PARTNER UPDATE

SPRING 2011

Partner Profile: Noble Energy

Noble Energy (Noble) joined Natural Gas STAR in 2005 as a production sector Partner with a commitment to cost-effectively reduce methane emissions. Noble has reserves of 1.1 billion barrels of oil equivalent, with core operations in the Denver-Julesburg Basin, deepwater Gulf of Mexico, offshore Eastern Mediterranean, and offshore West Africa.

Noble's participation in Natural Gas STAR over the years has included activities such as directed inspection and maintenance, reduced emission completions, installing plunger lifts, installing low bleed pneumatic controllers, retiring gas pneumatic chemical injection pumps, and vapor recovery. These activities have resulted in cumulative Natural Gas STAR methane emissions reductions of over 1 billion cubic feet. The company also gave two presentations at the 2010 Annual Implementation Workshop on several initiatives.

All of these efforts are part of Noble's complementary greenhouse gas (GHG) emissions awareness programs which also include Noble's Corporate Social Responsibility Policy and its Climate Change Committee. The Climate Change Committee meets periodically to review the research, policy and regulatory elements of climate change. The committee provides oversight of Noble's GHG emissions inventory, which was first prepared in 2006, and identifies potential reduction initiatives. An example of Noble's initiative in reducing methane emissions includes participation in the Carbon Disclosure Project (an independent non-profit organization operating a climate change reporting system) in 2009 and 2010.

Noble is expanding on these accomplishments via two projects—incorporating emissions reductions into the design of production facilities in Israel, and removing carbon dioxide (CO_2) during gas well completions in Oklahoma.

Design Phase Emissions Reductions – Tamar Project, Israel
Through its GHG emissions awareness programs, Noble noticed that many of its reduction projects were "lagging strategies" adopted in response to existing issues and existing infrastructure. Rather than react, Noble took "leading strategies" approach with the goal of introducing GHG emissions as a design parameter to consider during the early phases of a project.

The Tamar project in the Eastern Mediterranean Sea is one execution of leading strategies where the Environmental Engineering department has been closely involved since the conceptual phase. The Tamar project is the development of a natural gas field 52 miles off the coast of Israel (Exhibit 1). The field was discovered in 1999 and has an estimated 8.4 trillion cubic feet in gross reserves. Noble is currently designing the gas and liquids receiving facilities, both offshore and onshore, with first production expected between 2012 and 2013. Processes at the receiving facilities will include compression, electricity generation, glycol dehydration, dew point control (via Joule-Thomson valve), stabilization, and vapor recovery.

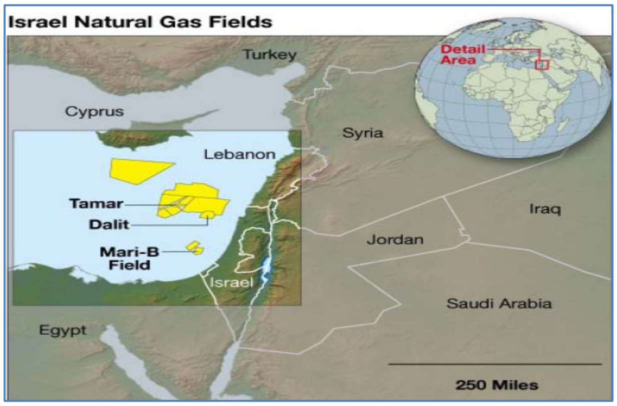

Exhibit 1: Tamar gas field off the shore of Israel in the Eastern Mediterranean Sea.

As part of the design process, Noble characterized baseline GHG emissions using ESS Essential Suite version 7.3.3, a GHG management software. The baseline emissions estimate was eye-opening to the design team and served as a key numerical result demonstrating the magnitude of methane emissions and showing that value can be derived from its capture and use.

Successes using the leading strategies approach in the Tamar project will include maximized vapor recovery by taking potential vent streams and routing to compression. The design also minimizes the flow rate of purge/sweep gas to the atmosphere to prevent backflow of air into the process. As a result of the baseline emissions estimate which quantifies methane leaks based on component counts, the Tamar project design has also minimized the number of valves and other components so that fugitive emissions are more readily managed with a planned directed inspection and maintenance program.

