Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers

Roger Fernandez, U.S. Environmental Protection Agency (EPA) Natural Gas STAR Program; **Robin Petrusak,** SPE, and **Donald Robinson,** SPE, ICF Consulting; and **Duane Zavadil,** Bill Barrett Corp.

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Introduction

U.S. demand for natural gas continues to grow dramatically, in large part because methane is the cleanest-burning fossil fuel. Onshore and offshore drilling and production continue to expand, often in very challenging plays ranging from shallow low-pressure coalbed methane to deep high-pressure/high-temperature gas production. A significant amount of this demand is expected to be met by independent producers.

The U.S. Dept. of Energy estimates that small and midsize independent operators produce more than two-thirds of the natural gas in the lower 48 states. Independent producers drill 85% of new gas wells in the U.S., and 80% of these companies have fewer than 20 employees.* Methane emissions from the U.S. natural gas production sector are approximately 150 Bcf/yr. With record sales prices for natural gas and high consumer demand, natural gas producers have great incentive and opportunity to reduce currently lost product and increase their revenue. Often many small producers lack the time and technical staff to research and evaluate cost-effective methane emission reduction opportunities, yet there are numerous proven and cost-effective methane emissions reduction technologies and techniques that are available today to the small to midsize producer.

While individual releases of methane may appear to be minor, emissions are often continuous in nature, and cumulatively they become economically significant. This article provides information on methane emission reduction options that were developed by operators and promoted by the U.S. Natural Gas STAR Program, and are economic for small and midsize producers. In addition to increased revenue through reduced methane loss, many of the technologies and practices outlined here reduce operating costs, increase overall production, and provide high rates of return. All of these technologies and practices have been reported by gas producers through their participation in the Natural Gas STAR Program. This paper provides information and tools to help independent producers determine the most profitable gas emissions savings options for their operations.

We describe 25 cost-effective methane emission reduction technologies and practices in **Table 1,** provide costs and savings data in **Table 2,** and crosswalk technologies and practices with production characteristics in **Table 3** to help determine where each methane savings option is most likely to work. Finally, we provide a method to scale this data to your operation and calculate your potential economics in **Fig. 1.**

Cost-Effective Options for Reducing Methane Emissions

Options for reducing methane emissions from the small to midsize natural gas producer range from cost-effective methods to find and fix fugitive emissions to installation of new technologies that frequently pay back investments in less than a year. Natural Gas STAR partner companies have implemented these options when the wellhead price of natural gas was between U.S. $1.75 and $3/Mcf. With the current higher price of natural gas, these practices and technologies are even more attractive today. High natural gas prices are motivating companies to seek even more new technologies and practices for natural gas emissions reductions. One exciting example is aerial optical leak imaging using an infrared camera mounted in a helicopter that can "see" natural gas leaks and emissions in real time, identifying the exact locations of leaks in gas-gathering pipelines and compressor stations. The camera can also be operated hand-held in ground facilities. One Natural Gas STAR partner company discovered that it was receiving only half the gas metered into its gathering system! It is now using aerial optical leak imaging to find those leaks.

Which Technologies Work for Your Production?

While total U.S. production of natural gas has remained relatively flat during the past 5 years, the resource mix in the U.S. has shifted away from conventional gas to more challenging unconventional gas production. Each type of gas production has unique technology and operational requirements, with different opportunities for gas savings. This section describes production characteristics and potentially applicable emission reduction opportunities from the Natural Gas STAR Program. Table 3 crosswalks the gas production characteristics with the Gas STAR technologies and practices that are most likely to be cost-effective.

U.S. gas production increasingly comes from unconventional gas reservoirs including low-permeability gas sands, coalbed methane, and gas shale. Unconventional resource plays extend over wide areas that are best developed by large numbers of wells, each draining a small area. Such reservoirs often require fracture stimulation, horizontal drilling, and multiple-zone completions. Producing fields are likely to require extensive gathering systems, more compression and fluid lifting, and more-frequent well intervention for stimulation, well treatments, and tubing change-outs to debottleneck production. The production challenges of extensive unconventional resource plays increase the possibility of gas loss and methane emissions. For example, more wells and more gathering lines provide more opportunity for leaks and fugitive emissions. More surface equipment and compression produce more process emissions, especially where gas pneumatic controls are used.

Conventional gas reservoirs have also become more challenging to produce. New technology allows smaller accumulations to be discovered and developed, and new producing zones and infill drilling are extending the productivity of mature fields. In many traditional producing regions, the new onshore gas completions typically have higher initial production rates, a steeper production decline, and

*Remarks by Robert Gee, Assistant Secretary for Fossil Energy, U.S. Dept. of Energy at the Society of Petroleum Engineers 12th Symposium on Improved Oil Recovery, Tulsa, 3 April 2000.

Table 1—Cost-Effective Options for Reducing Methane Emissions

Install Plunger-Lift Systems in Gas Wells. In mature gas wells, the accumulation of fluids in the well tubing can impede and sometimes halt gas production. Gas flow is often maintained by blowing the well to the atmosphere (venting), resulting in substantial methane emissions. Installing a plunger-lift system is a cost-effective alternative for removing liquids, maintaining production rate, and minimizing gas lost to emissions. A plunger lift uses gas accumulation at shut-in pressure in the well casing to push the plunger and a column of accumulated fluid up the well tubing. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdowns. In addition, reported gas production following plunger-lift installation increased by as much as 18 MMcf per well.

