Paper #2-15

AIR EMISSIONS MANAGEMENT

Prepared by the Technology Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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ABSTRACT

Natural gas production, processing and transmission include activities that result in emissions of regulated air pollutants. Emission sources are broken down into five categories: (1) Fugitive dust from vehicular traffic; (2) Combustion emissions; (3) Glycol dehydrators; (4) Sources of methane and volatile organic compounds (VOC; both fugitive and point); (5) Acid gas emissions from sour gas sweetening.

Best practices and appropriate application of emission control technologies can reduce emissions of air pollutants. For every source of air emissions from oilfield and gasfield operations, technologies have been developed to reduce emissions although widespread deployment of those technologies are not always economical for commercial projects. Ongoing challenges are to make retrofits of newer technologies easier and more economical for older systems and to make new technologies more affordable during construction of new systems. The more promising approaches include:

- Reduce road dust by reducing the vehicle miles traveled through consolidating and sharing roads, using existing roads wherever possible, and designing and managing operations to eliminate or reduce trips. Suitable consolidations would include multiple wells per pad and three-phase gathering (gas, petroleum liquids, produced water) which can eliminate the need to haul water and condensate.

- Reduce emissions from combustion sources using fuel cells can be used in lieu of combustion engines. However, additional research and development is needed to make fuel cells economical at the scale needed for oil and natural gas production.

- Reduce emissions from dehydration using an alternative process to glycol dehydrators. In areas where it is applicable, a desiccant dehydrator can substantially reduce methane, VOC and hazardous air pollutant (HAP) emissions.

- Reduce VOC and methane emissions from storage tanks and loading by reducing the number of tanks and loading demand on trucks. Closed-loop and three-phase gathering systems can reduce the number of tanks in a field and need for loading into trucks.

- Reduce fugitive emissions from other equipment through an enhanced directed inspection and maintenance (DI&M) program, beginning with a baseline survey followed by a comprehensive repair plan.

- Reduce acid gas emissions using underground injection of the acid gases where that avenue is available. Otherwise, work to optimize combustion flares where sulfur recovery is not practical.

INTRODUCTION

Pollutant emissions from natural gas production, processing, and transportation activities are controlled substantially by use of current technologies and best management practices. More cutting-edge technology, such as infrared cameras and variable-speed vapor recovery units, is being used more often. Several advanced technologies which are not cost-effective today might become more widely used as the economics of their deployment become more favorable.

Air emissions are associated with natural gas production, gathering and processing operations, and transmission. Natural gas production activities that can result in emissions of regulated air pollutants (EPA, 1995) include:

- Construction: Emissions from mobile source and fugitive dust emissions from roads and soil management.
- Drilling: Combustion emissions from engines used to power the drilling rig and support activities (e.g., mud pumps), and venting or flaring of gas produced prior to completion.
- Completion: Combustion emissions from engines used to power the completion rig and support activities (e.g., frac pumps), and venting or flaring of gas associated with flowback operations.
- Production: Venting or flaring of emissions from condensate and produced water storage vessels, venting or flaring of emissions from glycol dehydration units, leaking components (e.g., pump seals, flanges, values), truck loading of hydrocarbon liquids, pneumatic controllers, unloading well bore fluids, and combustion emissions from small process heaters (e.g., heater-treater separators, glycol reboilers, tank heaters, etc.).

Natural gas gathering and processing activities that can result in emissions of air pollutants include:

- Sour Gas Sweetening: Flaring of acid gas from amine units used to strip hydrogen sulfide (if no sulfur recovery) and carbon dioxide from coal bed methane.
- Sulfur Recovery: Claus plant tail gas venting or incineration.
- Gas Processing (Separation): Venting or flaring during emergency releases, venting or flaring of emissions from on-site storage of separated heavier hydrocarbons, leaking components, and combustion emissions from engines and process heaters.
- Gathering system leaks.

Transmission activities that can result in air emissions include:

- Compression: Combustion emissions from engines and turbines used to compress the natural gas to pipeline pressures, venting during compressor blowdown (depressurization), and leaking components (including leaking blowdown valves).

- Transmission pipeline leaks.

Greenhouse gas (GHG) emissions include carbon dioxide (CO_2) from combustion sources and amine unit venting; and system losses of natural gas which is primarily methane (CH_4).

In addition to emissions from production, processing and transmission equipment, vehicular traffic produces vehicle emissions and emissions of fugitive dust in unpaved areas.