Involvement of the Environmental Engineering department helped to establish that emission reductions are more effective during the design phase than lagging controls and that GHG emissions inventory management can be used as an aide during the design of a major construction project.

Flowback Gas Capture Using CO_2 Membrane Technology – Ellis County, Oklahoma
In some fracturing operations in Ellis County, Oklahoma, Noble Energy uses CO_2 during hydraulic fracture. Although effective for well productivity, this practice causes the initial flowback gas to contain high amounts of CO_2, and this gas must be sent to flare for several days until the energy content of the flowback gas is pipeline quality and/or is suitable for blending. To decrease methane emissions and increase the volume of gas sold, Noble Energy conducted a pilot project using CO_2 membrane technology. A membrane unit mounted on a trailer separates flowback gas into two streams, a methane-rich residue stream that meets pipeline specifications, and a CO_2-rich permeate stream which is vented. Exhibit 2 illustrates how the membrane separation process functions.

The CO_2 membrane system shown in Exhibit 3 was tested on ten wells. A total of nine tests took place, eight of which were flowbacks from a single well completion, and one of which was a commingled stream from two well flowbacks. Once the pilot project was complete, an approximate total of 175 MMcf of gas was sold instead of flared. The total cost of the pilot project was about $325,000,

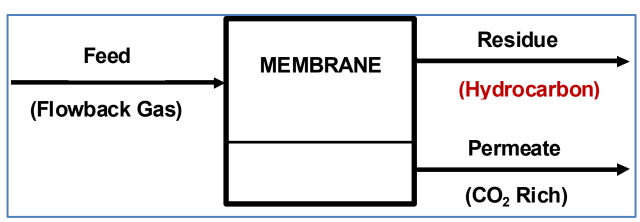

Exhibit 2: Membrane separation process, creating hydrocarbon and CO_2 rich streams.

including equipment rental and labor. Using an assumed gas sales price of $3.12/million BTU, the total net profit of the pilot project came to about $340,000, which is an average net profit of $34,000 per flowback. The potential for carbon credits is another advantage to utilizing this membrane system. In this pilot project, selling the natural gas that would have been traditionally sent to flare resulted in an estimated carbon savings of 1,300 to 5,300 tonnes of CO_2 equivalent per well.

Exhibit 3: CO_2 separation unit (portable membrane system) at a gas well site.

The project resulted in the reduction of methane emissions and provided economic advantages of selling gas that under normal circumstances would have been sent to flare. Commodity prices and the practicality of commingling the flowback gas from different wells will be important in determining future use. Commingling the flowback gas can double the gas savings for the same rental and set-up costs.

Further Down the Road

Noble's leading strategies for methane emissions management identify methane emissions before they occur, allowing the company to take action to keep more methane in its systems. Noble is planning to include these activities in its annual report to Natural Gas STAR and to continue to identify cost-effective methods to minimize methane emissions.

Technology Spotlight: Addressing Emissions via Internal Pipeline Coating and Pipeline Monitoring

Methane emissions from pipeline leaks can be attacked on two fronts: prevention and remediation. Internal pipeline coatings can minimize internal pipeline corrosion and fugitives while providing other benefits such as improved fluid flow. Inspecting and repairing pipeline leaks, on the other hand, can cost-effectively address existing leaks. These technologies are applicable to pipelines in all segments of the natural gas industry, although the benefits will likely be greater for larger, higher-pressure pipelines.

Coatings

Internal pipeline coatings (shown in Exhibit 1) typically consist of a liquid epoxy or fusion-bonded epoxy that creates a thin barrier between the internal pipeline wall and the transported material. Internal pipeline coatings offer protection against corrosive materials transported in the gas such as water, oxygen, hydrogen sulfide, carbon dioxide, or chlorides. This, in turn, mitigates the long term occurrence of pipeline leaks and pipeline repair procedures such as pipeline blowdowns resulting in methane emissions. An internal pipeline coating also reduces the friction forces experienced by the transported material along the pipeline wall. Less friction reduces the horsepower necessary to transport the material and consequently reduces fuel consumption and combustion emissions from the pumps and compressors transporting the fluid.