Green Completions. The common practice in completing a gas well following drilling or workover is to flare or vent initial produced gas to scour the producing zone of drilling fluids, sand, and water. An alternative is to bring to the wellsite portable equipment that cleans up most of the initial produced gas to pipeline sales standards. Equipment includes portable sand traps, separators, and a dehydrator if the permanent installation is not completed or is out of service for maintenance. For low-pressure wells, it may be necessary to include a portable compressor that can take suction off the sales line to inject gas into the well to initiate flow and then boost the gas to the sales line until liquids and solids are unloaded. This practice is called "green completions" by some Gas STAR partners.

Install Flash-Tank Separators on Dehydrators. Triethylene glycol is commonly used to remove moisture from gas. It also absorbs methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). Dehydrators with Kimray "energy exchange" pumps require extra gas for pump power. This gas is vented to the atmosphere with the absorbed methane, VOCs, HAPs, and water vapor (approximately 1.2% of production, or 12-Mcf/D methane emissions for a 1-MMcf/D gas dehydrator). A flash-tank separator, installed between the pump driver and glycol regenerator, operating at fuel gas system or compressor suction pressure, recovers approximately 90% of methane and 10 to 40% of VOCs and HAPs. Where there is a low-pressure outlet for recovered gas, flash-tank separators pay back investment in less than 1 year.

Replace Glycol Dehydrators With Desiccant Dehydrators. Glycol dehydrators vent methane, VOCs, and HAPs to the atmosphere from the glycol regenerator, bleed natural gas from pneumatic control devices, and burn natural gas in the glycol reboiler. Replacing glycol dehydrators with desiccant dehydrators reduces methane, VOC, and HAP emissions by 99% and saves fuel gas for sales. Desiccant dehydrators cost less to install and have lower operating and maintenance costs. In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets adsorb moisture from the gas and gradually dissolve. The unit is fully enclosed, and gas emissions occur only when the vessel is opened to add desiccant.

Reroute Glycol Skimmer Gas. Some glycol dehydrators have glycol still condensers and condensate separators to recover natural gas liquids and reduce VOC and HAP emissions. Noncondensable gas from the condensate separator (i.e., "skimmer gas") is mostly methane and is typically vented to the atmosphere. Rerouting the skimmer gas to the reboiler firebox or other low-pressure fuel-gas systems reduces methane emissions and saves fuel. Using glycol skimmer gas as a fuel directly offsets use of saleable gas, increasing product revenues and quickly paying back the low capital, operating, and maintenance costs.

Pipe Glycol Dehydrator Vapor to VRU. Another option for reducing methane, VOC, and HAP emissions from a glycol dehydrator is to pipe the regenerator vent stack to an oil-storage tank equipped with a vapor-recovery unit (VRU). The vapor space in the tank serves as a cushion for variations in pressure and flow from the dehydrator and oil production. Additional gas recovery enhances the economics of a VRU. The VRU boosts the recovered gas pressure enough to inject it into a fuel-gas system, compressor-suction, or gathering/sales line.

Convert Gas-Driven Chemical Pumps to Instrument Air. Circulation pumps in glycol dehydration units and chemical-transfer pumps are often powered by pressurized natural gas. Such pumps vent methane gas to the atmosphere as part of their normal operation. Replacing natural gas with instrument air to drive the glycol circulation and chemical-transfer pumps increases operational efficiency, decreases maintenance costs, and reduces emissions of methane, VOCs, and HAPs. This emission reduction opportunity utilizes excess capacity of an existing instrument-air system. The methane emission savings are determined by the glycol circulation rate and the water removal rate. Gas savings in the range of 2.5 to 9 MMcf/yr are possible. This technology has a quick payback. Capital costs are incurred to install piping between the air compressor and the glycol dehydrator pump and are assumed to be incremental to the cost of the air compressor already in use for pneumatic controls. The operating cost is incremental electricity for air compression.

Lower Heater-Treater Temperature. Heater-treaters use thermal, mechanical, gravitational, and chemical methods to break emulsions and separate crude oil from water. Elevated temperature is effective in lowering oil viscosity and promoting phase separation, but requires fuel gas and causes volatile hydrocarbons in the oil to vaporize and vent. Heater-treater temperature settings at remote sites may be higher than necessary, resulting in increased methane and VOC emissions. Identifying the lowest practical heater-treater temperature in conjunction with product quality standards and other treatment factors can reduce vented emissions. This practice can pay back the incremental labor with fuel-gas savings. No capital investment is required; however, additional de-emulsifier chemical, where used, may be needed to compensate for lower temperatures.

Install BASO Valves. Heater-treaters, gas dehydrators, and gas process heaters burn natural gas in air-aspirated burners. Wind gusts can blow out the flame and pilot, resulting in leaking gas and methane emissions until the pilot is relit. BASO valves prevent this gas loss. BASO valves are snap-action valves activated by a thermocouple that senses the pilot flame temperature. When the flame is extinguished, the valve shuts off the fuel-gas flow, preventing continued fuel loss and methane emissions. Each BASO valve costs less than U.S. $100, and the gas savings can be significant. One partner company reported saving more than 200 Mcf/yr for a single installation.

