Operations and Maintenance of Natural Gas Transmission and Distribution Systems Emission Reductions Projects

Final Report

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Table of Contents

Executive Summary

The Climate Action Reserve (the Reserve) is considering protocol development for projects in the natural gas transmission and distribution (NGTD) sector. This sector emits methane (CH_4) both from fugitive and vented sources. With a global warming potential 21 times that of carbon dioxide (CO_2), CH_4 is an important greenhouse gas (GHG). This issue paper highlights and discusses potential methodological issues associated with developing a carbon offset protocol from changing operation and maintenance practices on NGTD systems to prevent and avoid emissions of CH_4. The paper considers potential approaches to GHG emissions quantification, as well as options for defining project activities, setting project boundaries, developing performance standards and standardized baselines, and identifying potentially relevant regulations. The sections of the executive summary provide an overview of project types and conclusions regarding the Reserve's project eligibility considerations.

Project Types

This paper identifies nearly 100 potential NGTD sector emission reduction projects, grouped into broad categories of design, maintenance, and procedural. Design projects incorporate emission reduction technology or strategy either in the design or use phase. Maintenance projects improve equipment functioning or involve a change in maintenance practices that reduce emissions. Procedural projects affect operating procedures but do *not* alter the technologies or equipment in use.

Within these categories, vented and fugitive emission sources provide unique project opportunities. Further, emission reduction projects can be grouped by the type of equipment they involve such as compressors or valves.

Table ES1 identifies issues that accompany project types within the broad categories of design, maintenance, and procedural projects, for the more refined categories of vented and fugitive emissions, and by equipment type. Note that the table does not contain a column for eligibility criteria that have the same considerations regardless of project type (e.g., for ownership). Development of a protocol would be possible for each of these broad categories of project types.

In reviewing the project types, only three individual projects were identified as non-viable candidates.

1. Projects that reduce leaks from underground pipelines (Project IDs 42, 56, 76, 77). It is prohibitively difficult to quantify baseline and post-project emissions for this project type without the use of default emission factors.
2. Projects that replace cast iron pipes (Project ID 54). Cast iron pipelines are being phased out of gas distribution systems and so this project type could be considered business as usual.
3. Projects that reduce CH_4 emissions through gas quality control (Project ID 78 in Table 1.1). Due to difficulties in quantifying emission reductions, a protocol should not be developed for this project type.

Another project type, fugitive emission leak detection and repair, is likely non-viable. The challenge with this project type lies in available quantification methodologies for baseline and post-project emissions. Emission factor-based methods contain unacceptable levels of uncertainty for project quantification. Although correlation-based methods exist, they too contain high levels of uncertainty. Direct measurement techniques provide acceptable accuracy, but they are prohibitively expensive, especially if conducted on many components. The nature of these emissions requires ongoing measurements and statistical sampling to determine broad-system emission reductions. As a result of these challenges, it is recommended that the Reserve not develop a protocol for this project type at this time.

After ruling out the above-described projects, there remain many possible projects that could be the subject of Reserve protocols. Given the unique aspects of possible projects in the NGTD sectors, it is likely that multiple protocols will need to be developed. It would be difficult, for example, to write one protocol that encompassed reducing fugitive emissions from valves and vented emissions from compressors.

It is recommended that the Reserve focus initially on projects in the design category. Design projects are straightforward and do not require adherence to an operating procedure. Examining which sources contribute most to GHG emissions from the NGTD sector instructs as to which projects within the broad category of design may be most ripe for protocol development. Engineering vented emissions are the largest source of emissions in the transmission sector. Some example design project types that would address these emissions include rerouting vented gas from compressor rod packing to a fuel line. (Project ID 11 in Table 1.1) Fugitive emissions are very important in the distribution sector. To address fugitive emissions from compressors, rod packing can be replaced to prevent CH_4 leaks. (Project ID 44 in Table 1.1) Further, high-bleed pneumatic devices in the distribution sector can be replaced with no-bleed devices. (Project ID 47 in Table 1.1)

ADDITIONALITY

The Reserve considers two levels of additionality: regulatory and non-regulatory. As of the date of this publication, there are no existing federal, regional, state, or local air regulations that directly limit GHG emissions from the NGTD industry. One National Emissions Standard for Hazardous Air Pollutants indirectly limits CH_4 emissions from dehydrators through a limit on volatile organic carbon (VOC) emissions from this equipment. State VOC and permitting rules may affect regulatory additionality of projects. The Reserve may therefore wish to develop a catalogue of state VOC and permitting rules and their potential indirect impact on project additionality. Finally, individual projects will need to undergo a regulatory review to assess whether individual permitting or legal requirements (e.g., consent decrees) affect their additionality.

