TECHNICAL REPORT

Identification and Evaluation of GHG Reduction & Energy Efficiency Improvement Opportunities at Oil and Gas Facilities

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EXECUTIVE SUMMARY

This document presents guidance for conducting integrated GHG emissions and energy management audits at oil and natural gas facilities. Procedures are presented for focusing efforts on the types of facilities and operations most likely to offer opportunities for significant cost-effective improvements. While the document highlights standard approaches for controlling GHG emissions and improving energy efficiencies, it also identifies specific operational issues or problems to watch for that can be contributing to unaccounted for emissions, product losses and process inefficiencies.

Relevant standards, guidelines and best management practices are referenced wherever possible to provide the reader with access to more detailed information on available control technologies and measurement or assessment techniques.

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1 INTRODUCTION

This document presents a practicable approach to identifying cost-effective opportunities to reduce GHG emissions and improve energy efficiencies at oil and gas facilities. The presented approach comprises the application of integrated emissions and energy management audits. It is intended to apply to oil and gas facilities, both domestically and internationally, and reflects the experiences in North America and Asia. The overall aim is to maximize the effectiveness of GHG emission reduction efforts and provide the consistency in results needed to generate, and subsequently sustain, industry and investor support, while addressing local barriers.

1.1 Why Conduct Integrated Audits?

With rising energy prices and increasing domestic demand, the need to reduce avoidable wastage, losses and inefficiencies is only becoming more important. Based on experiences in many countries, there are significant cost-effective opportunities to reduce methane (CH_4) emissions and improve energy efficiencies at natural gas and oil production facilities. The financial payback periods of such opportunities are typically less than 2 years and often less than 6 months. Targeting such opportunities makes good financial sense, is good for the environment, and can contribute to increased output, reduced operating costs, resource conservation, reduced GHG emissions, associated reduction of other pollutant emissions (e.g., H_2S, VOC, NO_x, SO_2. CO and PM), a safer workplace, improved system reliability and best-in-class recognition.

Presently, many countries and companies are struggling with where and how best to allocate resources for reducing GHG emissions and have been arbitrarily picking control technologies and applying them without necessarily first seeking out the optimum applications for the technologies. This has provided mixed results.

The best approach is to first find specific cost-effective control opportunities and then determine the most practicable control option for each of these opportunities. The challenge is finding and delineating these opportunities sufficiently to make the necessary project business case. Federally funded research studies conducted in Canada by the Canadian Environmental Technology Advancement Corporation (CETAC-West) and the Petroleum Technology Alliance of Canada (PTAC), with the financial support of programs such as PERD, Technology Early Action Measures (TEAM) and the Office of Energy Efficiency (OEE), and similar work done in the United States by the US Environmental Protection Agency, have demonstrated that a systematic and holistic approach to first evaluating and benchmarking facilities, identifies the optimum emission reduction opportunities and produces the most consistent value-based results. Moreover, a well structured and transparent approach to finding and evaluating the best control opportunities also provides the information needed to ultimately generate verifiable carbon credits.

Efforts to identify significant cost-effective emission reduction opportunities at North American upstream oil and gas (UOG) facilities indicate many types of opportunities have a skewed distribution where a few facilities might be performing very poorly with respect to a specific emissions or efficiency matter while the rest are performing very well. At the same time, given the broad range of potential opportunities that exist, most facilities have at least some meaningful opportunity for emissions reduction or energy improvement. Accordingly, the application of holistic survey methods aimed at high-probability segments of the industry has proven successful in generating consistent environmental benefits with cost effective and easily implemented solutions. Moreover, this approach takes maximum advantage of the audit team's expertise and measurement equipment while they are on site, and increases the cost-effectiveness and economic impact of the survey. A rational and systematic approach to finding meaningful GHG emission reduction opportunities benefits the environment and is profitable for industry.

1.2 Why Do Significant Cost-Effective Opportunities for Improvement Exist?

There are two main reasons why a significant cost-effective opportunity for improvement may persist at a facility, either it does not produce a readily noticeable effect (e.g., they may develop gradually over time) or its magnitude cannot be easily determined to develop a business case for correcting the problem.

The reasons opportunities develop in the first place include the following:

- Progressive deterioration of facilities.
- Changes in operating conditions from initial design values.
- Outdated designs that are based on previous low energy prices.
- Use of outdated technologies.

1.3 What are the Key Advantages of Integrated Audits?

While self audits may be done, it is usually preferable to use a dedicated team that is equipped with the necessary tools resources to do the job. The main advantages are:

- Avoids exceeding available onsite resources.
- Fresh views and insight coupled with the expert knowledge and capabilities of the audit team.
- Increased probability of identifying significant cost-effective CH_4 emission reduction opportunities through a comprehensive multi-disciplinary facility examination.
- Potential synergies between disciplines for improved opportunity identification.
- Maximum utilization of the review team's expertise.
- Independent verification of the facility's performance.
- Transparent third-part determination of the emissions baseline and other data needed for the design of a carbon credit project.
- Opportunity for technology transfer to, and training of, facility staff.

Additionally, the audit provides the means to monitor performance over the long term by comparing performance against the baseline established at the time of the initial facility surveys. This process, or Benchmarking, can be applied at the facility level as well as at the individual process unit level.

1.4 What is the Opportunity Potential?

While the results achieved may vary dramatically between individual facilities, auditing programs conducted at facilities in North America and international indicate it is reasonable to anticipate average improvements of the order indicated in Table 1 below,

Table 1. Typical average improvements from implementing cost-effective emission reduction and energy efficiency improvement opportunities.

Parameter	Percentage Reduction
Fuel Gas Consumption	13%
Electricity Demands	9%
Fugitive Equipment Leaks	70%