Inspect Flowlines Annually. Flowlines are normally buried and can develop leaks from internal and external corrosion and abrasion. Many flowlines are inspected infrequently, and large leaks may go unnoticed for a long time. As a result, leakage from flowlines is one of the largest sources of methane emissions in the natural gas production sector. Annual flowline inspection and a regular leak-repair schedule will reduce gas losses and prevent small leaks from growing into major leaks. Leaks in buried flow lines may be detected by using an ultrasound detector, or infrared imaging, or through the temporary introduction of odorant into the gas stream. Walking inspections are more effective using leak-detection or leak-imaging devices or odorants. The average methane emissions from buried flowlines are estimated to be 53 scf/D per mile.

Composite Wrap To Repair Nonleaking Pipeline Defects. Composite wrap is a permanent, cost-effective pipeline-repair technology, suitable for nonleaking defects such as pits, dents, gouges, and external corrosion. Composite wrap can be installed on an operating pipeline with a lower-skill, lower-cost maintenance crew than the typical cut-and-weld repair. This repair technique is quick and restores the pressure rating of the pipeline. Composite-wrap repair avoids venting of the damaged pipe—reducing methane emissions, saving product, avoiding service interruption, and reducing repair costs. Savings from composite-wrap repair pay back costs immediately.

Begin Directed Inspection and Maintenance (DI&M) at Remote Facilities. Fluctuations in pressure, temperature, and mechanical stresses on pipeline components (such as valves and seals) eventually cause them to leak. A DI&M program concentrates on components such as valve packing, pneumatic controllers, open-ended lines, blowdown lines, pneumatic engine-starter motors, and pressure-relief valves, which are prone to large leaks that are cost-effective to find and fix. A survey is conducted in the first year of a DI&M program to identify leaking components. In subsequent years, inspection and repair efforts are focused on components that are the most likely to leak and most cost-effective to repair. Partner companies report that leak surveys cost U.S. $200 per station when multiple remote stations are surveyed at one time.

Table 1—Cost-Effective Options for Reducing Methane Emissions (Cont.)

Use Ultrasound To Identify Leaks. Some of the hardest leaks to find, and therefore among the largest leaks, are shutoff valves on open-ended lines that vent through an elevated stack. Ultrasound leak detectors are tuned to detect the high-frequency sounds associated with gas flowing through a valve that is not tightly closed. Lower-frequency background noises are filtered out. The magnitude of the sound corresponds to the magnitude of the leak. Ultrasound detectors can be applied to all in-service shutoff valves and pressure-relief, blowdown, starter-motor, and unit isolation valves. The cost of an ultrasound detector is approximately U.S. $250. Operating costs include the labor to locate and repair leaking valves, which may be as simple as tightening the valve. This emission reduction option is most cost-effective at facilities with a large number of valves.

Aerial Optical Leak Imaging. Infrared cameras, filtered and tuned for the wavelengths of sunlight absorbed and re-emitted by natural gas hydrocarbons, can present a visual image of leaking gas. Such cameras are operated in helicopters with global positioning systems (GPSs) and can detect leaks up to 2 miles away, depending on size and terrain. This is a very quick method to find and pinpoint location of pipeline and gathering-line leaks. Hand-held units are used on the ground in plants to quickly locate even very small leaks, less than 1 cf/hr.

Replace High-Bleed Pneumatic Devices. Pneumatic devices powered by pressurized natural gas are used widely in the natural gas production sector as liquid-level, pressure, and temperature controllers. Pneumatic controllers release gas to the atmosphere by design. Replacing or retrofitting high-bleed devices (average 363 scf/D methane emissions) with low-bleed (average 45 scf/D) at a time when the installed pneumatic device needs major overhaul is generally economical.

Convert Gas Pneumatic Controls to Instrument Air. Converting natural-gas-powered pneumatic control systems to compressed-instrument-air systems eliminates 100% of the methane emission from valve controllers and may also be used to eliminate methane emissions from pneumatic pumps and compressor-engine pneumatic starters. Applications are limited to field sites with available electrical power.

Convert Pneumatic Controls to Mechanical Controls. Remote gas production sites often use natural-gas-powered pneumatic controllers for automatic process control, resulting in significant methane emissions. Methane emissions can be avoided by converting some pneumatic controls to mechanical devices. The most common mechanical control device is a level controller, which controls the position of a drain valve by mechanical linkages to the position of a liquid-level float. The mechanical device eliminates both the process controller bleed and the valve-actuation vent emissions. Mechanical controls can be used where the process measurement is close to the flow control valve, with a savings of 500 Mcf/yr per controller.