DESCRIPTION OF THE TECHNOLOGY

For discussion purposes, emission sources are broken down into five categories: fugitive dust from vehicular traffic, combustion emissions, glycol dehydrators, sources of methane and volatile organic compounds (VOC; both fugitive and point), and acid gas emissions from sour gas sweetening. This section includes a discussion on technology to reduce air emissions, including descriptions of technology, broader uses of technology, environmental benefits, economic impacts, innovative ideas and future use.

Table 1 summarizes available technologies for controlling dust from road traffic, combustion emissions, glycol dehydrator emissions, fugitive and point source emissions, and acid gas emissions from amine units. Additional details on each technology follow. Available technologies are listed, but the cost and benefit of each technology and whether the technology should be used on a particular source is generally determined by federal or state rule-making or individual site and source determinations.

Table 1. Emission Control Technologies.

Technology	Description of the Technology
Dust from Road Traffic	
Surface treatment	Surface treatment includes the use of water or chemical dust suppressants to control dust emissions generated by vehicular traffic on unpaved roads.
Reduction of vehicle miles traveled	Reduction strategies include consolidation of wells to avoid road construction and minimize traffic, management of projects to minimize traffic, and three-phase gathering systems to avoid the need for truck traffic.
Emissions from Combustion Units	
Selective Catalytic Reduction (SCR)	For lean-burn, gas-fired engines and diesel engines. Add-on NOx control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NOx in the presence of a catalyst to form water and nitrogen.
Selective Catalytic Reduction (SCR) with particulate matter (PM) filters	For diesel engines. SCR with PM filter technology simultaneously reduces particulate matter and NOx content of the exhaust gas. The technology combines SCR and diesel particulate filter (DPF).

Technology	Description of the Technology
Non-Selective Catalytic Reduction (NSCR)	For rich-burn, gas-fired engines. A three-way conversion catalyst system that simultaneously reduces NOx, carbon monoxide (CO), and hydrocarbons (HC) and involves placing a catalyst in the exhaust stream of the engine.
Flue Gas Recirculation (FGR)	A portion of the flue gas is recycled from the stack to the burner windbox. Primarily, the re-circulated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NOx mechanism. To a lesser extent, FGR also reduces NOx formation by lowering the oxygen concentration in the primary flame zone.
Low-NOx Burners (LNB)	NOx emissions are reduced by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NOx formation.
Low-NOx Turbines	Low-NOx turbines are gas turbines using staged combustion. Fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel-air mixture which is delivered to a secondary stage where the combustion reaction takes place.
Flare	Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO_2) and water.
Alternative Energy Combustion Source	Elimination of the need for combustion from traditional sources through the use of adequately sized alternative or renewable energy sources, such as fuel cells.
Emissions from Glycol Dehydrators	
Flash Tank Separator	Reduces emissions from glycol still vent by flashing off most of the absorbed lighter hydrocarbons, especially methane, in a low-pressure separator prior to glycol regeneration in the still. Emissions are reduced if the flash tank vent is routed either to a nearby fuel system or by control device such as a flare or vapor condenser. It allows much more efficient use of a condenser on the glycol still vent.
Still Vent Condenser	A condenser, typically an air-fin design, is used to remove and collect condensable hydrocarbons from the glycol still vent.
Still Vent Combustion in Reboiler Firebox	Uncondensed hydrocarbons are mixed with fuel for combustion in the glycol still reboiler firebox. Typical destruction rates of 50% to 90% dependent on cyclic nature of glycol still reboiler firing. Modern patented firing systems can increase destruction efficiency and reliability.
Add-on Still Vent Combustion	Combustion of still vent vapors in a flare or thermal oxidizer. Destruction efficiencies up to 99%.
Alternative to Dehydrators	Development of a process to dehydrate gas using an alternative technology to glycol dehydrators that includes a closed-loop system. For example, a desiccant dehydrator can replace a glycol dehydrator reducing methane, VOC and hazardous air pollutant (HAP) emissions by 99 percent.
Emissions from Tanks and Loading, Vents, Pumps, Valves, Connectors, Seals, and Sampling Connections	
Vapor Recovery Systems	Vapor recovery systems require a compressor to collect emissions from storage vessels and return the gas to sales line or the suction line of another facility compressor.
Combustion Systems	In a typical thermal oxidation system, the air/vapor mixture is injected through a burner manifold into the combustion area of an incinerator.
Low-bleed Pneumatic Controls	New, technically advanced low-bleed devices and retrofit kits reduce methane emissions considerably.
Leak Detection and Repair (LDAR)	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.