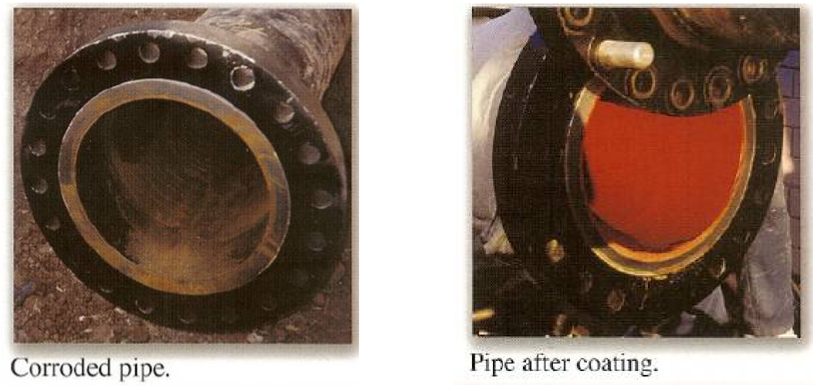

Exhibit 1: Corroded Pipeline and Internally Coated Pipeline
(IntraCoat Pipeline Services, Inc.)

An internal pipeline coating could also reduce the number of compressors required to move material through a pipeline, particularly for long transmission pipelines under high pressure. Eliminating compressors along a pipeline will reduce subsequent compressor-related fugitive and vented methane emissions such as potential methane emissions from reciprocating compressor rod packing or centrifugal compressor wet seals, compressor blowdowns, and unit and/or blowdown valve leakages. At the 2010 Natural Gas STAR Annual Implementation Workshop (epa.gov/gasstar/workshops/annualimplementation/2010.html), El Paso presented *Ruby: the First Carbon Neutral Pipeline*, which showcased the benefits of internal pipeline coatings on a 680-mile pipeline with a 1.5 billion cubic-foot design capacity. El Paso estimated the total horsepower (HP) requirements for this pipeline to be about 127,000 HP without the internal pipeline coating and 115,000 HP with the internal pipeline coating. This reduction in horsepower could potentially reduce the number of compressors required for the process.

Internal pipeline coatings can be applied at the design phase or *in situ* for existing pipelines. The first step in the *in situ* coating process includes cleaning the internal pipeline wall with abrasive blasting and chemical cleaning to smooth out and remove material deposits. This ensures the pipeline coating will properly adhere to the pipeline wall. Service providers including IntraCoat Pipeline Services, Inc. offer an *in situ* coating process that utilizes a pig to clean, prepare, and apply the coating to the inner wall of the pipeline. Exhibit 2 shows a diagram of the *in situ* coating process and photographs of the inside of a pipeline before and after the *in situ* coating application. Applying internal pipeline coatings, however, is an expensive solution to pipeline leaks in the short term and is typically justified by the additional benefits rather than by methane savings alone.

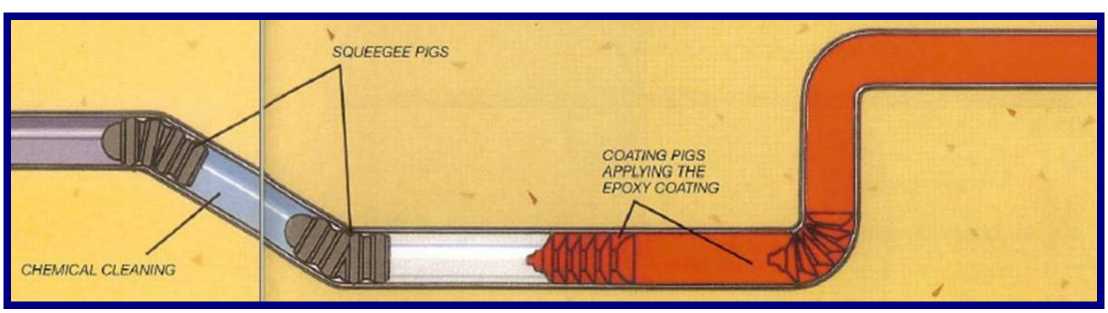

Exhibit 2: *In Situ* Pipeline
(IntraCoat Pipeline Services, Inc.)

