METHANE'S ROLE IN PROMOTING SUSTAINABLE DEVELOPMENT IN THE OIL AND NATURAL GAS INDUSTRY

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Introduction

Methane's unique role as a greenhouse gas and as the primary component of natural gas means that reducing methane emissions can yield significant economic, environmental and operational benefits. Methane emission mitigation activities undertaken by oil and natural gas companies prevent the loss of a valuable non-renewable resource by directing this clean energy source to beneficial use either via sales or internal use. At the same time, companies are reducing their emissions of greenhouse gases, improving operational safety and enhancing the efficiency of their operations. Further economic and operational benefits can result when methane mitigation activities reduce maintenance and fuel requirements or result in the capture of other valuable hydrocarbon resources. Numerous proven cost-effective technologies and practices exist that oil and natural gas companies have implemented to reduce methane emissions while also generating positive cash flows from utilizing the methane.

This paper summarizes a number of established methods to identify, measure, and reduce methane emissions from a variety of equipment and processes in oil and gas production and natural gas processing and transmission facilities. The following detailed discussions provide background on expected levels of vented and fugitive methane emissions from natural gas processing plants, compressor stations, storage tanks, centrifugal compressors, and well completion activities, based on published data and industry experience. This information is supported with case studies covering mitigation activities that have been undertaken by Petróleos Mexicanos (PEMEX) in Mexico, Pluspetrol in Argentina, EnCana Oil & Gas (USA), Inc. in the United States, and Gazprom in Russia. For each case study, operational, economic and environmental considerations are discussed to show how these companies are delivering greater revenue as well as environmental, efficiency and safety benefits while also conserving natural gas resources worldwide.

Background

By 2010, it is estimated that annual methane emissions from the global oil and natural gas industry will total 1.354 billion tonnes carbon dioxide equivalent[1]. This equates to 94.2 billion m^3 or U.S.$10.0 billion to U.S.$23.3 billion (at gas values of U.S.$106/thousand m^3 to U.S.$247/ thousand m^3) worth of natural gas lost to the atmosphere. By 2020, it is anticipated that these figures will increase by 35%, reaching 1.827 billion tonnes carbon dioxide equivalent, which equates to 127.9 billion m^3 of natural gas lost to the atmosphere. Methane represented 14 percent of total anthropogenic (man-made) emissions of greenhouse gases in 2004.[2] Emissions from the oil and natural gas industry are the largest anthropogenic source and second largest overall source of global methane emissions, accounting for 18 percent of worldwide methane emissions. With an atmospheric lifetime of 12 years, methane plays a critical role in achieving short-term climate impacts. A 2008 report by the Intergovernmental Panel on Climate Change (IPCC) shows that, over a relatively short time frame (20 years), the warming effect of year 2000 methane and carbon dioxide emissions will be the same, even though the volume of methane emissions is significantly smaller.[3]

In the oil and natural gas sector, the majority of methane emissions result from oil and natural gas production, and gas processing, transmission, and distribution operations. These emissions can take the form of unintentional leaks, intentional or designed venting from operational processes, and emissions due to maintenance or operational disruptions. Emissions from normal operations include: natural gas engines and turbine exhaust that includes uncombusted methane; bleed and discharge emissions from natural gas-driven pneumatic devices; vents from reciprocating and centrifugal compressors; emissions from storage tanks; and well workover, blowdown and completion activities. Fugitive leaks from system components can occur as gas moves through hundreds of valves, processing mechanisms, compressors, pipe connectors, pressure, level and temperature control valves, and other equipment. Whenever the gas moves through valves and piping connectors under high pressure, leaks can develop that allow methane to escape to the atmosphere. Maintenance emissions originate from pipelines, compressors, and other equipment when they are taken offline and natural gas is vented in order to safely perform maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.

To advance global reductions in methane emissions levels from the oil and natural gas sector, as well as other sources, the Methane to Markets Partnership was launched in 2004. Methane to Markets is an international public-private partnership that promotes cost-effective recovery of methane for use as a clean energy source. Participants currently include 28 national governments, including the U.S., Argentina, Mexico and Russia, and the European Commission, as well as over 900 other public and private sector organizations. With a focus on four major anthropogenic sources of methane emissions (oil and gas systems, agriculture (animal waste management), coal mines, and landfills), the

Partnership acts as a mechanism to bring together interested parties from national governments, private sector entities, development banks, non-governmental organizations, financial and technical experts, and other stakeholders to facilitate methane project development and implementation around the world.

In the oil and natural gas sector, the U.S. Environmental Protection Agency (EPA) contributes to these goals by drawing on a 16-year partnership with the oil and natural gas industry to promote technology transfer and capacity building in relation to numerous cost-effective methane mitigation options. Since 1993, oil and natural gas companies have partnered with the U.S. EPA's Natural Gas STAR Program to promote development, implementation and reporting of profitable, voluntary methane emission mitigation activities. This collaboration has resulted in the identification by industry of over eighty cost-effective methane mitigation technologies and practices.

Overview: Technical Mitigation Options & Case Studies

Through the Natural Gas STAR Program, in conjunction with the Methane to Markets Partnership, oil and natural gas companies are increasingly sharing information about successful implementation of methane mitigation projects. As the following case studies will show, companies can draw on existing commercially available, cost-effective technologies and practices to reduce methane emissions. By mitigating natural gas losses and contributing to gas sales and use, these activities can be a positive near-term focus for oil and gas companies interested in reducing their emissions of greenhouse gases and enhancing efficient management of this energy resource. The following sections discuss methane mitigation opportunities, including conducting methane emission detection and quantification surveys, implementing reduced emission completions, installing tank vapor recovery, and upgrading compressor seals. Paybacks range from 0.2 years to 3 years and these activities have broad applicability globally and across the industry.

Mitigation Opportunity - Methane Emission Detection and Quantification

Background
Operators at virtually every type of natural gas industry site have benefited by focusing on methane emission detection and quantification programs, given that repair of leaking components often amounts to tightening valves and connectors with immediate payback. In addition to finding leaking components, such targeted identification and quantification exercises also include quantification of process vent emissions from equipment such as tanks and compressors, providing oil and gas companies with the information needed to identify and prioritize focus areas for mitigation projects

Fugitive emissions from equipment leaks are unintentional losses and may arise due to normal wear and tear, improper or incomplete assembly of components, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and environmental effects. Components also tend to have greater average emissions when subjected to frequent thermal cycling, vibrations or cryogenic service. Typically a small percentage of equipment components have any measurable leakage, and of those normally a small percentage contributes to the majority of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.

Implementing a directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and address equipment leaks or other vented sources to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs are then made to the leaking components that are cost-effective to fix, based on criteria such as repair cost, expected life of the repair, and payback period. Subsequent surveys are designed based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.

Emission Detection and Measurement
A key barrier to addressing methane emissions has been the inability of companies to quickly and accurately detect, and subsequently quantify, methane emissions. Methane is a colorless, odorless gas and therefore emissions often go unnoticed. Though there are a variety of leak detection methods available, including soap bubble screening, electronic screening ("sniffers"), Toxic Vapor Analyzers and Organic Vapor Analyzers, ultrasound and acoustic leak detection, recent technology developments are improving operators' ability to comprehensively identify methane emission sources. One relatively new technology to detect hydrocarbon emissions is an infrared (IR) camera, which gives the camera operator a live, real-time visual image of methane emissions (see Exhibit 1). Hydrocarbon

emissions absorb infrared light at a certain wavelength. The IR camera uses this characteristic to detect and visually show the source of methane or other hydrocarbon emissions. The IR camera scans the components in real time at 30 to 50 Hz[4] scan frequency and spectral range of 3 to 5 microns. This scanned area is then converted into a live image in real time such that the gas plumes are visible due to their absorption of the IR light. Imaging can be performed from a distance from the target and the process doesn't impact plant operations. Operators regularly state that infrared cameras pay back in the first several uses due to the value of the gas saved from the leaks that are found and repaired.