Technology	Description of the Technology
Extended DI&M Programs	A more extensive LDAR program, which can include the use of infrared technology to discover leaks.
Acid Gas Emissions from Amine Units	
Vent gas flaring	Acid gas from amine units is routed to an elevated, open flare for combustion. The burner tip (flare tip) is located at the top of the flare stack. A continuously lit pilot or electronic auto ignition system ensures that vent gases are combusted at the flare tip.
Sulfur recovery plants	Acid gases from the amine unit are processed in a sulfur recovery plant, which uses the Claus process in the vast majority of cases. Generally, this option is employed at gas processing plants where the gas is sour enough to justify its use.
Underground injection	In cases where it is not economically feasible for companies to recover elemental sulfur for sale, acid gas is now being dissolved in oilfield produced water at the surface and injected into subsurface formations or injected directly with a high pressure compressor into a permitted disposal well.
Alternative to Amine Units	Technology that performs the same function but avoids any air emissions.

A. Fugitive Dust

Roads located at upstream oil and gas sites are typically unpaved. As such, vehicular traffic can generate dust emissions. The use of water as a dust suppressant works by keeping the road surface wet to control emissions. Surfactants or other additives, such as Alchem 8808, may be used with water (Succarieh, 1992). Chemical dust suppression attempts to change the physical characteristics of the unpaved road surface, thereby reducing dust emissions. With both techniques, reapplication is necessary and can vary depending on the technique and the weather conditions. For example, the necessary reapplication frequency for water in summertime can be several minutes, while chemical dust suppressants may only need to be reapplied after several weeks or even months (EPA, 2006). Other than water, petroleum resin products historically have been the most widely used dust suppressants on industrial unpaved roads. Examples include used oils, emulsified asphalt primer, Coherex, and Resinex 60 (Succarieh, 1992). Besides petroleum resins, other newer dust suppressants also have been successful in controlling emissions from unpaved roads (EPA, 2006). Examples include magnesium and calcium chlorides, lignin derivatives, and tree resin and synthetic polymer emulsions.

Both methods of surface treatment serve to reduce road dust emissions from vehicular traffic. However, chemical dust suppressants may result in unintended environmental impacts to soils, water, air, and flora and fauna.

Watering and chemical dust suppressants are available at moderate to low costs. However, those require frequent reapplication to maintain effectiveness. The cost of water can also vary depending on regional or local conditions related to climate and the availability of water. Chemical dust suppressants are generally more cost-effective in more permanent roads, but watering may be more cost-effective for temporary roads.

Besides surface treatment of roads, adherence to good neighbor practices such as minimizing vehicle speeds and field automation to reduce trips to the field are examples that minimize generation of fugitive dust.

The most effective means of reducing road dust is reducing the vehicle miles traveled. This can be achieved by consolidating and sharing roads, using existing roads wherever possible, and designing and managing operations to eliminate or reduce trips. For example, multiple wells per pad and consolidation of operations allows for fewer overall vehicle miles traveled. Consolidated systems, including three phased gathering, can eliminate the need to haul water and condensate. It eliminates tanks, separators, and other production site equipment.

B. Combustion Units

Engines, heaters, gas turbines, flares, and combustors are common sources of combustion emissions in the natural gas production process. Combustion, or the burning of a fuel and an oxidant, takes place in a combustion unit. Carbon dioxide (CO_2) and water, in addition to energy, are the by-products of this combustion reaction if complete combustion takes place. During incomplete combustion, some carbon is converted to carbon monoxide. In most industrial applications, air is the source of oxygen used as an oxidant for the combustion reaction. Although nitrogen present in air does not take part in the combustion reaction, at high temperatures, nitrogen is converted to nitrogen oxides (NOx).

Selective catalytic reduction (SCR) is one potential emissions control strategy for engines and heaters. SCR is an add-on NOx control placed in the exhaust stream following the engine or heater and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NOx in the presence of a catalyst to form water and nitrogen. Commercial SCR systems are typically found on large utility boilers, industrial boilers, and municipal solid waste boilers and have been shown to reduce NOx by 70 to 95 percent. More recent SCR applications include diesel engines, such as those found on large ships, diesel locomotives, gas turbines, and even automobiles. Such systems may also include an ammonia oxidation catalyst to remove any excess ammonia. The effectiveness of SCR depends on fuel quality and engine load fluctuations. Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. "Ammonia slip" is an industry term for ammonia passing through the SCR un-reacted; it occurs when ammonia is over-injected into the gas stream, temperatures are too low for ammonia to react, or the catalyst has degraded. Temperature is one of the largest limitations of SCR and is a factor for gas turbines, cars, and diesel engines which all have a period during start-up when exhaust temperatures are too cool for NOx reduction to occur. Pure anhydrous ammonia is extremely toxic and difficult to safely store, but needs no further conversion to operate within an SCR. It is typically favored by large industrial SCR operators. Aqueous ammonia must be hydrolyzed in order to be used, but it is substantially safer to store and transport than anhydrous ammonia. Urea is the safest to store, but requires conversion to ammonia through thermal decomposition in order to be used as an effective reductant. CO_2 is a reaction product when urea is used as the reductant.