Pipeline Monitoring

An alternative for preventing existing pipeline leaks is periodically monitoring pipelines using a combination of ground transportation and the appropriate hydrocarbon leak detection device. This combination increases measurement speed and effectiveness when performing mobile inspections of large networks of gathering, transmission, and distribution pipelines. The Apogee Leak Detection System (LDS) that was featured in the summer issue of the 2009 *Partner Update* (epa.gov/gasstar/newsroom/partnerupdate.html) can be mounted on various vehicle types, including a truck or all-terrain vehicle. Exhibit 3 shows the Apogee truck-mounted leak detection system.

Exhibit 3: Apogee Truck-Mounted Leak Detection System
(www.apogee-sci.com/Forms/ApogeeLDS012610v1.pdf)

The LDS measures gas concentrations by continuously capturing samples of ambient air using a blower. The sample is analyzed with a series of mirrors and lasers to detect any appreciable hydrocarbon gases. Concentration measurements occur approximately 20 times per second with methane, total hydrocarbon, and carbon dioxide measured separately.

Another method used by Heath Consultants is to mount an optical methane detector to a vehicle (e.g. trucks and all-terrain vehicles) and perform the pipeline leak detection from the vehicle. Exhibit 4 demonstrates a few examples of vehicles equipped with optical methane detectors.

Exhibit 4: Heath Optical Methane Detector
(www.heathus.com/_hc/index.cfm/products/gas/omd)

The ground-based pipeline leak detection method, as opposed to air-borne leak detection, is less costly. However, this method is limited to pipelines on navigable and passable land. Walking surveys are also feasible using optical and infrared leak detection devices; however, they can be time consuming and tedious for long stretches of pipeline.

Conclusion
The use of internal pipeline coatings and monitoring will reduce greenhouse gas emissions. Internal pipeline coatings mitigate corrosion preventing pipeline leaks in the long term and immediately, albeit indirectly, reducing pump and/or compressor combustion emissions. In the short term, operators can also implement a directed inspection and maintenance (DI&M) program on their pipelines to reduce methane losses from pipeline leaks. Through a combination of internal pipeline coating application and ground-based pipeline leak detection, companies can prevent methane and potentially other air pollutant emissions from their pipeline operations.

Prospective Projects Spotlight: Artificial Muscle Technology

As gas wells mature, liquids begin to accumulate in the well bore impeding the flow of gas. Gas flow is maintained by removing accumulated fluids through the use of a sucker rod pump or other remedial treatments (see sidebar). These fluid removal techniques may result in significant costs and/or methane emissions to the atmosphere.

A prospective alternative explored in this article is the combination of artificial muscle technology with existing hydraulic downhole deliquification pumps.

Existing Well Liquids Removal Options

- Sucker rod pumps
- Plunger lifts
- Swabbing
- Soaping
- Velocity tubing strings
- Gas Lift
- Venting
- Electric Submersible Pumps (ESPs)

BACKGROUND
Although it is common for wells to produce some water and/or hydrocarbon condensate, it is not a problem until the liquids begin to accumulate in the well bore and impede production. For most wells, the gas is flowing fast enough that the liquids blow out as droplets and accumulate in the separator at the surface. For mature or depleting wells, the velocity of the gas flow in the well bore declines which results in a lower ability to carry the liquids. As a result, liquids begin to accumulate, and production volumes suffer.

To maintain productivity, profitability and extend the well's life, operators will determine which liquids unloading method is most applicable to the specific well based on individual well characteristics. As the well becomes more mature, the flow of gas may become too low to use a liquids unloading option that does not involve adding energy to the reservoir. Adding energy to the reservoir requires additional costs. Under these circumstances, a downhole pump or gas lift is usually employed. Eventually, as the well continues to mature, it will be shut in and abandoned. This decision is based on an economic evaluation which determines when the investment required to maintain productivity exceeds the revenue from the well. Often, gas will remain in the reservoir, but a well is shut in because it is no longer economic to attempt to extract the remaining gas.

