volume of dry flue gas generated to the caloric value of the fuel, dsm^3/J (dscf/million Btu), and

Percent 0_2 = oxygen content by volume (expressed as percent), dry basis.

Note: For the calculations shown in Table B.1, ppm of SO_2 was converted to ng/J using a conversion factor of 2.66×10^6 ng/scm/ppm and an F factor of 2.72×10^{-7} dsm^3/J.

For complete explanation of the equations and calculations, see 40 CFR; Part 60; Appendix A; Method 19; 5. Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates.

After the data are converted to the units of the standard, the Relative Accuracy (RA) is calculated by using the equations in Section 4.5.8. For convenience in illustrating the calculation, these equations (B-3 through B-8) are also shown here.

The average difference d, is calculated for the SO_2 monitor using Equation B-3.

Equation B-3

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} (X_i - Y_i) = \frac{1}{n} \sum_{i=1}^{n} d_i$$

$$= \frac{1}{9} (84.9) = 9.43 \ ng/J$$

where

n = number of data points,
X_i = concentration from reference method (Rm_d in Table B.1), ng/J,
Y_i = concentration from the CEMS ($CEMS_d$ in Table B.1),
d_i = signed difference between individual pairs, X_i and Y_i, ng/J, and
$\sum d_i$ = algebraic sum of the individual differences, d_i, ng/J.

The standards deviation S_d is calculated using Equation B-4:

Equation B-4

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \frac{1}{n}(\sum_{i=1}^{n} d_i)2}{n-1}}$$

$$= \sqrt{\frac{(2344) - \frac{1}{9}(84.9)^2}{8}} = 13.9 \ ng/J$$

The 2.5 percent error confidence coefficient, CC, is calculated using Equation B-5.

$$CC = t_{0.975} \frac{s_d}{\sqrt{n}}$$

Equation B-5

$$= 2.306 \frac{13.9}{\sqrt{9}} = 10.68 \ ng/J$$

where

$t_{0.975}$ = t-values in Table B.2 for n = 9

Table B.2 Values of t for 95 Percent Probability[a]

n[a]	**$t_{0.975}$**	**n[a]**	**$t_{0.975}$**	**n[a]**	**$t_{0.975}$**
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

[a] The values in this table are already corrected for n^{-1} degrees of freedom. Use n equal to the number of individual values.

The RA for the RATA is calculated using Equation B-6

$$RA = \frac{|\bar{d}| + |CC|}{\overline{RM}} X\ 100$$ **Equation B-6**

$$= \frac{|9.43| + |10.68|}{426} x\ 100 = 4.72\%$$

Where

RA = relative accuracy, %,

$|\bar{d}|$ = absolute value of the mean differences from Equation B-3, ng/J.

$|CC|$ = absolute value of the confidence coefficient from Equation B-5, ng/J, and

$\overline{RM}$ = average reference method value or applicable standard, ng/J.

APPENDIX C - BIBLIOGRAPHY

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AIR QUALITY MODEL

GUIDELINE

Alberta
ENVIRONMENT

October 2000

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PREFACE

The Alberta Environment (AENV) Air Quality Modelling Guideline (Guideline) is intended for operations and proposed operations that require an Environmental Protection and Enhancement Act (EPEA) approval or that operate under a Code of Practice for emissions to the atmosphere.

Alberta Environment has developed the Guideline to ensure consistency in the use of dispersion models for regulatory applications in Alberta. The practices recommended within this guideline are a means to ensure that these objectives are met.

The Guideline outlines Alberta Environment's dispersion modelling requirements and methods. Although some specific information on models is given, the user should refer to user guides and reference materials for the model of interest for further information on dispersion modelling. The Guideline will be reviewed regularly to ensure that the best available tools are being used to predict air quality.

Additional information relevant to dispersion models can be located at these web pages:

- http://www.gov.ab.ca/env/air/
- http://www.gov.ab.ca/env/air/airqual/airmodelling.html
- http://www.gov.ab.ca/env/air/airqual/metdata.html
- http://www.epa.gov/scram001
- http://www.cmc.ec.gc.ca

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1 INTRODUCTION

This guideline provides detailed guidance on suitable methods and approaches that should be used to assess air quality from emission sources. It sets out

- the statutory authority,
- an overview of the approach,
- guidance on appropriate technical methods, and
- the information required to demonstrate that a source meets the Alberta Ambient Air Quality Guidelines (AAAQG).

It is not intended to provide a technical description of the theory behind dispersion modelling—such information is widely available in other published documents, and references are provided within the text.

Detailed advice on the types and uses of dispersion models is provided in Sections 2 to 4. Section 5 provides guidance on the application of regulatory models, describing individual models and their intended uses. Section 6 gives internet addresses for a variety of modelling resources. Appendix A lists the contents of screening assessments expected by Alberta Environment. Appendix B lists the expected contents of refined and advanced assessments

1.1 Purpose of the Air Quality Modelling Guideline

Alberta Environment (AENV) has developed the Air Quality Modelling Guideline to ensure consistency in the use of dispersion models in air quality assessments. The objectives are to

- provide for uniform benchmarking,
- provide a structured approach to selection and application of models,
- ensure that there is a sound scientific basis for the use of alternatives, and
- detail the required content of assessments submitted to the department.

The Guideline addresses only primary substances directly emitted from a source. Some substances are formed in the atmosphere as a result of the interaction of these primary substances with substances from either natural or industrial sources. These are known as secondary substances (e.g., Ozone). Concentrations of secondary substances must be estimated by other means acceptable to AENV.

1.2 Statutory Authority

This guideline is issued by Alberta Environment, under Part 1, 14 (4), the Environmental Protection and Enhancement Act 1992 (EPEA). This document replaces all previous versions of the Alberta Air Quality Model Guidelines.

This guideline should be read in conjunction with the Alberta Ambient Air Quality Guidelines and the Air Monitoring Directive.

1.3 Air Quality Models

Alberta Environment works with Albertans to protect and enhance the quality of the air through a regulatory management approach that includes

- air quality models,
- ambient air quality guidelines,
- atmospheric emission inventories,
- source emission standards,
- approvals,
- environmental reporting,
- ambient air quality monitoring,
- source emission monitoring,
- inspections/abatement, and enforcement, and
- research.

Information from emission inventories and source controls are utilized in air quality modelling to relate the resulting ambient air quality to the ambient air quality guidelines. Ambient monitoring determines the actual air quality resulting from the emissions.

The purpose of a dispersion model is to provide a means of calculating ambient ground-level concentrations of an emitted substance given information about the emissions and the nature of the atmosphere. The amount released can be determined from knowledge of the industrial process or actual measurements. However, predictive compliance with an ambient air quality guideline is determined by the concentration of the substance at ground level. Air quality guidelines refer to concentration in the ambient air, not in the emission source. In order to assess whether an emission meets the ambient air guideline it is necessary to determine the ground-level concentrations that may arise at various distances from the source. This is the function of a dispersion model.

A dispersion model is a set of mathematical relationships or physical models, based on scientific principles, that relate emission rates of an air contaminant to the resulting ambient concentrations. Model predictions are useful in a wide variety of air quality decisions, including determining appropriateness of facility location, monitoring-network design, and stack design. Models also provide information on the areas most influenced by emissions from a source, the contribution of weather to observed trends, and the air quality expected under various scenarios. Dispersion modelling requires knowledge of emission rates and the local meteorology and topography.

1.4 Levels of Modelling

The choice of dispersion model depends on a number of factors. There is a wide range of models available, and it is important that the user selects the model that fits the demands of the task. Generally, there are three levels of assessment:

1. Screening assessment is utilized to determine a specific event or the likelihood of a specific event. (e.g., to predict the worst-case concentration.)