The SCR with particulate matter (PM) filter technology simultaneously reduces the PM and NOx content of the exhaust gas. The technology combines SCR and diesel particulate filter (DPF).

Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric, or fuel-rich relative to stoichiometric, in terms of ideally-proportioned reaction chemistry. As a result, the exhaust gas has little or no excess oxygen. Under those conditions, non-selective catalytic reduction (NSCR) is a potential emissions control option. NSCR, which involves placing a catalyst in the exhaust stream of the engine, is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NOx, CO, and hydrocarbons.

The effectiveness of NSCR can be limited by elevated oxygen levels and low temperatures, and catalyst degradation. The reaction requires that the oxygen levels be kept low and that the engine be operated at fuel-rich, air-to-fuel ratios. The reaction needs a specific temperature window and also needs sufficient reaction time in that temperature window to be efficient.

Low NOx burners (LNB), a potential emissions control option for heaters, reduce NOx by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NOx formation. LNBs have been used with success on natural gas-fired boilers. The two most common types of LNBs being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with LNBs. The LNB has been in use at industrial facilities since its invention in the 1990s. Staging helps in minimizing fuel and air imbalances within the burner. However, the technology is capital-intensive compared to other NOx reduction control technologies. Also, since NOx formation is a square-root function of the oxygen concentration, the NOx reduction capability of this stoichiometry-based technology is limited.

In a flue gas recirculation (FGR) system, also a potential emissions control option for heaters, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inert components during combustion of the fuel-air mixture. The FGR system reduces NOx emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NOx mechanism. To a lesser extent, FGR also reduces NOx formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing the NOx emission rates for these systems. An FGR system normally is used in combination with specially designed LNBs capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When LNBs and FGR are used in combination, those techniques are capable of reducing NOx emissions by 60 to 90 percent. Recirculation of flue gas back to the combustion zone has been one of the most effective methods of NOx control in gas- and oil-fired boilers since the early 1970s. The FGR system is highly effective in reducing NOx emissions and may be used with existing burners, as well as LNBs. In general, FGR is only feasible for larger boilers and heaters and not typically used for the small- and medium-size heaters and boilers found at oil and gas sites.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean pre-mix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. That feature generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-pre-mix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel-air staging, including fuel staging, air staging, or both. Gas turbines using staged combustion are known as low NOx turbines. One drawback is that CO emission control can be difficult for a low NOx turbine.

Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, produced as waste gases from industrial operations. Natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the waste gases flared. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form CO_2 and water. In some waste gases, CO is the major combustible component. During a combustion reaction, several intermediate products are formed, and eventually, most are converted to CO_2 and water. Some quantities of stable intermediate products such as CO and hydrocarbons will escape as emissions. Depending on the heat content and the exit velocity of the stream, a typical flare can achieve 98 percent destruction efficiency. A flare that meets the regulatory requirements of 40 CFR 60 Subpart A (40 CFR 60.18) is commonly referred to as a "60.18 flare". The flare must meet the operational requirements such as a net heating value of 300 Btu/scf or greater, or an exit velocity of 37.2 m/sec or less, for a non-assisted flare with a diameter of 3 inches or greater. Although flares are fairly low-maintenance and do not require electricity to operate, potential economic value of the waste stream flared, potential high operating cost and emissions of criteria (regulated) pollutants are some disadvantages of operating such a control device.

New, non-road diesel engines are subject to certain emission standards, which in essence constitute emission control technologies. Those "Tier" standards are discussed below.

<u>Tier 1-3 Standards.</u> The first federal standards (Tier 1) for new non-road (or off-road) diesel engines were adopted in 1994 for engines over 37 kW (50 hp), to be phased-in from 1996 to 2000. In 1996, a Statement of Principles (SOP) pertaining to non-road diesel engines was signed between the US Environmental Protection Agency (EPA), California Air Resource Board (ARB) and engine makers. On August 27, 1998, the EPA signed the final rule reflecting the provisions of the SOP. The 1998 regulation introduced Tier 1 standards for equipment under 37 kW (50 hp) and increasingly more stringent Tier 2 and Tier 3 standards for all equipment with phase-in schedules from 2000 to 2008. The Tier 1-3 standards are met through advanced engine design, with no or only limited use of exhaust gas after-treatment (oxidation catalysts). Tier 3 standards for NOx and VOCs are similar in stringency to the 2004 standards for highway engines; however Tier 3 standards for particulate matter (PM) never were adopted.