Non-regulatory impacts on additionality must be identified through careful examination of business-as-usual conditions and industry standard practice. Resources for conducting this examination include the EPA Natural Gas STAR website (www.epa.gov/gasstar) and industry groups like the American Petroleum Institute (API), the American Gas Association (AGA), and the Interstate Natural Gas Association of America (INGAA).

Performance Standard

Possible performance standards could be based on emissions intensity, efficiency level, emissions reductions thresholds, or technology performance. Of these, a design-based performance standard is least likely to exclude projects based on the amount of emissions reductions. Further, the design-based performance standard may be the most straightforward to establish once industry standard practice is better understood. Information from the industry associations or EPA's Natural Gas STAR program may provide information to support development of a performance standard for some of the design projects types identified.

Baseline Quantification

Three potential baseline scenarios apply to NGTD reduction projects:

1. Continuation of current activities;
2. A technology representing an economically attractive course of action considering barriers to investment; and
3. Using average emissions of similar project activities.

For many of the potential NGTD projects, continuation of current practices is a feasible baseline scenario and provides for accurate determination of baseline emissions.

Cost Effectiveness

Emission reductions in the NGTD sectors can be very cost effective. Many have a payback period of less than one year. However, this has implications in the evaluation of additionality.

Project Boundary and Leakage

The project boundary could include only the affected equipment. It is possible however, that resources used to maintain another part of the system could be diverted to the equipment included in the project. To firmly rule out this potential for leakage, the Reserve could require that the entire system to which the affected equipment belongs be included in the project boundary. Alternatively, an approach similar to the urban forestry project could be taken. In that case, project developers would need to submit documentation analogous to a tree maintenance plan in the urban forestry protocol to demonstrate that emissions from non-project equipment have not increased.

Ownership

As with existing Reserve project types, ownership of the project must be established *a priori* because a suite of entities could lay claim to the emissions reductions achieved in an NGTD sector project.

Permanence

Emissions reductions from NGTD sector projects are expected to be permanent because NGTD projects irreversibly either conserve or destruct CH_4.

MEASUREMENT

Established techniques with reasonable uncertainty levels exist to measure vented and fugitive emissions from the NGTD sector.

Although pipeline natural gas composition is relatively uniform, pre- and post-project emissions calculations should be based on measurements rather than a default value.

PRE- AND POST- PROJECT EMISSIONS QUANTIFICATION

Although emission factors exist for all equipment types that could be involved in NGTD sector projects, the bulk of these are based on a 1996 study and were calculated to represent industry average conditions. As such, they are not appropriate for project-level calculations. It is recommended that emission factors should not be used to quantify baseline or post-project emissions. Rather, it is recommended that engineering estimates or direct measurements be used to calculate baseline and post-project emissions.

Fugitive emissions are more difficult to quantify than vented emissions. Direct measurement of leak rates and CH_4 concentration in the leaked gas is the most accurate approach to quantify fugitive emissions.

RELATED PROGRAMS

The United Nations Framework Convention on Climate Change Clean Development Mechanism Methodologies (UNFCCC CDM) has published two relevant methodologies for the project types considered in this issue paper. Although there are significant differences between the Reserve's and the UN's programs, elements of the CDM methodologies are instructive. Existing Reserve protocols draw on information in CDM methodologies (e.g., the Livestock protocol). This paper therefore describes these methodologies and the elements of them that could be applicable to a Reserve performance standard.

The World Resources Institute presents an instructive case study depicting the installment of high-efficiency compressors that outlines the development of a performance standard for this project type.