Install VRUs on Crude-Oil and Condensate Storage Tanks. Transferring crude oil and condensate from the low-pressure separator to an atmospheric storage tank results in vaporization and venting of light hydrocarbons, including significant amounts of methane, to the atmosphere. Furthermore, during storage, more light hydrocarbons evaporate from the oil and vent with working and standing losses. Oil tank emissions are the second largest source of production-sector methane emissions. VRUs are relatively simple systems that can capture approximately 95% of the Btu-rich vapors for sale or for on-site fuel. With electrical power available at a site, a conventional rotary compressor VRU can be cost-effective. Without electrical power, and with a high-pressure compressor with spare capacity, an “ejector vapor recovery unit” can be cost-effective and more reliable, having no moving parts.

Recycle Line Recovers Gas During Condensate Loading. Lease condensate, when transferred from storage into tank trucks, can generate significant volumes of methane caused by pressure and temperature changes and evaporation. This methane is typically vented to the atmosphere but can be contained by connecting the tank truck vent to the condensate storage tank with a vapor-recovery system. This emission reduction practice applies to all condensate production operations using tank trucks or railroad tank cars for transportation. Recovered methane can offset the low cost of this project.

Connect Casing to VRU. Crude-oil wells produced with downhole pumps accumulate gas in the casing that may be vented directly to the atmosphere to prevent vapor lock of the pump. Connecting the casinghead vent directly to an existing VRU can reduce methane emissions. Operating requirements may include a pressure regulator if low-pressure casinghead gas is combined with higher-pressure sources at the suction of a VRU. Only small-diameter piping is required to join a casinghead vent to the VRU.

Reduce Methane Emissions From Compressor-Rod Packing Systems. Calculating an economic rod packing replacement threshold, and monitoring packing leakage, can save both methane emissions and maintenance costs on reciprocating compressors. Gas leaks from compressor rods represent one of the largest sources of emissions at natural gas compressor stations. All packing systems leak under normal conditions. A new packing system, properly aligned and fitted, may lose approximately 11 to 12 scf/hr. One gas producer measured emissions of 900 scf/hr on a single compressor rod. A simple calculation using company-specific financial objectives and monitoring data can determine emission levels at which it is cost-effective to replace rings and rods.

DI&M at Compressor Stations. Fugitive emissions from equipment leaks at compressor stations produce an estimated 50.7 Bcf of methane emissions annually from excessively leaking compressor seals and other components exposed to the thermal and vibrational stresses associated with a compressor, such as valves, flanges, connections, and open-ended lines. Implementing a DI&M program at compressor stations has proved to find gas emissions that are cost-effective to repair. A DI&M program begins with a baseline survey to identify and quantify leaks. Surveys typically find that the majority of fugitive methane emissions are from a relatively small number of leaking components. This being a nonregulatory program, subsequent surveys can concentrate on the components that are most likely to leak and are profitable to repair. Initial survey costs, estimated at U.S. $1 per component for large stations, typically pay back in the first year of gas savings.

Replace Gas Starters With Air. Engines for compressors, generators, and pumps are often started using small gas-expansion turbines. Pressurized gas expanded across the starter turbine rotates the engine for startup, and then vents to the atmosphere. Replacing the natural gas with compressed air will eliminate this source of methane emissions. A stationary or mobile air compressor is required. Other implementation costs include installation of piping between an existing air compressor and the starter motor and electrical power for the compressor. Methane emission reductions depend on the number of engine startups and the volume of gas needed to start the motor. One partner reported total methane savings of 500 Mcf/yr for multiple engine startups.

Replace Ignition/Reduce False Starts. Before starting a compressor, the discharge header is unloaded by depressuring gas to the atmosphere. The engine is then turned over, often using a gas-expansion turbine starter. Both operations vent methane to the atmosphere. If the ignition system is in poor condition, the engine will not start promptly or will stall when the compressor is loaded, resulting in excessive methane emissions with each restart attempt. Replacing old point-contact ignition systems with newer electronic designs reduces false starts. In addition to eliminating methane emissions, new ignition systems can significantly reduce operating costs. One partner company reported saving 1 Mcf of gas per start. This technology can pay back quickly by reducing the labor cost to attend to a unit with many false starts.

Install Electric Starters. Gas-expansion starter turbines on compressors, generators, and pumps can also be replaced by electric starter motors, similar to an automobile engine starter. The technology may include a connection to utility electrical power, site-generated power, or solar-recharged batteries. Conversion to electric starters completely eliminates the venting of methane to the atmosphere and potential leakage of methane through the gas shutoff valve. Partners have reported savings of 23 to 600 Mcf/yr depending upon how frequently engines are restarted and how readily the engine starts up. A single start of a properly tuned engine may require 1 to 5 Mcf of gas at 200-psig average volume tank pressure, depending on engine size. This technology can pay back in less than 3 years.