<u>Tier 4 Standards</u>. On May 11, 2004, the EPA signed the final rule introducing Tier 4 emission standards, which are to be phased-in over the period of 2008-2015 (69 FR 38957-39273, 29 Jun 2004). The Tier 4 standards require that emissions of PM and NOx be further reduced by about 90%. Such emission reductions can be achieved through the use of control technologies --

including advanced exhaust gas after treatment -- similar to those required by the 2007-2010 standards for highway engines. At the Tier 1-3 stage, the sulfur content in non-road diesel fuels was not limited by environmental regulations. The oil industry specification was 0.5% (weight percent); with the average in-use sulfur level of about 0.3%. To enable sulfur-sensitive control technologies in Tier 4 engines -- such as catalytic particulate filters and NOx adsorbers -- the EPA mandated reductions in sulfur content in non-road diesel fuels, as follows:

- 500 ppm effective June 2007 for non-road, locomotive and marine (NRLM) diesel fuels.
- 15 ppm (ultra-low sulfur diesel) effective June 2010 for non-road fuel and June 2012 for locomotive and marine fuels.

The most effective strategy to reduce emissions from combustion sources is to find a technology that provides combustion using alternative energy. For example, fuel cells can be used in lieu of combustion engines. A fuel cell uses an electrochemical oxidation reaction of a fuel material to generate an electric current (NASA-GRC, 2005). The fuel reacts with an oxidant as both materials flow into a reaction chamber, reaction products flow out of the chamber and currents flow through an electrolyte that remains stationary. Fuel cells can operate continuously as long as the necessary reactant and oxidant flows are maintained. Fuel cells are already used as power sources in remote locations and different types of fuel cells can use either hydrogen or methane as the reactant. The main limitation at this time is the cost of an appropriately sized fuel-cell engine that becomes prohibitively expensive when scaled upward to the needs of oil and natural gas production.

C. Glycol Dehydrators

Glycols, such as triethylene glycol, diethylene glycol and ethylene glycol, are used for the removal of water vapor from natural gas and natural gas liquids. Triethylene glycol is commonly used in the oil and gas industry. When produced from a reservoir, natural gas usually contains a large amount of water vapor and is typically completely saturated or at the water dew point. That entrained water can cause several problems for downstream processes and equipment. At low temperatures the water can either freeze in piping or, as is more commonly the case, form hydrates (icy solids) with CO_2 and other hydrocarbons. Glycol dehydrators help prevent those issues by removing water from natural gas and natural gas liquids. However, as the dehydrators absorb water, they also absorb methane and other volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). When triethylene glycol is regenerated through heating in a reboiler, absorbed methane, VOCs and HAPs desorb and are released into the ambient air. The amounts of methane, VOCs and HAPs are proportional to the glycol circulation rate. Installing a flash tank separator on glycol dehydrators reduces methane, VOC and HAP emissions as long as the flash tank outlet is routed either to a nearby fuel system or to a control device. In a dehydration process with a flash tank separator, “lean” ethylene glycol is sent to the contactor (absorber), where it strips water, methane, VOCs and HAPs from the gas stream before entering the separator. In the separator, the pressure is stepped down, allowing most of the methane and lighter VOCs to flash into the gaseous phase. The flashed methane can be captured and used as fuel gas or compressed and reinjected into the sales line. The glycol solution flows to the reboiler, where water and remaining gases are boiled off, and it is recycled back to the contactor. To prevent discharge of HAPs and VOCs not recovered through the flash process, dehydration systems also can be fitted with air- or water-cooled condensers, which capture additional compounds as they move through the reboiler stack. The flash tank separator system results in almost 90% reduction in methane emissions and between 10-90% reduction in HAP and other VOC emissions. An attractive economic benefit of this technology is the recovery of methane, which can be used as on-site fuel or compressed and reinjected into the sales pipeline. Also, installation and operating and maintenance costs are low.

Another approach is to optimize the dehydration unit. Operators can reduce the glycol circulation rate to the minimum required to ensure adequate freeze protection or optimize the temperature of the unit.

The most effective manner to reduce emissions from dehydration is to find an alternative process to glycol dehydrators. For example, the Natural Gas STAR program (EPA, 2011) has determined that replacing a glycol dehydrator with a desiccant dehydrator will reduce methane, VOC and HAP emissions by 99 percent. It can also reduce operation and maintenance costs. Wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. The unit is fully enclosed so gas emissions occur only when the unit is opened to add new desiccant tablets. This will reduce fuel gas use, vented gas, and operation and maintenance needs. However, the use of the alternative desiccant technology may not apply to all areas.