Exhibit 1 Infrared Camera Display of Gas Plume Invisible to the Eye

Another infrared emission screening device is the Remote Methane Leak Detector (RMLD)[5]. The handheld RMLD allows remote detection of methane gas emissions, indicating presence of methane with audible signals and a Parts-per-Million-Meter (ppm-m) numeric display. Methane emissions absorb infrared light at a certain wavelength and the RMLD uses this characteristic to detect and indicate the presence of methane. The RMLD transmits an infrared laser beam and has a separate, visible spotting laser to guide the operator in pointing the IR beam. If methane is not present, the infrared laser is reflected back at the instrument by a background object. The extent to which the reflected beam is absorbed by methane indicates the extent to which methane gas is present in the beam's path, reported in ppm-m.

Once emissions are identified, the next step is to measure volumes of emissions to quantify emissions levels and fully analyze costs, benefits and outcomes of mitigation options. High volume samplers and calibrated bagging can be used to accurately quantify emissions rates from components in a DI&M program. High volume samplers work by pulling the emissions, plus a large volume sample of the air around the leaking component, into the instrument through a vacuum sampling hose. Dual hydrocarbon detectors then measure the concentration of hydrocarbon gas in the captured sample, as well as the ambient hydrocarbon gas concentration. Sample measurements are corrected for the ambient hydrocarbon concentration, and a mass leak rate is calculated by multiplying the flow rate of the air and gas pumped through the instrument by the difference between the ambient gas concentration and the gas concentration in the air stream. Methane emissions are obtained by calibrating the hydrocarbon detectors to a range of concentrations of methane-in-air. High volume samplers measure leak rates up to 0.2 m^3 per minute, equivalent to 326 m^3 per day

Leak rates greater than 0.2 m^3 per minute can be measured using bagging techniques or flow meters. Calibrated bagging uses bags of known volume (e.g., 1 m^3, 2 m^3), made from antistatic plastic with a neck shaped for easy sealing around the emission source. Measurements are made by sealing the bag around the emissions stream (usually a vent pipe) and measuring the time it takes for the bag to inflate to full capacity. This rate is used to calculate annual flow rates. Leak rate measurement using bagging techniques is accurate within ± 10 to 15 percent.

Rotameters and other flow meters are used to measure extremely large leaks that would overwhelm the high flow sampler or calibrated bags. Rotameters channel gas flow vertically upward from a leak source through a tapered calibrated tube. The flow lifts a "float bob" within the tube, indicating the leak rate. Because rotameters are bulky, these instruments work best for open-ended lines and similar components, where the entire flow can be channeled upward through the meter. Rotameters and other flow metering devices can supplement measurements made using bagging or high volume samplers.

In addition to identification and measurement, a key element to accurately calculating methane emissions rates is knowledge of the composition of the gas stream. This allows the operator to calculate the volumes of methane and other valuable hydrocarbons they are losing, which will facilitate economic analysis of mitigation options.

Methane Emission Detection and Quantification – PEMEX Case Study

Background
Petroleos Mexicanos (PEMEX) began exploring methane emissions capture as a business opportunity in 2004, with its participation in the Methane to Markets Partnership as a Co-Chair of the Oil & Gas Sector Subcommittee. PEMEX, Mexico's nationally owned petroleum company, is a major natural gas and petroleum supplier and is responsible for about one-third of Mexico's revenue. Fugitive methane emissions reduction became a priority project due to its merits of economic results, safety and environmental benefits. PEMEX pursues methane emission reductions with the goals of reducing their greenhouse gas emissions, increasing safety and operational efficiency, and generating revenues from methane emissions recovery.

Emission reduction activities began in 2006 with a multi-faceted approach, including DI&M, to address compressors, energy efficiency, fugitive emissions, and other sources in three of its gas processing complexes. PEMEX's eleven gas processing and compression facilities represent thousands of valves, connectors, open-ended lines, compressor seals, and other components, each of which is a potential path of methane emissions to the atmosphere and source of product loss. At the outset of their DI&M efforts, the company sought to learn the extent of fugitive and vented methane emissions losses, identify component types within facilities that are prone to leaks, assess leaking components for repairs, and determine cost-effectiveness of mitigation options. Through this effort, they built internal expertise for leak detection and measurement and developed cost effective best practices for a sustained leak detection and repair program.

Through its partnership with Methane to Markets, PEMEX developed a facility-level DI&M program that it has replicated at a total of six locations to date. PEMEX began with a baseline field study to identify and quantify fugitive methane emissions from all components, providing the initial data set for further business decisions. PEMEX then identified leaks and vents that were cost-effective to repair, conducted follow-up surveys, and reviewed leak data to identify trends to direct future DI&M work.

Survey instruments included electronic screening devices, infrared cameras, and the Remote Methane Leak Detector (RMLD). Quantification instruments for methane included the Hi Flow Sampler® and calibrated vent bags. Leak repair work was conducted by PEMEX personnel and included tightening, regreasing, repacking of valve stems, valve replacement, and centrifugal compressor seal retrofit.

PEMEX Facilities with DI&M Projects

1. Pemex Gas and Basic Petrochemicals Nuevo Pemex (processing)
2. Poza Rica (processing)
3. Burgos (processing)
4. Cactus (processing)
5. Ciudad Pemex (processing)
6. Pemex Exploration and Production Cunduacan (compressor station)

Results
Results for the baseline surveys are summarized in Exhibit 2. The baseline surveys identified a total of 12,255 thousand m^3/year of fugitive methane emissions from these six facilities. Methane emissions at individual facilities varied greatly, from 30 to 6,770 thousand m^3/year.

Exhibit 2 Summary of Fugitive Methane Emissions by PEMEX Facility

Facility	Number of Leaks	Methane emissions, thousand m^3/year
Poza Rica	194	6,770
Nuevo PEMEX	132	*2,571*
Ciudad PEMEX	17	2,022
Cactus	14	137
Burgos	16	30
Cunduacan	52	724
Total	**425**	**12,255**

The facility level results illustrate the value of baseline surveys as an initial step in a DI&M project in that the results allowed management to focus subsequent work on facilities with the most significant opportunities. In the case of the PEMEX baseline surveys, it was discovered that more recent construction had fewer component leaks, which is a useful result for decision-making when replicating survey work at other locations. In the cases of Poza Rica, Nuevo PEMEX, Ciudad PEMEX, and Cunduacan, a significant portion of the methane emissions are derived from the de-gassing vents of centrifugal compressors using wet seals. During normal operation of centrifugal compressors with oil-based or “wet” seals, a large amount of gas may become entrained in the seal oil, which must then be de-gassed in order to maintain viscosity and lubricity. Given that the de-gassed methane is often vented to the atmosphere, seal oil de-gassing can be a large source of methane emissions. These emissions are classified as a process-related vented emissions rather than fugitive leaks, but were included in the field study since they are a potentially large source and therefore critical for establishing integrated baseline analyses of methane emissions from these processing facilities. Emissions from centrifugal compressor seal oil de-gassing is treated in more detail in a later section.

Methane emissions by component type are further explored in Exhibit 3 which categorizes leaking components discovered during the baseline survey by type. For each component type, Exhibit 3 lists the number of leaks discovered during the baseline surveys and the methane emissions rate in thousand m^3/year. Typical repair cost for each component type and value of emissions is also provided.