2. Refined assessment, because of its higher level of sophistication, more closely estimates actual air quality impacts.

3. Advanced assessment treats specific dispersion processes in greater detail. It potentially gives more accurate results but requires more input data. The user must be careful to ascertain whether the selected dispersion model is being applied to a situation for which the model was designed.

2 MODELLING PROTOCOL

A dispersion model is a series of equations describing the relationships between the concentration of a substance in the atmosphere arising at a chosen location, the release rate, and factors affecting the dispersion and dilution in the atmosphere. The model requires information on the emission characteristics (see Section 3.1) and the local meteorology (see Section 3.2). Modelling can also be used to predict future scenarios, short-term episodes, and long-term trends.

Nearby buildings and complex topography can both have significant effects upon the dispersion characteristics of a plume. Buildings may cause a plume to come to ground much closer to the stack than otherwise expected, causing significantly higher substance concentrations. Plumes can impact directly on hillsides under certain meteorological conditions, or valleys may trap emissions during low-level inversions.

A hierarchy of commonly used dispersion models has been established, categorizing the models according to how they might be used within the assessment process. For example, 'screening' models are used as a benchmark or an initial step of the review, and refined models for more detailed analysis. Advanced models may be needed, depending upon the type of source(s) being studied and the complexity of the situation.

2.1 Modelling Decisions

All proposed emissions to the atmosphere that are subject to an EPEA approval from AENV or that operate under a Code of Practice are subject to the appropriate modelling which includes background assessment (see Section 4.2). The flow chart for modelling categories is shown in Figure 1.

For other types of facilities, the dispersion models outlined in this guideline or equivalent ones developed in consultation with AENV may be used to demonstrate compliance with the AAAQG.

When a renewal is required for existing facilities, a screening assessment using the current models must be submitted for benchmarking. Further modelling may be required at the discretion of the Director, if

- the screening modelling predicts exceedance of AAAQG,
- the monitoring data show exceedances,
- there are many other emission sources in the area,
- the area contains sensitive receptors, or
- changes in emissions are expected at the facility.

The flow chart is shown in Figure 2.

Figure 1: Flow chart indicating situations in which different categories of dispersion models might be used

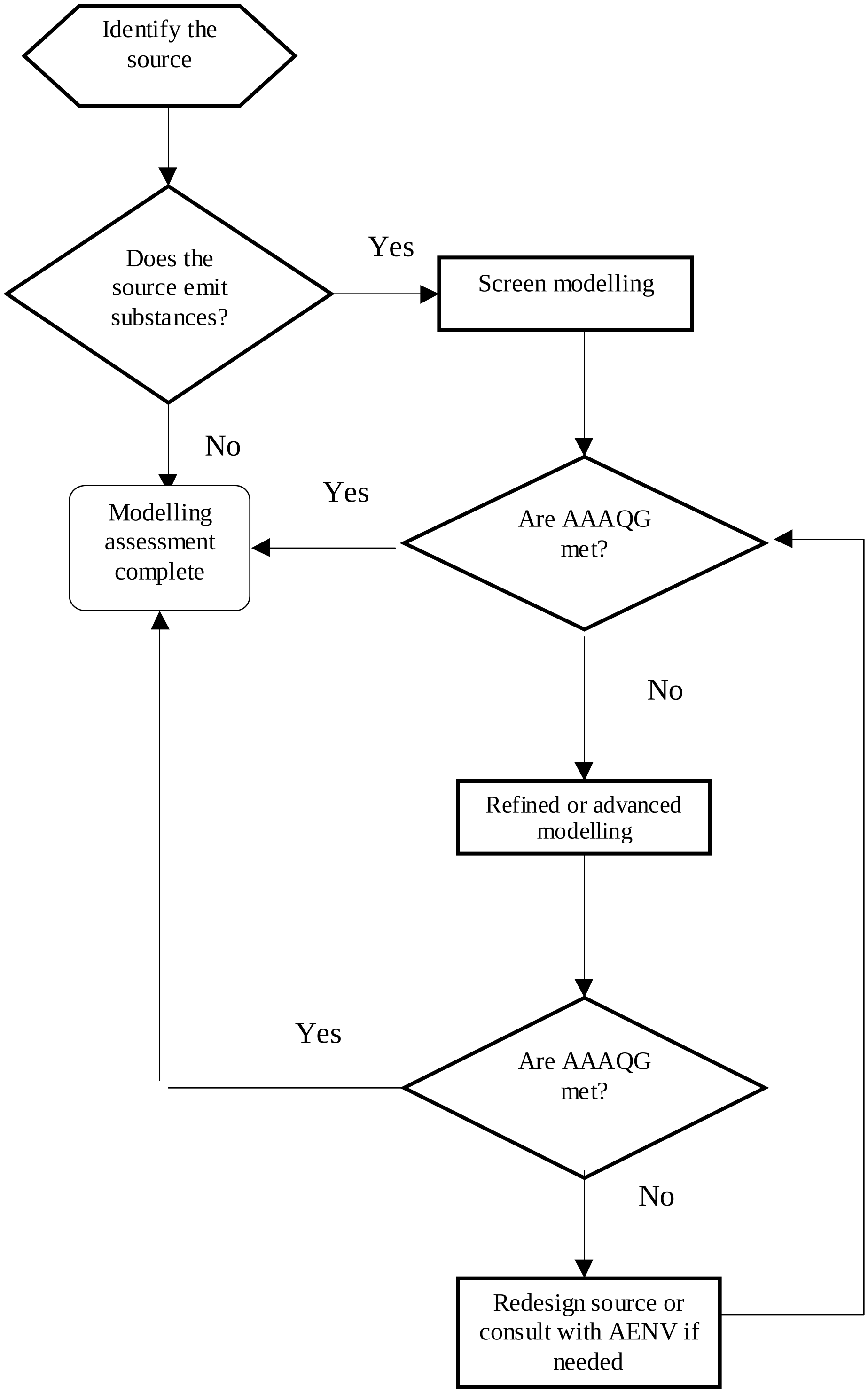
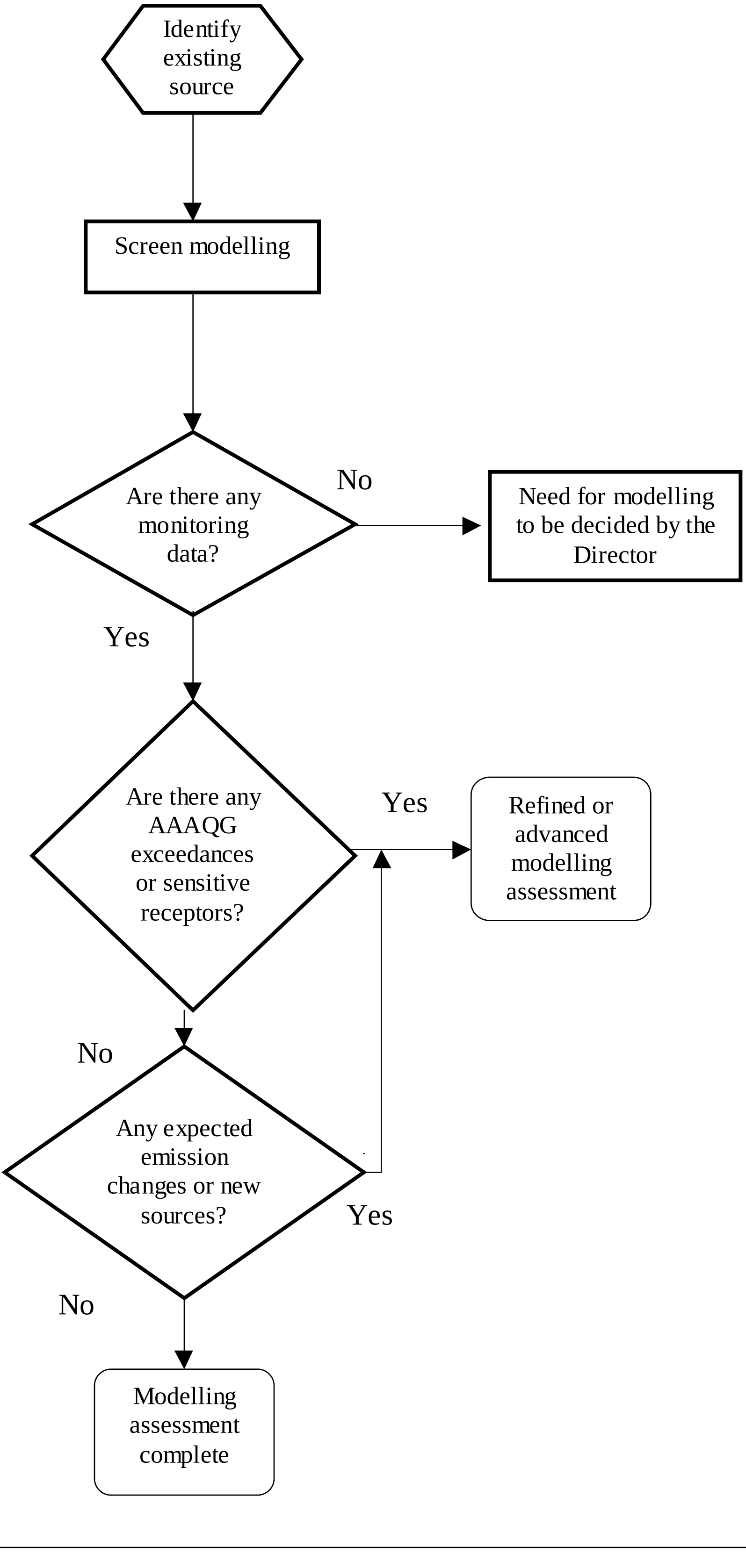