NEW TECHNOLOGY
One company is currently focusing on combining technology used in military applications, called Shape Memory Alloy (SMA), with existing hydraulic downhole deliquification pumps (see Exhibit 1). This new deliquification system, called SmartLift,

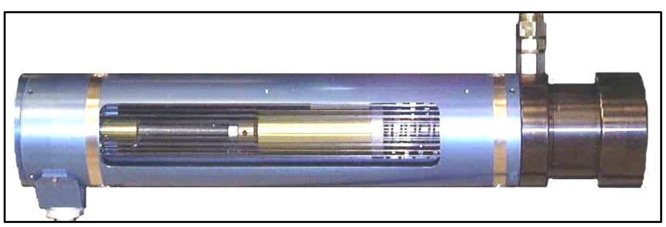

Exhibit 1: A high-pressure pump powered by a Shape Memory Alloy

would be electrically powered and is projected to be less costly than existing artificial lift technologies. By applying an electric potential through the alloy, the metal will take a shape that it has stored (as if by memory). When the electric potential is no longer applied, the metal returns to its original shape. Use of this technology for a pump driver results in a piston syringe pump being driven by an electric muscle. A significant advantage of this type of pump is its ability to create a linear pumping motion with only two moving parts. This technology could also be combined with numerous existing hydraulic pumps.

POTENTIAL METHANE SAVINGS AND PROJECT ECONOMICS

Emissions reductions will vary for each individual application depending on well and reservoir characteristics. Based on a Natural Gas STAR Partner experience, it is estimated that emissions reductions resulting from the installation of a downhole pump could be as high as 973 thousand cubic feet (Mcf) per year per well[1]. Exhibit 2 illustrates a comparison of emissions reductions and capital/installation costs for three possible scenarios: a) no liquids removal, b) typical downhole pump, and c) a Shape Memory Alloy pump.

Exhibit 2: Cost Estimate and Potential Savings Comparison

PROJECT SUMMARY: SmartLift vs. Typical Downhole Pump			
Type of Artificial Lift	None	Typical Downhole Pump (Pump Jack)	Shape Memory Alloy Pump
Annual Emissions from Liquids Unloading (Mcf per year per well)	973	0	0
Capital & Installation Costs Ratio	0	1.0	0.55[a]
Gas Production	Reduced	Improved	Improved
Methane Saved (Mcf per year per well)	0	973	973

[a] In general, the cost of a system using a Shape Memory Alloy pump is 55% that of a comparable downhole pump system.

As shown in Exhibit 2 above, the reduction in emissions from implementation of a system using Shape Memory Alloy technology is equivalent to reductions from a typical downhole pump. The system using new technology requires an investment that is projected to be approximately 45 percent lower. Both types of artificial lift will extend the useful life of the well by efficiently unloading liquids that build up in the well bore resulting in additional revenue from gas sales. The difference, however, is that the new technology is projected to be more cost-effective as illustrated in Exhibit 3. Because the new technology requires a smaller investment to install, it is possible that a larger population of wells could benefit from the installation of an artificial lift system.

As illustrated in Exhibit 3, a system using this new technology could be more cost-effective than some downhole pump options because both installation and operation are simpler. The equipment is much smaller and lighter than a sucker rod pump and will be installed from a reel rather than using a pulling unit. The new artificial lift system, which employs the SMA technology, has demonstrated reliability and long service life in other applications and could potentially operate longer than a typical downhole pump, reducing annual operating and maintenance (O&M) costs.

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[1] Partner Reported Opportunity Fact Sheet No. 707. "Install Pumpjacks on Low Water Production Gas Wells". January 2004. Available at: http://epa.gov/gasstar/documents/gaswells.pdf