TABLE 2—METHANE EMISSION REDUCTION TECHNOLOGIES AND PRACTICES

TECHNOLOGIES & PRACTICES	COSTS & BENEFITS Equipment Cost	O&M Costs	Saleable Gas Savings	Operating Requirements	Basis for Cost & Savings	Other Benefits
	$	$/yr	Mcf/d			
Well Performance						
Install Plunger Lift Systems*	$8,000 per well	$1,000 per well	12.9 - 50	Well shut-in pressure significantly higher than sales line pressure	Installation of a plunger lift system in one well	Lower capital cost than beam lift; Less well maintenance
Green Completions*	N/A	$14,000 per well	7,000 per well per year	Connection to sales line	Per well contract service including transportation, connection and operation	Recover average 2.5 barrels of condensate per well
Separation/ Dehydration						
Install Flash Tank Separators in Glycol Dehydrators	$5,000	N/A	10	Low pressure destination for recovered gas, i.e. compressor suction or fuel gas system.	Flash tank separator for a 20 MMcfd glycol dehydrator with a glycol circulation rate of 150 gal/hr	Reduce VOCs & HAPs; Recover gas for sales or fuel use
Replace Glycol Dehydrators with Desiccant Dehydrators	$12,750	$1,200 net savings	1.5	Require cool produced gas stream, weekly salt make-up	Replace 1 MMcf/d glycol dehydrator, cost includes 50% salvage value	Reduce VOCs and HAPs
Reroute Glycol Skimmer Gas*	<$1,000	$100	20.8	Condensate separator at higher pressure than reboiler fire box	Dehydrator throughput = 20 MMcfd; Glycol circulation rate = 300 gallons/hr	Reduce VOCs and HAPs; fuel gas savings
Pipe Glycol Dehydrator Vapor to VRU	$1,000	$3,000	9.0	Existing VRU with excess capacity	Dehydrator throughput = 10 MMcfd Operating cost is incremental electricity	More gas to sales or fuel
Convert Gas Driven Chemical Pumps to Instrument Air	$1,000	$1,000	6.8	Excess capacity in existing instrument air system	Glycol pump on a 10 MMcfd dehydrator operating cost is incremental electricity	Increase in operational efficiency, Reduced maintenance costs
Lower Heater-Treater Temperature*	NA	<$100	0.4	Periodically inspect oil quality	Average well head heater treater	Fuel gas savings
Install BASO® Valves*	$200	<$100	0.6	Max inlet gas pressure is 0.5 psig	Installing one BASO® valve on a 1000 bbl/d heater/treater with a flameout of 10d/yr	Improved safety
Flowlines/ Gathering Systems						
Inspect Flowlines Annually	$250	$5,000	5.0	Purchase Ultra Sound leak detector for buried pipe leak detection	Inspecting 100 miles of pipeline one month, finding a leak each 3 miles	Prevent small leaks from increasing in volume over time
Composite Wrap for Non-Leaking Pipeline Defects	$4,000	$10,000 net savings	11.0	Reduce pipeline pressure during repair	Repair 6-inch defect on a 20" pipeline, O&M net savings over weld repair	No service interruption, reduced labor costs
Facilities - General						
Begin DI&M at Remote Facilities	NA	$1 per compontent screened	1.0	Soap solution and/or Gas Detector	Screening 200 components, repair leaks in one open-ended blowdown valve and one control valve stem seal	
Use Ultrasound to Identify Leaks	$250	$1,200	5.5	N/A	Testing 10 compressor trains finding 100 leaking valves on open ended lines	
Aerial Optical Leak Imaging*	N/A	$450/hr travel plus $65/mile	2,000	Operating location ≤5 hours helicopter travel time from service provider base	Surveillance of 500 miles of flowlines, identifying leaks totalling 2% of 100 MMcf/d production	Reduced VOC emissions
Production Facility Controls/Pneumatics						
Replace High-Bleed with Low-Bleed Pneumatics*	$1,350	$1,100 savings	0.5	May need to clean gas supply tubing and replace regulator	Replace one high-bleed pneumatic device when it needs a major overhaul	Increased operational efficiency, Financial return from reducing gas losses
Convert Gas Pneumatics to Instrument Air*	$10,000	$7,500	15.0	Electrical power supply	Small production site with 10 pneumatic gas control loops	Can use excess pneumatic air for pumps and compressor starters
Convert Pneumatic Controls to Mechanical Controls*	$1,000	$100	1.4	Mechanical linkages must be lubricated	Replace one liquid level control loop to mechanical dump valve	High controller reliability
Venting/ Flares						
Installing Vapor Recovery Unit on Crude Oil Storage Tanks	$26,500	$5,000	12	Electrical power supply for VRU compressor	Installing one 25 Mcfd VRU on crude oil or condensate storage tank(s)	Reduced VOC and HAP emissions
Recycle Line Recovers Gas During Condensate Loading*	$1,000	$100	0.3	Vapor recovery on the stock tank	Vapor recovery line attached to truck loading line, for shipments every 3-5 days with minimal additional labor	Reduced VOC and HAP emissions
Connect Casing to VRU	$1,000	$3,400	27.0	Pressure regulators may be required	Connecting one casing to an existing stock tank with VRU, O&M cost is incremental electricity	Reduced VOC and HAP emissions
Compressors/ Engines						
Reducing Methane Emissions from Compressor Rod Packing Systems*	$1,200	N/A	2.4	Periodically monitor rod packing leak rate	Replacing one compressor rod packing after 3 years rather than 4 years	Longer compressor rod life
Directed Inspection and Maintenance at Compressor Stations*	N/A	$26,000	80.0	Soap solution and/or Gas Detector	Annual screening of 2,700 components in a compressor station, 5% leaking	Subsequent screening more focused and cost-effective
Replace Gas Starters with Air*	<$1,000	$1,000	3.7	Existing air compressor	One 3,000 HP compressor; 10 starts/yr, O&M is incremental electricity	Reduced VOC and HAP emissions
Replace Ignition / Reduce False Starts*	$1,000 - $10,000	$700 net savings	0.1	Small amount of electricity for electronic ignition system	Reducing start-up attempts from 15 to 1/yr for a 3000 hp engine	Reduced operating cost
Install Electric Starters*	$10,000	$50	3.7	Requires electrical power supply	One starter, 10 starts/yr with average leakage through the gas shut-off valve	Reduced operator attention
* Technologies and practices that the Equipment Cost is directly proportional to the "Basis for Cost & Savings."						