Exhibit 3 Summary of Fugitive Methane Emissions by Component Type

Component	Number of leaks	Methane emissions, thousand m^3/year	Typical repair cost per leak , U.S. $	Gas value at U.S. \$106/thousand m^3 (\$3/Mcf)	Gas value at U.S. \$247/thousand m^3 (\$7/Mcf)
compressor seal	38	10,178.3	240,000[6]	1,078,335	2,516,116
valve stem packing	35	572.2	300	60,624	141,455
gate valve stem packing	157	440.4	442	46,658	108,869
open ended line	22	305.4	68	32,351	75,485
control valve stem packing	44	186.9	356	19,804	46,210
flange	55	159.7	146	16,917	39,472
plug valve stem packing	10	104.0	68	11,013	25,697
grease fitting	8	70.1	442	7,428	17,331
valve seat	3	66.7	300	7,069	16,495
threaded connection	14	33.2	20	3,512	8,196
plug valve seat	3	32.8	68	3,470	8,096
other	4	27.1	68	2,870	6,696
compressor starter vent	3	23.1	200	2,445	5,704
regulator	2	18.1	175	1,920	4,479
control valve seat	6	16.6	200	1,763	4,114
tube fitting	10	15.6	20	1,656	3,864
gate valve seat	6	2.7	75	281	655

needle valve stem packing	2	1.3	442	137	319
pressure relief (safety) valve	2	1.2	68	131	306
globe valve stem packing	1	0.2	442	16	37
Total	425	12,255.4		1,298,399	3,029,598

The PEMEX baseline survey results illustrate a common principle of DI&M: a small number of leak sources are responsible for the majority of methane emissions and can be targeted for repair and follow-up monitoring. Across the six facilities sampled, approximately 425 components out of a total of 7,500 components were found to have measurable emissions. By volume, the largest contributor was centrifugal compressor wet seals, which account for only 9 percent of the number of emitting components but 83 percent of total emissions (10,178 thousand m^3/year). The second largest emissions source is general valve stem packing, followed by gate valve stem packing. The top three sources account for 54 percent of the number of emitting components but 91 percent of the emissions volume.

PEMEX reviewed the baseline survey data and directed major repair, replacement, and retrofit efforts at the top three sources by volume. PEMEX began retrofitting wet seal centrifugal compressors with dry seals. It began with three compressor units at Ciudad PEMEX in 2007 and will replicate the process in at least 15 more compressors in 2010. They also instituted a valve repair and replacement program to target stem packing leaks, open-ended line leaks, and valve seat leaks.

Valves can develop leaks either externally around the packing or internally in the valve seat. For external valve leaks, tightening packing, repacking or regreasing immediately upon leak discovery is a very cost-effective mitigation option, typically providing an immediate payback given the low cost of packing materials and the negligible field staff time required. Internal leaks can be mitigated often by just tightening valve closure, by removing and rehabilitating the valve or replacing it outright. Additionally, a sustained maintenance schedule of valve servicing and flushing can reduce the frequency of fugitive emissions since an accumulation of debris can obstruct the valve seat as it is actuated over time, creating a pathway for gas to the atmosphere. PEMEX determined the most cost-effective solution for each valve leak type by considering the cost of various valve mitigation options, the potential value of the methane savings, and operating schedules at each facility such as scheduled shutdowns for plant-wide maintenance.

In addition to the valve program, PEMEX also addressed other emissions where cost-effective. For example, tube fitting leaks can often be eliminated through tightening tubing connectors and provide immediate payback based on the value of the avoided methane emissions.

Implementation Benefits

Cost-effectiveness is discussed here by defining mitigation costs and methane savings, and then presenting typical project economics[7]. DI&M costs include survey costs and repair costs. Typical baseline survey costs range from U.S. $15,000 to 20,000 per large gas plant facility. Periodic follow-up survey costs are lower (U.S. $9,000 to 15,000) since emphasis can be placed on specific facility areas or component types identified in the baseline. Repair and maintenance costs will vary by equipment type and corresponding mitigation option chosen.

Companies can control costs by designing DI&M strategies for each facility. For example, PEMEX's initial DI&M work at its Cactus, New PEMEX, and Ciudad PEMEX facilities was optimized based on time and resource constraints. The three facilities were included in a single one-week survey, and facility areas were prioritized for survey work. As a result, baseline survey costs were shared amongst three locations, providing PEMEX with an initial sense of how fugitives vary by facility, but at the expense of being less comprehensive. This flexibility was important for future PEMEX decision-making on replicating the work at other locations. A company can also choose to utilize external service providers or purchase equipment and develop an internal team. For the baseline surveys, PEMEX and Methane to Markets used third parties as a way to provide facility staff access to new technologies and additional expertise.

Determining the value of gas saved is required to estimate project economics and prioritize repair and other mitigation activities. The 12,255 thousand m^3/year of methane emissions discovered in the PEMEX baseline surveys represents a recovery opportunity of over U.S. $1.3 million at U.S.

$3/thousand cubic feet (Mcf) ($106/thousand m^3) or a value of U.S. $3 million per year at U.S. $7/Mcf ($247/thousand m^3).

PEMEX's repair effort addressed both emissions from leaking components and centrifugal compressor vents. To better study the economics of leak repair alone, Exhibit 4 evaluates non-capital intensive repair activities typical of routine preventive or corrective maintenance, using methane emissions rates from the PEMEX field studies paired with typical costs for this project type. A methane emissions reduction of 2,077 thousand m^3/year, or all component leaks found by PEMEX, was assumed for emissions reductions to illustrate project economics. Simple payback period was calculated using two gas values, U.S. $3/Mcf ($106/thousand m^3) and U.S. $7/Mcf ($247/thousand m^3).

Exhibit 4 DI&M Project Summary, Leak Identification, Quantification, and Repair		
CAPITAL COSTS	U.S. $90,000 baseline surveys for 6 facilities (U.S. $15,000 per facility)	
PERIODIC LABOR & MAINTENANCE COSTS	U.S. $115,246 repair costs U.S. $54,000 follow-up surveys for 6 facilities	
Gas Price per thousand m^3	**U.S. $106**	**U.S. $247**
Annual Value of Gas Saved, U.S. $	220,064	513,482
Payback Period in Years	1.2	0.5

Exhibit 4 shows that the value of the recovered gas value alone pays for the leak survey and repair work in 1.2 years or less, depending on how the gas is valued. DI&M surveys identify needed repairs, many of which can be considered routine maintenance activities, from which companies can save a significant volume of methane. In the case of the leak volumes found by PEMEX, repairs provide additional annual revenue from gas sales ranging from U.S. $220,064 to U.S. $513,482.

Exhibit 5 depicts project economics for both the leak repairs as well as for wet seal centrifugal compressor retrofit to dry seals. Exhibit 5 includes the same fugitive emissions reduction of 2,077 thousand m^3/year from Exhibit 4 and also includes the actual measured emissions reduction of 1,918 thousand m^3/year realized by retrofit of three wet seal centrifugal compressors, for a total emissions reduction of 4,849 thousand m^3 methane/year. Simple payback period was calculated using assumed repair and other mitigation costs, as well as two gas values.

Exhibit 5 DI&M Project Summary, Leak Identification, Quantification, Repair, and Centrifugal Compressor Retrofit		
CAPITAL COSTS	U.S. $90,000 baseline surveys for 6 facilities U.S. $720,000 for dry seal retrofit of 3 centrifugal compressors	
PERIODIC LABOR & MAINTENANCE COSTS	U.S. $115,246 repair costs U.S. $54,000 followup surveys for 6 facilities	
COST SAVINGS	U.S. $189,000 reduced operating costs from 3 centrifugal compressors	
Gas Price per thousand m^3	**U.S. $106**	**U.S. $247**
Annual Value of Gas Saved, U.S. $	423,313	987,731
Payback Period in Years	1.6	0.8

Exhibit 5 shows how a DI&M program can be harnessed for additional methane emissions mitigation project work such as replacement of wet seals on centrifugal compressors. The combined DI&M/centrifugal compressor project requires a higher initial capital investment, but can result in increased annual revenues of U.S.$423,313 to U.S.$987,731 and gives a payback period of 0.8 to 1.6

years depending on gas value. Centrifugal compressor emissions and mitigation are discussed in detail in another section of this paper.

Thus, Exhibit 4 represents the cost-effectiveness of DI&M even when there is only minimal capital investment available for mitigation. By identifying and repairing leaking components, a significant volume of natural gas previously lost to the atmosphere is now maintained in the system, with resulting gas savings adding to revenue through sales or contributing to internal fuel supplies, in either case contributing to domestic gas supplies. Exhibit 5 represents the cost-effectiveness of DI&M paired with compressor seal emissions reduction, in which a larger capital investment provides for even greater savings and benefits.