D. Tanks and Loading

Liquid hydrocarbon storage tanks and truck loading of the liquids are sources of VOC and methane emissions in the natural gas production process.

As oil under pressure is routed from either from the wellhead or separator, light hydrocarbons dissolved in the oil flash into the gaseous phase and either fill the space between the liquid oil surface and the tank roof or escape through the tank vent. As the oil is stored, light hydrocarbons also vaporize and either add to the vapor in the space between the liquid oil surface and the tank roof or they escape through the tank vent. The chief component of the flashed or vaporized gas is typically methane, although other gases such as propane, butane, ethane, nitrogen, and carbon dioxide may be present. The vapor also contains HAPs such as the BTEX compounds (benzene, toluene, ethylbenzene, and xylene). VOC and HAPs also are released from flashing of oil or condensate when letdown from higher equipment operating pressures to atmospheric storage. When loading liquid cargo trucks, emissions result when the existing vapor in the cargo tank is pushed out as the liquid is loaded.

Various vapor recovery systems can be used to collect emissions from storage vessels. The recovery systems either compress the vapor so it can be returned to higher-pressure process equipment or converts it into liquid products. Several vapor recovery processes may be used, including vapor/liquid absorption, vapor compression, vapor cooling, vapor/solid adsorption, or a combination of those techniques. Among the various vapor recovery systems, compression by a vapor recovery unit (VRU) is most often used in the oil and gas industry. The overall control efficiencies of vapor recovery systems are as high as 98 percent, depending on the methods used, the design of the unit, the composition of vapor recovered, and the mechanical condition of the system.

In addition to vapor recovery, storage tank emissions and loading emissions also can be controlled by combustion devices. Flares, enclosed flares, and thermal oxidizers are typically used in the oil and gas industry.

The most effective method of reducing VOC and methane emission from storage tanks and loading is to reduce the number of tanks and reduce the need for loading into trucks. Closed loop and three-phase gathering systems can reduce the number of tanks in a field and need for loading into trucks.

E. Fugitive Components

As part of normal operations, pneumatic devices that are driven by field gas typically release natural gas (primarily methane) to the atmosphere. New, technically advanced low-bleed devices and retrofit kits offer comparable performance characteristics to high-bleed models, yet reduce methane emissions considerably. On average, low-bleed pneumatic devices vent 90 percent less methane. The cost of retrofitting existing controls is the primary cost involved with this technology. In some instances where electrical power is readily available, small compressors are installed and the controllers are driven by compressed air.

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. An LDAR program is a structured program to detect and repair equipment that is identified as leaking beyond acceptable limits. It is designed to identify pieces of equipment that are emitting sufficient amounts of material to warrant reduction of the emissions through repair. Those 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 has proved to be best suited for centralized facilities where there are a large number of sources under high pressures such as valves and pumps, and can also be implemented for connectors. LDAR programs have proven to be less economical and not well suited for field areas such as dispersed well sites or field gathering systems where the pressures are lower and considerable travel must be done to survey the entire field.

Several equipment leak emission control technologies are discussed below. Often, those technologies are incorporated into the design of piping systems.

(1) Closed-Vent System. 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 vapor that is routed to the control device and the efficiency of the control device.

(2) Dual Mechanical Seals on Pumps. A dual mechanical seal, installed on pumps, 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.

(3) Seal-Less Pumps. When operating properly, a seal-less pump will not leak because the process fluid cannot escape to the atmosphere. Seal-less 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 seal-less pumps is essentially 100 percent; however, if a catastrophic failure of a seal-less pump occurs, there is a potential for a large quantity of emissions.

(4) Improved Compressor Seals. 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.

(5) Seal-Less Valves. Emissions from process valves can be eliminated if the valve stem can be isolated from the process fluid. Two types of seal-less 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.

(6) Welded 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.

An enhanced directed inspection and maintenance (DI&M) program is a program that promotes a systematic approach to finding and repairing significant leaks at natural gas operations. It begins with a baseline survey and then leaks are screened and measured. DI&M can be conducted using soap bubble screening, electronic screening, toxic vapor analyzers, organic vapor analyzer, ultrasound leak detection, acoustic leak detection or infrared leak detection. Implementation of the program often results in initial costs savings. Savings may be reduced over time as the more significant leaks are repaired.