lower ultimate recoveries, thus requiring more drilling and more-efficient well completions to sustain current production levels. As mature conventional fields are infilled and new producing zones are completed, field production systems must adapt to accommodate both low-pressure, older producing wells and high-pressure, rapidly declining new completions. The production challenges of mature conventional fields often increase the opportunities for gas loss and methane emissions through more frequent need to blow wells to the atmosphere to unload liquids.

For example, consider a conventional gas field in the Rocky Mountains that produces wet gas in a remote location. The reservoir is fairly deep, but normally pressured. Typical operations would involve glycol dehydrators and gas pneumatic controllers, both of which vent significant quantities of natural gas to the atmosphere.

TABLE 3—PRODUCTION CHARACTERISTICS FOR TECHNOLOGIES AND PRACTICES

TECHNOLOGIES & PRACTICES	GAS PRODUCTION CHARACTERISTICS: High Pressure Wet Gas	Low Pressure Wet Gas	Gas & Condensate	Coalbed Methane	Low Pressure, Dry Gas	Acid Gas - High CO_2 or H_2S	Oil & Associated Gas
Well Performance							
Install Plunger Lift Systems	X	X	X			X	X
Green Completions	X	X	X	X	X	X	
Separation/ Dehydration							
Install Flash Tank Separators in Glycol Dehydrators	X	X	X	X		X	X
Replace Glycol Dehydrators with Desiccant Dehydrators	X		X				
Reroute Glycol Skimmer Gas	X		X				
Pipe Glycol Dehydrator Vapor to VRU	X		X				X
Convert Gas Driven Chemical Pumps to Instrument Air						X	
Lower Heater-Treater Temperature							X
Install BASO® Valves	X	X	X	X		X	X
Flowlines/ Gathering Systems							
Inspect Flowlines Annually	X	X	X	X	X	X	X
Composite Wrap for Non-Leaking Pipeline Defects	X	X	X	X	X	X	X
Facilities - General							
Directed Inspection and Maintenance at Remote Facilities	X	X	X	X	x	X	X
Use Ultrasound to Identify Leaks	X	X	X	X	X	X	X
Aerial Optical Leak Imaging	X	X	X	X		X	X
Production Facility Controls/ Pneumatics							
Replace High-Bleed with Low-Bleed Pneumatics	X		X				X
Convert Gas Pneumatic Controls to Instrument Air	X		X			X	X
Convert Pneumatic Controls to Mechanical Controls	X		X			X	X
Venting/ Flares							
Install Vapor Recovery Units on Crude Oil Storage Tanks			X				X
Recycle Line Recovers Gas During Condensate Loading			X				
Connect Casing to VRU	X		X			X	X
Compressors/ Engines							
Reduce Methane Emissions from Compressor Rod Packing Systems	X	X	X	X	X	X	X
Directed Inspection and Maintenance at Compressor Stations	X	X	X	X	X	X	X
Replace Gas Starters with Air	X	X	X	X	X	X	X
Replace Ignition / Reduce False Starts	X	X	X	X	X	X	X
Install Electric Starters	X	X	X	X	X	X	X

As the field matures and the wells age, occasional venting may seem an economic way to unload liquids. As well unloading increases, expensive beam pumps might be installed at the wellhead to pump accumulated liquids (often largely water) to tankage. If the gas has high impurities content, particularly CO_2 and H_2S, flowline leaks may occur more frequently because wet sour gas is more corrosive. Table 3 shows that several emission reduction options are appropriate for this type of natural gas production.

Some of these options and their relative cost ranges are described below. The cost ranges are defined as follows: higher costs are greater than U.S. \$10,000; moderate costs are between U.S. \$1,000 and U.S. \$10,000; low costs are less than U.S. \$1,000.

• Glycol dehydrator emissions can be reduced by up to 90% at moderate cost by installing flash-tank separators.

• Glycol dehydrators can be replaced altogether with desiccant dehydrators at a higher cost, nearly eliminating gas emissions and also saving both fuel gas used for the glycol reboiler (sometimes a gas heater) and pneumatic gas used for glycol-unit controllers.

• High-bleed pneumatic controls can be replaced with low-bleed models at a low cost, cutting emissions by 90% and resulting in gas savings of –500 Mcf/yr.