Table ES.1 Eligibility Considerations by Project Type

		Additionality - Regulatory	Additionality - Non Regulatory	Project Boundary
Project Type	Design	Projects need to exceed the requirements in 49 CFR 92, a U.S. Department of Transportation regulation that lays out specification for NGTD design, construction, and operation.	Projects must exceed industry standard practice and business-as-usual conditions. There may be less publicly available information that can be used to establish industry standard practice for maintenance or procedural projects compared to design projects.	The project boundary could include the newly installed equipment and any components that are directly impacted by the installation of the new equipment.
	Maintenance			
	Procedural			
Emission Type	Vented	See comments for dehydrator projects.	Industry standard practice must be identified for each unique project type.	The project boundary can include only components affected by the project or the entire system to avoid leakage affects if the Reserve decides that such a step is necessary to completely avoid leakage.
	Fugitive	No direct regulatory requirements affect additionality.		
Equipment Type	Compressor	No direct regulatory requirements affect additionality.	Must identify industry standard practice in terms of compressor models used.	Including only the affected compressor station(s) may be most appropriate
	Dehydrator	The National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Oil and Natural Gas Production and Natural Gas Transmission and Storage [40 CFR 63] indirectly affects CH_4 emissions from dehydrators. Any dehydrator project should be evaluated for additionality against the requirements of this regulation.	Must identify industry standard practice in terms of dehydrator technologies used.	The project boundary can be drawn around the affected dehydrators.
	Pneumatics, Valves	No direct regulatory requirements affect additionality.	Must identify industry standard practice in terms of technologies used (e.g., valve models) and inspection and maintenance practices.	The project boundary can include only components affected by the project or the entire system to avoid leakage affects if the Reserve decides that such a step is necessary to completely avoid leakage.
	Pipelines		Must identify industry standard practice in terms of average age of pipeline and materials of construction for majority of pipeline in use and that is used in replacements.	The project boundary can include only the pipeline segment the project affects or the entire system to avoid leakage effects if the Reserve decides that such a step is necessary to completely avoid leakage.
	Tanks		Must identify industry standard practice in terms average age of tanks and materials of construction for majority of tanks in use and that are used in replacements.	The project boundary could include only the affected tanks without introducing much risk of leakage.

1.0 Background

This paper explores the feasibility and desirability of protocol development for greenhouse gas (GHG) emissions reductions projects in natural gas transmission and distribution (NGTD) systems. The natural gas production and delivery system is illustrated in Figure 1. The NGTD system encompasses entities that transport (yellow highlight) and distribute (red highlight) natural gas after the point of custody transfer from natural gas production and gathering facilities. This point of custody transfer separates the NGTD sector from the Oil & Gas Production sector. Natural gas compressor stations and gas plants are part of the NGTD sector if they transmit or treat gas after the point of custody transfer at which the delivered gas is *contractually* required to meet pipeline tariff specifications.

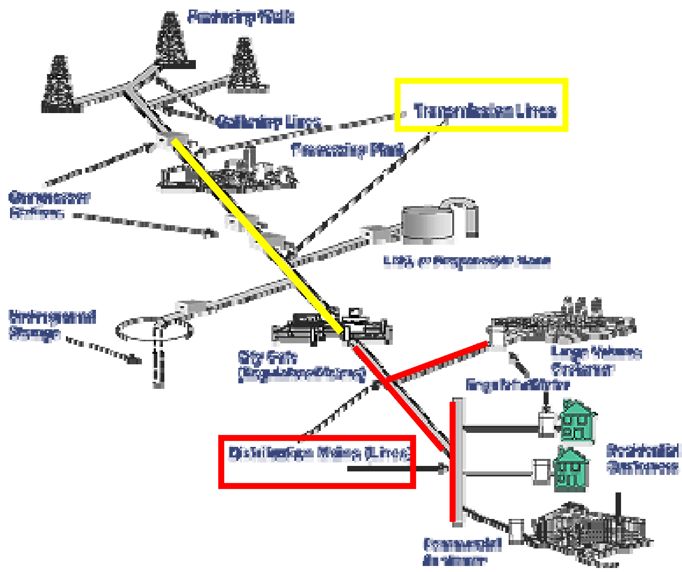

Figure 1. Natural Gas System [U.S. EPA, 2009a]

Entities within the NGTD sector usually have facilities classified under the following North American Industry Classification System (NAICS) codes:

- Pipeline Transportation of Natural Gas (NAICS Code 486210)
  This industry comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems.
- Natural Gas Distribution (NAICS Code 221210)
  This industry comprises: (1) establishments primarily engaged in operating gas distribution systems (e.g., mains, meters); (2) establishments known as gas marketers that buy gas from the well and sell it to a distribution system; (3) establishments known as gas brokers or agents that arrange the sale of gas over gas distribution systems operated by others; and (4) establishments primarily engaged in transmitting and distributing gas to final consumers.

The NGTD sector includes the following types of facilities:

- Natural gas transmission and distribution pipelines,
- Natural gas compressor stations located on gas transmission and distribution pipelines,
- Natural gas processing plants associated with transmission and distribution,
- Natural gas metering and regulating (M&R) stations,
- Natural gas storage reservoirs, and
- Liquefied natural gas (LNG) facilities.