1.5 What are the Uncertainties?

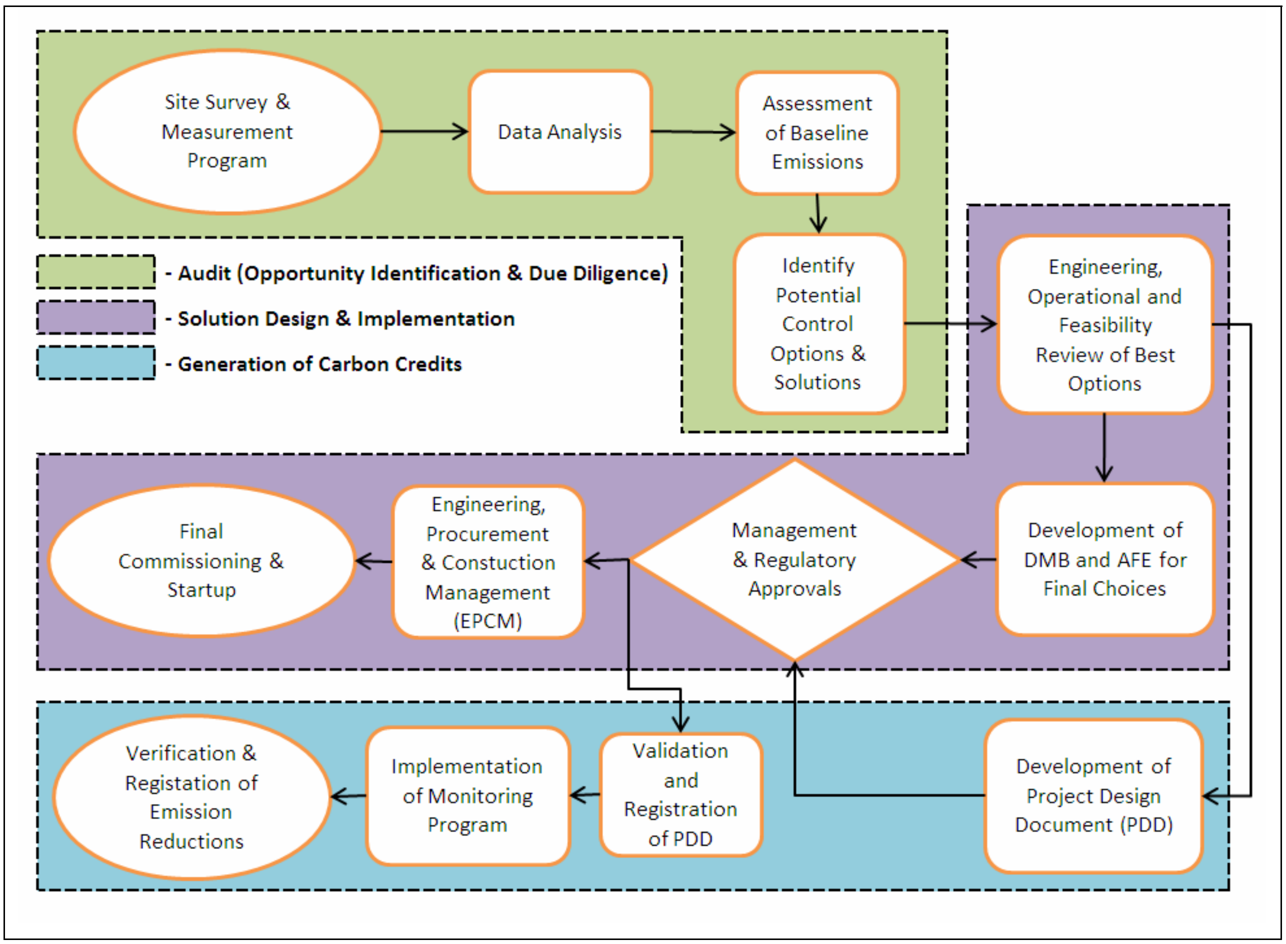
The key uncertainties are potential differences in opportunity economics and probability distributions. Factors that contribute to these uncertainties include the following:

- Differences in design standards and operating practices.
- Reduced use of process instrumentation and continuous monitoring systems making it more difficult to identify and evaluate opportunities.
- Rules, regulations, management systems and fiscal policies that may be a disincentive to emissions reduction.
- Low labour costs and the corresponding emphasis on manual versus instrumented or automated solutions.
- Limited access to, and increased costs of, foreign technologies.
- Potential quality control issues with locally produced products and technologies.
- Reduced use of instrumentation and difficulties in obtaining equipment design data.
- Protectionist laws and duties aimed at excluding foreign goods and services.

2 BASIC AUDIT STRATEGY

2.1 Sequence of Events

Conducting an emissions and energy management audit at a facility is only the first in a sequence of steps needed to implement a final solution and generate marketable carbon credits or offsets. Figure 1 depicts the general case where the emission reduction or energy efficiency improvement requires a capital solution. Where only a simple maintenance or operational solution is needed these may usually be addressed through normal facility operating budgets and thereby avoiding the more onerous and time-consuming requirements of capital project.



DBM – Design Basis Memorandum

AFE – Authority for Expenditure

Figure 1. General project flow diagram.

2.1.1 Opportunity Identification and Due Diligence

The emissions and energy management audit serves to key purposes. First, it is a useful tool for seeking out potential opportunities for significant cost-effective improvements, and provides a preliminary listing of potential control measures. Secondly, it provides a reliable assessment of baseline emissions and the quantitative source-specific information needed to for a detailed engineering, operational and feasibility assessment of the most promising opportunities.

2.1.2 Solution Design and Implementation

Once a potential opportunity has been identified, a front end engineering review and feasibility assessment is needed to determine if the opportunity is practicable. Usually there are a number of site-specific constraints that may adversely affect the feasibility of a potential solution. These may include the following:

- Disincentives such as contractual agreements, administrative structure and corporate policies that prevent those responsible for the costs of implementation from sharing in the benefits achieved.
- Lack of practicable on-site opportunities to utilize waste energy and uneconomic access to nearby markets for the energy.
- Increased manpower requirements and the need for specialized disciplines that cannot be fully utilized.
- Overloading of existing utilities (e.g., fuel gas, instrument air and electricity) and significant cost premiums to meet the incremental demands.
- Lack of sufficient spacing and either a premium cost or inability to meet the incremental needs.
- The need to install lengthy runs of piping (e.g., for vapour collection lines, access to the flare header, instrument air and fuel gas), wiring (e.g., for electric power and data acquisition lines) and associated support structures (i.e., pipe racks and cable tray).
- A need for costly safeguarding and monitoring measures.
- Excessive variability or intermittent nature of the source.
- Creation of excessive emissions of other pollutants (e.g., NO_x).

In developing countries and countries with economies in transition, additional considerations may include:

- Disincentives such as contractual agreements, administrative structure and corporate policies that prevent those responsible for the costs of implementation from sharing in the benefits achieved.
- Reduced environmental accountability.
- Lack of access to information, contractors, experience and the necessary financial resources needed to complete the front end engineering assessment.
- Cultural, language, and calendar differences that require more planning and longer response times.
- Differences and difficulties in the local political context in which the companies are operating.

- Slowness of local companies to embrace an international program, for reasons ranging from corporate policy independence, to reticence regarding commitments.

Assuming the above matters can all be addressed, the project will still have to compete against other potential investment opportunities. Not only must the project be competitive from a financial perspective, but it must overcome the traditional focus on increasing shareholder value through exploration and development rather than reducing wastage and improving efficiency.

2.1.3 Generation of Carbon or GHG Offset Credits

The requirements for generating marketable carbon credits will depend on the market. In all cases there is a strong emphasis on transparency and accuracy. A formal project design document must be prepared which describes the method or technology that will be used to generate the emission reductions, the monitoring that will be done and calculations performed to quantify the amount of these reductions, and the quality assurance (QA)/quality control (QC) to be applied. Lastly, there is a requirement for independent validation of the plan by an accredited third party, and ongoing verification of the reduction claims, usually by a different accredited third party.

Where project financing has been provided, the investors will usually require, as a QA/QC measure, ongoing technical oversight by a qualified third party advisor of their choosing.

In the Kyoto market there is a particular emphasis on additionality and managing project leakage. Additionality is the criterion used to assess whether a project results in GHG reductions or removal enhancements in addition to what would have occurred in its absence. Each market provides specific tests to be applied in determining additionality. Project leakage is a term that refers to market transformation or activity shifting resulting from the project. Leakage may be either positive (i.e. good) or negative (i.e. bad).

2.2 Facility Selection

Significant cost-effective emission control opportunities can and have occurred in almost all conceivable situations. Notwithstanding this, they are more likely to occur in certain predicable situations. The best place to begin is with facilities that have compression or significant process heat demands, are more than 20 years old (i.e., the typical maximum design life of a facility) and either have gone through multiple ownership changes or seen significant decline in production.

Most older facilities were designed at a time when energy prices were low and energy efficiency was less of a concern; therefore they offer good efficiency improvement opportunities. Facilities that were designed during periods of fiscal constraint are also likely to have significant efficiency improvement opportunities.

Facilities that have gone through multiple ownership changes are usually either marginally economic or are believed to be approaching the end of their useful life, as are those that have experienced significant decline in production. Notwithstanding this, there are many facilities operating today that are 40 and 60 years old but were originally only designed to operate for 20 years. As energy prices increase and drilling and production technologies improve, the life of facilities is frequently being extend well beyond initial expectations. Even facilities that are known to be within a few years of closure may be worth considering for audits given the short payback periods for some opportunities, especially where carbon credits can be produced.