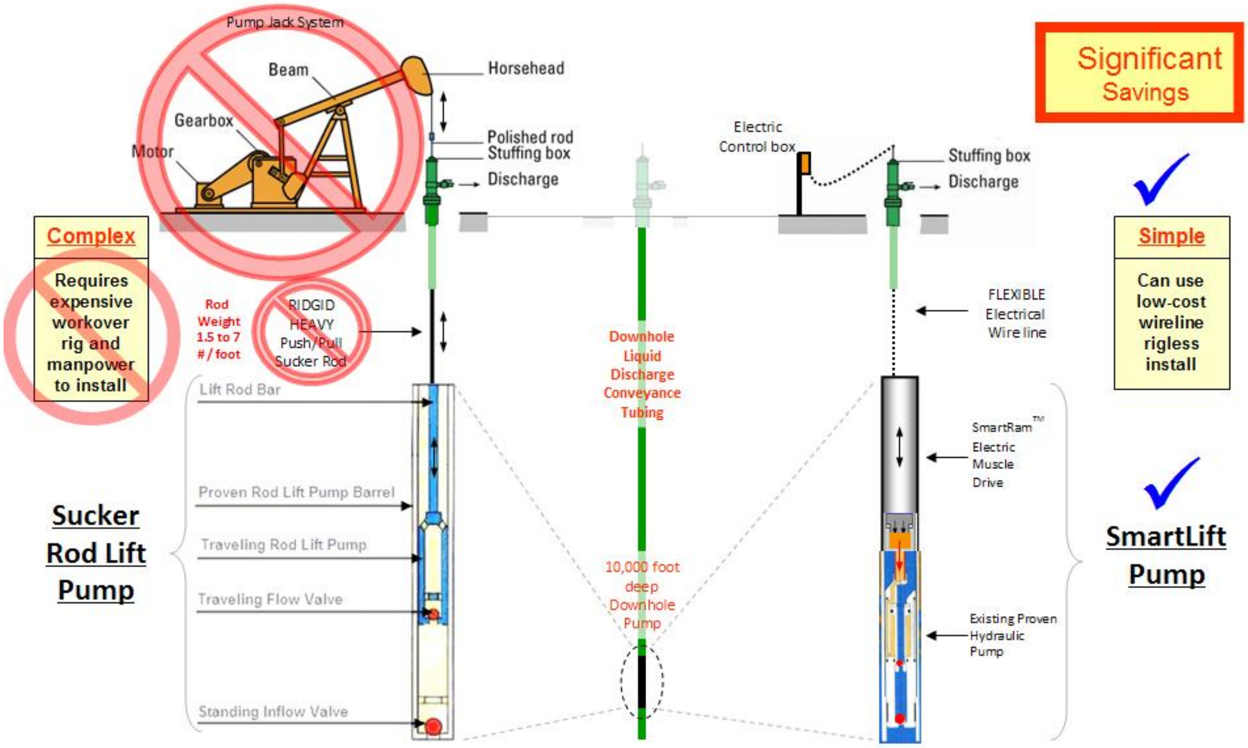


Exhibit 3: Replacing Large & Complex Topside Pump Jacks

ADDITIONAL APPLICATION

Besides the intended application for downhole pumps, this technology might also be useful in pneumatic actuators by replacing the power gas used for moving large valves. Instead of using natural gas pressure for pneumatic controls, this technology could be used to provide the pressure necessary for actuation of the device wherever electric power is available. As a result, this device would effectively transform bleeding pneumatic devices into no-bleed devices. This application would lead to significant emissions reductions as well as additional revenue from the gas sales since less gas would bleed through the pneumatic devices.

CONCLUSION

If electric power is available on-site, this new technology could be used with downhole pumps to increase efficiency and simplicity of installation and operation, reducing costs and methane emissions. This technology also has the potential to be used in other applications, such as replacing power gas to pneumatic actuators.

Development of the SmartLift system is currently supported by a contract with Linear Motion Technologies (LMT) and the Stripper Well Consortium (www.energy.psu.edu/swc/), which is funded by the U.S. Department of Energy and operated by Penn State University. The current objective of the SmartLift development effort is the selection of an initial sizing for a prototype that will address the needs of a significant portion of the U.S. gas well population.

Natural Gas STAR: Annual Reporting Season is Underway!

The Natural Gas STAR 2011 reporting season is underway. Partners are kindly requested to submit information on any voluntary methane emissions reduction activities undertaken in the 2010 calendar year by **April 29th, 2011**,

Suggested Procedure for Identifying New Projects to Report to Natural Gas STAR:

1. Review operations.
2. Identify differences between your operations and current PROs.
3. Report emission reduction activities for 2010.

Natural Gas STAR Partners should have received annual reporting information (along with login and password information) by email at the beginning of March. Please contact your STAR Service representative with any reporting questions. Partners can submit reports in hard copy, email, fax, or electronically through a secure, password-protected online reporting form.

