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UNDERSTANDING METHANE EMISSIONS SOURCES AND VIABLE MITIGATION MEASURES IN THE NATURAL GAS TRANSMISSION SYSTEMS: RUSSIAN AND U.S. EXPERIENCE

A. Ishkov (OAO Gazprom), G. Akopova, (Gazprom VNIIGAZ LLC), M. Evans (PNNL), G. Yulkin (Gazprom VNIIGAZ LLC), V. Roshchanka (PNNL), S. Waltzer (U.S. EPA), K. Romanov (OAO Gazprom), D. Picard (Clearstone Engineering), O. Stepanenko, D. Neretin (Gazprom Transgaz Samara Ltd)

ABSTRACT

Russia and the United States (U.S.) are the world's largest consumers and producers of natural gas, and consequently, have some of the largest natural gas infrastructure. This paper compares the natural gas transmission systems in Russia and the U.S., their methane emissions and experiences in implementing methane mitigation technologies.

Given the scale of the two systems, many international oil and natural gas companies have expressed interest in better understanding the methane emission volumes and trends as well as the methane mitigation options. This paper compares the two transmission systems and documents experiences in Russia and the U.S. in implementing technologies and programs for methane mitigation. The systems are inherently different. For instance, while the U.S. natural gas transmission system is represented by many companies, which operate pipelines with various characteristics, in Russia predominately one company, Gazprom, operates the gas transmission system. However, companies in both countries found that reducing methane emissions can be feasible and profitable. Examples of technologies in use include replacing wet seals with dry seals, implementing Directed Inspection and Maintenance (DI&M) programs, performing pipeline pump-down, applying composite wrap for non-leaking pipeline defects and installing low-bleed pneumatics.

The research methodology for this paper involved a review of information on methane emissions trends and mitigation measures, analytical and statistical data collection; accumulation and analysis of operational data on compressor seals and other emission sources; and analysis of technologies used in both countries to mitigate methane emissions in the transmission sector.

Operators of natural gas transmission systems have many options to reduce natural gas losses. Depending on the value of gas, simple, low-cost measures, such as adjusting leaking equipment components, or larger-scale measures, such as installing dry seals on compressors, can be applied.

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I. INTRODUCTION

Natural gas is a major source of energy both in Russia and the U.S., accounting for about 25% and 55% of primary energy use in each country, respectively (1). While natural gas is a relatively clean fuel, it is also an important source of methane emissions, contributing to climate change. In fact, according to the Intergovernmental Panel on Climate Change (IPCC), methane's ability to trap heat in the atmosphere is 25 times stronger, by weight, than carbon dioxide's (CO_2) over a 100-year period (2). Reducing methane losses from the natural gas sector can simultaneously reduce emissions of this potent greenhouse gas and provide natural gas companies with a financial benefit, since methane is a valuable commodity when it can be transported to market or utilized locally.

Natural gas systems are a significant source of anthropogenic methane emissions globally. Moreover, it is estimated that, compared to the 1990 level, by 2020 global methane emission from both oil and natural gas systems will increase by 84 percent (3), and thus, the importance of methane emissions from natural gas systems is only expected to grow.

In the natural gas industry, methane emissions can come from production, processing, transmission, storage or distribution. They can be either unintentional emissions such as from equipment leaks (also referred to as fugitive emissions) and system upsets or intentional, designed releases such as venting from well completions during production. This paper specifically focuses on emissions and mitigation technologies in the transmission sector.

One of the key challenges that companies in the U.S., Russia and other countries face is quickly identifying and measuring methane loss. Some of the largest sources of emissions in this sector include compressor seals and packing, pneumatic devices, blow-down of pipeline segments or compressors and equipment leaks such as from unit isolation valves and scrubber dump valves. Generally, compressor stations (not linear pipelines) account for the largest volume of methane emissions from natural gas transmission systems because compressor stations have more components that can leak and are subject to more frequent venting activities.

Identifying and eliminating methane emissions can present an opportunity for natural gas companies to increase corporate revenue and deliver a highly valuable fuel to the market. Thus, measures taken to eliminate methane emissions can be very cost-effective. For instance, expenses of converting pneumatic controls from the use of natural gas to compressed air can be recovered in several months, depending on the price of natural gas. Additional economic benefits accrue when carbon financing is an option, and since methane is such a potent greenhouse gas, the value of each ton of methane saved can be high. Similarly, in some countries, like Russia, the legislation requires payment of fees for methane emissions, which can be reduced with successful mitigation.

Both countries are partners to the Global Methane Initiative (GMI). GMI is an international public-private partnership established to urge stronger international action to fight climate change while developing clean energy and stronger economies. The partnership, formerly known as Methane to Markets was launched in 2004 by 14 partner countries, of which the U.S. and Russia were both founding partners. It has since grown to 38 partner countries and a large Project Network of private-sector entities, financial institutions and other governmental and non-governmental organizations with an interest in methane capture and use projects. Through this partnership, Russia, the U.S. and other member countries along with the project network collaborate to bring together technical, financial and market expertise, necessary for developing projects around the world on capturing and bringing methane to markets. The projects outlined in this paper strongly support the goals of this important initiative. This paper begins by comparing key characteristics of the natural gas transmission systems in the U.S. and Russia. It then describes the experience in each country with implementing relevant methane mitigating technologies and practices. The paper also includes a discussion on emission trends and future opportunities for reducing emissions.

II. COMPARISON OF THE NATURAL GAS TRANSMISSION SYSTEMS IN RUSSIA AND THE UNITED STATES: KEY CHARACTERISTICS OF THE SYSTEMS

Russia and the U.S. have the largest natural gas transmission systems in the world. This reflects the fact they are also the world's largest producers and consumers of natural gas. However, there are significant differences between the systems' basic characteristics. (Comparative statistics of Russian and U.S. transmission systems are shown in Table 1).