Other indicators to look for include the following:

- Poor housekeeping – this is usually an indicator of poor moral which may contribute to neglect and deteriorated equipment performance.
- Significant venting and flaring at older facilities – the economics of waste gas recovery or utilization may have improved dramatically from the time the facility was first commissioned.

2.3 Focusing Onsite Efforts

It is not practicable to expect that the audit team would conduct an exhaustive effort to identify and evaluate all potential opportunities at each target facility. There is ultimately a point of diminishing returns, both in terms of the size and diversity of the audit team assigned to the task, and the scope of work to be performed. Sections 3 to 8 of this document highlight a range of opportunities that are generally worth considering.

The aim should be to acquire as much useful information on the facility as possible in advance of the audit to help plan and focus the auditing efforts. Additionally, once at the site, a meeting should be conducted with senior facility personnel to discuss the facilities operations and areas of potential concern before actually beginning the audit. Often facility personnel will be fully aware of good opportunities but will simply lack the quantitative data needed to make a defensible business case to management. It is important to take advantage of this information but not let it bias the audit (i.e., causes other opportunities to be missed). Ultimately, professional judgement will need to be applied and the team will have to adapt to the actual circumstances at the time. For this reason, it is important that the audit team comprise senior personnel able to make sound judgements in the field.

The time and effort spent on each item should be commensurate with the magnitude of the opportunity. For example, as soon as is there is a reasonable quantitative or qualitative indication that an opportunity will be small, the team should document the basis for this conclusion and move on to the next item. If a large opportunity is identified, then it may be appropriate to conduct replicate measurements and better document its variability.

Data collection sheets and checklists should be used throughout the audit to help guide the process and avoid missing critical information.

The type of information to be requested prior to the site visit should include the following:

- Site plot plan.
- Production accounting summary including flow rates of all input and output streams and a fuel gas disposition analysis.
- Summaries of purchased propane, fuel and electricity.
- Copies of recent stream analyses for use in performing mass balances.
- Lists of all engines and process heaters, and if possible, information on their make, model, age, rated capacity and emission controls.
- Process flow diagrams showing all points where flow rates are metered.
- Screen shots from the process data acquisition system and/or process log sheets showing all monitored temperatures, pressures and flows throughout the facility.

This information can be used to conduct preliminary mass balances and energy balances to help identify areas where excessive losses or low efficiencies are occurring.

2.4 Safety Issues

Emission measurements and process tests should only be performed where safe to do so. The audit team should be responsible for providing their basic personal protective equipment. The host facility should be responsible for providing any special provisions (such as ladders, man lifts, lanyards, safety watches, supplied breathing air, etc) needed to safely access individual components and vent outlets (e.g., compressor-seal vent outlets).

3 STORAGE TANKS

Production and processing facilities are often equipped with one or more atmospheric tanks for temporary storage of the produced hydrocarbon liquids (i.e., oil or condensate) and water. If these tanks are vented to the atmosphere, they are sources of storage losses (i.e., product is lost to the atmosphere due to evaporation effects). The amount and type of emissions normally depends on the composition of the stored product, its vapour pressure, storage conditions and the amount of liquid level movement in the tank. In tanks containing hydrocarbon liquids, the true vapour pressure of the product at storage conditions should be well below atmospheric pressure to avoid boiling or flashing losses.

Depending on the amount of evaporation loss and the value of the product, it may become economical to install vapour controls. Vapour controls may have been uneconomical when the facility was first designed, but this situation may have changed over time due to the rising value of oil and natural gas. As well, process conditions may have changed resulting in greater losses than intended.

Methane emissions from storage tanks occur where one or more of the following conditions apply: (1) the gas has been in direct contact with natural gas in a pressurized vessel immediately prior to entering the atmospheric storage tank (i.e., some of the natural gas will have dissolved in the liquid hydrocarbons and will flash out upon entering the storage tank), (2) the tank is equipped with a natural gas blanketing system that is designed to vent directly to the atmosphere or is experiencing operational problems, or (3) there is unintentional gas carry through to the tanks.

3.1.1 Recommended Checks

The emission rates from all atmospheric storage tanks containing process liquids (i.e., produced oil, condensate or water) should be measured and the value of conserving these vapours determined. Furthermore, the cause of any emission contributions in excess of normal design (or intended) evaporation losses should be determined and resolved. Specific emission contributions to focus on are as follows:

Flashing Losses

Flashing losses occur when the produced hydrocarbon liquid has a vapour pressure greater than local atmospheric pressure. When this material enters the stock tank its vapour pressure decreases rapidly towards local atmospheric pressure (i.e., it boils), and then more slowly as the rate of evaporation stabilizes. The vapour pressure of the incoming product will be equal to the vapour pressure of the first vessel upstream of the tanks (usually 275+ kPa at oil production facilities and 2000+ kPa at gas production facilities). At oil batteries this vessel is usually either the inlet separator or the treater. At gas facilities it is usually the inlet separator or, in the case of compressor stations, the suction and interstage scrubbers.

Unintentional Gas Carry-through to Storage Tanks

There are various opportunities for unintentional carry-through of natural gas to storage tanks. These may include the following:

- Inefficient separation of gas and liquid phases upstream of the tanks allowing some gas carry-through (by entrainment) to the tanks. This may occurs where inlet liquid production (e.g., produced water) has increased significantly overtime resulting in a facility's inlet separators being undersized for current conditions.
- The liquid level control valve on the upstream separator may not be seating properly at the end of a dump cycle allowing the separator to empty to the point of allowing gas to carry through to the storage tank.
- The liquid level setpoint for the level controller may be set too low.
- A manual drain valve may get left partially or fully open or may not be seating properly allowing the vessel to be drained of liquids and gas to carry through to the storage tanks.
- If there is a purge system connected to the liquid header and the purge valve may get left partially of fully open or may not be seating properly.
- Piping changes resulting in the unintentional placement of high vapour pressure product in tanks not equipped with appropriate vapour controls (e.g., routing of liquids from compressor suction and interstage scrubbers directly to atmospheric storage tanks).
- Displacement of large volumes of gas to storage tanks during pigging operations.

Malfunction Gas Blanketing Systems

The purpose of a gas blanketing system is to keep air out of the vapour space and, where the tank is connected to a vapour collection system, to prevent an over vacuum condition. If the system is functioning properly, gas should only be flowing into the tank when the liquid level is falling or there is a cooling effect (e.g., due to a drop in ambient temperature) which causes to pressure inside the tank to drop below the setpoint of the blanket gas system. The rest of the time there should be zero gas flow into the storage tank.

Malfunctioning or improperly set blanket gas regulators and vapor control valves can result in excessive blanket gas consumption and, consequently, increased flows to the end control device (e.g., vent, flare or vapor recovery compressor). The blanket gas is both a carrier of product vapors and a potential pollutant itself (i.e., natural gas is usually used as the blanket medium for blanketed tanks at gas processing plants).

Undersized Vapour Recovery Units

Vapour recovery systems can become undersized due to changes in production levels and vapour collection lines can become fouled thereby restricting vapour flow out of the tank. Both situations will contribute to over pressure conditions in the tank and cause gas to be relieved through the pressure vacuum valves on the roof of the tank. Where this is occurs, there will usually be visible indications of condensation or fouling on the outlets of the pressure vacuum valves. Moreover, once these conditions begin the pressure vacuum valves will eventually have trouble seating causing a continuous loss of blanket gas.

3.1.2 Measurements

The above emission contributions may be determined by measuring venting rates and comparing the observed emissions to calculated working losses for conditions at the time of testing. Refer to Section 5.2 for potential measurement techniques.