Next steps

Through its baseline fugitive methane emissions surveys, PEMEX confirmed that DI&M at its facilities is not only cost-effective but also profitable. The dual accomplishments of reducing emissions and increasing throughput contribute to operational safety, efficiency and environmental performance while increasing revenues. As demonstrated above, these activities can pay back in less than one year, which in addition to being beneficial economically, can also increase engagement at the management and field level and contribute to the likelihood of successful replication at other locations. Based on the economic and sustainability merits of the work, PEMEX is continuing to explore replication of DI&M programs at other facilities. In 2007, PEMEX Gas purchased infrared cameras for all of its gas processing plants. In mid-2009, PEMEX Gas is undertaking a training session for a special DI&M team that will help focus on fugitive emissions throughout the PEMEX Gas system. Additionally, PEMEX, in cooperation with Methane to Markets, has also initiated a comprehensive marginal abatement curve analyses for methane and is using data gathered during measurement studies to inform these analyses. These analyses will be used to quantify the total volume of cost-effective methane reduction potential in PEMEX operations and the company intends to use these analyses in setting climate policy goals and allocating capital resources.

Mitigation Opportunity – Reduced Emission Completions

Background

Increased natural gas demand over the last few decades has increased drilling of new wells in more expensive and more technologically challenging unconventional gas reservoirs, including those in low porosity and permeability (tight) formations. High demand for gas and high prices also justify extra efforts to reinvigorate production from existing wells in tight reservoirs where the down-hole pressure and gas production rates have declined, a process known as well workovers or well-reworking. In both cases (completions of new wells in tight formations and workovers of existing wells), hydraulic fracturing the reservoir rock with very high pressure water bearing proppant (generally sand) that "props open" the reservoir is the preferred method of gas recovery.

These new and workover wells may require multiple intervals of hydraulic fracturing, depending on the pay thickness in the reservoir. Based on the amount of load recovery of fluids between fractures, these multiple interval completions can take anywhere from one day to several weeks. After hydraulic fracturing, the well produces at a high rate to clear the well bore and formation of the load fluids prior to gas flow. The typical historical practice for this initial well completion step has been to flow the well to a pit or tanks where sand and slugs of water are captured and hydrocarbon liquids and gas are vented to the atmosphere or flared. This process is utilized until the gas meets specific pipeline specifications and can go to a permanent sales line. After all of the intervals are fractured, a workover rig or coiled tubing unit will clean out the well prior to the final production phase. The initial well completion is not finished until one to two days after the well has been cleaned out and connected to a permanent sales line.

Reduced emissions completions (RECs, also called "Green Completion") capture much of the gas that would have been otherwise vented or flared during the completion process. RECs use portable two-phase completion flowback equipment that is specifically designed and sized for the initial high rate of water, sand and gas flow. Sand traps are used to remove the finer solids present in the production stream and a plug catcher removes any large solids, such as drill cuttings, that could damage the separation equipment. In addition to the separation equipment, RECs may require a compressor to withdraw gas from the sales line to pump down the well casing for artificial gas lift of the fluids, plus a wet screw compressor to aid in boosting low pressure gas back into the sales line until normal reservoir flow and pressure are established.

Initial coordination between permitting and construction prior to the completion phase is essential to insure a permanent sales line is within a reasonable distance of the wellhead. Wells that are refractured and worked over normally already have a sales line, and consequently, RECs can also be utilized. Depending on the gas gathering system, it may be necessary to dehydrate the produced gas before it enters the sales pipeline. Moisture levels are reduced to pipeline quality gas specifications with the permanent or a portable dehydrator and flow is measured with a permanent custody transfer meter.

The portable two-phase completion flowback equipment used during RECs is only used for cleaning up the well; therefore, it is essential that all the equipment can be readily transported from different sites to be used in a number of well completions. A truck-mounted skid is ideal for transporting the equipment between sites and is large enough to carry all the necessary equipment. In a large basin that has a high level of drilling activity, it may be economic for a gas producer to build its own REC skid. For some producers, contracting a third party to perform completions may be a better fit with their annual drilling program.

Natural gas flared or vented during well completion and testing can be as much as 700 thousand m^3 per well (US$75,000 to US$175,000[8] in lost revenue), depending on well production rates, the number of zones completed, and the amount of time it takes to complete each zone. This gas is unprocessed and also contains volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) along with methane. Flaring gas reduces methane, VOC and HAP emissions by as much as 90%, but creates NOX and other combustion by-products in the process. A burning flare is safer than venting by reducing the chance of flamable gases in the air. Flaring is not always a practical option when the well is located near residential areas or where there is a high risk of forest fires. Most importantly, flaring results in the waste of natural gas, lost revenue, and air pollutant emissions.

RECs bring economic benefits as well as environmental benefits. Some operators have reported that RECs reduce completion time, allowing them to bring some wells online more quickly. Because flow is measured with a permanent custody transfer meter, gas savings, and corresponding increases in revenue, can be accurately assessed. The incremental costs associated with the rental of third party equipment for performing RECs can be offset by the additional revenue from the sale of gas and condensate. According to data collected by the U.S. EPA, RECs have become a major source of oil and gas sector methane emission reductions in the U.S. since 2000. EPA Natural Gas STAR partner companies reported that emission reductions between 2000 and 2005 from RECs have increased from 566 thousand m^3 to cumulatively over 198,240 thousand m^3. This represents additional natural gas being delivered to consumers as well as increased revenue from sales of recovered natural gas of over US$49 million in 2005 (at US$247/ thousand m^3).

Not all gas fields will benefit from flowback units. Wells without a production sales line within a reasonable distance will not be able to utilize flowback units. Wildcat, exploratory, and step-out wells are examples of these types of wells. When a well initially flows back 100% liquid and very little sand then the benefits of a flowback unit are also significantly reduced. In this case the completion fluid would flow to a tank, and after initial high water rates, the gas production is connected to the permanent separation equipment. Consequently there is no need to flare due to the distinct phases producing from the well. Some separation equipment requires a minimum gas pressure to actuate the pneumatic level controller inside the vessel. A small amount of flaring or venting would be needed if the gas production was not at the minimum separation pressure.

Reduced Emission Completions – EnCana Case Study

EnCana Corporation is the largest natural gas producer in North America, with 1.4 trillion cubic feet of natural gas production in 2008. EnCana Oil & Gas (USA) Inc. is a 2007 U.S. EPA Natural Gas STAR Award winner and is dedicated to ongoing environmental excellence through innovative energy efficiency initiatives. EnCana is committed to environmental stewardship through minimizing the impacts from activities through creative and innovative application of technology.

The Jonah Field is one of EnCana's key resource plays and is located 30 miles south of Pinedale, Wyoming. Jonah Field is geographically small at approximately 23,000 acres, but produces 1.5 percent of the daily natural gas needs in the United States. EnCana has contributed to the development of this field since 2002 and plans to continue drilling for several years.

Background

EnCana's completion technique involves hydraulically fracturing multiple intervals within a well. Between fracturings, a composite flow through bridge plug is used to separate the lower interval from the interval being fractured. After each fracturing, the well is flowed back to clean up any residual fluids in the formation. Once the entire well bore is fractured, a workover rig or coiled tubing unit is brought in to drill out the composite plugs. Prior to 2003, the flowback gas was sent directly to a flare until the entire well bore was completed and then the well was connected to sales. During this time, the liquids were placed into a pit on location.

In 2003, when plans for the Jonah Infill Drilling Project Environmental Impact Statement (JIDP EIS) were being developed, public and regulators raised concerns about the completion flares emissions. To address these concerns, EnCana developed a method of RECs. The use of flareless flowback demonstrates that EnCana is committed to environmentally responsible methods of development throughout the life of the field.

Results
In mid-2003, EnCana began using flareless flowback units in the Jonah Field. These units separate the gas from the liquids and send the gas downstream through central separation equipment with other producing wells and thus avoid flaring. A flowback unit includes a plug catcher device to remove large particles created in drill out operations from the separation equipment. The recovered oil is piped to storage tanks for future sale and the water enters the Jonah Field water recycling program. A 24-hour, two-person crew hooks up the flow lines from the wellhead to the separation device and then to the gas sales lines and condensate tanks. To reduce the amount of sand production and sand crushing inside the reservoir, initial completion flowback is not immediately unloaded to atmospheric pressures. Instead, the well is brought on slowly through a series of chokes which are designated by the flowback crew. A 24-hour flowback crew is needed to accommodate the choke schedule and the 24-hour hydraulic fracturing. In the Jonah Field, the flowback equipment and the crew are supplied by a third-party contractor.