To begin, in Russia, the open joint stock company Gazprom, which also extracts natural gas, owns and operates the largest gas transmission system belonging to any one company in the world. Gazprom's system, also called the Unified Gas Supply System of Russia (UGSS), carries over 99% of Russia's transported gas (4). Gazprom also operates 514,200 km (80%) of Russia's distribution lines. In 2010, the company supplied Russian cities with 354.9×10^9 m^3 of natural gas. As can be seen from Table 1, the UGSS is over 161,700 km long, with a substantial part of the pipeline crossing the entire Russian territory and the territory of other countries. The system encompasses 283 compressor stations, which are designed to transport natural gas over long distances to consumers in Russia and abroad. In 2010, Gazprom marketed 148.1×10^9 m^3 of natural gas in Europe and nearly 70.2×10^9 m^3 in the CIS and the countries of the Baltic region (5).

By contrast, the U.S. transmission system is operated by hundreds of companies, some of which play only a transportation function and others distribute and sell gas locally. Because natural gas prices in the U.S. are "unbundled" from the cost of transporting and storing, natural gas transmission companies compete against each other to transport and store gas, requiring an interconnected "open access" transmission network. Thus, the U.S. has a very competitive market for natural gas, in which production, transmission and distribution are operated separately. Collectively, U.S. companies operate 485,300 km of pipelines, supplying in 2010 627.6×10^9 m^3 of natural gas to domestic consumers (7). There are 2,182 compressor stations, typically located every 80 km along the pipelines (6). Another important characteristic of the U.S. is a supply network for liquefied natural gas (LNG), which is only in experimental stage in Russia.

Table 1. Comparative Statistics for the Russian and U.S. Natural Gas Transmission Systems

Parameters	Russia	U.S.
Total length, thousand km	161.7	485.3
Total number of compressor stations, including:	283	2,182
*Linear compressor stations**	266	1,790
Storage compressor stations	17	392
Gas pumping units at compressor, including*:	4,268	7,864
Gas turbine-driven (centrifugal) compressors	3,417	722

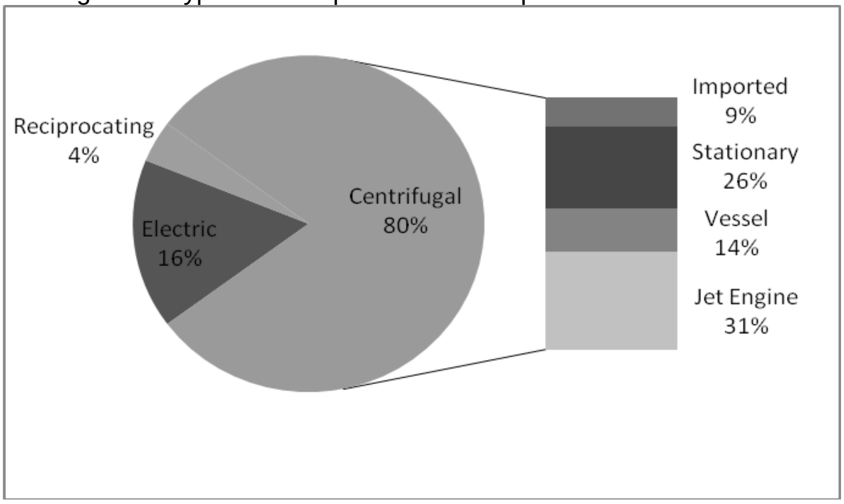
Gas engine-driven (reciprocating) compressors	152	7,197
Electric motor-driven compressors	699	Unknown

*Note: Russian data includes booster stations from gas productions sites.

Sources: Russia (5); U.S. (8).

Typically, in the transmission sector, the largest amount of methane is emitted from compressor stations, as they have more components that can leak and are subject to more frequent venting activities. In Russia's UGSS, compressor stations operate several types of gas compressors, as presented in Figure 1. The predominant types of compressors in the Gazprom compressor fleet are centrifugal compressors, which make up about 80% of all natural gas compressor units.

Figure 1. Types of Compressors at Gazprom Facilities

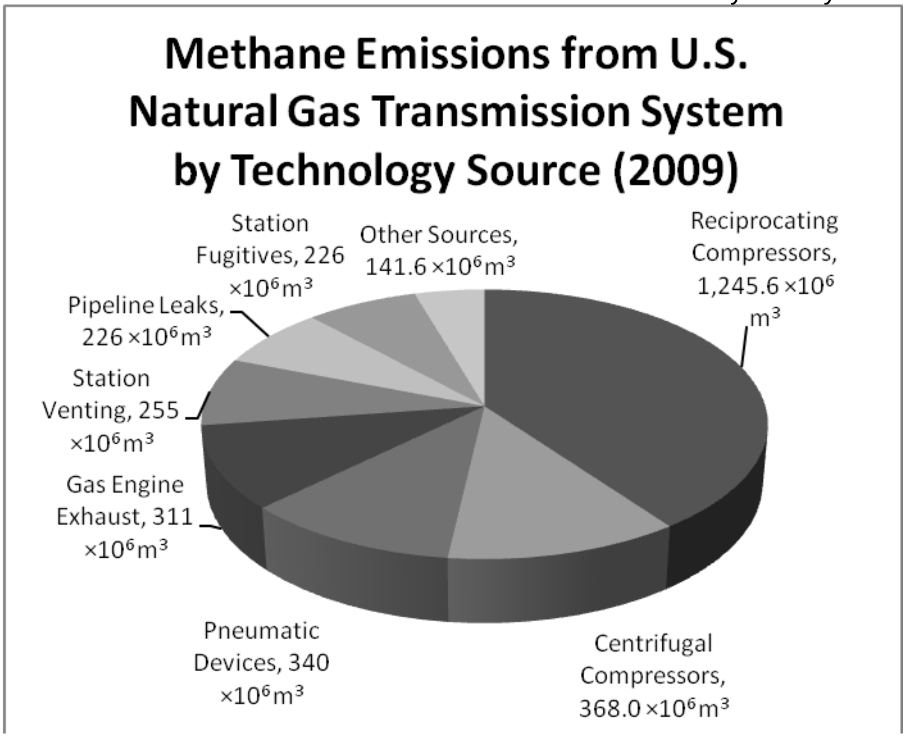


Note: Electric compressor can be either reciprocating or centrifugal. For the purposes for this analysis, electric compressors were placed into its own category.