3.1.3 Reduction Potential

Tanks at 5 gas-processing plants (3 in the US and 2 in Canada) were recently checked for emissions in excess of normal weathered-product evaporation losses. Two sites showed abnormally high emissions from storage tank vents. Total hydrocarbon emissions in one case amounted to 4.56×10^3 m^3/d (or roughly 0.017 Mt/y of CO_2E emissions based on the CH_4 content of the vapours), and 1.39×10^3 m^3/d (0.005 Mt/y of CO_2E emissions) in the other case. Averaging these losses over the 5 sites surveyed amounts to 0.0045 Mt of CO_2E emissions per year due to excess venting by storage tanks. Thus, while excess storage losses do not occur at all sites, where it does occur, the amount of emissions can be very significant, and consequently, very economical to control. The frequency of such situations is sufficiently high to warrant targeting these sources.

The following is a list of control measures that may be considered:

3.1.3.1 Process Optimization

There are several process variables that may be optimized to help minimize the amount of storage losses and the size/cost of any additional add-on controls that may be required. If flashing losses occur then significant benefit may be gained from minimizing the following variables:

Vapour Pressure of the Product to be Stored. There are three options that may be considered for reducing this variable. These are:

- Lower the operating pressure of the first vessel upstream of the tanks. The initial vapour pressure of the hydrocarbon liquids will be the same as this pressure at most oil and gas field facilities. There will likely be some trade-off between increased energy requirements (e.g., increased pumping or compression requirements) in other parts of the process and reduced storage losses; however, this option could prove beneficial in many cases.
- Install a gas boot directly upstream of the storage tanks and connect the off-gas line to the flare system. A gas boot is a two-phase separator that is operated at just enough pressure to push the vapours into the low pressure flare system and the oil into the storage tanks. This approach may eliminate the need to install a costly vapour collection system on the storage tanks.
- Install a stabilizer upstream of the storage tanks. This option may only be feasible at gas processing plants where relatively large volumes of very volatile hydrocarbon liquids are involved.

Amount of Product to be Stored. At compressor stations it may be appropriate to simply pump the hydrocarbon liquids from the scrubbers to the compressor discharge piping rather to an on-site storage tank. This would allow for more centralized handling of the liquids but may only be practicable where the amount of liquid is relatively small compared to the amount of gas.

This same approach may be considered for use at field dehydrators. However, in this case care must be exercised. Condensate in the inlet separator contains dissolved water. This water may be enough to cause hydrate problems even though the gas is dehydrated. The condensate may also need to be dehydrated.

Peak Emission Rates. The recycling of product back to the treater at oil batteries allows the oil to re-absorb solution gas and thereby increases flashing losses. Consequently, any efforts to reduce the amount of oil recycling will be beneficial. Typically, 10 to 15 percent of the produced oil is recycled and this is usually done in batches. Since any add-on controls that may be required will be sized to handle the maximum emission rate, it would be useful to minimize the actual pumping rate during these recycle operations.

This same logic applies to batch shipments of oil that may be brought on site by tank truck for treatment or cleaning.

It may also be possible to minimize the displacement of vapours from the tank due to rising and falling of the liquid surface (i.e., working losses) by properly scheduling filling, emptying and recycling activities. For example, if product can be shipped from a tank at the same time it is being filled, the net change in the liquid level and amount of working losses will be reduced.

If the product has been weathered or stabilized prior to storage then no flashing losses will occur and minimization of the following variables may be helpful:

- **Storage Temperature**. Lowering the temperature of the stored product will reduce the vapour pressure of the product and thereby serve to reduce evaporation rates. The storage temperature can be lowered applying reflective paints to the outside of the tank, decreasing the set point of the tank heaters, and possibly decreasing the set point of any process heaters directly upstream of the tanks.
- **Exposed Liquid Surface Area**. It is not uncommon for the tanks to be oversized for the amount of production at many older facilities. If these tanks can be exchanged for more appropriate, smaller diameter tanks it will reduce standing losses by the percent change in the cross-sectional area, and working losses to a much lesser extent. Accordingly, this strategy will be of most benefit for tanks that experience low turnover rates (e.g., slop or waste oil tanks).

The potential for reducing emissions through process optimization depends very much upon the age and design of the plant, maintenance and operating practices, the training of the personnel, and the commitment by management.

3.1.3.2 Pressure-Vacuum Valves

A pressure-vacuum valve is a control device that is used to regulate the outflow of vapours and inflow of air for tanks storing products at or near atmospheric pressure. It allows the tank to experience a slight pressure rise or vacuum (usually up to 30 cm of water pressure) before opening to allow any ventilation of the tank. Once activated the valve remains open until the pressure in the tank is back to within the limits of the two set points.

In addition to protecting the tank from any damaging effects of overpressure or overvacuum, the control action helps to inhibit certain types of evaporation loss, namely standing losses, and to a lesser extent, working losses. However, it provides little control of emissions in cases where flashing losses are significant or where the tank is not in vapour-tight condition.

3.1.3.3 Floating Decks

A floating deck is an impermeable plate-like structure that rests freely on the liquid surface. It reduces storage losses by providing a barrier to evaporation from the liquid surface.

Automatic bleeder vents are used on the deck to prevent gas from accumulating under it (e.g. solution gas or slugs of gas from the pipeline) as this could cause the deck to tilt and bind or possibly collapse and sink. These vents also serve to equalize the pressure of the vapour space across the deck, when the deck is either landed on or floated off its supports. Legs or suspended cables are used to hold the deck a predetermined distance off the tank bottom to prevent damage to fittings underneath the deck and to allow for tank cleaning or repair.

Because of the use of bleeder vents and the need to operate the tanks near atmospheric pressure, a floating deck is only effective in reducing standing and working losses; it will have no impact on flashing losses. The usefulness of a floating deck is therefore limited to applications involving products with a true vapour pressure below local atmospheric pressure (e.g., weathered or stabilized products).

The effectiveness of a floating deck (excluding flashing losses) is determined by how well the deck is maintaining a vapour-tight barrier across the liquid surface. Typically, losses will result from evaporation in gaps between the tank wall and the perimeter of the deck, and through any bolted seams or fittings that penetrate the deck. In addition, any liquid that clings to the walls as the deck descends during removal of product is subject to evaporation. Sealing and wiping mechanisms are used to help reduce these losses, but radial variances in the tank shape and the nature of deck fittings precludes the use of a completely vapour-tight seal.

There are some potential problems in using floating roof tanks to store heavy, waxy crudes. The solid wax tends to adhere to the shell as the deck is lowered and then melt and run onto the roof and sealing mechanism as the tank walls heat during the day. This can pose a fire hazard and foul some fittings on the deck. Also, if hard seals are used they can scrape wax from the walls onto the deck to aggravate the situation, or they may cause the deck to bind in the presence of a wax buildup. However, the potential for these problems is much greater on external floating roofs as they are more susceptible to fouling and use more rigid seals than internal floating roofs (U.S. EPA, 1987).

In the event of these problems, internal floating roof tanks may be insulated and equipped with steam coils to keep the wax in solution. However, this will result in higher operating costs and will require a source of steam.

3.1.3.4 Vapour Control Systems

Vapour control systems are used to either recover or dispose of the vapours from the stored product. At the same time, they can also help reduce evaporation at the liquid surface by maintaining high concentrations of hydrocarbon vapour above the liquid. So there can be less vapour to handle than would occur for freely-vented conditions.

This option may be considered for all storage applications; however, it is particularly suited to those involving significant flashing losses.

An important consideration in the design of any vapour recovery or disposal system is that the vapours from the gas boot or stock tanks are usually rich in easy-to-condense hydrocarbons. This creates two problems. First, there is a potential for free liquids to occur throughout the system which can adversely affect the performance of the end control device. So, good scrubbing facilities, mist eliminators and line drains are required. Secondly, any condensed liquids that may be present in the system are very volatile and difficult to pump. Consequently, a blow case system is usually needed to transfer the liquids back to the stock tanks or other appropriate storage containers.