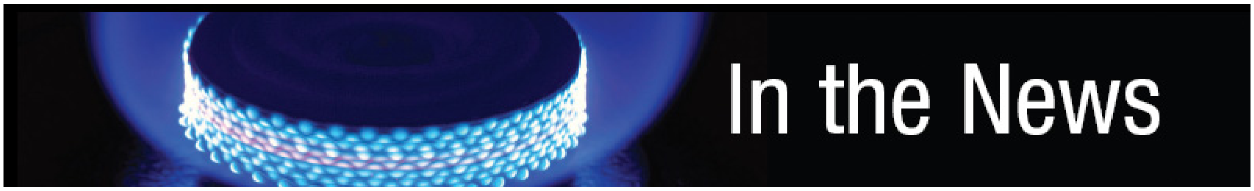
Below is a suggested procedure for reporting 2010 activities to Natural Gas STAR:

1. Review operations. Engage in discussions with field personnel who can identify recent improvements or current challenges. Other information sources useful for identifying opportunities include facility emission inventories, copies of process and instrumentation diagrams, and repair/maintenance logs.

2. Identify differences between your operations and current PROs. Compare the technologies and practices used in your operations to the Partner Reported Opportunities (PROs) available on the Gas STAR website. PROs are any practice or technology included in a Partner's annual report that reduces methane emissions. Determine whether certain activities are unique or are improvements on current PROs. Highlight these findings in your annual report to notify Natural Gas STAR of a new innovative activity.

3. Report emission reduction activities undertaken in 2010. Review current PROs and report to Natural Gas STAR all voluntary methane emissions reduction activities completed in the 2010 calendar year. A complete listing of all reported PROs can be found on the Program's Web site at epa.gov/gasstar/tools/recommended.html.

Submit Online at: http://app6.erg.com/gasstar/



Natural Gas STAR International Collaborates with Russian Independent Oil and Gas Producers on Methane Mitigation Technologies and Strategies

October 4, 2010—Moscow, Russia

In the fall of 2010, the Global Methane Initiative and Natural Gas STAR International held a seminar with independent oil and natural gas producers in Russia to discuss best practices for methane emissions reductions on an international stage. The seminar drew participants from companies including Lukoil, TNK-BP, and Gazprom VNIIGAZ. The one-day workshop in Moscow addressed methane emissions from both the production and processing sectors—well completions/workovers, liquids unloading, storage tanks, pneumatic devices, dehydrators, reciprocating/centrifugal compressors—and covered programs such as directed inspection and maintenance (DI&M) to help detect, prioritize, and repair leaks. Several companies also gave presentations on their related experience in both methane mitigation technologies and GHG accounting and reporting. More information on the workshop and presentations can be found at epa.gov/gasstar/workshops/techtransfer/2010/moscow_en.html.

Natural Gas STAR International and Gazprom Conduct Site Tour and Workshop on the Accounting and Control of Methane Emissions in the Russian Gas Sector

December 14 to 16, 2010—Novy Urengoy, Russia

Under the Global Methane Initiative, Natural Gas STAR International and Gazprom, the world's largest producer of natural gas, co-hosted a production site tour in Yamburg and a technical seminar in Novy Urengoy, December 14 to 16. Located above the Arctic Circle, the event included a two-day tour of Gazprom's Yamburg gas production and processing sites and a technical conference to exchange information on methane emission reduction strategies and climate policy. Natural Gas STAR Program Manager, Scott Bartos, also met with senior Gazprom management in Moscow.

U.N. Study Says Global Warming Rate Could be Halved by Controlling Two Pollutants

A recent study by the United Nations Environment Programme (UNEP), *Integrated Assessment of Black Carbon and Tropospheric Ozone*, suggests that the projected rise in global temperatures can be cut in half if both black carbon and ground-level ozone (and by extension methane) are reduced. Although not a greenhouse gas, black carbon exists as particles in the atmosphere and warms the atmosphere by absorbing sunlight. Ground-level ozone is formed by the reaction of sunlight with ozone precursors (methane is considered an ozone precursor in the UNEP report) and is hazardous to human health and ecosystems. In addition to reducing the amount of ground-level ozone, the report states that mitigating methane emissions has the added benefit of reducing global warming.