F. Acid Gas Emissions

Amine units remove acid gases, such as hydrogen sulfide (H_2S) and carbon dioxide (CO_2), from the gas stream by scrubbing with a water solution of an organic amine, such as diethanolamine (DEA) or methyl diethanolamine (MDEA). The resultant scrubbed gas can be vented to atmosphere if little H_2S is present, vented to an acid gas flare, sent to a sulfur recovery plant, or disposed by underground injection. As regulatory scrutiny increases on vent gas flaring and the economic benefits of recovering elemental sulfur decrease, underground injection is becoming an increasingly popular option for disposal of acid gases from amine units.

Flares have been used for decades to control vent gas emissions of VOCs and acid gases from a wide range of industrial processes, including the upstream oil and gas industry. In a typical application, acid gas from the amine unit is routed to an elevated, open flare for combustion. The burner tip (flare tip) is located at the top of the flare stack. A continuously lit pilot ensures that vent gases are combusted at the flare tip. Elevated flares have the environmental benefit of reducing H_2S emissions, but will generate sulfur dioxide (SO_2) emissions (and possibly other reduced sulfur compounds) during the combustion process, depending on the level of conversion achieved. Auxiliary fuel combustion (i.e., natural gas) is required for the pilot flame and is also a source of additional combustion emissions.

Elevated, open flares are a low capital cost and low maintenance emission control device (Hendler et al., 2006). However, they do require fuel (i.e., natural gas) for the pilot flame. The primary barrier to their future use is increased regulatory focus on flare combustion efficiency. The most likely advancements in combustion efficiency will come from a better understanding of key operational parameters such as turndown ratio and air/steam assist ratios.

Sulfur recovery plants generally are used at natural gas processing plants where the gas is sufficiently sour but they also are a potential option for use at upstream oil and gas sites with amine units. The Claus sulfur recovery process, first developed over 100 years ago, is still the most widely used process today. Between 90 and 95 percent of the total sulfur recovered worldwide uses a variation of this process (EPA, 1993). Sulfur recovery plants have the environmental benefit of improved air quality through sulfur recovery. However, the resulting gas stream often is sent to a tailgas treating unit where it is incinerated, generating SO_2 during the combustion process. Sulfur recovery plants allow operators to economically process sour gas and thereby provide increased access to sour natural gas resources. They also allow for the sale of recovered sulfur as a commodity, although the pertinent market is becoming increasingly saturated and economically less appealing.

Underground injection of acid gas is an attractive option in cases where it is not economically feasible for companies to recover elemental sulfur for sale. Acid gas can be compressed to high pressures and injected underground directly in permitted injection wells. Acid gases can also be dissolved in oilfield produced water at the surface and injected into subsurface formations. Although this technology, which began in Canada in the 1980s, is in the demonstration stage, it potentially offers producers a low-cost, environmentally sound alternative to vent gas flaring and sulfur recovery. Canadian oil and gas processing companies pioneered the effort to dispose of acid gases in subterranean brine-saturated aquifers. The technology has advanced rapidly with hundreds of projects worldwide.

Underground injection is environmentally beneficial through elimination of vent gas flaring and sulfur recovery plant tailgas treatment units. It also proves to be an opportunity for CO_2 sequestration and enhanced oil recovery.

VARIATIONS BASED ON RESOURCE TYPE AND LOCATION

- Onshore vs. offshore operation. Emissions from offshore production and completion operations will be similar to those for onshore activities except that offshore operations will not produce fugitive dust. [Excluded from discussion here are mobile source emissions. Offshore production requires a very different mix of mobile sources (ships and helicopters) relative to onshore production (trucks).]

- Wet gas vs. dry gas production. Production of wet gas (significant amounts of condensable hydrocarbons) requires use of separators and tankage to store the produced liquids. A very dry gas (little or no condensable hydrocarbon production) may only require separation and storage of produced water, eliminating potential emissions from condensate storage and transfer operations.

- Sour gas vs. sweet gas. A sour gas containing higher concentrations of hydrogen sulfide (H_2S) and other sulfur compounds will require "sweetening" prior to transmission and distribution. Sweetening is accomplished through use of an amine unit. Natural gas containing little or no sulfur compounds may require no sweetening -- or sweetening of only a portion of the total gas flow.

LONG-TERM VISION

Much progress has been made, and continues to be made, in reducing air emissions from natural gas production, processing and transmission systems. Examples of this on-going progress include:

- Where economically viable, implementation of directed leak detection and repair (LDAR) programs that integrate use of technologies beyond passive infrared cameras to "see" hydrocarbon leaks. For example, the use of airborne path-integrated differential absorption LIDAR, or DIAL, to survey pipelines for leaks.