Figure 2: Flow chart indicating dispersion modelling situations for renewal of approval for existing facility



2.2 Screening Models

The first tier of evaluation for single- or multiple-source impact employs a screening method using SCREEN3 or ISC3 with regional screening data (See Section 3.2.2). The screening model results serve as benchmarks for each type of source and for comparison against other sources.

In order to simplify the running of a computer model, some models, such as SCREEN3, already have preset meteorological conditions included within them. There is then no need to consider local meteorology. The models will calculate worst-case concentrations and may provide the user with information on the meteorological conditions that gave rise to these concentrations.

Screening models quickly give an initial impression of the highest concentrations that are likely to occur. SCREEN3 can only treat one source at a time, however, if multiple sources are not further than 500 m apart or at different elevations, the sources can be modelled separately, and the maximums (regardless of location) should be totalled. In such approach building downwash needs to be assessed carefully.

If concentrations, after adding the background, are below the air quality guidelines, it is usually unnecessary to undertake further modelling (see Section 4.2). Figure 3 shows the flow chart for the screening level.

2.3 Refined Models

If the screening assessment has predicted exceedances of AAAQG, the second tier is required.

The second tier, to address the impacts of single or multiple sources, involves a refined assessment. Refined assessments are required if any of the following conditions apply:

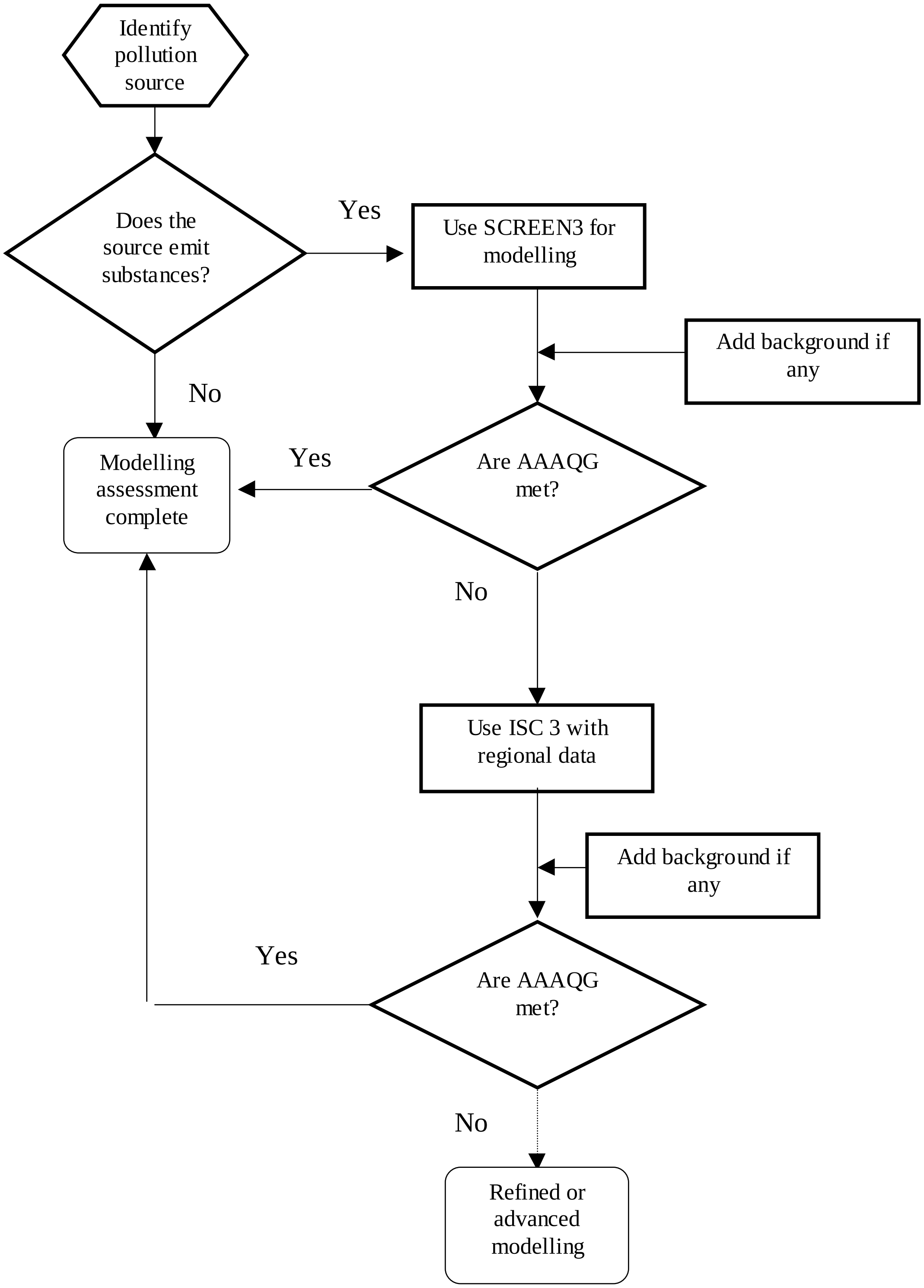
- The source is in an airshed where there are other emissions such as an industrial park, industrial region, or urban area.
- The area is environmentally sensitive (e.g., a national park).
- Public concerns need to be addressed.

Brief descriptions of the regulatory refined models are presented in Section 5 (See Section 4 for output interpretation).

2.4 Advanced Models

For an advanced assessment using an alternative or modified model, details should be verified with AENV prior to submission.

Figure 3: Flow chart for screen modelling tier



3 INPUT DATA

All dispersion models require some form of input data that describe how much substance material is being released, details on how the substance is being released, and the environment into which the release occurs. It is also necessary to define the locations at which the impact of the emissions is to be predicted; these are termed 'receptor' locations.