• Directed inspection and maintenance (DI&M) at remote locations will find excessive gas leaks at a low cost, some of which may be reduced by simply tightening connectors or valve-stem packing. DI&M can reduce fugitive emissions by as much as 70% with repairs that pay back in months. Inexpensive soap solutions can be used to screen piping and tubing fittings for leaks. Moderately expensive ultrasound detectors can be used to quickly screen pressure-relief valves, blowdown valves, and isolation valves for internal leaks that go undetected because the gas emissions occur through inaccessible roof vents. Higher-cost optical leak-imaging technology, using either ground or aerial methods, can find these leaks quickly, in addition to those from buried gas-gathering pipes.

• External damage to flowlines that has not yet caused a leak can be repaired using moderate-cost composite wrap while the pipeline remains in service. This quick and cost-effective repair eliminates the need to shut down equipment and vent wells to the atmosphere, and it requires less skilled labor than the traditional cut-and-weld repair.

As a producing field matures, some areas may be infilled or recompleted, which may require production from higher-pressure new wells to be gathered with production from lower-pressure older wells. To prevent the production from older wells being kicked off line, additional compression and artificial lift may be installed in parts of the field.

• Plunger lifts are a moderate cost and eliminate the need to blow wells to the atmosphere to unload fluids, reducing emissions by as much as 50 Mcf/D per well. More importantly, plunger lifts increase gas production, minimize downhole scale formation, and extend the life of the well.

• Green completion is a higher-cost option that captures the gas and condensate normally vented and/or flared during well completion or workover. The portable equipment, consisting of a three-

Example: Replace a 2-MMcf/D glycol dehydrator with desiccant dehydrator with a gas price of U.S. $5/Mcf (after royalties)

From Table 2: Basis for cost and savings is a 1-MMcf/D desiccant dehydrator
Equipment cost=U.S. $12,750
O&M Cost=U.S. –$1,200
Gas Savings=1.5 Mcf/D

Calculation 1:
Equipment cost=square root (your size÷basis size)×basis cost
=(2 MMcf/D÷1 MMcf/D)×−U.S. $12,750
≈1.4×U.S. $12,750
≈U.S. $17,850

Calculation 2:
Your O&M cost=(your size ÷ basis size)−basis O&M cost
=(2 MMcf/D÷1 MMcf/D)×(−U.S. $1,200)
=2×−U.S. $1,200
=−U.S. $2,400

Calculation 3:
Your gas savings=(your size÷basis size)×basis gas savings
=(2 MMcf/D÷1 MMcf/D)×1.5 Mcf/D×365 days
=2×1.5×365
=1,095 Mcf/yr

Calculation 4:
Payback=Equipment Cost
(Annual Gas Savings×Price of Gas)×1 Year O&M
=U.S. $17,850
1,095 Mcf/yr×U.S. $5/Mcf×(−U.S. $2,400)
=2.3 years

For opportunities that the equipment cost is proportional to the basis:

Calculation 5:
Payback=Equipment Cost Basis
(Annual Gas Savings Basis×Price of Gas)−1 Year O&M Basis

Fig. 1—Calculating economics according to size of operation.

phase separator, dehydrator, and portable compressor, can be contracted or purchased, with payback in 2 years.

Determine Costs, Savings, and Economics

Once you are familiar with the technologies and practices described in Table 1, you can estimate your potential costs, savings, and economics using Fig. 1 and the data presented in Table 2. There are three basic factors required to determine a project's economics:

- Installed equipment cost.
- Annual operating and maintenance (O&M) costs.
- Annual savings.

In Table 2, the equipment costs in Column 2 include installation.

The simple economic measure that we calculate is "payback," defined as the number of years it will take to recover your installed-equipment cost, not counting tax and inflation. After the payback period, the difference in annual savings and annual O&M costs is pure profit.

Table 2 lists, for each of the technologies and practices described in Table 1, the installed equipment costs, O&M costs, saleable gas savings, operating requirements, and the basis for costs and savings. Other benefits are shown in the last column, but not quantified in the economics.

The "Basis for Costs and Savings" in Column 6 of Table 2 is important because this is what is used to scale the listed examples to the right size for your operation. A simple method of scaling the economics is described below, with equations and an example shown in Fig. 1. Note that we are calculating approximate economics for industry-average applications for your size. If these estimates look very attractive (i.e., less than 1-year payback), chances are that a more detailed analysis will also provide positive economics.

The data in Table 2 is derived from Natural Gas STAR partner company-reported installations, which probably do not exactly match each of your opportunities. Therefore, it is necessary to scale the data to your size application. Several of the technologies and practices involve installed-equipment costs that vary with the size of the operation. For example, flash-tank separators and desiccant dehydrators are sold in a range of sizes for different gas throughputs and pressures. For these applications, one cannot assume that double the throughput means double the installed-equipment cost. One rule of thumb is that capital and installation costs increase with the square root of the size change. This means that if your application is double the throughput basis in Table 2, Column 6, the cost will be the square root of 2, or approximately 1.4, times the base cost. For example, you want to evaluate replacing a 2-MMcf/D glycol dehydrator with a desiccant dehydrator. Table 2 shows that a 1-MMcf/D desiccant dehydrator costs U.S. $12,750 for the equipment (less 50% salvage value for the glycol unit replaced). Your size is two times the basis, so your cost would be estimated at 1.4 times U.S. $12,750, or U.S. $17,850.