Source: (5).

By contrast, the U.S. transmission system mostly operates reciprocating compressors (over 90%) (8). Logically, most of U.S. methane emissions in the transmission sector comes from reciprocating compressors, as Figure 2 shows. Other methane emissions sources include centrifugal compressors, pneumatic devices and gas engine exhaust.

Figure 2. Methane Emissions from U.S. Natural Gas Transmission System by Technology



Source: (8)

III. RUSSIAN AND U.S. EXPERIENCE WITH IMPLEMENTING METHANE MITIGATION TECHNOLOGIES AND PRACTICES

Both Russia and the U.S. have extensive experience with implementing methane mitigation technologies and practices in the natural gas transmission sector. In the U.S., there are some applicable regulations at the State level and certain Federal regulations currently under review for potential expansion (see below). However, one of the key mechanisms for promoting methane emission reductions across the oil and gas industry to date has been EPA's Natural Gas STAR Program. Since 1993, the Natural Gas STAR Program is a voluntary partnership with oil and gas companies to develop detailed technical information on innovative cost-effective ways to reduce methane emissions and then facilitate the sharing of that information across the industry. In Russia, by contrast, the main policy has been of direct regulation. One way the Russian government encourages emissions control is through fees that oil and natural gas companies must pay for methane emissions.

Methane mitigation studies in Russia and the U.S. showed that opportunities to reduce methane emissions in the oil and gas sector are plentiful in both countries. For instance, a study of the Russian gas industry demonstrated that among opportunities to reduce emissions, up to 60% are within the transmission system, especially at compressor stations (9). To reduce methane losses, Gazprom currently implements a number of technologies, including mobile compressors for pipeline pump-down, electric-start compressors and low-bleed pneumatics. The Inventory of U.S. Greenhouse Gas Emissions and Sinks provides estimates of methane emissions sources in the oil and gas sector (8). Figure 2 demonstrates that the U.S. transmission sector presents significant opportunities to reduce methane losses (8). As discussed further below, it is also important to note that recently passed Subpart W of the Greenhouse Gas Reporting Rule requires oil and gas companies to monitor and report their GHG emissions, which will provide more comprehensive data and information on the location and size of emissions sources in the oil and natural gas sector. In addition, as noted above, the Natural Gas STAR program has identified and developed detailed information on cost-effective opportunities to reduce these emissions, including their environmental, operational and financial benefits.

Table 2 (below) outlines some of the major technologies and practices used both in the U.S. and Russia to reduce methane emissions. The measures covered include replacing wet seals with dry seals on centrifugal compressors, Directed Inspection and Maintenance (DI&M) at compressor stations, pipeline pump-down, composite wrap for repair of non-leaking pipeline defects and low-bleed pneumatics. The table provides information on the average cost and estimated payback for implementing the outlined technologies, based on experience of U.S. companies participating in Natural Gas STAR Program. To estimate the payback period for Russia, it was assumed that the implementation cost for technologies/practices is the same as in the U.S., the value of gas in Russia is $70/thousand m^3 and that companies in Russia are charged a fee for methane emissions. It should be noted that the economic estimates below are based on experience of specific companies, and that the actual implementation costs and payback times may vary depending on individual operating conditions.

Table 2. Methane Reduction Technologies in the Natural Gas Transmission Sector

Technology/ Practice Name	**Description**	**Average Cost (in U.S.)**	**Estimated Payback Time in Russia**	**Estimated Payback Time in the U.S.**
Dry Seals (Replacing Wet Seals)	Centrifugal compressors have seals along their shaft to keep gas from escaping. Wet, or oil-lubricated, seals are common and by design result in methane leakages, sometimes substantial ones. Dry seals operate mechanically without seal ring lubrication, which in its turn reduces gas leakage	$324,000 per compressor	8 to 24 months	10 months
Directed Inspection and Maintenance (DI&M)	A technique to find, quantify and reduce leaks in a facility on a planned schedule based on frequency of leaks and cost-effectiveness. Quantification of leaks allows companies to prioritize repairs and evaluate cost-effectiveness.	$26,248 per station	4 months	Less than 12 months
Pipeline Pump-down	Instead of venting gas from a section of pipeline that is being depressurized for maintenance, this technology uses a portable compressor to pump much of the gas in an adjacent operational	$98,800 (assuming 4 pump-downs per month on 16 km segment)	2 months	1 month

	pipeline segment.			
Composite Wrap for Non-Leaking Pipeline Defect	Composite wrap permanently repairs non-leaking pipeline defects. It is very cost-effective because it allows for pipeline repairs during pipeline operation, so gas does not need to be vented.	$5,600 per 8 meter pipeline segment	6 months	3 months
Low-Bleed Pneumatics	Gas-operated pneumatic devices such as controllers vent methane by design. Because of the large number of pneumatic devices at compressor stations, the total emissions from such devices can be substantial at a facility. Low-bleed pneumatics can significantly reduce these leaks, through either replacement of high bleed devices with low bleeds or retrofitting existing high-bleed devices.	$675 to $1,850	1.1-2.6 years	6-18 months

Sources: (10), (11), (12), (13), (14). Natural gas pricing data for Russia was provided by VNIIGAZ.

As Table 2 shows, the payback time for investment into the above mitigation options varies and these differences will influence corporate methane mitigation strategies. The costs for implementing the technologies shown in this table are based on U.S. estimates. These costs may be lower in Russia, particularly if labor is a major component of the implementation cost. At the same time, cost-effectiveness may be higher in the U.S. because of higher natural gas prices. The next section will examine specific experiences with these technologies in Russia and the U.S.

Dry Seals on Centrifugal Compressors

In Russia, Gazprom's experience has shown that the reliability of compressor units is mostly defined by their technical characteristics, in particular their compressor seals. Normally, gas compressors are equipped with rotating shafts that require isolating seals to prevent high-pressure gas from leaking out where the shaft exits the casing.