Typical performance standards for vapour control systems are a minimum control efficiency of 95 percent.

3.1.3.5 Gas Boot Vapour Collection System

A gas boot is a vertical vessel designed to liberate and remove any gas that may be in solution or entrained in the hydrocarbon liquid to be stored. The gas line off the top of the vessel is connected directly to the vapour collection system and the liquid line off the bottom is connected directly to the stock tanks. Sometimes the vessel is equipped with several trays to promote complete flashing of the solution gas.

The vapour pressure in the boot is determined by the amount of friction losses through the vapour collection piping and by the suction pressure and capacity of the control device. Typically, the pressure is near local atmospheric conditions, and slightly higher than for a stock tank vapour collection system (e.g., 15 to 30 cm of water column pressure). The design shut-in pressure of a gas boot is usually about 40 kPa. Consequently, the boot can be operated over a much wider range of pressures than can stock tanks, and it is much less susceptible to damage in the event of a system upset or malfunction.

To eliminate any need for pumps, the boot is either elevated a sufficient distance above the ground or is made tall enough for the liquid to flow by gravity to the stock tanks. It must usually be at least 5 m taller than the stock tanks to overcome the friction losses in the connecting piping and check valve.

Hydrocarbon liquid enters the boot with a true vapour pressure of about 250 to 400 kPa (i.e., the absolute operating pressure of the next upstream vessel, namely the treater or inlet separator), and leaves with a true vapour pressure of about 90 to 100 kPa (i.e., about local atmospheric pressure). Therefore the product to be stored is still quite volatile. So, use of a gas boot vapour collection system does not necessarily preclude the need for some form of emission control on the stock tanks. The specific advantages of the gas boot system are that it is simple, protects the tanks from possible pressure damage from sudden unexpected gas slugs, and can be less costly to implement if there are many tanks to connect to the vapour collection system.

A limitation of the gas boot system is it is not effective in liberating solution gas from heavy viscous oils, particularly crude bitumen (i.e., there is not enough residence time to achieve vapour-liquid equilibrium).

4 FUGITIVE EQUIPMENT LEAKS

Fugitive equipment leaks are unintentional leaks from equipment components including, but not limited to, valves, flanges and other connections, pumps, 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. Once a leak starts it tends to be a continuous source of emissions until it is repaired.

Some noteworthy leaks trends and considerations are as follows:

- Components on fuel gas systems tend to leak more than components on process gas systems. This likely reflects a lower level of care and attention and use of lower quality components in fuel gas applications.
- The potential for leaks tends to decrease as the value or toxic nature of the process fluid increases, and where gas has been odorized. Thus, leak frequencies for equipment components in sour service are much lower than for components in sweet service. At sour gas plants, often only a small portion of the plant is actually in sour service.
- The stem packing on control valves tends to leak more than on block valves.
- Hydra-mechanical governors[1] on compressor engines tended to be the most leak prone component in control valve service. Their average leak rate is 0.479 kg/h/source compared to a value of 0.049 kg/h/source for other control valves and 0.011 kg/h/source for block valves.
- Components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations, or cryogenic service.

4.1 Recommended Checks

It is good practice to include a comprehensive leak survey as part of the audit since these emissions are often the easiest and most cost-effective to control and usually do not require any capital expenditures. Moreover, leaks are more apt to pose a safety issue than other types of opportunities highlighted in this guide.

4.1.1 High Leak Potential Sources

It is important to recognize that different types of components in different service applications will have different leak potentials (i.e., different probabilities of leaking and different average leak rates when they do leak). Usually, most of the emissions from fugitive equipment leaks at a facility are contributed a few big leakers rather than many smaller leaks. While in theory, any component could be a big leaker, the most probable sources of these big leaks are:

- Compressor seal vents.
- Pressure relief valves.
- Leakage into intermittent vent or flare systems.

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

- Leaking pressure vacuum relief valves, thief hatches and gauge well covers on storage tanks equipped with gas blanketing.

Accordingly, these components should be given the greatest attention. This is reflected in Table 2 where sample statistics are presented for a gas transmission system. Valves and connectors make up most of the component population (97.96 percent) but contribute a relatively small portion of the total emissions (13.0 percent), while open-ended lines, blowdown systems and compressor seals make up a very small portion of the component population (1.7 percent) but contribute 86.7 percent of the total emissions.

Unfortunately, the components that have the highest leak potential are often the ones that are most difficult to access, and therefore, are most likely to get excluded from a leak survey thereby potentially missing significant control opportunities. Accordingly, it is important that advance arrangements be made with the facility to provide any special assistance that may be needed to access the high potential leak sources. Ultimately, facilities should move towards installing easy-access monitoring ports, sample lines or permanent instrumented monitoring solutions to facilitate easy self monitoring of these components.

Table 2. Sample leak statistics for a gas transmission facility.

Major Category	Sub-Category	Typical Leak Frequency (%)	Portion of Component Population (%)	Contribution To Total Leakage (%)
Connectors	All	1.21	87.33	6.06
Valves	Control Valves	14.65	0.27	1.34
	Block Valves	3.98	10.36	5.63
Open-Ended Lines	All	N/A	1.33	28.27
Pressure Relief Devices	All	14.65	0.20	14.21
Pressure Regulators	All	16.28	0.30	0.25
Blowdown Systems	Pressurized Station or Compressor Unit	73.53	0.08	18.38
	Depressurized Reciprocating Compressor	73.33	0.00	0.00
	Depressurized Centrifugal Compressor	61.11	0.00	0.00
Compressor Seals	Reciprocating Compressor	86.11	0.06	10.62
	Centrifugal Compressor	95.23	0.07	15.24
Flow Meters	Orifice Meters	20.19	0.00	0.00
	Other	2.63	0.00	0.00
	All	100	100.00	100.00

The following are special considerations when checking selected high leak potential components:

- Leakage into a compressor blowdown system is less when the compressor is pressurized than when it is depressurized. In the pressurized case there is only leakage past the seat of the blowdown valve. In the unpressurized case there is leakage past the seats of the upstream and downstream unit block valves.

- When checking compressor seals in is important to check the packing case, distance piece and lube oil drain tank (or degassing reservoir) vents for emissions.
- Compressors that feature a seal gas recovery system are normally designed with a pressure relief vent for discharging any seal gas flows in excess of the capacity of the seal gas recovery system. These vents and the compressor crankcase vent (i.e., on reciprocating compressors) should be checked for leaks.

4.1.2 Low Leak Potential Components

While less likely to be the source of a big leak, low leak potential components such as connectors and valve stem packing systems can, on occasion, be major leak sources. Examples of situations where this or other unexpected significant leak contributions may occur include the following:

- Connections left untightened after a plant turnaround or maintenance which go unnoticed due to high background noise levels or because the component is in a difficult to access or infrequently visited location (e.g., at high elevation location or on a pipe rack).
- Holes have developed in equipment or piping due to corrosion, abrasion or damage.
- Components have been improperly installed or were forgotten to be installed (e.g., a pressure gauge removed during maintenance work was not put back into its monitoring port and the valve on the port is in open or partially open position).
- A major failure of a valve stem packing system (e.g., blowout of the packing material) has occurred.

Accordingly, there is still value in surveying low leak potential components and process areas.

4.2 Measurements

The Canadian Association of Petroleum Producers (CAPP) has developed a Best Management Practice (BMP) for detection, measuring and managing fugitive emissions at oil and gas facilities. Additionally, useful guidance on leak control technologies and quantification procedures is provided at US EPA's Gas Star web site.