O&M costs generally scale directly with size. Therefore, the U.S. $1,200 net savings in O&M (i.e,. a negative cost) for a 1-MMcf/D desiccant unit vs. a glycol unit can be doubled for a 2-MMcf/D unit, or a savings of U.S. $2,400/yr. Similarly, the gas savings generally scale directly with size. So a 2-MMcf/D desiccant dehydrator will save two times the 1.5 Mcf/D of gas, or 3 Mcf/D (multiplied by 365 days a year for annual savings). Fig. 1 shows equations for scaling Table 2 data to your size application, and then using your estimated costs and savings to determine how long it should take to pay back your costs and start making money. Of course, the payback depends on the price you receive for gas. With current high prices for natural gas, all of the technologies and practices should pay back more quickly than the original applications reported by Natural Gas STAR partner companies over the past 10 years.

Some of the technologies and practices listed in Table 2 do follow the description "one size fits all." For example, pneumatic controllers, plunger lifts, compressor-rod packing, and BASO valves are roughly the same size and cost for most gas-production applications. For these, use the costs and gas savings proportional to the number or frequency of applications shown in the Column 6 basis, and substitute your price for gas to determine your economics for each application you choose to evaluate. A good example is low-bleed pneumatic controllers, which generally cost from U.S. $400 to $1,350 depending on the type of service and functionality chosen. If you have the opportunity to replace two high-bleed level controllers, one on your glycol contactor and one on the reboiler, this will be twice the cost of the one-pneumatic-controller basis in Table 2, Column 6. Two controllers will save twice the gas. The economics (payback) for two will be the same as for one. Fig. 1, Calculation 5 shows the simple equation for determining the payback of these one-for-one technologies and practices using your gas price.

It is important to remember that these estimates are intended only to identify potentially attractive opportunities; they are not detailed enough to make engineering decisions. For actual projects, operators should contact their local equipment supplier for more-accurate equipment requirements and costs. Also note that the gas price used to estimate your economics should be the wellhead price minus royalty. For example, if your royalty is 12% and the wellhead price is U.S. $5.68/Mcf, the gas price used should be approximately U.S. $5/Mcf.

What Is the Natural Gas STAR Program?

The Natural Gas STAR program is a voluntary partnership of the U.S. natural gas industry and the federal government that promotes voluntary methane emission reductions through technologies and practices that provide an economic return to the companies. Gas STAR partner companies share cost-effective practices with the program, and with company permission, the program shares these successes publicly through the Gas STAR website, technology transfer workshops, public service announcements, and articles (like this one) in industry publications. More than 109 oil and gas companies are partners, and 12 of the largest oil and gas associations endorse the program. As of 2004, gas-production companies participating in the Natural Gas STAR Program represent 67% of U.S. production.

All gas industry sectors including production, processing, transmission, and distribution emit methane to the atmosphere to varying degrees. Since the program began in 1993, Natural Gas STAR partner companies have reported elimination of approximately 350 Bcf of methane emissions through the implementation of the Gas STAR Program's core Best Management Practices (BMPs), as well as other activities identified by partner companies, referred to as Partner Reported Opportunities (PROs). During this period, Natural Gas STAR partners saved more than a billion dollars by keeping more gas in their systems for sale in the market. Production sector partners reported 24 Bcf of methane emission reductions in 2002 and a total of 187 Bcf since 1990.

The Natural Gas STAR Program website, www.epa.gov/gasstar, lists all the partner companies and sponsoring associations. The "Documents, Tools, and Resources" section provides technical studies called "Lessons Learned" that describe in detail many of the key technologies and practices in Tables 1, 2, and 3. Others are presented in technology briefs, called "PRO Fact Sheets," which provide a one- to two-page summary of partner-reported technologies and practices.

Conclusions

Using the information, data, and simple tools in this report will help you identify cost-effective opportunities for your company. Each volume of gas not vented or leaked to the atmosphere is a volume of gas sold. With increasing natural gas demand and high prices, your emissions reductions will result in increased gas sales and greater revenue. Many of the technologies and practices will also reduce operating costs and improve well recoveries.

The data and simplified calculations presented here are economic screening tools, not design tools. If you find some good opportunities and want to go forward with implementation, the Gas STAR Program provides more information on the website, including contact information for seeking direct assistance from technical experts. Staff members in small and midsize producing companies typically have multiple roles and wide-ranging responsibilities in the organization. Often, they want to focus their valuable time only on new production practices and technologies that make economic sense for their operations and producing regions. The purpose of this article has been to provide the small and midsize independent operator with practical guides and tools to identify the costs and benefits of practices and technologies that will reduce leaks and methane emissions and send more hard-earned gas through the sales meter. The featured technologies and practices apply across a wide range of natural gas production operations and regions. Most importantly, these are company-reported opportunities and lessons learned by operators that have been field tested, implemented, and found to be cost-effective. That is what the voluntary Natural Gas STAR Program is all about: methane emission reductions that are economic for the gas-production, gas-processing, and transmission and distribution companies, including small to midsize independent producers. JPT

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