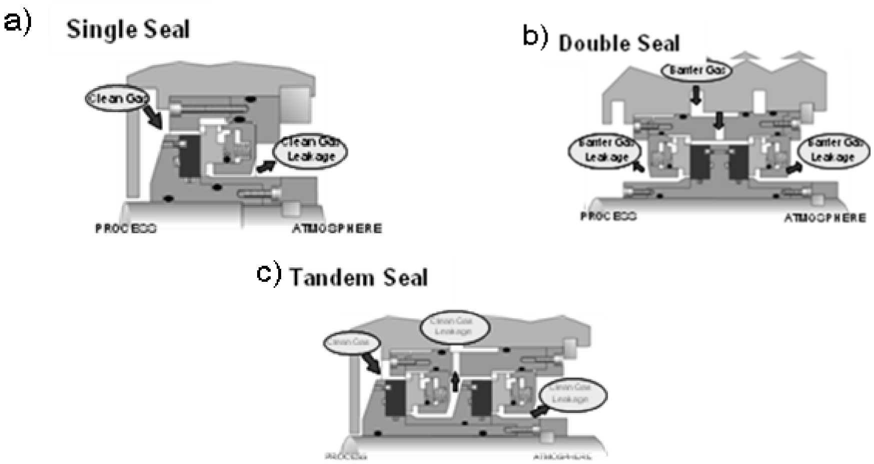
Russia's Gazprom operates the following types of seals, as depicted in Figure 3:

a) A single seal design is suitable for applications where the seal gas, is neither flammable nor harmful to the environment, for example, when air, nitrogen or carbon dioxide is used as a seal gas. A labyrinth seal may be integrated to reduce the amount of leakage in the event of a failure;

b) The double opposed seal configuration requires a barrier gas pressure higher than the pressure of the process gas being sealed. This configuration can be used where no leakage of the process gas is permissible and where consumption of filtered buffer gas needs to be minimized;

c) The tandem seal provides full pressure breakdown across the primary seal faces. The secondary seal faces normally operate under low pressure. In the event of primary seal failure, the secondary seal acts as an installed spare. The process gas has controlled leakage across both sets of seal faces. The tandem seal has become an industry standard for hydrocarbon or critical applications.

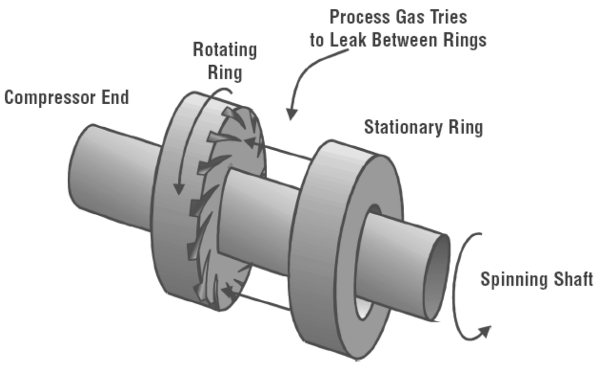
Figure 3. Types of Seals Operated in Gazprom Facilities



Source: Flowserve Corporation, (2010)

Currently, traditional compressors operated by Gazprom can have wet seals or dry seals. Realizing the evident advantages of dry seals outlined below (Figure 4), Gazprom has been implementing the technology within a corporate program of reconstruction and modernization of its compressor fleet. In response to modern market demand, the leading global manufacturers of gas compressors have started supplying dry seal compressors as a default option.

Figure 4. Typical Schematic of a Dry Seal



Source: (10).

Gazprom has accumulated much experience in the development, implementation and operation of dry seal systems for 4 to 25 MW compressors (on over 250 compressors). The experience resulted in environmental benefits, which included methane emission reductions, a considerable decrease in operational costs and enhanced the compressor throughput capacity.

The main advantages of dry seals include:

- Decrease in the unit capacity loss by removing drag in seals. A one-percent decrease in drag cuts fuel consumption by several percent;

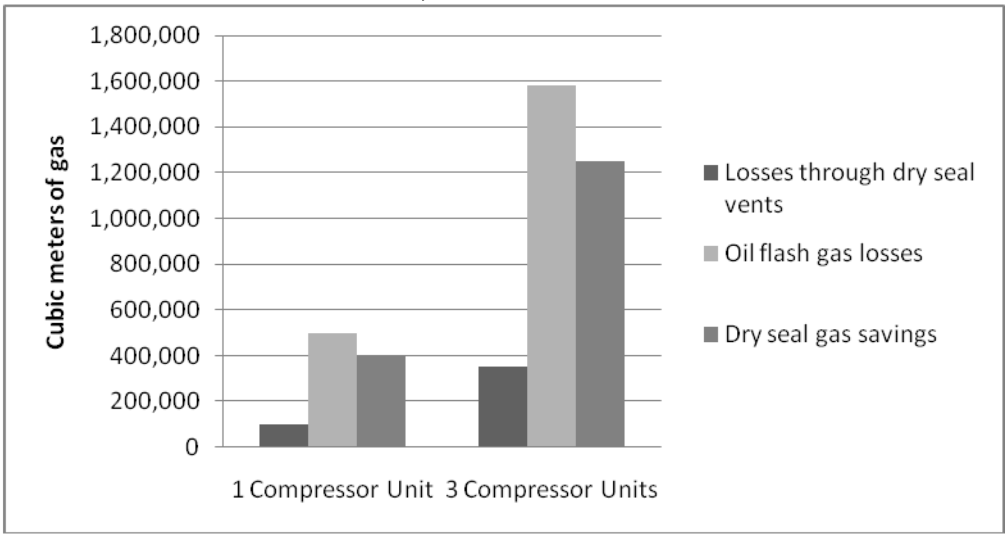
- Service life prolongation, reduced maintenance (once in 1 to 3 years), lower compressor down time and improves system reliability;

- Methane emission reductions and elimination of flash gas emissions from seal oil. According to international data sources, wet seal emissions are 20 to 100 times greater than dry seal emissions, although actual emission rates can be very site-specific, and some recent studies have indicated that many factors may determine the actual emissions rate of wet seals.