The flowback process is not entirely flareless. When the well initially starts flowing back, there is more liquid than gas and the gas pressure may not be high enough to go to the sales line. During this short time, the flowback crew will send the gas to a flare. Exhibit 6 shows the percent of gas that was sent to flare during the years listed. The amount of gas flared depends upon the sales pipeline pressure. In 2007, the Jonah Field gathering endpoint was at 600 psi. After adding a compressor station, the pressure gradually dropped and is now operating at 250 psi. Therefore, the 0.1% flared in 2009 (YTD) should be an indicative value for the rest of the year.

Exhibit 6 Flared Volume

Year	Total Gas through Unit thousand m^3/year	% Flared
2001	0	0.00%
2002	0	0.00%
2003	12,999	3.70%
2004	176,632	1.01%
2005	509,335	0.61%
2006*	267,936	1.46%
2007	240,493	0.87%
2008	420,042	0.45%
2009YTD	80,655	0.10%

*Increased Energized Fracturing Fluids

A common completion technique in tight gas reservoirs is to energize the hydraulic fracturing with nitrogen or carbon dioxide to increase the percent of pumped liquids from the formation back to surface. Nitrogen or carbon dioxide mixes with reservoir gas to create a flowback gas that is not acceptable for sales due to downstream sales criteria gas quality. Use of nitrogen or carbon dioxide increases the amount of gas sent to flare. Jonah is a high pressured reservoir and, therefore, typically has adequate energy to remove fracturing fluids without nitrogen and carbon dioxide. Some gas reservoirs require energized fluids to optimize fracturing and, therefore, will not see as high an efficiency for utilizing flowback units. In 2006 the Jonah Field energized multiple intervals to assist with liquid recovery and, consequently, increased the percent flared as shown in Exhibit 6.

Flowback units allow the fluids from the fracturing process to be recycled. Instead of using fresh water from local aquifers for fracturing, Jonah uses a combination of 60% produced water from nearby production wells and 40% recycled drilling/completions fluids.

Through the years, the Jonah Field team has developed a technique so that more than one well can produce through a single flowback unit. Up to three wells have been placed through the same flowback unit without any operational issues. The biggest concern with increasing the number of wells is the lack of individual well data for analysis. Also, instead of a two–person, 24-hour crew EnCana has moved to a one-person, 24-hour crew for multiple units. The maximum number of units supervised by a one-person crew to date has been three. By these developments, the overall flowback equipment and crew cost per well are significantly reduced. This technique significantly reduces equipment rental times by better utilization.

Implementation Benefits
The amount of gas sold rather than flared is substantial, and the overall REC project paid out within the first year. The net present value (NPV) of the project in 2003 was US$190,070,000. The cost and sales revenue is shown in Table 2.

Exhibit 7 Economics[9]

Year	**Gas to Sales**	**Gas Price**	**Cost of Flow Back**	**Gas Sale Revenue**
	thousand m^3/year	**US$/MCF**	**Unit and Crew US$**	**US$**
2003	12,517	$4.62	($3,036,200)	$2,040,973
2004	174,848	$5.87	($8,857,800)	$36,260,555
2005	506,248	$7.80	($9,112,400)	$139,454,713
2006*	264,027	$6.34	($16,800,000)	$59,151,099
2007	238,398	$4.43	($37,728,000)	$37,268,080
2008	418,173	$7.01	($40,425,000)	$103,438,462
2009YTD	80,570	$3.19	($9,075,000)	$9,063,281

*Increased Energized Fracturing Fluids

Conclusions and Other RECs
Flowback units have significantly reduced air emissions in the Jonah Field. Due to the naturally high pressure of the reservoir this field has seen a high rate of success and does not require energizing fluids to move fracturing fluids from the well bore.

Another method of RECs used in the Jonah Field is remote hydraulic fracturing. Remote fracturing involves setting up a hydraulic fracturing crew and equipment on one location and running pipelines across the surface up to 762 meters away to fracture a well remotely. This technique reduces movement of heavy fracturing equipment from one to two times per day to about once every one to two days. The emissions reduction has not been quantified, but there is a benefit in significantly reducing fracturing crews moving and rigging-up time.

Mitigation Opportunity – Vapor Recovery from Tanks

Background
Production field tanks hold crude oil and condensate to stabilize flow or for trucking or pipeline transportation. During transfer from the gas-oil separators to field storage tanks, light hydrocarbons dissolved in the liquids—including methane—vaporize (flash) and vent to the atmosphere. Tanks can vent 0.2 to 1.2 m^3 per year of methane per barrel of oil or condensate. Sites without vapor recovery therefore may lose significant volumes of product in this manner.

One way to capture this gas and yield significant economic savings is to install vapor recovery units (VRUs) on storage tanks. Over the past five years, this technology is consistently in the top five “best management practices” reported by U.S. oil and gas companies for reducing methane emissions. While most methane capture projects deal with the compression of relatively dry (1,000 Btu) gas from suction pressures over 50 psig, one of the more challenging technologies for methane capture is the vapor recovery of associated gas from field storage tanks. This gas is typically very wet, and at pressures less than 1 psig.

Operators have opted to install VRUs at production sites in Latin American and globally due to the combined benefits of reduced methane emissions; utilization of methane as an onsite fuel source or sales gas; and recovery and sale of valuable heavier hydrocarbons such as propane and butane. An additional benefit is that VRUs serve as a collection point for other sources of low-pressure methane emissions throughout the facility. Re-directing these low-pressure methane emission sources to the VRU allows for the capture and use or sale of natural gas previously vented to the atmosphere.

VRUs can recover about 95 percent of tank vapors, which contain methane as well as other valuable heavier hydrocarbons. The volume of gas vapor coming off a storage tank depends on many factors. Vapor losses are primarily a function of oil or condensate throughput, gravity, temperature, and gas-oil separator pressure. There are three types of losses: 1) flash losses occur when crude oil or condensate is transferred from a gas-oil separator at higher pressure to a storage tank at atmospheric pressure; 2) working losses occur when crude or condensate levels change and when liquid in tank is agitated; and 3) standing losses occur with daily and seasonal temperature and barometric pressure changes.

The makeup of these vapors varies, but the largest component is often methane (between 40 and 60 percent). Other components include more complex hydrocarbon compounds such as ethane, propane, butane, and natural gasoline (pentane-plus heavier hydrocarbons including hazardous air pollutants such as benzene, toluene, ethyl-benzene and xylenes, collectively referred to as BTEX). Production gas often includes other non-hydrocarbon gases such as nitrogen, helium, hydrogen sulfide and carbon dioxide. Since recovered vapors contain hydrocarbons heavier than methane, on a volumetric basis, they can be more valuable than methane alone.

VRUs can provide significant environmental and economic benefits for oil and gas producers. The gases flashed from crude oil and condensate and captured by VRUs can be sold at a profit or used as a fuel in facility operations. Additionally, other sources of low-pressure methane vented throughout the facility can be directed to the VRU for capture. These recovered vapors can be:

- Piped to natural gas gathering pipelines for sale at a premium price as high Btu natural gas.
- Used as a fuel for onsite operations.
- Piped to a stripper unit to separate natural gas liquids (NGLs) and methane when the volume and price for NGLs are attractive.

Vapor Recovery Unit Design Considerations

Unlike typical pipeline compression, the design of vapor recovery units requires several added elements which allow the units to operate effectively in extremely low pressure and highly variable flow of wet gas applications. The compressor is the heart of the system, and compressor selection is key for these wet gas applications. Preferred options include rotary screw, scroll, venturi jet, and rotary vane compressors. Rotary vane compressors are typically the lowest cost alternative. These units handle wet gas very well (although not liquid slugs) and large volumes, but are limited on discharge pressure to 70 psig. Scroll compressors work well and have a large pressure range (from zero to 325 psig), but are limited on volume (generally 150 mcfd (4.2 thousand m^3/day) for two dual modules). Oil flooded rotary screw compressors are a great option and the most versatile, especially when coupled with a variable frequency drive – and can handle the widest range of pressures and volumes. However, these units generally cost more initially and have higher operating costs than rotary vanes. Screw compressors utilizing ductile iron rotors and rotary vanes using ductile iron bodies work well in these applications due to the corrosive nature of some gas streams containing significant quantities of H2S, CO2, or high levels of water vapor. Venturi jet systems are designed in same manner, utilizing a venturi jet powered by high pressure produced water (Vapor Jet®) or high pressure process gas (EVRU®) in lieu of a compressor. Each system works well in its niche, but has limitations on discharge pressure (40psig to 60 psig) and requires approximately a four to one power fluid to suction gas ratio.