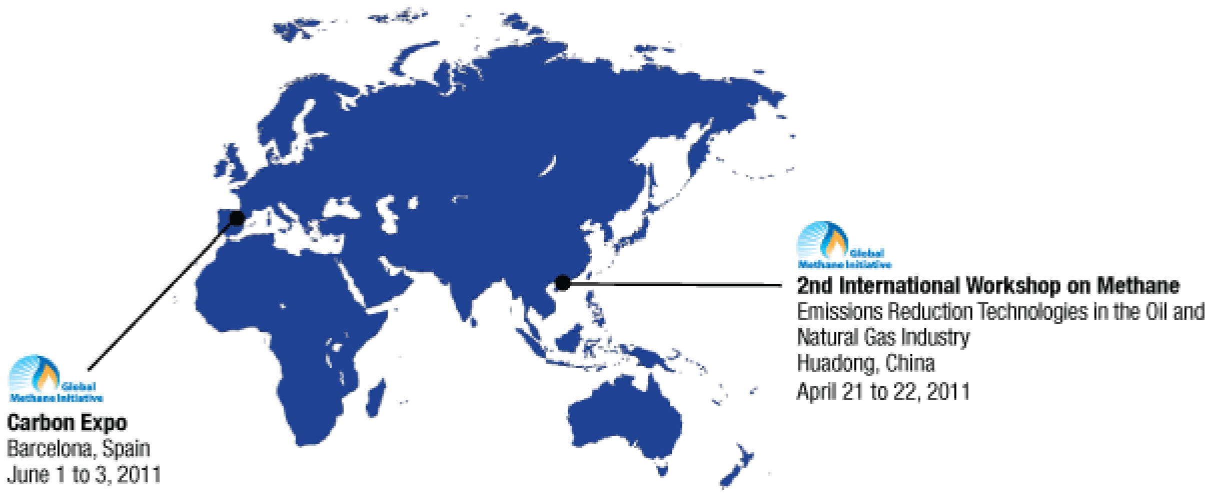
Rather than focusing on carbon dioxide alone, this report recommends that reducing air pollutants with short lifetimes is the most viable way to mitigate global warming over the next 20 to 30 years. One way to control ground-level ozone covered in the report is to reduce methane emissions from long-distance natural gas transmission pipelines, an activity that is also beneficial for maximizing natural gas supply. As concerns about near-term impacts of climate change increase, many organizations are now beginning black carbon and ground-level ozone reduction projects located around the world (e.g., China, Brazil, and India). Additional article details and the UNEP report are available at http://www.washingtonpost.com/wp-dyn/content/article/2011/02/23/AR2011022306885.html.

BOEMRE Holds Workshop on Potential Flaring Requirement for Offshore Petroleum Production Facilities to Reduce GHG Emissions

March 30, 2011—New Orleans, Louisiana

The Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) held a public workshop in New Orleans to discuss the possibility of requiring existing venting of natural gas from offshore petroleum production facilities to be directed to flare. This issue was brought forth by the Government Accountability Office (GAO), which recommends companies to consider the benefits and economics of flaring natural gas vents whenever possible. The workshop intended to bring parties together to give recommendations on what facilities the flaring requirement should apply to, what the emissions threshold should be, and which equipment types require venting rather than flaring for safety reasons. More information about the workshop, including the agenda and presentations, will be available soon on the BOEMRE website at boemre.gov.

Upcoming Events



Natural Gas STAR Contacts

Program Managers

Scott Bartos (bartos.scott@epa.gov)
Phone: (202) 343-9167

Jerome Blackman (blackman.jerome@epa.gov)
Phone: (202) 343-9630

Carey Bylin (bylin.carey@epa.gov)
Phone: (202) 343-9669

Roger Fernandez (fernandez.roger@epa.gov)
Phone: (202) 343-9386

Suzie Waltzer (waltzer.suzanne@epa.gov)
Phone: (202) 343-9544

Natural Gas STAR Program U.S. Environmental Protection Agency

1200 Pennsylvania Ave., NW (6207J) Washington, DC 20460

For additional information on topics in this *Update*, please contact Jerome Blackman.