- Energy efficiency. As the dry seal system requires no auxiliary circulation pumps and systems, the energy saving effect which resulted from the exclusion of "parasitic" energy consumption is also noteworthy. Oil systems demand **50 to 100 kW/hour**, whereas dry seal systems have a power load of only **5 kW/hour**, which is **10 to 20 times more efficient** (15).

One of the major factors influencing the economic feasibility of deploying dry seals for Gazprom's compressors is determined by the natural gas savings from compressors with dry seals compared to those with wet seals. A 2005 study estimated potential gas savings and payback for replacing dry seals at compressor stations with one and three compressor units (Figure 5). The results of the study showed that gas saving could be significant, with a payback of 8 to 12 months for a compressor station operating for about 8,000 hours a year (16).

Figure 5. Expected Minimal "Own Use" Gas Savings When Using Dry Compressor Seals to Replace Wet Seals.



Source: (16).

While several companies internationally have reported significant benefits from dry seals, as outlined above, some recent analyses have indicated that emissions from wet seals might not be universally high. VNIIGAZ found this in measurements of the compressor seal vents as part of a study conducted jointly with the EPA, Pacific Northwest National Laboratory (PNNL) and Clearstone Engineering. This study, described in more detail below under the DI&M section, showed that methane emission rates from the compressors with dry seals were only slightly lower than from the compressors with wet seals This result may indicate that oil laden with flash gas is entering the pipeline or the gas is being flashed at other, unexpected points. The preliminary results indicate seal and compressor operating and maintenance practices may play a critical role in methane emission rates. Alternatively, a few other companies have systems to re-route seal vent gas to compressor fuel supply lines integrated into their compressor seal design. This can greatly reduce emissions. Equipment vendors and operators have noted that this practice can provide a very cost-effective option for reducing methane emissions associated with wet seals.

Several U.S. EPA Natural Gas STAR partners have also noted benefits from deploying dry seals compared to wet seals. For example, one U.S. company reported wet seal emissions of 2,123 m^3/day. Another partner found that installing a dry seal on an existing compressor reduced emissions by 97%, saving almost $187,000 in natural gas alone (10). Other partners have found that dry seals can save as much as $315,000 per year, depending on the wet seal emissions of the existing compressor before the retrofit (10). Pemex found that before installing dry seals, compressors had an emissions factor of 641.3×10^3 m^3 per year; after the retrofit, this factor dropped to 0.3 m^3 per year (17). However, U.S. companies too have noted that measurement and analysis are essential to confirm project economics before an investment, as wet seal emissions vary (10).

Directed Inspection and Maintenance (DI&M)

Companies in both countries have well-developed DI&M programs. These programs can dramatically reduce fugitive losses from equipment. These programs involve identifying, quantifying and fixing leaks that are cost-effective to repair. Typically, a DI&M program involves a major survey of a facility approximately once a year and more targeted surveys of components known to need more frequent attention. A range of screening technologies exist, including test using a soap solution, electronic sniffers, toxic vapor analyzers, ultrasonic leak detectors, laser-based remote leak detectors and infrared leak detection cameras. There are also a range of technologies to measure/quantify the emissions detected such as High Volume Samplers, Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs), calibrated bags, and rotameters. The cost, ease-of-use and accuracy of these technologies vary. For example, bubble tests are very easy to perform and cost-effective for detecting leaks, but do require staff time to apply to each component and are not effective on some components, such as open ended lines. Infrared cameras to detect leaks can cost up to $100,000, but can quickly scan large areas for leaks, including ones that are in unsuspected locations or hard-to-reach areas. Calibrated bags are a simple inexpensive method for accurately determining the emissions volume; however, they can be labor intensive especially when measuring a large number of leaks. While High Volume Samplers are one of the more expensive measurement technologies, they can directly measure the leak rate of large emissions sources more quickly. OVA/TVAs can be used to estimate mass leak rate based on correlation equations.

In Russia, Gazprom regularly conducts instrumental studies to assess the amount of losses of methane and executes statistical analysis of research on greenhouse gas emissions at representative sites of subsidiaries. The measurements have a broad geographic scope, covering the territories of Central Russia and Western Siberia, where Gazprom’s facilities are located. The targeted facilities include those from gas production, processing, transport, storage and distribution systems. To-date, field measuring has provided Gazprom with solid and crucial data on methane emissions. In general, the conducted measurements and calculations proved that methane emissions from the gas transmission system of Russia are less than 1% of the gas production volume. Research tools comprise modern leak detection and measurement technologies (remote and contact) provided by Russian, German and Japanese manufacturers.

In 2010, jointly with EPA, PNNL and Clearstone specialists, Gazprom/ VNIIGAZ conducted a full-scale study to assess methane emissions at compressor stations in the Syzran pipeline section of Gazprom Transgaz Samara. The scope of the study covered all active or pressurized process equipment installed in two workshops. The team jointly conducted detection and measurement activities that encompassed the valve and vent stacks of the compressor station, while Gazprom also examined the linear part of the pipeline. In total, more than 5,550 locations with potential leaks points were examined, of which 3,350 were at the compressor stations and 2,200 were along pipelines. In total, 116 leaks were detected, which included 89 leaks from the compressor stations and 27 leaks from the linear sections of pipelines.

The team examined 123 vent stacks, including 95 at two compressor stations and 28 along linear sections of pipelines. In total, 18 leaks were found from vent stacks, of which 15 were at the compressor stations and 3 along linear sections of pipelines, which were measured by Gazprom/ VNIIGAZ. Because leaks along the linear section of the pipeline were larger, they produced more emissions by volume. Thus, out of the measured daily methane loss of 2,460 m^3, 70% was along linear sections of pipelines, 17% was at compressor station #10 with dry seals and 13% was at compressor station #23 with wet seals (Figure 6).