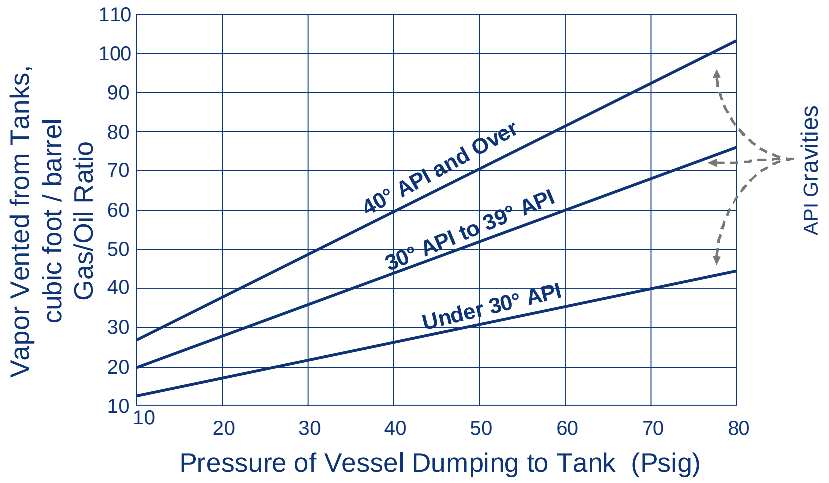
Packaging designs should incorporate transmitters to monitor tank pressures, an on-skid bypass system to re-circulate gas to minimize shutdowns, and a computer driven automated system of liquid and pressure controls to minimize field maintenance and insure the system never pulls air into the tanks and into the recovered gas. Electric motor drive units are recommended as the fuel gas provided at many tank batteries contains contaminants or liquids that make running small horsepower natural gas engines problematic. A good gas analysis from the tanks is critical in order to evaluate the dew point of the gas, and the dew point should be considered in system design. Facility design considerations should include a gas blanketing system that is designed to backfill the tanks with fuel gas or nitrogen as the tanks are emptied of oil. A closed system is imperative, so a review to insure all thief hatches and safety relief valves on the tanks are sealed and operational and the tank fixed roof is in good repair are also important. Finally, it is recommended that a sloping line (4 inch minimum diameter) is run from the tanks to the VRU, with no low spots or U traps in the line that could fill with condensate and block the low pressure gas flow.

In sizing the VRU, emissions from tanks should be quantified by measurement to ensure adequate capacities based on fluctuations of volume over time. When measuring tank vapors, two key factors to achieving accurate measurements include: measuring flow of vapors over time to capture a complete tank cycle from full to empty back to full, and ensuring that all emissions escaping from the tank are directed to a single flow measurement point such that true volume can be captured. One method for measuring tank emissions is the Daniels' turbine meter, which can be affixed to a tank outlet and used to measure flows exceeding 17 actual cubic meters (am3). An orifice well tester and recording manometer (pressure gauge) can be used to measure maximum emissions rates since it is the maximum rate that is used to size a VRU. Orifice meters, however, might not be suitable for measuring total volumes over time due to the low pressures at tanks.

Estimating tank vapors might be useful for very preliminary consideration of VRU installation. There are two approaches to estimating the level of vapor emissions from crude oil tanks. Both use the gas-oil ratio (GOR) at a given pressure and temperature and are expressed in standard cubic feet per barrel of oil (scf per bbl).

The first approach analyzes API gravity and separator pressure to determine GOR (Exhibit 8).

Exhibit 8[10] Estimated Volumes of Tank Vapors



° API = API gravity

These curves were constructed using empirical flash data from laboratory studies and field measurements. As illustrated, this graph can be used to approximate total potential vapor emissions from a barrel of oil. Once the emissions rate per barrel is estimated, the total quantity of emissions from the tank can be determined by multiplying the per barrel estimate by the total amount of oil cycled through the tank. The shortcoming of this approach is that it does not generate information about the composition of the vapors emitted. In particular, it cannot distinguish between VOC and HAP, which can be significant for air quality monitoring, as well as determining the value of the emitted vapors.

The second approach is to use the software package E&P Tank. Developed by API and the Gas Research Institute (now the Gas Technology Institute), this software estimates emissions from all three sources—flashing, working, and standing—using thermodynamic flash calculations for flash losses and a fixed roof tank simulation model for working and standing losses. An operator must have several pieces of information before using E&P Tank, including:

1. Separator pressure and temperature.
2. Separator oil composition.
3. Reference pressure.
4. Reid vapor pressure of sales oil.
5. Sales oil production rate.
6. API gravity of sales oil.

E&P Tank also allows operators to input more detailed information about operating conditions, which helps refine emissions estimates. With additional data about tank size, shape, internal temperatures, and ambient temperatures, the software can produce more precise estimates. This flexibility in model design allows users to employ the model to match available information. Since separator oil composition is a key input in the model, E&P Tank includes a detailed sampling and analysis protocol for separator oil.

Vapor Recovery from Tanks – Pluspetrol Case Study

Background
Founded in Argentina in 1976, Grupo Pluspetrol began its operations with an enhanced recovery project in the province of Neuquen. Pluspetrol began evaluating the opportunity to capture the vent methane at the Palmar Largo facility in 2007. After a detailed engineering review, the company determined it was economical to capture the vent gas from their two tanks (2,000 m^3 and 330 m^3). Producing 320 m^3 per day of 43 degree API gravity crude oil through the facility, the project sought to capture approximately 15,000 m^3/day (500 mcfd) of low pressure vent gas.

Vent gas from oil storage tanks is typically 2,200 to 2,400 Btu – which makes it a very valuable, but also very wet gas stream. As an example, the vent gas from this location had a specific gravity of 1.35, versus the process gas stream of 1.03. Pluspetrol's goals were to maximize condensate production from this gas stream, and compress the remaining gas into their gas plant to be used in the circuit of "gas lift" for enhanced oil recovery. Based on the field conditions, Pluspetrol selected a fully automated vapor recovery unit utilizing a rotary vane compressor and electric drive motor to help minimize downtime. Hy-bon Engineering in Midland Texas was selected for the design and manufacture of the vapor recovery unit, installed earlier this year.

In this installation, 15,000 m^3/day (500 mcfd) is captured from the oil storage tanks and pulled through a fin fan cooler in order to drop out condensate, then piped to a vessel to capture the condensate, and compressed by the VRU to 65 psig to the on-site plant (Exhibit 9). The automated vapor recovery unit has a programmable logic controller (PLC), which automatically monitors and pumps liquids from the vessels, maintains all key components within their safe operating ranges, and shifts the unit between on, off and bypass depending on fluctuating tank pressures. An electric motor drive unit was selected to minimize downtime and take advantage of the available power on location. The overall installation was designed with no "U traps" in the piping, and sloping lines where possible from the tanks to help insure proper gas flow. A rotary vane compressor was used in this application due to the extremely wet nature of the gas, coupled with a relatively low discharge pressure of 65 psig. These compressors are also easy to rebuild in the field, which is an advantage in remote locations.

Exhibit 9 Pluspetrol Salta Argentina 125 150- HP VRU

Pluspetrol anticipated capturing 10 m^3 (or 63 bbls)/day of condensate and a significant quantity of residual gas. The compressed gas, which totals approximately 7,500 m^3/day, goes to a gas plant to be prepared for use in the gas lift system. In this way, gas used for gas lift is maintained in a closed loop system. Recovered condensate goes to the liquid storage tank (oil + water). Total fluid condensate is measured in the separator and indirect measures allow for approximation of the amount of other liquids in the tank. Pluspetrol is capturing 10 to 13 m^3 /day of condensate, and 3 to 4 m^3 /day of other liquids (approximated volume). There is more water produced in the process than was originally estimated.