A single entity may have operations that fall within both of the above NAICS categories. A single entity may also have operations within both the NGTD sector and the upstream Oil & Gas production sector.

While CO_2 makes up the majority of GHG emissions in the United States, emissions for natural gas systems consist mostly of CH_4. Methane has a global warming potential 21 times greater than that of CO_2. After gas processing, CH_4 comprises over 90% of natural gas in the pipeline in the transmission and distribution sectors. [INGAA, 2005]. Although gas is processed before it enters the transmission sector to remove the naturally-occurring CO_2 to meet pipeline quality specifications, small amounts of CO_2 are still present (not to exceed 2%) [AGA, 2008]. Hence, there are some CO_2 emissions associated with CH_4 wherever natural gas is released to the atmosphere, but generally at much lower concentrations than CH_4. As a result, this paper focuses on methods of controlling CH_4 emissions and calculating the emissions reductions benefits of those controls.

Natural gas systems, from production to distribution, are the third largest emitters of CH_4 in the United States, emitting approximately 18 percent of total US CH_4 emissions [U.S. EPA, 2009b]. Emissions primarily result from normal operations, routine maintenance, fugitive leaks and system upsets. Emissions from natural gas systems in the United States totaled 104.7 million metric tons of carbon dioxide equivalent (Tg CO_2 Eq.) of CH_4 and 28.7 Tg CO_2 Eq. of non-combustion CO_2 in 2007 [EPA Inventory 2009, p. 3-39], or just under two percent of total US GHG emissions. However, despite an increase in production, CH_4 and non-combustion CO_2 emissions from natural gas systems have decreased approximately 19 and 15 percent since 1990 levels, respectively, due to improvements in technology and management practices, as well as some replacement of old equipment [U.S. EPA, 2009b].

Figures2a and 2b summarize GHG emissions contributions from the four stages of natural gas systems in the United States in 2007. Figures 3a and 3b summarize the breakdown in sources of vented and fugitive emissions from the transmission and distribution stages of natural gas systems

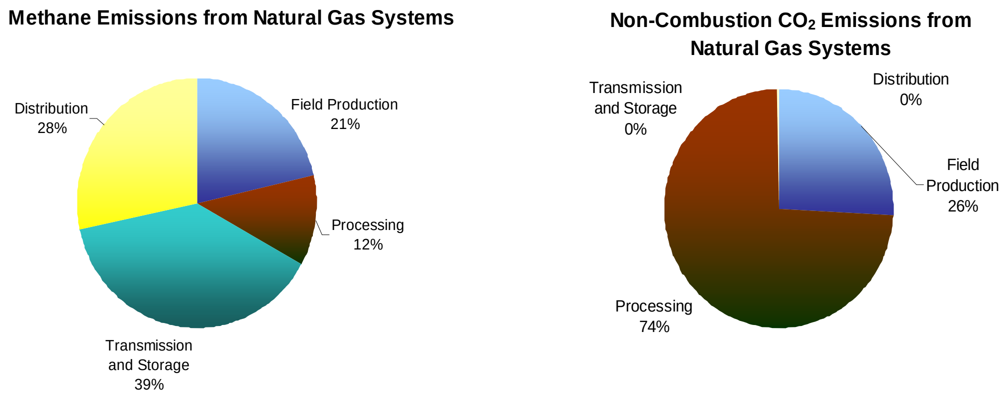

Figure 2a and 2b. CH_4 and Non-Combustion CO_2 Emissions from Natural Gas Systems [U.S. EPA, 2009b (Tables 3-33 through 3-36)]