The study also included a comparative evaluation of the detection and measurement methodologies conducted by two groups: Gazprom/VNIIGAZ and PNNL/Clearstone. The resulting total measurements of methane emissions were fairly similar: 0.49×10^3 m^3 per 10^9 m^3 of transported gas (Gazprom/VNIIGAZ) and 0.43×10^3 m^3 per 10^9 m^3 of transported gas (PNNL). While Gazprom/ VNIIGAZ's and PNNL's measurements at a compressor station with wet seals were comparable, measurements at a compressor station with dry seals were diverging (Figure 7). Although in both cases dry seals showed lower emissions than the wet seals, according to Gazprom/VNIIGAZ's measurements, dry seal emissions were only slightly lower than those from wet seals. Potential reasons for this finding are described above; however, further study is needed to make definitive conclusions.

Figure 6. Volume Shares of Identified Methane Emissions and Leaks

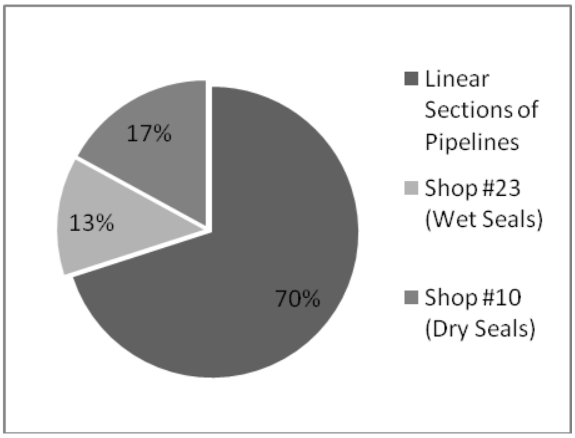
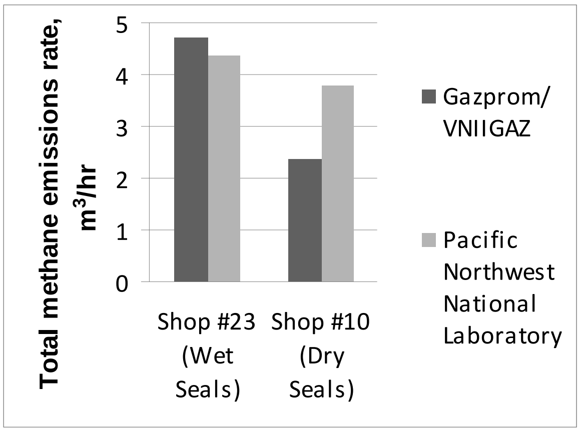


Figure 7. Methane Emissions Rates from Vent Stacks of Wet (Shop #23 with 4 Compressors) and Dry (Shop #10 with 2 Compressors) Seals



Source: (18).

In general, the study showed methane losses from compressor stations' process equipment and linear pipeline sections (valves and vent stacks) were 0.0002% of the gas transported by the Syzran subsidiary of Gazprom Transgaz Samara.

In the United States, many transmission companies have experience with DI&M programs, with this service also being provided by specialized companies. One EPA Natural Gas STAR partner, Northern Natural Gas, reported significant savings from its DI&M program. In 2006, it screened 659 rod packings on reciprocating compressors. Through this initial inspection and repair, as well as regular monitoring of the leaks, it was able to reduce gas losses from these packings by 2×10^6 m^3 annually. Northern Natural Gas also hires a specialized company to conduct aerial leak surveys with a laser-based remote sensing technology (LIDAR). This has allowed Northern to find and repair numerous leaks along its pipelines (19). EnCana, a natural gas producer in the U.S., has also rolled out a corporate-wide DI&M program, including development of a corporate DI&M guidance document, a training program, and integration into the company's environmental health and safety management system. EnCana has saved $2.5 million a year with this program (20).

Pipeline Pump-down

Pipeline pump-down allows gas pipeline operators to reduce vented methane emissions when they take a section of pipeline offline for repairs. Normally, for safety reasons, the operator must vent the gas before repair work begins. This can involve the loss of substantial volumes of gas and money, as well as significant emissions of methane. Instead, with pipeline pump-down, the operator can use either a portable compressor, in combination with the in-line compressors, to move the majority of the gas to the next pipeline segment before depressurization. The calculations provided in Table 3 reflect the costs and savings when using a portable compressor. A portable compressor can pump down a greater percentage of the gas (up to 90%) and can conduct the operation faster than in-line compressors. However, using in-line compressors involves less capital expense.

In Russia, Gazprom developed and verified a joint implementation project "Use of Mobile Compressor Stations for Pumping Natural Gas from the Gas Pipeline Section" (21). Gazprom plans to implement the project in the UGSS of Russia applicable for both existing and projected pipelines with diameters ranging from 700 to 1,420 mm. The project enables gas to be pumped forward from sections of gas pipelines scheduled for repair. In 2010, pilot (qualification) tests on the mobile compressor stations were made in the area of the Ust-Buzuluksk trunk line of Gazprom Transgaz Volgograd. The tests consisted of experimental gas pumping using a mobile compressor made in Russia by the company OOO Gazag. The main technical specifications of the tested mobile compressor are provided in the Table 3:

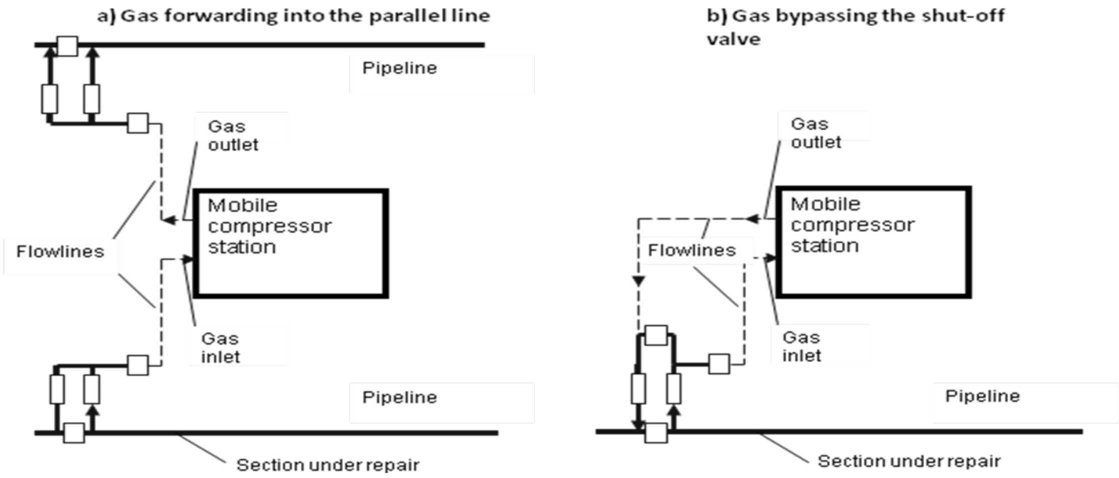
Table 3. Technical Specifications for a Mobile Piston-Type Compressor Station

Parameter	**Unit**	**Value**
Installed capacity	kW	2,375
Own needs consumption for the whole period of period of pumping	m^3	46,777
Volume of gas pumped from the isolated pipeline section	m^3	3,097,476
Number of compressors in the set, required to pump out one pipeline section	units	5
Number of applications per year		18
Time needed to lower the pressure down to 1 MPA in the section	hours	90

Source: (21).

Mobile compressors use two typical schemes of gas re-routing, or pump-down, from the withdrawn section of pipeline, as presented in Figure 8.

Figure 8. Typical Schemes of Application of Mobile Compressor Stations



Source: (21).

In the U.S., several EPA Gas STAR partners have successfully used pipeline pump-down. One example is Southern Natural Gas Company, which reported that it used portable compressors three times at one location over a year to save $228,000 in recovered gas at a cost of about $68,000. The effort paid for itself in four months; other companies reported even faster payback times (12).

Composite Wrap

Composite wrap can serve as an alternative to cutting and replacing a segment of defective pipeline or covering it with a steel sleeve, both of which are expensive and time consuming. Composite wrap can thus permanently repair non-leaking pipelines in a cost-effective manner; the repair work can take place without shutting down operations. This also means that the natural gas in the pipeline is not vented, resulting in significant savings and reduced emissions. Many composite wrap products are available on the market, using a range of wrap and adhesive materials.

To save gas, Russia's Gazprom has been applying composite wraps on pipelines and other reliable sealing materials in other parts of the transmission and distribution system. Application of composite wraps and sealing materials in Gazprom facilities saves annually $3\times10^6 m^3$ of natural gas.

In the U.S., safety regulations have permitted composite wraps for repairs since 2000. One Gas STAR partner has reported that it has successfully installed composite wrap on over 300 pipeline segments. Another company reported completing up to 65 repairs annually and saving 14.9×10^3 m^3 to 778.5×10^3 m^3 of natural gas per year, totaling in over 3×10^6 m^3 in saved methane (13). Natural Gas STAR partners typically find that the most compelling benefits are the continuity of pipeline operations, the quick repair time and the reduced safety risks of the repair. Examples of composite wrap vendors in the U.S., include Armor Plate, Inc.; the Clock Spring® Company L.P.; the StrongBack Corporation and WrapMaster, Inc. All of these companies have pipeline operators, such as Duke Energy, as clients.

Pneumatic Instrument Controllers and Other Pneumatic Devices

Transmission facilities use natural gas-powered pneumatic devices for a wide range of purposes, including pressure regulators, valve controllers and liquid level controllers. However, these devices, by design, vent some natural gas as they operate. Some vent greater volumes of gas, some lower. Also, with age or poor installation, pneumatics can vent more gas than they are designed to (in fact, identifying these high-bleed devices is typically the first step in mitigating emissions). While the vented gas from each individual device may not appear significant, the total amount can be substantial because of the large number of devices at compressor stations or other facilities, and because some devices can have large venting rates. Retrofitting key components or replacing high-bleed devices with low-bleed ones can significantly reduce emissions and wasted gas. Table 2 shows the possible payback periods with component retrofits and device replacement, respectively. An additional benefit is that retrofitting or replacing worn units can improve operational performance and reliability system-wide.

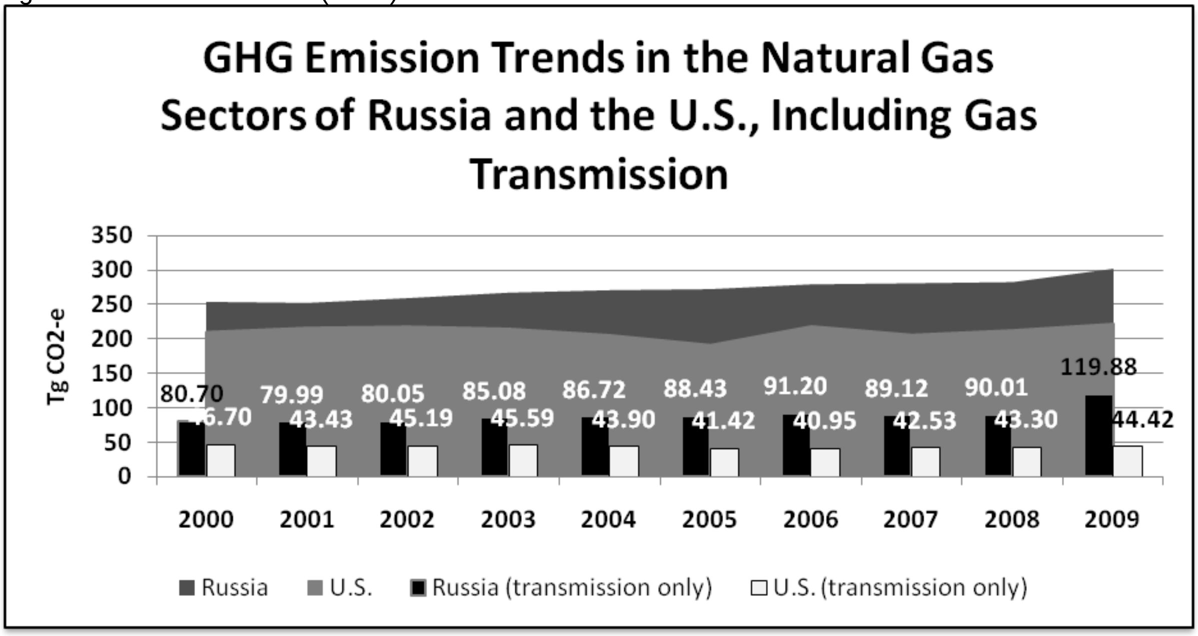
In order to reduce methane emissions associated with compressor start attempts, Gazprom has begun installing electric-powered hydraulic starters instead of pneumatic starters on compressor units. Additionally, Gazprom is increasing its use of hydraulically-operated instead of pneumatically-operated block valves. The gas consumption rate for 50 to 1,420 mm pneumatically actuated block valves ranges from 0.034 to 15,500 m3/activation event. The emission reductions that result from the avoided use of these pneumatic devices are calculated in every single case, considering the associated activity rates and design specification. This avoidance of pneumatic starters and block valves by using electric-powered hydraulic systems has a low-cost and is implemented in all new construction facilities.