The accuracy of the data input to the model has a significant effect on the accuracy of the predicted concentrations. Where the model assumes that the emissions are not chemically transformed in the atmosphere, (except for CALPUFF), the predicted concentration is directly proportional to the emission rate, i.e., if the emission rate is doubled, the predicted concentration also doubles. This relationship follows regardless of how simple or sophisticated the dispersion model is. The collation of accurate emissions data is therefore extremely important.

3.1 Source Input Data

Different source types are defined as follows:

- ***Point sources*** are localized sources such as stacks or flares. The simpler models can treat only one point source at a time, though more sophisticated programs can include a very large number of stacks simultaneously.

- ***Line sources*** are sources where emissions are in linear form such as roads.

- ***Area sources*** are clusters of point or line sources (e.g., fugitive emissions from industrial processes having numerous vents).

- ***Volume sources*** are three-dimensional sources such as area sources distributed with a vertical depth, for example, emissions from lagoons.

The selection of emission rates for input to the model depends on the type of model and the purpose for which the model is being used. When using models for stack design the approved hourly maximum emission rate should be used. However, when the model is used to predict annual average concentrations, typical emission rates will be adequate for the purpose.

For areas with multiple facilities, the emissions of all of the other sources in the airshed should be included. Stack parameters from existing facilities can be determined from approval limits, Continuous Emission Monitoring Systems (CEMS), or manual stack surveys. In some cases it is not practical to conduct manual stack surveys, so emission factor estimates from published sources can be used (manufacturer specifications or AP-42) (U.S. EPA, 1995a).

If sources operate only during specified hours, the modelling analysis can be restricted to the hours of operation. If this type of assessment is selected, special approval conditions may apply to restrict the operation to the time periods that were modelled.

Continuous flares should always be designed in conformance with the most current guidelines and standards recommended by Alberta Environment or the Alberta Energy and Utilities Board. Emergency flares should be modelled and assessed using guidance from the most current document, by AENV 1999, entitled “Emergency/Process Upset Flaring Management: Modelling Guidance” (AENV, 1999a).

If the stack emissions contain large particles (greater than about 40 µm in diameter), information relating to the particle size distribution may also be required.

3.2 Meteorological Data

3.2.1 Screening Meteorological Data Set

Since most screening models handle only a single source at a time, wind direction is not a factor in determining worst-case conditions in flat terrain in the case where buildings do not exist. For multiple-source combinations, use of a variety of wind directions is important.

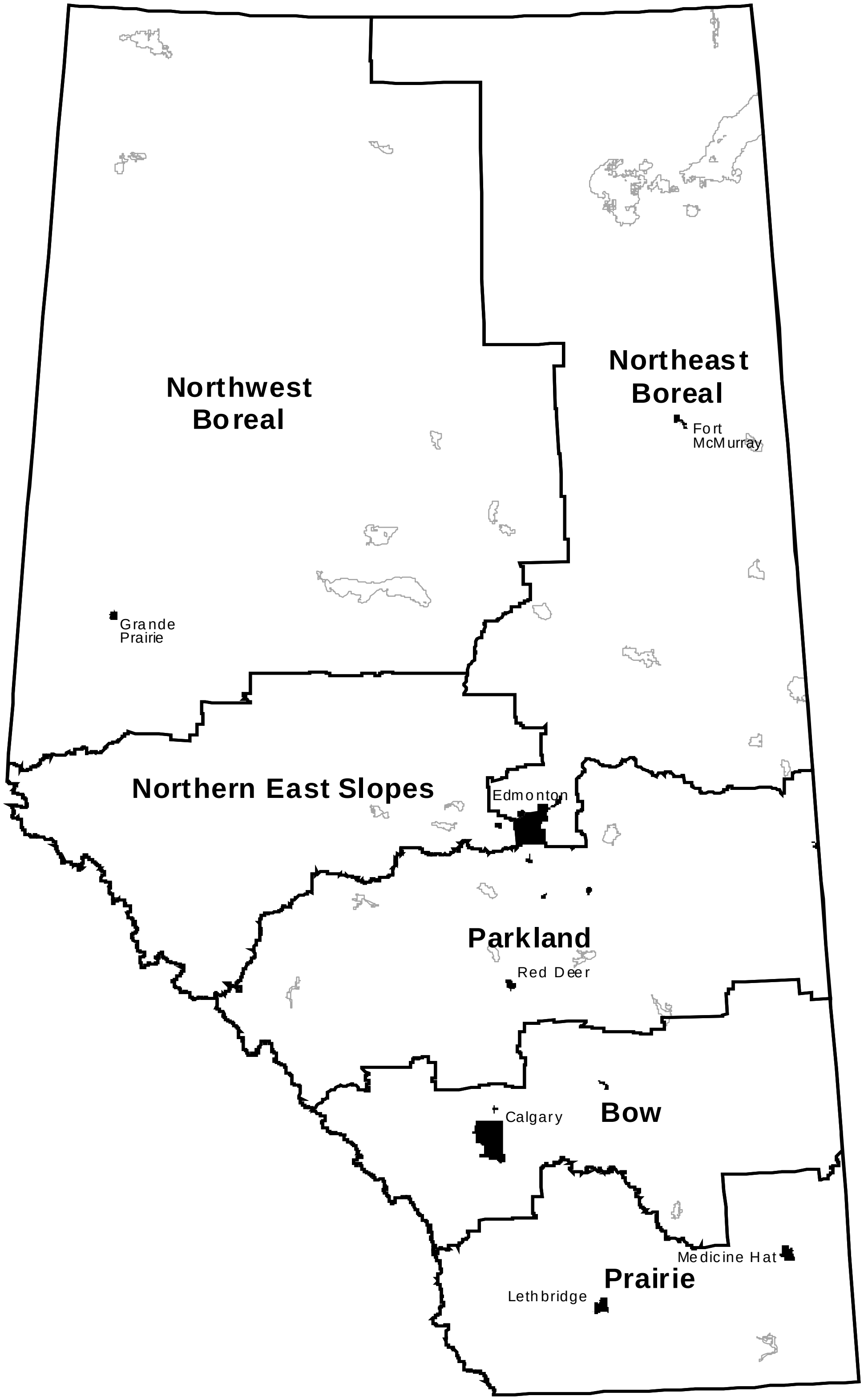
AENV has developed regional screening meteorological data for the six regions (see Figure 4), which can be used for screening purposes only. The data, in ISC3 format, are available on the AENV web page, as noted in Section 6.1. Supporting documentation for the six regional data sets can be found in Comparison of Meteorology Elements in the Alberta Environment Regional Screening Dispersion Modelling Data Sets (AENV, 1999).

3.2.2 Refined and Advanced Meteorological Data Sets

For refined assessments, actual near-site data are used. The representativeness of the actual data depends on the proximity of the meteorological monitoring site to the activity, the complexity of the terrain, the exposure of the instruments, the time of data collection, and the data recording method (Hoffnagle et al., 1981; Nappo et al., 1981; Walmsley & Bagg, 1978). Data for refined modelling must be shown to be temporally and spatially representative of the site of the facility. One of the following meteorological data sets should be used in a refined assessment:

- A minimum of 1 year of site-specific meteorology. Site-specific data must be related to the longer term (seasonal or annual) by statistical methods. Relating site-specific meteorology to data from climate or meteorological stations having longer collection periods ensures that site data are temporally representative.

Figure 4: Map showing AENV administrative regions of Alberta



- The most recent 5 years of meteorological data, readily available from a nearby airport station, must be utilized. When using airport meteorological data in refined modelling, studies have shown that at least 5 years of data must be used to obtain stable distributions (U.S. EPA, 1998).