Overall payback on the project was originally projected at 30 months. After installation and commissioning in early 2009, Pluspetrol found that actual daily condensate and gas production exceeded expected levels. Final payback numbers are still in process due to one of the production tanks being taken out of service for repair earlier this year, but anticipated payback is estimated to be 20 to 30 months based on the following factors. The cost of installing the VRU was U.S.$350,000, including material, equipment (air cooler, separator, pumps and VRU compressor) and labor. On-going costs include U.S.$1000/month (operation and maintenance) and oil transport costs of U.S.$3.34/bbl (or U.S.$21.01/ m^3). Revenues were calculated according to an oil sale price of U.S.$35/bbl (or U.S.$220.14/ m^3). Evaluating the project over 5 years, and assuming a decline in production, payback is calculated to be 20 to 30 months, assuming condensate production levels of 13 to 10 m^3/day, respectively. This assumes a flat oil price for the next 5 years, so an improvement in this price will result in a payback of less than 20 months.

Considering local pricing for natural gas (generally less than U.S.$71/ thousand m^3 or U.S.$2/mcf), the potential for condensate recovery from these high Btu gas streams really helps the project economics – a factor often overlooked by companies in evaluating VRU projects.

Mitigation Opportunity – Installing Dry Seals on Centrifugal Compressors

Background

Centrifugal compressors are becoming more widely used in processing and transmission of natural gas[11]. Seals on the rotating shafts prevent the high-pressure natural gas from escaping the compressor casing. Traditionally, these seals use high-pressure oil as a barrier against escaping gas. While oil seals form a good barrier to prevent the release of gas at the seal face, in some cases these oil seals can still result in large emissions of methane.

Centrifugal compressors increase natural gas pressure when a series of rotating impellers accelerate the gas. The impellers are driven by a rapidly spinning shaft, and this shaft extends from the compressor case to bearings at each end. Where the drive shaft exits the compressor case presents an opening for gas leakage to occur. Compressor seals fill the space around the shaft and prevent gas from contaminating the bearing lubrication and leading to the atmosphere. Traditionally, centrifugal compressor seals use rings that are lubricated by circulating seal oil between them. Two stationary rings form a barrier for high-pressure gas inside the compressor, and in between the stationary rings is a third ring rotating on the shaft. High-pressure seal oil is pumped between the rings to form a thin layer of lubrication and to act as another barrier between the natural gas and the atmosphere.

When properly installed, this “wet seal” assembly is effective at minimizing gas leakage past the shaft, but in some cases large volumes of gas can be absorbed by the seal oil. While very little gas escapes through the oil barrier, the gas comes into contact with the seal oil under the high pressure at the “inboard” (compressor side) seal oil/gas interface. This may result in a significant amount of gas being absorbed by the seal oil, thus contaminating it. Seal oil is de-gasified to maintain its viscosity and lubricity (using heaters, flash tanks, and degassing techniques) and recirculated. Because the purged methane is commonly vented to the atmosphere, the seal oil degasifying process results in methane emissions.

It has been found that there is variability in the volume of methane emissions from centrifugal compressor wet seal de-gassing in any given compressor. One source estimates that methane emissions from wet seals can range from 1.1 to 5.7 m^3/minute[12]. Other recent emissions rate measurements highlight this variability. Methane to Markets experience, combined with another assessment of four natural gas facilities[13], has identified measurements from 48 wet seal centrifugal compressors, with methane emissions totaling 14,860 thousand m^3 methane/year. The data, which show that seal oil degassing rates for individual compressors could range from 0 to 2,756 thousand m^3/year, can be divided into two groups: a low-emitting group (33 compressors) and a high-emitting group (15 compressors). The low emitters have an average emission rate of 26 thousand m^3 methane/year for a single compressor. The high emitters have an average emission rate of 934 thousand m^3 methane/year for a single compressor. Most measurements were conducted using anti-static calibrated vent bags, where a bag of a known volume was placed over the de-gassing vent stack to completely capture the emission, inflation time was measured, and the gas stream was adjusted for methane content.

These findings point to the potentially large volumes of methane emissions from this source at facilities world-wide and the need to do measurement to identify specific units to target for repair/retrofit when instituting a methane emissions reduction project. In addition to potential methane emissions, there are other disadvantages to wet seals. Compressors operating with wet seals also require extra equipment and operating expenses to circulate, regenerate, and replenish seal oil. Seal oil can also leak into the natural gas stream, contaminating the product and fouling the pipeline.

Mitigation Option: Install Dry Seals
An alternative to the traditional wet (oil) seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Dry seals, which use high-pressure gas to seal the compressor, emit a much smaller quantity of natural gas (0.014 to 0.085 m^3/minute per seal[14]). A compressor dry seal upgrade therefore reduces methane emissions as much as 2,637 thousand m^3 /8,000-hour year[15], or U.S.$279,522 to U.S.$651,339 (at U.S.$106/thousand m^3 to U.S.$247/thousand m^3). Maximum expected methane venting to the atmosphere under normal operation from each compressor dry seal would be 11 m^3/hour.

Exhibits 10 through 12 show typical project economics for dry seal conversions assuming a range of potential emissions levels and gas prices. Each exhibit shows typical capital costs to retrofit one compressor, operating costs, and operating cost savings[16].

Exhibit 10 Economics of Low-Emitting Centrifugal Compressor (150 thousand m3 methane/year)

PROJECT SUMMARY: Replacement of Low-Emitting Wet Seals		
CAPITAL COSTS	U.S. $240,000 for dry seal retrofit of one centrifugal compressors	
PERIODIC LABOR & MAINTENANCE COSTS	U.S. $10,000 for operation and maintenance of dry seal	
COST SAVINGS	U.S. $73,000 avoided operation and maintenance of wet seal	
Gas Price per thousand m^3	**U.S. $106**	**U.S. $247**
Annual Value of Gas Saved	U.S. $15,892	U.S. $37,080
Payback Period in Years	3.0	2.4

Exhibit 11 Economics of Moderate-Emitting Centrifugal Compressor (934 thousand m3 methane/year)

PROJECT SUMMARY: Replacement of Moderate-Emitting Wet Seals	
CAPITAL COSTS	U.S. $240,000 for dry seal retrofit of one centrifugal compressors
PERIODIC LABOR & MAINTENANCE COSTS	U.S. $10,000 for operation and maintenance of dry seal
COST SAVINGS	U.S. $73,000 avoided operation and maintenance of wet seal

Gas Price per thousand m^3	**U.S. $106**	**U.S. $247**
Annual Value of Gas Saved	U.S. $98,952	U.S. $230,887
Payback Period in Years	1.5	0.82

Exhibit 12 Economics of High-Emitting Centrifugal Compressor (2756 thousand m3 methane/year)

PROJECT SUMMARY: Replacement of High-Emitting Wet Seals		
CAPITAL COSTS	U.S. $240,000 for dry seal retrofit of one centrifugal compressors	
PERIODIC LABOR & MAINTENANCE COSTS	U.S. $10,000 for operation and maintenance of dry seal	
COST SAVINGS	U.S. $73,000 avoided operation and maintenance of wet seal	
Gas Price per thousand m^3	**U.S. $106**	**U.S. $247**
Annual Value of Gas Saved	U.S. $291,982	U.S. $681,291
Payback Period in Years	0.48	0.27

These exhibits show that targeting specific centrifugal compressors for retrofit can lead to economic projects with paybacks with 3 years or less. This economic benefit is based on methane savings, as well as operational and efficiency improvements. Dry seal installations are mechanically simpler than wet seals and require fewer auxiliary components for handling seal oil, so power consumption is reduced, reliability is improved and maintenance costs are lower. Additionally, substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas. Because of these benefits, companies worldwide are benefiting in a variety of ways from implementing dry seals on their centrifugal compressors.