EPA's Natural Gas STAR program considers any pneumatic device as high-bleed if it vents over 1.4×10^3 m^3 of natural gas per year (14). Several Natural Gas STAR partners have reported savings with measures to install low-bleed pneumatics. Two examples are Marathon Oil Company and Union Pacific Resources. Marathon surveyed over 150 devices at 50 facilities with a High-Flow Sampler; it found that one-quarter had high bleed rates (13). Union Pacific Resources, after retrofitting 330 high-bleed pneumatic devices and replacing 70 low-bleed pneumatic devices, reported a reduction of methane emissions of 1.4×10^6 m^3 per year (13). U.S. EPA estimated that high-bleed pneumatic devices cause a loss of 340×10^6 m^3 of natural gas in the U.S. transmission systems (14).

IV. EMISSIONS AND OPPORTUNITIES FOR FUTURE REDUCTIONS

Over the past 10 years in the U.S., methane emissions have remained relatively stable in the natural gas sector in general and for transmission systems in particular, whereas in Russia methane emissions have followed an upward trend with the major sources concentrated at natural gas transmission facilities (Figure 9). At the same time, methane mitigation in the natural gas industry has proven to be feasible for natural gas companies, providing a payback through lower operating costs, reduced methane fees, or carbon credits.

Figure 9. Greenhouse Gas (GHG) Emission Trends in the Natural Gas Sectors of Russia and the U.S.



Source: (4), (22).

The latest research on the current and future situation in the Russian gas industry shows that the natural gas transmission sector presents a major potential for methane emission reductions. Projections for methane mitigation depend on the future trend in natural gas production and demand in Russia and Europe, as well as the development of advanced technologies and the overall evolution of the international gas supply system.

Like companies in the U.S., Gazprom has been implementing innovative technologies to reduce methane emissions within its corporate program of energy saving. The company has evaluated its investment potential and identified the crucial investments projects. This includes applying mobile compressor stations for pipeline pump-down, performance optimization of the transmission system using automated systems, electric-start compressors and other technologies. By 2020, Gazprom intends to reduce its GHG emissions by 40%. Methane mitigation with the help of innovative technological solutions can be profitable to companies such as Gazprom. Investing in such technologies will improve the energy and resource efficiency in the natural gas sector in Russia.

Because the U.S. natural gas transmission system involves many different operators, it is more useful to talk about trends affecting investments and opportunities rather than specific investment areas. As natural gas has risen in price in the past decade, at least indirectly, companies have seen growing pressure to reduce gas losses. At the same time, the market has given rise to a range of supporting service companies that can implement methane mitigation programs in cooperation with pipeline operators. This allows for faster learning and easier implementation of projects in many cases. Likewise, the number of new methane mitigation technologies available on the market continues to grow in response to this underlying market demand. For example, there are many new technologies available to identify and measure leaks. There are also new options for mitigating leaks, including new composite wrap materials, improved seal technologies and new options for reducing natural gas venting by pneumatic devices.

Looking forward, there are several new regulatory initiatives in the U.S. that will impact both the information reported and the potential emission control requirements. The new Subpart W of the Greenhouse Gas Reporting Rule in the U.S. requires oil and gas companies to monitor and report their GHG emissions. This rule will provide important data and information on the location and size of emissions sources in the oil and natural gas sector. In addition, the U.S. is conducting a required review of the Oil and Gas New Source Performance Standards (NSPS), which currently requires leak detection and repair at processing plants only. The current review is evaluating the full scope of oil and gas operations and is scheduled for proposal in summer of 2011.

V. CONCLUSION

Natural gas companies in Russia, the U.S. and other countries have found that reducing methane emissions can be profitable and feasible. Operators of natural gas transmission systems have many technology options to reduce natural gas losses at the same time that they reduce methane emissions. These range from simple, low-cost measures, such as adjusting leaky equipment components, to larger-scale measures, such as installing dry seals on compressors. The value of the natural gas saved is typically what makes these measures profitable for a company. However, additional benefits can also be substantial. For example, in the case of dry seals, the reduction in "own losses" and in energy consumption in auxiliary equipment have played a large role in Gazprom's strategy to install dry seals on its compressors. Likewise, composite wrap can reduce down time and labor costs.

Sharing information on new methane mitigation technologies can help speed their adoption and provide operators with more options for reducing their gas losses. Both Russia and the U.S. have experience in mitigating methane emissions and through collaboration such as through the Global Methane Initiative, can continue to learn from each other regarding new emission reduction opportunities and the benefits of implementing such technologies and practices. In this way, operators in both countries stand to profit while improving the environment.

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