These data can be purchased from Environment Canada's Meteorological Service.

Missing meteorological data must be processed prior to being utilized in a model. There are numerous methods of processing missing data. Generally:

- Consecutive years of data should be used.
- A data set should not be used if fewer than 90% of the annual data are available.
- When missing data values arise, they should be handled in one of the ways listed below, in the following order of preference (U.S. EPA, 1987):

    1. If there are other on-site data, such as measurements at another height, they may be used when the primary data are missing and corrections based on established vertical profiles should be made. Site-specific vertical profiles based on historical on-site data may also be appropriate to use after consultation with AENV.

    2. If there are only one or two missing hours, linear interpolation of missing data may be acceptable, however, caution should be used when the missing hour(s) occur(s) during day/night transition periods.

    3. If representative off-site data exist, they may by used. In many cases, this approach is acceptable for cloud cover, ceiling height, mixing height, and temperature.

- Consult with AENV regarding substitution of data for longer periods, or if insufficient data is available. For these cases, shorter periods or appropriate substitution of data can be used with approval from AENV.

3.3 Surface Roughness

Surface roughness determines the degree of ground turbulence caused by the passage of winds across surface structures. The following method is to be used for selecting the rural or urban surface roughness category.

Classify the land use within a 3-km radius of the source. If more than 50% of the land use falls within the following categories—heavy or light industrial, commercial, and compact residential (two-story dwellings, limited lawn sizes)—it is considered to be urban. Otherwise, use the rural coefficients by selecting rural roughness, except for forests, which are treated as urban locations.

3.4 Local Buildings

To take account of local building effects, models generally require information related to the dimensions and location of the structures with respect to the stack. If the stack is located on the top of a building, or adjacent to a tall building, it may be necessary to consider the size of these buildings. As a general guide, building downwash problems may occur if the height of the top of the stack is less than 2 ½ times the height of the building upon which it sits. It may be necessary to consider adjacent buildings if they are within a distance of 5 times the lesser of the width or peak height from the stack (5L). This distance is commonly referred to as the building's *region of influenc*e. If the source is located near more than one building, assess each building and stack configuration separately. If a building's projected width is used to determine 5L, determine the *apparent width* of the building. The apparent width is the width as seen from the source looking towards either the wind direction or the direction of interest. For example, the ISC3 model requires the apparent building widths (and also heights) for every 10 degrees of azimuth around each source. Due to the complexity of building downwash guidance, the U.S. EPA has developed a computer program for calculating downwash parameters for use with the ISC models. The U.S. EPA Building Profile Input Program (BPIP) is designed to calculates building heights (BH’s) and the *apparent width* (U.S. EPA, 1993a), and it is available from the U.S. EPA SCRAM web site. Use the most current version of the BPIP to determine downwash parameters for use with the ISC models. Building downwash should not be analyzed for area or volume sources.

To account for downwash, the SCREEN3 model requires the height of the building or structure and the respective maximum and minimum horizontal dimensions. Generally, include the building with dimensions that result in the greatest stack height for that source, to evaluate the greatest downwash effects. Be aware that when screening tanks, the tank diameter should not be used. The SCREEN3 model uses the square root of the sum of the squares of the width and length of a structure in order to calculate the projected width. Because most tanks are cylindrical, the projected width is constant for all flow vectors. However, using the actual tank diameter for both width and length will result in a projected width that is too large. Therefore, when screening tanks, the model user should divide the diameter of the tank by the square root of 2.

3.5 Selecting Receptor Grid

The user needs to define the locations at which ground-level concentrations are to be predicted. In selecting receptor locations, it is general practice to identify the nearest, sensitive locations to the stack, such as residential housing, hospitals, etc. A careful selection of receptor points should be made so that the maximum ground-level concentration is found.

Most models allow the selection of a polar or a Cartesian receptor grid. A polar grid, consisting of a number of radials, is most useful when only one source is present. A

Cartesian grid (can be regularly or irregularly spaced) is better for multiple-source facilities. Since the number of allowed receptors is limited, they should be more densely located where maximum impacts are expected. To ensure the maximum concentrations are obtained, the model should be run with the following set of receptors:

- 20-m receptor spacing in the general area of maximum impact and the property boundary,
- 50-m receptor spacing within 0.5 km from the source,
- 250-m receptor spacing within 2 km from the sources of interest,
- 500-m spacing within 5 km from the sources of interest,
- 1000-m spacing beyond 5 km.

It is best to run the model twice, first with the coarse grid to determine the areas of impact, and then with the finer grid in the vicinity of the impacted area to obtain the maximums.

In areas with many industrial sources, or for large buoyant sources (100-m tall stacks, high exit temperature), a larger 250-m grid, and a coarse grid out to a distance of 20 km may be necessary to find the area of maximum impacts. In some cases, an even larger grid may be necessary.

The model domain for any assessment should not exceed the limitations of the model. If it is necessary to model at points beyond the model limitations, the results should be interpreted with extreme caution.

3.6 Terrain Situation

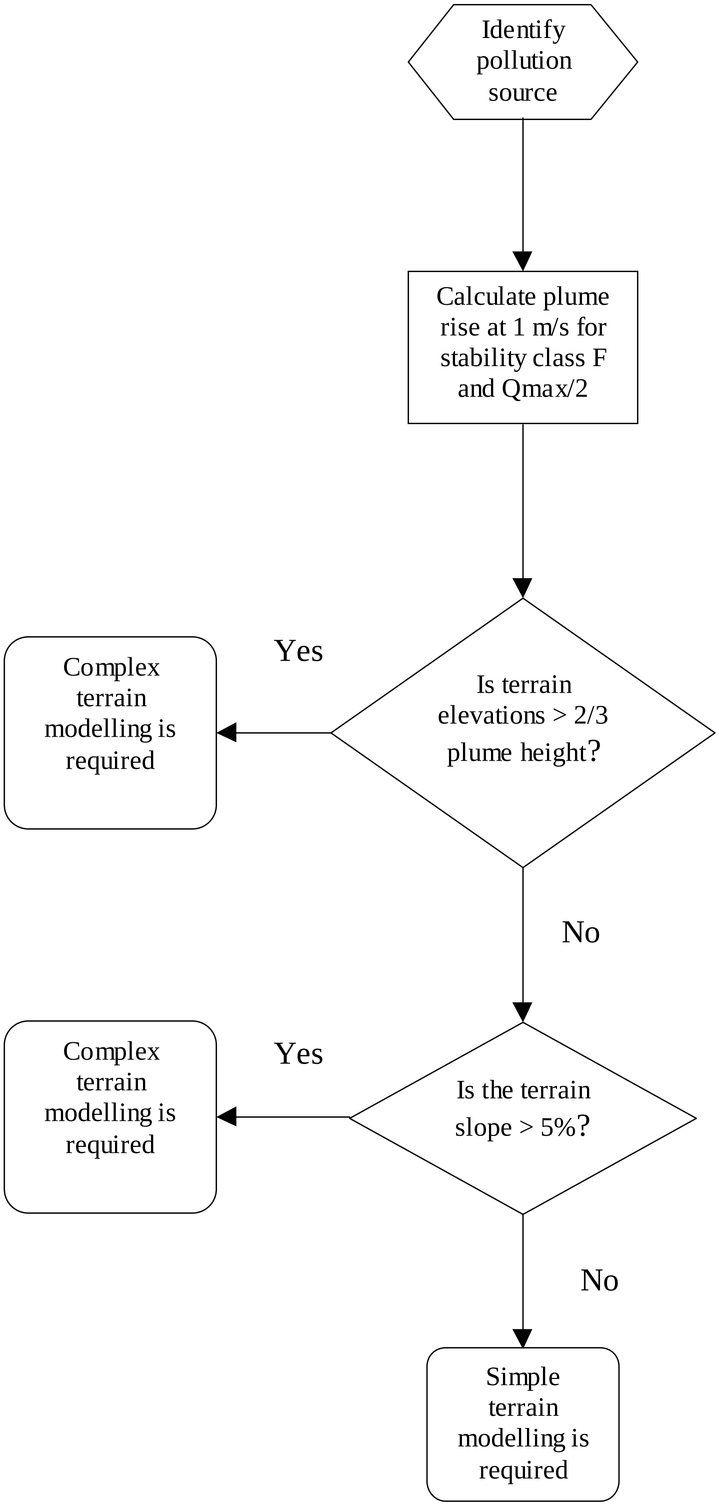
The terrain in the vicinity of a source can fall into two main categories as defined, based on Rowe (1982) definition, by AENV:

- Simple terrain (parallel air flow) - terrain whose elevation does not exceed 2/3 of the plume height (plume rise + stack height) at stability category F with a wind speed of 1 m/s and a flow rate of Qmax/2. The maximum terrain criteria can be calculated using spreadsheet posted on http://www.gov.ab.ca/env/air/airqual/airmodelling.html under model support bullet.
- Complex terrain – topography where elevations are greater than those used to define simple terrain.

In general, the larger the source, the greater the distance to which consideration of possible impacts of terrain elevations must extend. When modelling a facility, terrain in the local airshed surrounding the source must be considered if (see Figure 5):

- there is any complex terrain within the modelling domain, or
- terrain elevation rises more than 50 m per 1000 m distance from the source.

Figure 5: Flow chart for simple and complex terrain determination



4 OUTPUT INTERPRETATION

The input to dispersion models consists essentially of emissions and meteorological data. The output from dispersion models consists of concentration values. Predicted concentrations are expressed as micrograms per cubic metre ($\mu g/m^3$) of air. Concentrations of gases may also be expressed as the ratio of the volume of the substance to the volume of air. In this case, concentrations are expressed as parts per million (ppm) or parts per billion (ppb). The following equation is recommended for converting the concentrations in $\mu g/m^3$ to ppm at standard conditions (T_{std} = 25°C, P_{std} = 101.325 kPa):

$$[ppm] * 40.8862 * \text{molecular weight} = [\mu g/m^3] \qquad (4.1)$$

4.1 Meeting Alberta Ambient Air Quality Guidelines

The concentration of a substance will vary from second to second because of turbulence in the atmosphere. For practical use, concentrations are expressed as averages over specified time periods. Ambient air quality guidelines are usually stated for 1-hour averages, 24-hour averages, and annual arithmetic means.

For a given emission rate, predicted concentrations at ground level can be high due to extreme, rare, and transient meteorological conditions. These maximum ground-level concentrations are considered outliers and should not be used as the basis for selecting stack height. Therefore, the highest eight 1-hour predicted average concentrations in each single year should be disregarded. This approach is to be followed only for screening modelling using a regional data set and for refined and advanced modelling.

If Alberta Ambient Air Quality Guidelines do not specify a value for the substance, the lesser of Ontario point-of-impingement or Texas Ambient Air Quality Guidelines concentrations should be used. If neither Ontario nor Texas has a value for the substance of interest, a risk assessment should be conducted. Contact AENV to work out details.

4.2 Background Concentrations

Background air quality includes chemical concentrations due to natural sources, nearby sources, and unidentified, possibly distant sources. When conducting a screening or refined assessment, the background value for the same substance must be added to the predicted value, for new sources only, before a comparison to the ambient air quality guideline is made. Assessing the effects of the background component becomes more complex when the number of exceedances of a short-term concentration standard (1-hour, 24-hour averages) is being considered. In this case, ground sources and elevated sources must be treated differently.

For example, the highest concentrations from ground sources will likely occur under calm and stable conditions during the winter. In the case of an elevated source, the weather conditions that result in the highest concentrations are convective or neutral conditions. Therefore, the addition of the maximum background concentrations to model predictions should be made under similar weather conditions.

Consider, as an example, a situation where the highest 1-hour concentration of NO_X predicted to arise from a stack is 230 $\mu g/m^3$. During calm, stable conditions, the impact of the stack emissions is likely to be very low. The highest 1-hour ground-level NO_2 concentration is estimated by adding the calculated concentration to the annual average NO_X background. For example, 76 $\mu g/m^3$, the estimated ground-level concentration would be 76 + 230 = 306 $\mu g/m^3$ NO_X.

Air quality data collected in the vicinity of the proposed source may be used as background values. The following method should be used to determine a background concentration:

- Generally, at least one year of monitoring data is necessary, as there are usually significant seasonal differences in ambient concentrations. This can be due to atmospheric differences or because of the seasonal nature of some operations.
- All monitoring data should be subjected to validation and quality control to ensure its accuracy (Nelson et al., 1980).
- Model the background sources using average emission rates.