Installing Dry Seals on Centrifugal Compressors – Gazprom Case Study

Background

Gazprom is the largest natural gas company in the world, possessing the largest natural gas reserves and operating the largest gas transmission system globally. The Unified Gas Supply System of Russia spans 156.9 thousand km and has over 4,000 centrifugal compressors in operation. Gazprom and its subsidiaries also service 514.2 thousand km (80 percent) of the national gas distribution pipelines, and in 2006 supplied 316.3 billion cubic meters (bcm) of gas to 79,750 population centers in Russia. Gazprom has been actively involved in the Methane to Markets partnership and other methane mitigation activities participating in international methane conferences in Novosibirsk (2000) and Tomsk (2005) as well as hosting the Methane to Markets seminar in Moscow in 2008.

Implementation of Dry Gas Seals in Gazprom's System

In reviewing available data and information on compressor seals, Gazprom determined dry gas seals are more economic than wet oil seals on centrifugal compressors and identified a range of additional benefits. These added benefits included the elimination of oil contamination of combustible gas, increased compressor capacity, and minimal maintenance. Gazprom also determined that the cost of a new centrifugal compressor with dry seals does not exceed the cost of a unit with wet seals and overall, wet seals are economically inefficient as compared to dry seals. Furthermore, industry standards, such as those from the International Organization of Standards (ISO) and the American Petroleum Institute (API), advise against using wet oil seals in new compressors for safety reasons.

Based on these factors, Gazprom recognized the clear benefits of dry gas seals and plans to implement broad scale upgrades of its over 4,000 centrifugal compressors to replace wet seals with dry gas seals. There are several companies producing and implementing dry gas seal systems. John Crane Inc., UK, a British and Russian company, a developer and producer of high-tech sealing systems, complex sealing solutions and service equipment, has been successfully working in Russia since 2003. In particular, Gazprom is using John Crane dry gas-dynamic seals and control panels at its facilities. Throughout 2006-2008, Gazprom completed dry seal upgrades of 60 compressor units and is planning to continue these upgrades system wide.

Outcomes
Gazprom now has substantial experience in the development, adoption and operation of dry seal systems for compressor units with capacity ranging from 6.3 up to 25 MW. Practical use by Gazprom shows that replacement of dry hydrodynamic seals has a range of significant advantages over using wet oil seals. For wet seal compressors, for isolation of injector shafts, seals are applied with oil as an isolating material (floating-ring seals, front oil seals). The most common disadvantages of wet seals include operational complexity; large support system causing safety concerns; increased chance of rejection and increased costs of maintenance and repair work; high energy consumption; fire hazard and danger to the environment; and oil contamination of gas flow (the longer the seal in use, the higher the contamination will be).

Gazprom determined that the best solution to address these issues is to begin replacement of wet seals with dry gas seals broadly across the entire Gazprom system. They have already completed this effort successfully at eleven facilities, resulting in the following key benefits:

- <u>Elimination of combustible gas contamination by oil</u>. Oil contamination of the gas had resulted in gas pipeline discharge capacity reducing by 1-2 %. This issue is alleviated with the installation of dry seals.
- <u>Decrease in compressor's capacity losses by reducing friction in seals</u>. Friction in wet seals causes substantial reductions in capacity of the compressor (10 times and more). When compressor throughput capacity is lowered by 1%, compressor efficiency drops by several percent. Therefore, the positive impacts of dry seals are increased efficiency in compressors with turbine drives
- <u>Increase in operational life</u>. Dry seals are designed to last the lifetime of a compressor. Dry seal systems do not require oil circulation components and treatment facilities, such as a seal oil pump and cooling fan, and degassing facilities such as heaters and flash tanks. Because dry seals have fewer ancillary components, they require minimal maintenance (once every 1-3 years) mostly consisting of visual examination and replacement, if needed, of filter elements and seal rings. This translates into lower maintenance costs, higher overall reliability and less compressor downtime.
- <u>Energy efficiency</u>. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet systems require 50 to 100 kiloWatt/hour, while dry seal systems need about 5 kiloWatt of power per hour.

Gazprom has identified and observed through practical experience the clear economic and operational advantages allowing the company to justify retrofitting centrifugal compressors with dry gas seals broadly across their system. In addition to the benefits described above, dry seals also have important environmental and economic benefits, especially through reductions in methane emissions to the atmosphere. Estimates of the methane emission rate from a dry seal are 1.5 to 3.5 m^3/hour (according to most recent publications). According to Gazprom's inspection, the emission rate from a wet oil seal ranges from 1.1 – 27.5 m^3/hour. However, further study, analysis, and measurements are needed to accurately quantify the specific methane emission reductions achieved by replacing wet with dry gas seals in their system. As indicated from the emissions rates above, while methane emissions are reduced by installing dry gas seals, Gazprom has also found that they do not completely eliminate emissions. Gazprom continues to build on their implementation success with their ongoing efforts to continue replacing centrifugal compressor wet seals with dry seals throughout their operations.

Overall Results from Technical Case Studies

Methane emissions reduction projects are increasingly becoming a focus of the oil and natural gas community due to their multiple benefits and attractive project economics. Companies operating in many different market environments have successfully identified methane emissions as a climate change and economic issue, reviewed proven project types, implemented mitigation activities and now continue to reap benefits after implementation. The five projects highlighted here have resulted in a significant volume of methane emission reductions, with payback periods ranging from 0.2 years to 3 years. It has been demonstrated that in some cases, benefits exceed the value of the natural gas saved, with recovered condensate, cost savings, efficiency improvements and maintenance savings being additional positive outcomes.

The five case studies here also illustrate the different operator approaches and project magnitudes. PEMEX's focus on DI&M resulted in potential methane emissions reduction of 4,849 thousand m^3/year, or U.S.$423,000 to U.S.$987,000 (at gas values of U.S.$106/thousand m^3 to U.S.$247/ thousand m^3). PEMEX used this project as a pilot effort at a subset of facilities and is using results to potentially replicate the work across its supply chain. Mitigation efforts also varied from targeted maintenance activities to relatively capital-intensive wet seal to dry seal conversion in their centrifugal compressors. EnCana's use of reduced emission completions reduced methane emissions by 418,173 thousand m^3 in 2008, or U.S. $44 million to U.S.$103 million worth of gas (at gas values of U.S.$106/thousand m^3 to U.S.$247/ thousand m^3) and is an operating practice that can be perpetuated on future well completions. The Pluspetrol case study of tank vapor recovery illustrates their capture and use of 7,500 m^3 natural gas per day, as well as 10 to 13 m^3 of valuable condensate. Pluspetrol has reduced methane emissions by utilizing the natural gas in a closed-loop gas lift system, while selling 3,650 to 4,745 m^3 /year of condensate worth over U.S.$803,000 to U.S.$1.045 million (at condensate value of U.S.$35/bbl or U.S.$220.14/ m^3), helping to drive positive economics. This installation of a control technology provides long-term benefits of capturing multiple hydrocarbon resources for sale and internal use. Centrifugal compressor wet seal replacement implemented by Gazprom and other companies demonstrates that such activities have potential methane emissions reductions up to 2,758 thousand m^3/year per compressor, or U.S.$292,000 to U.S.$681,000 (at gas values of U.S.$106/thousand m^3 to U.S.$247/ thousand m^3) and shows how methane emissions reduction can be a quantifiable co-benefit in addition to increased efficiency, lower operating costs and other operational benefits.

Conclusion

The case studies presented here and the complete range of projects being implemented by industry demonstrate that reducing methane emissions can yield significant, quantifiable benefits that can be replicated throughout oil and natural gas operations. Identification and quantification of existing methane emissions constitutes a key first step for project evaluation and implementation. Once emissions sources and levels are identified, quantified, and monetized, proven methane recovery technologies can provide compelling economic and environmental benefits, in addition to operational and maintenance improvements, cost savings, and enhanced safety. In some cases, these benefits also include recovery of other valuable hydrocarbon resources, which can further improve project economics. With mitigation options that range from installation of new technology, to retrofit of existing technology, to changes in operating practices, companies can choose activities that fit within available resources and can accelerate implementation by aligning resources and capital to implement a range of methane emissions reduction projects.

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[7] These are average costs and may not necessarily reflect actual implementation costs incurred by Pemex.

[8] Assuming a natural gas cost of U.S.$106/thousand m^3 to U.S.$247/ thousand m^3

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