4.3 Reduction Potential

Field studies have shown that simply pursuing leak control opportunities with a 1-year payback or better can reduce the amount of fugitive emissions by 70 percent or more. Any leak that can be readily repaired should be repaired; however, the focus should clearly be on finding and controlling the few big leaks that occur at sites.

5 VENT AND FLARE SYSTEMS

Flare and vent systems exist in essentially all segments of the oil and gas industry and are used for two basic types of waste gas disposal: intermittent and continuous. Intermittent applications may include the disposal of waste volumes from emergency pressure relief episodes, operator initiated or instrumented depressurization events (e.g., depressurization of process equipment for inspection or maintenance purposes, or depressurization of piping for tie-ins), plant or system upsets, well servicing and testing, pigging events, and routine blowdown of instruments, drip pots and scrubbers. Continuous applications may include disposal of associated gas and/or tank vapours at oil production facilities where gas conservation is uneconomical or until such economics can be evaluated, casing gas at heavy oil wells, process waste or byproduct streams that either have little or no value or are uneconomical to recover (e.g., vent gas from glycol dehydrators, acid gas from gas sweetening units, and sometimes stabilizer overheads), and vent gas from gas-operated devices where natural gas is used as the supply medium (e.g., instrument control loops, chemical injection pumps, samplers, etc.). Typically, waste gas volumes are flared if they pose an odour, health or safety concern, and otherwise are vented.

5.1 Recommended Checks

5.1.1 Continuous Venting or Flaring

Continuous vents or flares should be reviewed to accurately determine the amount of gas being disposed of and determine whether current market conditions now make the gas economical to conserve or utilize. Additionally, sufficient review of the process should be conducted to determine whether the measured values are consistent with what would be expected, and if any unintentional contributions are occurring.

5.1.2 Intermittent Vent and Flare Headers

Key issues with intermittent vent or flare systems are:

- They often either do not have a flow meter, or if one is provided it is sized to monitor the peak flows during relief or blowdown events. The low flow readings which occur the rest of the time are usually ignored and treated as meter noise.
- In the absence of any instrumentation, it is difficult to detect excessive residual flows, except in very extreme cases. This is partly because the discharge point is an elevated source and generally inaccessible. As well, these systems are designed for large blowdown, purge or relief events, so much lesser flows do not produce a perceptible olfactory, audible or visual (OAV) indication, yet when allowed to persist for prolonged periods of time, they can become a major contributor to emissions and a loss of marketable gas.
- Lastly, flares require a reasonable degree of turbulence at the flare tip to promote good destruction efficiencies. Destruction efficiencies achieved at low flows will be much less than those achieved during flaring episodes at design conditions.

5.1.2.1 Leakage into the Vent or Flare Header

Intermittent vents and flares should be checked for leakage into the collection header. Where residual flows in the header are detected, further efforts should be undertaken to determine the exact cause of the leakage or residual flow. The cause may be leakage past the seat of a connected pressure relief valve or blowdown valve; however, it may also be that a manual blowdown valve has inadvertently been left partially or fully open.

Ultimately, facilities should consider installing flow meters, monitoring ports or flow switches on intermittent vent or flare systems to allow for frequent or continuous self monitoring of leakage into vent and flare systems.

Where significant losses into the vent or flare header are difficult to avoid, consideration should be given installing a flare or vent gas recovery system.

5.1.2.2 Excessive Purge Gas Consumption

All flares should be checked to confirm purge gas consumption rates are reasonable (i.e., are sufficient to safely meet the minimum requirements). Specific matters to check or consider are as follows:

- Some facilities use flash gas from amine sweetening units or glycol dehydrators as a replacement for, or supplemental source of, purge gas. This may greatly exceed the necessary requirements and should be reviewed to consider conserving these gas streams and only providing enough purge gas to safely meet the minimum requirements.
- The control system for supplying purge gas to a flare system is usually just a manual valve and possibly a regulator or a fixed orifice plate with no actual flow indication or monitoring. The tendency in these cases is to err on the side of conservatism which potentially results in far more purge gas consumption than required. Frequently, operations personnel will manually adjust the purge rate until a reasonable sized flame is visible at the flare tip, without any specific criterion on how big the flame actually needs to be and without realizing that small changes in the flame size can represent large changes in the amount of purge gas being supplied.
- Many fares do not feature, and would greatly benefit from, the installation of a purge reducing seal. The purge seal is a device installed near the tip of the flare stack which greatly reduces the minimum purge gas flow rate needed to keep air from flowing down into the flare and causing burn-back which could damage the flare tip and pose a safety issue.
- In cases where the flare has been equipped with an unreliable pilot or ignition system, operations personnel increase purge gas flows to help maintain a flame at the flare tip. While this is an easy short-term solution to the problem, it can become an extremely costly long term solution due to excessive fuel consumption.

5.1.3 <u>Flare Gas Enriching Systems</u>

Flare gas may sometimes be enriched with fuel gas to either meet local regulatory requirements on the minimum required heating value of the flare gas (i.e., to ensure stable combustion) or to promote greater atmospheric dispersion of the flaring emissions (particularly SO_2) through increased thermal buoyancy. The installed flare gas enriching systems are often a manual system designed the same way that purge gas systems are, and therefore may suffer from of the same issues (see Section 5.1.2.2) and need to be checked.

5.1.4 Low Efficiency Pilots on Continuous or Intermittent Flares

In recent years there have been a number technological advancements in the design of flare pilot systems which have greatly improved their reliability, performance and efficiency with respect to fuel requirements. The fuel consumption of existing pilots should be reviewed to determine if significant savings may be achieved by upgrading to a more advanced design.

5.2 Measurements

The Global Gas Flare Reduction (GGFR) Partnership (a World Bank lead public-private initiative) is developing a guide on flare and vent gas measurement which should be applied. Although still in draft form and not publicly available at the time of this report, the guide is expected to be available soon.

5.3 Reduction Potential

Useful reference documents on reducing venting and flaring and optimizing these systems include the following:

- Canadian Association of Petroleum Producers (CAPP) (2006): Best Management Practice – Facility Flare Reduction
- CAPP (2008): Best Management Practice – Reducing Fuel Consumption in Flaring Operations (This document is still in draft form but is expected to soon be made publically available).
- American Petroleum Institute (API): Recommended Practice 521: Guide for Pressure-Relieving and Depressuring Systems.
- API: Recommended Practice 520: Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries.
- API: Recommended Practice 537: Flare Details for General Refinery and

6 COMBUSTION EQUIPMENT

Heaters, boilers and engines are widely used throughout the oil and gas industry and, collectively, are the dominant source of GHG emissions due to the large amounts of fuel they consume. At most facilities, natural gas, or sometimes even oil, is taken from the process and used as fuel. On an industry-wide basis, most of this fuel is used by compressor engines, pump engines, heaters and boilers. The estimated disposition of this fuel by type of device is presented in Table 3.

Other fuel uses include make-up gas to flare gas streams to satisfy minimum heating value requirements, supplemental fuel for incinerators to achieve good destruction efficiencies and/or to maintain the minimum stack temperatures need to achieve good atmospheric dispersion of the emitted pollutants, flare and incinerator pilot gas, and flare and vent header purge gas (see Section 5).

Table 3. Disposition of burned fuel gas by subsector of the upstream oil and gas industry.