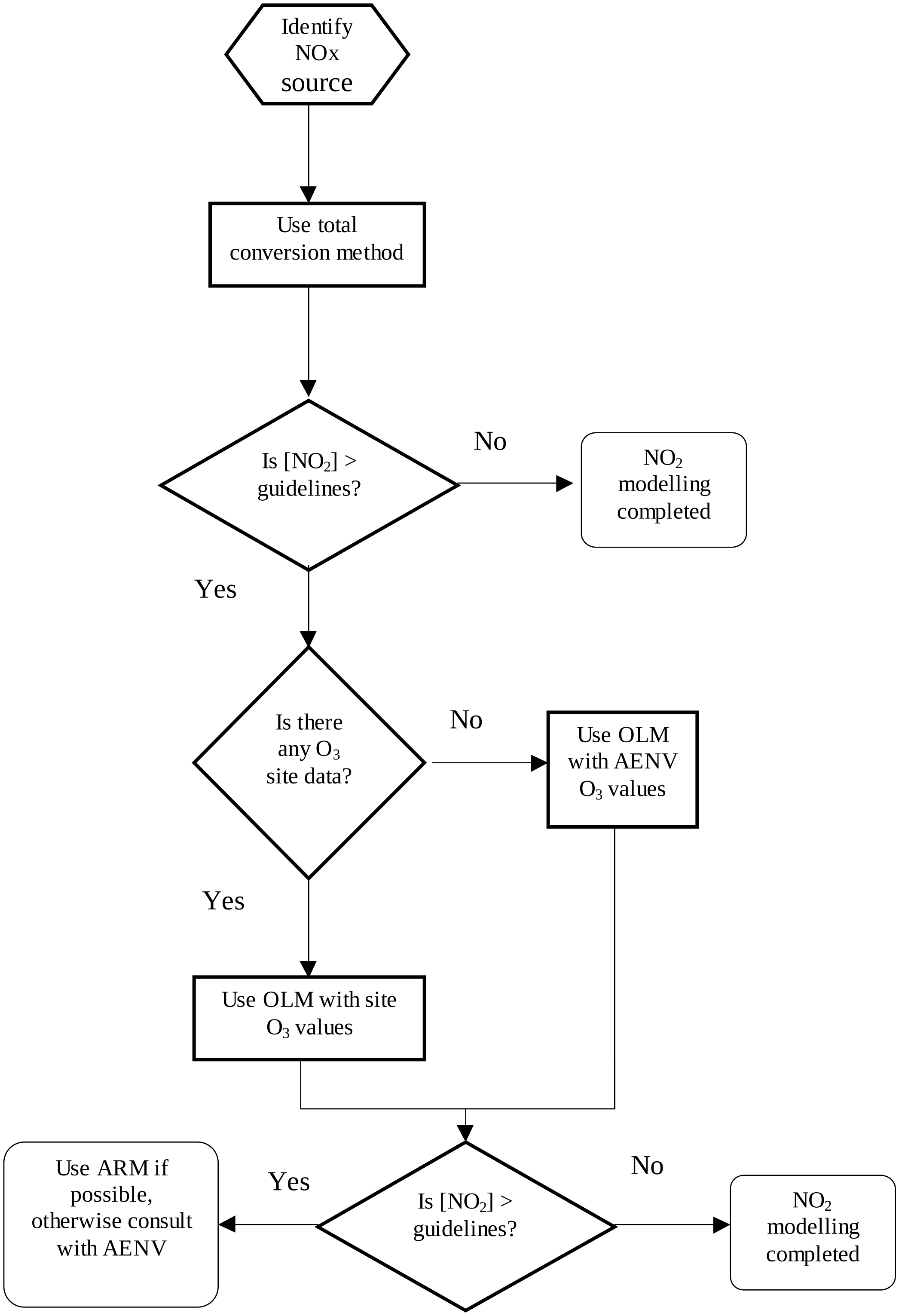
4.3 Relationship between NO_X and NO_2

Of the several species of nitrogen oxides, only NO_2 is specified in the Alberta Ambient Air Quality Guidelines. Since most sources emit uncertain ratios of these species and these ratios change further in the atmosphere due to chemical reactions, a method for determining the amount of NO_2 in the plume must be given. The recommended methods, described below, are implemented using a tiered approach as shown in Figure 6:

1. Total Conversion Method

   In this conservative screening approach, the emission rate of all NO_X species is used in the dispersion model to predict ground-level concentrations of total NO_X. These levels of NO_X are assumed to exist as 100% NO_2, and are directly compared to the AAAQG for NO_2. If the AAAQG are met, the second and third tiers are not necessary.

Figure 6: Flow chart indicating the relationship between NO_X and NO_2



2. Ozone Limiting Method (OLM) (Cole & Summerhays, 1979)

If no on-site ozone data are available, use the ozone data, shown in Table 1, based on ambient air quality monitoring data in Alberta from 1986 to 1998 (Alberta Environmental Protection 1986 – 1998; CASA, 1999). Otherwise, ISC_OLM can be used. The results of the Total Conversion Method must also be presented to the reviewer.

Table 1: AENV recommended ozone levels

	Urban	Rural
1-hour average	0.05	0.05
24-hour average	0.035	0.040
Annual average	0.020	0.035

Using this measurement as a conservative assumption in the ozone limiting method produces the following:

Use the following equation with $[O_3] = 0.050$ ppm
If $[O_3] > 0.9*[NO_X]$ then $[NO_2] = [NO_X]$ (4.2)
otherwise $[NO_2] = [O_3] + 0.1*[NO_X]$

All concentrations in the previous equations are in ppm. The predicted NO_X concentrations are calculated as equivalent NO_2.

According to Equation 4.2, if the ozone concentration is greater than 90% of the predicted NO_X concentrations, all the NO_X is assumed to be converted to NO_2. The OLM is based on the assumption that approximately 10% of the NO_X emissions are generated as NO_2. The majority of the emission is in the form of NO, which reacts with ambient levels of ozone to form additional NO_2. Alternatively, if hourly ozone data are available, they can be utilized in conjunction with the hourly predictions to determine concentrations of NO_2.

If the period of interest is for the 24-hour or annual guideline, the model user has two options:

- The hourly predictions at each location can be ozone limited, and the averages could be used to determine the maximum 24-hour and annual concentrations.
- The 24-hour or annual concentration can be determined as direct output and the following O_3 concentrations can be utilized:

$[O_3] = 0.045$ ppm for 24-hour
$[O_3] = 0.025$ ppm for annual

If the ambient ratio method is selected as the conversion method, both the maximum 100% conversion, and the maximum ozone-limited concentrations must be presented.

3. Ambient Ratio Method (ARM)

If there is at least one year of monitoring data available for NO_X and NO_2 within the airshed, an empirical NO_X /NO_2 relationship can be derived and used as an alternative to the ozone limiting method. AENV must approve this approach prior to its use.

5 REGULATORY MODELS

A tiered approach will save both time and money, as the aim is to progressively reduce uncertainty by moving from simple and cautious models to complex and more reliable ones, as circumstances warrant. One screening model and five refined models are recommended by AENV.

All the regulatory models are short-range. That means that only air quality within about 25 km of the source is predicted reliably, except for CALPUFF, which can be used up to 200 km.

The user of a model should be able to justify the choice of any particular model and demonstrate its 'fitness for purpose'. If a simple screening model shows that emissions from a certain process can result in concentrations that are well below the air quality objective, including background levels, more detailed modelling should not normally be necessary. Refined or advanced models need to be used if the screening predictions of ambient ground concentrations exceed the relevant air quality guidelines. The choice of model is dependent on the quantity and quality of the available input data. If the screening review indicates that more refined modelling is required, more accurate meteorological and emission data must be used.

5.1 Screening Models

- **SCREEN3** This U.S. EPA, PC-based model uses worst-case meteorological data. It can model a single point, area, or volume source, and can take account of building wake effects. It has a limited ability to treat terrain above stack height (U.S EPA, 1995d).

- **Industrial Source Complex (ISC3-PRIME and ISC_OLM) with regional screen meteorological data** - This is a U.S. EPA multi-source Gaussian model capable of predicting both long-term (annual mean) and short-term (down to 1 -hour mean) concentrations arising from point, area, and volume sources. Gravitational settling of particles can be accounted for using a dry deposition algorithm; wet deposition and depletion due to rainfall can also be treated. Effects of buildings can be considered. The model has urban and rural dispersion coefficients.

5.2 Refined Models

- **Industrial Source Complex (ISC3-PRIME and ISC_OLM) with refined meteorological data** – same as above but using more refined meteorological data (see Section 3.2.2).

- **AERMOD** - This is the new-generation U.S. air quality modelling system. It contains improved algorithms for convective and stable boundary layers, for computing vertical profiles of wind, turbulence, and temperature, and for the treatment of all types of terrain. It was developed by the U.S. EPA, in collaboration with the American Meteorological Society.

- **Rough Terrain Diffusion Model (RTDM)** This is a U.S. EPA Gaussian model capable of predicting short-term concentrations arising from point sources in complex terrain. It calculates 1-hour averages only; building wake effects cannot be modelled; only rural dispersion coefficients are available. RTDM requires on-site hourly measurements of turbulence intensity, vertical temperature difference, horizontal wind shear, and wind profile exponents. RTDM may also be used with routinely available meteorological data relating to wind velocity and stability categories.

- **Complex Terrain Diffusion Model (CTDMPLUS)** This model is a refined air quality model that is preferred for use in all stability conditions for complex terrain applications. CTDMPLUS is applicable to all receptors on terrain elevations greater than stack top height. However, the model contains no algorithms for simulating building downwash or the mixing or recirculation found in cavity zones in the lee of a hill.

- **CALPUFF** This model is a multi-layer, multi-species, non-steady-state puff dispersion model that can simulate the effects of time- and space-varying meteorological conditions on substance transport, transformation, and removal. CALPUFF can use the three-dimensional meteorological fields developed by the CALMET model, or simple, single-station winds in a format consistent with the meteorological files used to derive ISCST3 steady-state Gaussian models.

5.3 Advanced Models

In some cases the particular circumstances of topography, climate, source configuration, emissions characteristics, sensitivity of receptors, local concerns, or other unusual features will require the selection of the model better suited to the situation. Regulatory models may need to be modified to reflect these unique conditions; these modifications will be accepted if they can demonstrate that they perform better than the recommended model when tested against the available air quality data. Model selection and the level of assessment to be performed can be verified by contacting AENV.