- Use of newer engines and process heaters that are more efficient (consuming less energy) and produce fewer combustion emissions. In a similar fashion, optimization of engine horsepower by consistently downsizing engines when natural declines in natural gas volumes require less horsepower.

- Use of electric motors to power pumps and compressors in areas of significant air quality concern and where there is ready access to the electric grid. Electrification eliminates combustion emissions for that source.

- Beginning to use renewable energy in certain, limited applications. The best example is the use of solar-powered methanol injection pumps.

- Centralized production in the drilling of more wells from a single pad. This approach results in less infrastructure needs with fewer engines, fewer haul roads with associated fugitive emissions, fewer but more highly utilized liquids storage tanks that are more amenable to VRU application, as well as less piping and opportunities for leakage.

- Use of helicopters to bring in and remove equipment in sensitive areas. This eliminates haul roads and associated fugitive dust emissions.

One can envision a future where air emissions from natural gas production, completion, processing and transmission operations are nearly eliminated. Technologies that are either under development or have actually been used in limited field applications include:

- Continued improvements in open-path instruments used to detect leaks and focus repair programs. As an example, EPA is developing a low-cost, fenceline monitor that can be used to rapidly detect elevated hydrocarbon emissions. Similar (albeit, more expensive) systems have been used in the process industries to direct LDAR program responses and dramatically reduce leak times.

- Produce gas from more, smaller holes. Smaller holes reduce drilling completion infrastructure needs and the associated air emissions.

- In place of venting, capture amine unit emissions (or sulfur recovery plant tail gas) and either inject into underground formations or compress and pipe to areas for enhanced oil recovery applications. This would eliminate the GHG and other pollutant emissions from these units.

- Three-phase gas gathering (gas, condensable hydrocarbons, and produced water), where the production fluids are transported by pipeline to a centralized separation and processing facility. This can eliminate the need for field storage tanks as well as the associated tank emissions and haul truck traffic. Centralized storage facilities with higher production rates are expected to be more amenable to VRU application. Three-phase gas gathering has been field tested in areas where the terrain allows for gravity flow of the production fluids from the producing wells to the centralized processing facilities.

- Remote operation of production sites, reducing the need for visits to the site and the associated vehicular traffic and fugitive dust emissions. Remotely operated facilities already have demonstrated a two-thirds reduction in vehicular traffic.

- Replacement of combustion sources with electric motors powered by alternative energy sources. Examples could include:

    - Fuel cell-powered drilling and completion rig engines.

    - Fuel cell-powered compressor stations.

- Construction of near-leakless transmission pipelines and gathering systems. Plastic liners can be inserted into main transmission lines, resulting in a significant reduction in leakage. Coupled with near-leakless components (compressors, valves, etc.), a near-leakless pipeline can be constructed using currently-available technologies. Improvements in component and system design over the next 25 years should allow for even further reductions in pipeline losses.

FINDINGS

For every source of air emissions from oilfield and gasfield operations, technologies have been developed to reduce emissions although widespread deployment of those technologies are not always economical for commercial projects. Ongoing challenges are to make retrofits of newer technologies easier and more economical for older systems and to make new technologies more affordable during construction of new systems. After review of technologies available for the major sources of emissions, the main findings are:

- The most effective means of reducing road dust is reducing the vehicle miles traveled which can be achieved by consolidating and sharing roads, using existing roads wherever possible, and designing and managing operations to eliminate or reduce trips. Suitable consolidations would include multiple wells per pad and three-phase gathering which can eliminate the need to haul water and condensate.

- The most effective strategy to reduce emissions from combustion sources is to find a technology that provides combustion using alternative energy. For example, fuel cells can be used in lieu of combustion engines. The main limitation at this time is the cost of an appropriately sized fuel-cell engine that becomes prohibitively expensive when scaled upward to the needs of oil and natural gas production.

- The most effective manner to reduce emissions from dehydration is to find an alternative process to glycol dehydrators. In areas where it is applicable, a desiccant dehydrator can substantially reduce methane, VOC and HAP emissions while sometimes also reducing also reduce operation and maintenance costs.

- The most effective method of reducing VOC and methane emission from storage tanks and loading is to reduce the number of tanks and reduce the need for loading into trucks. Closed-loop and three-phase gathering systems can reduce the number of tanks in a field and need for loading into trucks.

- Fugitive emissions from other equipment is best addressed through an enhanced directed inspection and maintenance (DI&M) program, beginning with a baseline survey followed by a comprehensive repair plan.

- Reduction of acid gas emissions should not ignore the proven effectiveness of combustion flares although more attention should be paid to underground injection of the acid gases where that avenue is available.

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