Sector	Fraction of Fuel Burned (percent)			
	Reciprocating Engines	Gas Turbines	Heaters/ Boilers	Incinerators
Oil production	40.0	0.0	60.0	0.0
Gas Production	68.9	3.5	27.6	0.0
Heavy Oil Production	0.0	0.0	100.0	0.0
Crude Bitumen Production	0.0	0.0	100.0	0.0
Sweet Gas Plants	84.9	0.0	15.1	0.0
Sour Gas Plants – Flaring	17.5	11.4	71.1	0.0
Sour Gas Plants – Recovery	15.6	10.2	73.4	10.9
Reprocessing Plants	0.0	85.0	15.0	0.0
Gas Transmission	5.3	94.3	0.4	0.0
Propane Consumption	40.0	0.0	60.0	0.0

6.1 Recommended Checks

There are two key areas that should be evaluated for cost-effective opportunities to reduce fuel consumption: process optimization to minimize heat demands and engine loads and optimizing the operation of each individual heater, boiler, engine or incinerator. The first type of evaluation may comprise a review of the facility design to ensure that all reasonable opportunities for waste heat recovery are utilized and that pressure drops and recycling are minimized. As well, performance benchmarking against rigorous process simulations or historical baselines may be performed as a global check for proper performance.

The evaluation of individual units (engines or heaters) involves conducting performance tests to confirm that the equipment is operating at acceptable efficiency levels, and in the case of engines, that the coupled pump or compressor is also operating efficiently. These tests should comprise the following: confirming proper air-to-fuel ratios, good combustion and that the unit is operating on an efficient portion of its performance curve.

Consideration should also be given to performing checks for internal process leaks that may be contributing to reprocessing of process streams, especially on reciprocating compressors. On reciprocating compressors, valve leakage causes some recompression of gas resulting in higher cylinder exit temperatures.

Additionally, all heat exchangers should be checked to confirm that they are performing in accordance with design specifications and have not become fouled. A small change in the temperature differences achieved across the heat exchanger may have a large impact on fuel or energy demands in other parts of the process.

6.2 Measurements

6.2.1 Fuel Consumption

There is a wide variety of fuel gas metering arrangements that may occur at facilities, which complicates production account requirements and thereby introduces a potential for errors. At many facilities, a single flow meter is installed to measure the total amount of fuel withdrawn from the process. Sometimes secondary meters are installed to determine the fuel disposition by major fuel-use category. In some cases, the available fuel gas meter or meters may measure only a portion of the fuel gas usage. For example, it is common practice for packaged compressor units to be supplied with a dedicated fuel gas meter. A facility might rely on these meters to determine fuel use by the compressor engines, and simply estimate the amount of fuel consumption by all other sources (e.g., fuel for heaters, reboilers, incinerators, flare pilots, and for flare header purge and makeup gas). Fuel gas used for non-combustion purposes (e.g., instrument gas, compressor start gas, dehydrator stripping gas, blow-case supply gas, and some blanket gas and equipment purging applications) may occur either upstream or downstream of available fuel gas meters, or a combination thereof. Complexities in fuel gas metering and accounting are often introduced as a result of additions and changes to an existing facility over time.

Information on the fuel disposition by type of combustion device is most important for determining emissions of criteria air contaminants such as CO, NO_x, and PM, since the emission factors for these pollutants vary greatly according to the type of combustion device (i.e., reciprocating engine, turbine engine or heater/boiler). For GHG emissions it is less of an issue since CO_2 is the predominant contributor to GHG emissions from fuel combustion, and the emission factors for this pollutant vary little with the type of combustion device. Methane emission factors for fuel combustion do vary significantly with the type of combustion device and may contribute up to 17 percent of fuel-use GHG emissions. N_2O emissions from fuel combustion are a much lesser contributor to fuel-use GHG emissions. Moreover, N_2O emission factors currently are independent of the type of combustion device.

For natural gas, the composition of the fuel may vary appreciably from site to site but the actual carbon content of the fuel is much less sensitive. Typical values may range from 64 to 76 percent on a mass basis for different types of gas streams (e.g., raw gas, processed gas, tank vapours and dehydrator vent gas). For processed natural gas, the carbon content may only range from about 72 to 74 percent on a mass basis.

6.2.2 Performance Tests

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

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

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

Measured fuel and exhaust gas compositions should be used to determine the air-to-fuel and exhaust-to-fuel ratios. Species mole balances and the following simple combustion relation may be applied for this purpose:

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

where, a carbon mole balance is used to determine b, a nitrogen balance to determine a and a hydrogen balance to determine d. These coefficients may then be used to determine the flow rates of the unknown streams from the known flow.

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

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

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

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

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

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

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

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

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

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

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

And for gas turbines:

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

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

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

where

$$\begin{aligned} Heat\ Input = {} & Energy\ Content\ of\ Fuel + Sensible\ Heat\ in\ Fuel \\ & + Sensible\ Heat\ in\ Combustion\ Air \end{aligned}$$

$$\begin{aligned} Stack\ Losses = {} & Energy\ Content\ of\ the\ Exhaust\ Gas + Convective\ Stack\ Losses \\ & + Sensible\ Heat\ in\ the\ Exhaust\ Gas \end{aligned}$$

The optimum air-to-fuel ratio varies significantly for reciprocating engines according to make and model of unit. Accordingly, specific manufacturers' values should be used. For heaters and boilers, 15 percent excess air may be assumed to be sufficient for proper operation.

6.2.3 Internal Process Leakage

In the case of reciprocating compressors, the occurrence of valve leakage may be detected by monitoring interstage and discharge process gas temperatures. The amount of leakage and the resulting performance loss can be backcalculated through simulation of the compression process. Thermal imaging is another common means for detecting internal leakage problems and can often detect drain or by-pass valves that are not seating properly. Ultrasonic techniques offer the greatest sensitivity for detecting leakage past valve seats.

6.3 Reduction Potential

CAPP has commissioned the development of a series of Best Management Practices specifically aimed at improving energy efficiency in the oil and gas industry. These guidance documents are expected to be available early in 2008. In general, fuel use at oil and gas facilities may be reduced through the implementation of more aggressive energy auditing and conservation programs.

The relative potential for reductions in fuel use will generally be lowest at large newer facilities with dedicated full-time maintenance staff, and greatest at older unmanned facilities, especially where the facility is deemed to be in the latter stages of its useful life. Recent experiences at a variety of different facilities indicate average potential reductions of 10 to 15 percent in fuel use. Notwithstanding this, it should be noted that the average specific energy intensities of oil and gas production is generally increasing with time due to increased water disposal and gas compression requirements as reservoirs are depleted, and increased transportation distances as companies must search farther afield to replenish reserves.

The following are key elements to be considered as part of an energy management program at oil and gas facilities:

- Process optimizations to reduce both direct energy requirements, as well as the amount of recycling and reprocessing at facilities. For example, some sour gas processing plants are finding financially attractive opportunities to optimize fuel use by tail gas incinerators by introducing complex control loops to evaluate fuel requirements as a function of both process conditions and local meteorology.
- Improvement of energy efficiencies of gas-fired equipment through increased monitoring of unit performance and frequency of servicing. Most manufacturers recommend conducting minor tune-ups to adjust air-to-fuel ratios at least 4 times per year (i.e., with each changing season). The engines should also be checked at these times for possible valve or ignition problems through analysis of the flue gas. Additionally, regular checks for gas flows from the engine crankcase should also be performed. Engine crankcase vents usually are not checked as part of normal engine inspections and can contribute significantly to energy losses due to blow-by past the engine piston rings.

- Where process conditions differ appreciably from initial design specifications, there may be an opportunity to replace oversized compressor and pump engines with smaller units to allow operation at more efficient points on the performance curve. For example, specific fuel consumption for a typical 746 kW natural gas-fuelled engine is 16.7 lower at full load than at half load. Up to 50 percent reductions in fuel consumption are possible in extreme cases.
- At larger facilities, consideration may be given to implementing waste heat recovery or co-generation schemes.