Any modification to a recommended model or any other generally available dispersion model must be supported by at least one of the following:

- a detailed observational study (field, wind tunnel, or water channel),
- theory supported by comparisons in literature,

- theory supported by comparison with on-site data.

All modified models must be shown to perform better than the regulatory model when tested against site-specific ambient monitoring data. Performance against the refined model must also be documented.

In general, a performance evaluation consists of the following (U.S. EPA, 1992a):

- accuracy of peak predicted concentrations (against site-specific air quality data),
- a correlation analysis,
- test of model precision, and
- test of model bias.

6 OBTAINING MODELS AND RESOURCES

This section contains instructions for accessing information relevant to dispersion modelling. There are two areas of information, AENV web page, and the U.S. EPA web page. The Alberta Environment home page contains general information about AENV, Alberta regulatory information, regional meteorological data sets, and updates of these model guidelines. The U.S. EPA home page has a link to its Support Centre for Regulatory Air Models (SCRAM) page.

Whenever using these dispersion models, it is the responsibility of the user to ensure that they are running the current version of the model. This is easily checked by comparing the Julian date on the model output (example "version dated 92245") with the date given in the *Listing of Model Version Numbers* section of the SCRAM site, or by contacting AENV. The use of methods and models other than the previously mentioned regulatory models should always be confirmed with AENV before proceeding.

Most of the files are in a compressed format for faster downloading. Documents and manuals are usually written with WordPerfect 5.1 format, and should be printed from this software for best results. They are also available in Adobe Acrobat format. This viewer software is available on the internet at no charge.

6.1 Alberta Environment Home Page

Alberta Environment has developed a home page on the internet. Browser software is necessary to view this home page. The address for this page is:

http://www.gov.ab.ca/env/air/

This home page contains information about air quality monitoring in the province, the Clean Air Strategic Alliance, and a section related to air quality modelling. The web address of the modelling section is:

http://www.gov.ab.ca/env/air/airqual/airmodelling.html

These guidelines and information relating to the guidelines can be found at this address. AENV has set up an e-mail list server where information on updates and new versions of the guidelines will be sent periodically. The e-mail list is free, and instructions for signing up can be found at the above site.

http://www.gov.ab.ca/env/air/airqual/metdata.html

The meteorological data sets that are ready as input into ISC3 are also linked to this web site, and can be downloaded by following the links at the address above.

The Protection/Enforcement section contains information related to the regulatory approval process, including the EPEA and AAAQG.

6.2 U.S. EPA SCRAM Home Page

The SCRAM site covers topics related to dispersion models. The internet site can be accessed at the following address:

http://www.epa.gov/scram001/index.htm

6.3 Canadian Climate Normals

The Canadian Climate Normals are available free of charge at the following web site:

http://www.cmc.ec.gc.ca/climate/

This information can be utilized for comparison with dispersion model results for simple cases and to compare the representativeness of site data or other meteorological data for the region. If sufficient data are available, climatological wind directions, wind speeds, and temperatures can be analyzed to determine the frequency of particular meteorological conditions. This could be compared to the worst-case modelled condition, to help determine possible frequencies of occurrence of elevated concentrations.

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APPENDIX A: EXPECTED CONTENT OF SCREENING ASSESSMENTS

1.0 Sources and Emissions

1.1 Source Data

- Number and type of sources (stack, flare, etc.)
- Plot plan
- Locations and dimensions of buildings (length, width, height)
- Design capacity (normal or average capacity may also be needed)

1.2 Characteristics of Emissions

- Chemical composition (substance type) and emission rates (g/s)
- Exit (stack) height above ground (m)
- Temperature (K) or heat content (MJ/m^3 and cal/s)
- Exit velocity (m/s)
- Stack top inside diameter (m)
- Other parameters if not a point source

1.3 Potential Emissions during Abnormal Operations Start-Up or Shutdown

2.0 Topography

- Description and map if necessary
- Vegetation cover/land use
- Sensitive receptors nearby (public buildings, homes, etc.)
- Location of meteorological and air quality stations

3.0 Meteorology

- Speed and direction distributions (wind roses)

4.0 Results - Dispersion Model Predictions

- Summary of background air quality if available or applicable (from air quality stations - same or other facility, or appropriate Alberta Environment station)
- Building downwash (include whether effects seen on or off facility property)
- Discussion of topographic effects with model predictions if necessary
- Predicted 1-hour average maximums and 24-hour average if possible.
- Discussion of meteorology leading to highest concentration(s)
- Comparison with existing monitoring data (if applicable)
- Soft copy of dispersion model input and output files

APPENDIX B: EXPECTED CONTENT OF REFINED AND ADVANCED ASSESSMENTS

1.0 Sources and Emissions

1.1 Source Data

- Number and type of sources (on-site and off-site)
- Plot plan
- Dimensions of nearby buildings
- Design, average and nominal capacity

1.2 Characteristics of Emissions

- Temperature or heat content at exit
- Exit velocity
- Stack top inside diameter (m)
- Exit height above ground
- Chemical composition and emission rates
- Particle sizes and amounts
- Water content
- Other parameters for non-point sources

1.3 Time Variations (Short and Long-Term)

1.4 Potential Emissions during Abnormal Operations

- Start-up or shutdown
- Pollution control equipment failure
- Process equipment malfunction
- Damage to storage vessels
- Other accidental/unplanned emissions

1.5 Other Major Existing or Proposed Sources

2.0 Topography

- Description and map

- Elevation maxima and minima
- Vegetation cover/land use
- Sensitive receptors
- Parks, campgrounds, and wilderness areas
- Population centres and public facilities
- Location of meteorological and air quality stations

3.0 General Climatology

- Temperature
- Precipitation
- Fog
- Humidity
- Pressure
- Solar radiation
- Wind
- Severe weather (thunderstorms, tornados/dust devils, lightning, hail, icing, heavy rainfalls, heat waves, etc.)
- Cloud cover
- Synoptic patterns (air masses, fronts, surface and upper-level air flows)

4.0 Meteorology

- Sources of data
- Representativeness of measurements (time and space)
- Topographic influences

4.1 Wind

- Speed and direction distributions (roses)
- Relation of short-term on-site to long-term off-site
- Persistence
- Diurnal and seasonal variations

  - Extreme values
  - Mean speed
  - Prevailing and resultant winds
  - Relation to visibility restrictions
  - Relation to topographic effects

4.2 Temperature

  - Inversion heights, strengths, frequencies, and persistence
  - Mixing layer heights, diurnal and seasonal variation
  - Magnitude and behaviour, diurnally and seasonally

4.3 Turbulence

  - Direct measurements - frequency distributions, diurnal and seasonal variations
  - Indirect determinations, definition of stability parameter (thermal/mechanical turbulence index) and description of inference scheme
  - Frequency distribution, diurnal and seasonal variations

5.0 Atmospheric Dispersion (Short- and Long-Term Concentrations)

- Summary of background air quality
- Contribution of sources to maximums, nearby and distant
- Building downwash
- Stack aerodynamic downwash
- Buoyancy momentum rise
- Topographic effects
- Model description and references
- Predicted hourly averages - magnitude, frequencies, duration, and timing
- Discussion of meteorology leading to highest concentrations
- Predicted daily averages
- Predicted annual averages
- Predicted depositions

- Comparisons to standards
- Expected odour frequencies
- Expected frequency of visibility impairment due to smoke, particulate, or condensed water vapour

6.0 Special Topics

- Risks due to uncontrolled releases
- Unusual natural phenomena
- Atmospheric chemical transformations
- Chemical reactions between plumes containing different substances
- Synergistic effects of multiple-component emissions
- Icing caused by water vapour emissions

7.0 Conclusion

- Summary of impact on concentrations, depositions, visibility, and odour.
- Soft copy of the input and output files.