7 RECIRCULATING CHEMICAL TREATMENT SYSTEMS

Glycol dehydrators and amine sweetening units are the most common types of re-circulating chemical treatment systems encountered at oil and gas facilities. In these case, the circulated liquor is brought into contact with a gas stream, usually in an absorber (or contactor) column, and then separated and passed through a regeneration loop before returning to the absorber section. The regeneration loop features a reboiler which applies heat to the liquor to reverse the absorption process.

A low pressure flash separator is sometimes installed between the absorber and regenerator to release any solution gas that may be entrained in the rich (wet) liquor. The gas separated in the flash separator may be used to supplement the fuel and stripping gas required for the reboiler. Any excess vent gas is discharged through a back pressure valve to atmosphere. The system will also feature a heat exchange to preheat the rich liquor before it reaches the reboiler.

The primary causes of hydrocarbon emissions are secondary absorption/desorption by the liquor, entrainment of some gas from the absorber in the rich liquor, and potentially the use of stripping gas in the reboiler. For glycol and amine systems, the key secondary compounds that may be removed by the liquor are aromatic hydrocarbons (e.g., benzene, toluene, ethylbenzene, and xylenes [BTEX]), which are notable toxic substances.

7.1 Recommended Checks

The key matters to be considered with respect to re-circulating chemical treatment systems are:

- Optimization of the unit to minimize the liquor circulation rate, and thereby reduce duty on the reboiler and emissions or secondary absorption products released in the flash gas and reboiler.
- The disposition of the flash gas. If the flash gas usually may be recovered and either used as fuel or compressed back into the process.
- The disposition of the offgas from the reboiler. For glycol systems there may be an opportunity to condense the water vapour and recovery the hydrocarbons. For amine systems, there may be more efficient disposal options available.

7.2 Measurements

Refer to Section 6.2 for performance of the reboiler and Section 5.2 for any related process venting of flaring. Process simulations are normally performed to determine optimum operating conditions for the overall re-circulating chemical treatment process.

7.3 Reduction Potential

CAPP (2000) has developed a Best Management Practice for Control of Benzene Emissions from Glycol Dehydration which provides guidance on measuring and managing process emissions from these units. Additionaly, the CAPP will be publishing, as part of its energy management series, a Best Management Practice that deals specifically with energy efficiency opportunities related to glycol dehydrators and gas sweetening units. Additionally, useful guidance on relevant control technologies and quantification procedures is provided at US EPA's Gas Star web site.

The following, for easy reference, are a few process variables that may be optimized to help minimize the heating load on the reboiler, and to a lesser extent, control emissions/losses of secondary absorption products:

- **Flash Tank**: If appreciable quantities of natural gas are absorbed or entrained in the liquor, a two-phase flash separator should be installed downstream of the rich/lean liquor heat exchanger. The separated gas can be used as fuel for the reboiler or as stripping gas, or, as a last resort, sent to flare for disposal. If significant amounts of hydrocarbon liquids are encountered at this point, the flash tank should be designed for three-phase separation. Otherwise, the hydrocarbon liquids could cause problems in the reboiler (i.e., gradual coke accumulation on the fire tube) and lead to reduced boiler efficiency and increased combustion emissions.

- **Glycol Circulation Rate**: The amount of actual gas treatment provided by recirculating chemical treatment system is, for the most part, determined by the liquor circulation rate. However, since this rate also determines the amount of secondary absorption products emitted, it is important that the circulation rate not be set any higher than is needed. Notwithstanding this, usual practice is to set the circulation rate for peak flows plus a comfortable safety factor (e.g., 10 percent). Thereafter, adjustments to the circulation rate with changes in throughput are made infrequently, if at all. Consequently, there is considerable potential for optimization of the liquor circulation rate. This will not only reduce venting emissions, but will remove unnecessary load from the reboiler and thereby lower combustion emissions and conserve fuel.

  One option is to conduct periodic performance tests (e.g., sample the rich and lean glycol) on each unit and manually adjust the glycol circulation rate. Sometimes it may even be necessary to replace the existing pump with a smaller pump (i.e., it is not uncommon for the glycol pump and other components of the dehydrator to be oversized because of production declines or low gas demand).

  Another option is to implement a continuous feedback control loop to regulate a variable speed recirculation pump.

- **Inlet Gas Temperature and Pressure**: The amount of emissions that may occur for a well posed application involving properly trained operators is ultimately determined by the amount of contaminant to be removed by the chemical treatment system. For glycol dehydrators, the amount of water vapour to be removed is determined by the inlet temperature and pressure of the gas. The water content of the gas will decrease through condensation as temperature is lowered and pressure is increased. So, also, will the concentration of higher boiling point aromatics and their corresponding emissions. Accordingly, the operating temperature should be minimized and the operating pressure maximized to the fullest extent possible. However, in most cases temperature will be the easiest to adjust and will likely offer the greatest gains.Sometimes if the pressures are relatively low, it may be feasible to install an inlet air cooler when the inlet gas temperature is too high. Although, if the temperature gets too low the liquor may become sufficiently viscous to impair efficient contact in the absorber.

- **Reboiler Temperature**: The operating temperature of the reboiler should be as high as possible without exceeding the maximum heat tolerance of the liquor to ensure maximum reconcentration of the liquor and thereby suppress the necessary re-circulation rate. If temperatures are too high it will lead to excessive liquor losses and possibly thermal decomposition of the liquor. On a standard unit (i.e. one with a gas fired reboiler) this temperature is thermostatically controlled and fully automatic. Nonetheless, the reboiler temperature should be occasionally verified with a test thermometer to make sure true readings are being recorded. The reboiler operates best when it is able to achieve a uniform temperature. If the temperature fluctuates excessively when operating below the design capacity, the fuel gas pressure should be reduced. Conversely, if the reboiler temperature cannot be raised as desired, it may be necessary to increase the fuel gas pressure up to about 200 kPa and readjust the dampers on the air intake.

8 PNEUMATIC DEVICES

In the upstream petroleum industry, it is common practice to use natural gas as the operating medium for pneumatic instrumentation systems and gas operated devices (e.g., chemical injection pumps and compressor starters) where compressed air is unavailable or deemed uneconomical to provide. This is usually the case at single-well oil batteries, single-unit compressor stations, well-site facilities, minor field installations, and at some small (design capacity below 0.7 Mm^3/d) and medium sized (design capacity of 0.7 to 7 Mm^3/d) gas processing plants. Natural gas may also be used in specific applications where the available air pressure is too low to operate a given device (e.g., large valves).

8.1 Recommended Checks

Measurements should be performed to quantify gas consumption rates by gas-operated devices that use natural gas as the supply medium. Experience has been that consumption rates are often notably greater than expected due to the following factors:

- Limited information is available on the number of consumption devices and usually the number of devices is underestimated.
- These devices tend to receive very little attention and have not been tuned for optimum performance. For example, supply pressures may be greater than needed, device activity levels may be set too high, etc.
- Some devices will begin to use more gas as they wear such as continuous bleed instrument control loops.

8.2 Measurements

Gas consumption by pneumatic devices is not routinely measured at oil and gas facilities. For smaller devices, these measurements may be performed using rotameters, diaphragm meters or HiFlow samplers. For larger devices such as pneumatic starter motors it may be difficult to perform a reliable measurement due to the brief duration of the event and the high flow rates involved. In these cases, common practice is to refer to the manufacturer's data.

8.3 Reduction Potential

The following options may be considered to eliminate or reduce the amount of emissions from gas-operated instrumentation systems:

•Control Loop Tuning,
•Low-consumption Control Systems,
•Use of Air As the Supply Medium,
•Replacement With Equivalent Electronic Systems, and
•Vent Gas Disposal or Recovery Systems.

Useful guidance on these control technologies is provided at US EPA's Gas Star web site.