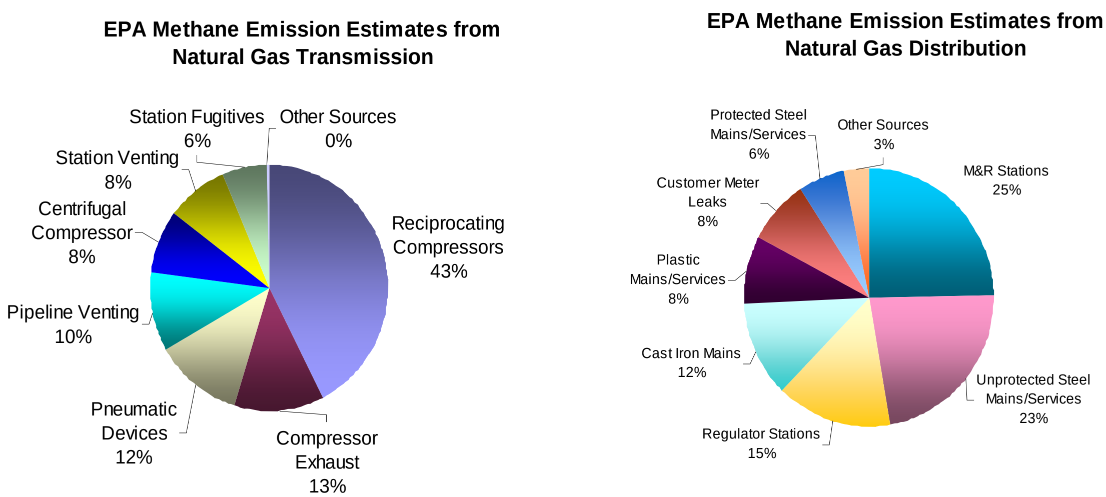

Figure 3a and 3b. CH_4 Emissions Estimates from Natural Gas Transmission and Distribution [U.S. EPA, 2009b (Tables A-118 and A-119)]

Many potential GHG emissions reductions projects can be implemented in the NGTD sector through reducing natural gas emissions, which are mainly comprised of CH_4. This issue paper discusses the broad range of opportunities for CH_4 reduction in the NGTD sector and their potential as quantifiable and creditable Reserve GHG emission reduction projects. This paper addresses aspects of emission reduction projects the Reserve will consider when deciding whether to develop a protocol for the project types addressed in this paper. These considerations include the existence of high-quality quantification methods with reasonable uncertainty, potential for clearly-defined additionality criteria, ease of baseline quantification, project cost effectiveness, project boundaries, clarity of project ownership, leakage potential, permanence, and feasibility of performance standard development.

Tables 1 through 3 provide an overview of emission reduction project types in the NGTD sector. Table 1 contains design projects, which introduce new technology or alter the design of existing technology. Table 2 contains maintenance projects, which improve equipment functioning or involve a change in maintenance practices that reduce emissions. Table 3 lists procedural projects, which affect operating procedures but do *not* alter the technologies or equipment in use. For example, a project that increased the frequency of pipeline inspection would be procedural.

Each project is further classified as either reducing emissions from vented or fugitive sources. Where vented emission sources are reduced, the tables indicate if the natural gas is captured (resulting in a reduction of CH_4 emissions) or flared (converting CH_4 emissions to CO_2). In the following two sections, vented and fugitive sources are described in greater detail.

Table 1. Design Projects in the Natural Gas Transmission and Distribution Sectors

ID	Project Description	Vented Emissions Reductions			Fugitive Emissions Reductions	Accurate Quantification Methods Exist
		Capture	Flare	Reduce Venting		
1	**Use "Zero Emissions" dehydrators -** Zero emissions dehydrators reduce emissions by using electric power for pumps and re-using still column vapors for fuel.	X			X	X
2	**Inject blowdown gas into low pressure mains** – This is one example specific to the distribution sector. This project involves the transfer of gas from one part of a system to another as a substitution for maintenance repair venting.	X				X
3	**Fuel Gas Recovery Blowdown Valve for Compressor Blowdowns** – This is a specific design approach for tying the compressor blowdown system to the fuel gas system.	X				X
4	**Use Portable Compressors to Transfer Gas to Fuel Systems or Another Pipeline to Reduce Venting on Line Purges –** A portable compressor makes the transfer to another line possible when the pressure on the vented line is lower than the host line to which the gas is being transferred. Transfer of the gas prevents direct venting emissions or CH_4 emissions from incomplete combustion, CO_2 emissions, and N_2O emissions from flaring.	X				X
5	**Recover vented gas from pipeline pigging operations** – A portable compressor can be used to recover otherwise vented gas from pipeline pigging.	X				X
6	**Install vented fuel capture and recovery systems or thermal gas oxidation systems –** Collect vented gas with a portable compressor. Route it to a gas line or to the fuel gas system to fuel other equipment.	X				X
7	**Pipe glycol dehydrator to vapor recovery unit -** An example of preventing venting by recovering gas for reuse.	X				X
8	**Reroute glycol skimmer gas -** This is one technique of avoiding venting by rerouting the gas to other fuel systems for fuel use.	X				X

Table 1. Design Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions: Capture	Vented Emissions Reductions: Flare	Vented Emissions Reductions: Reduce Venting	Fugitive Emissions Reductions	Accurate Quantification Methods Exist
9	**Install ejector -** Installing ejectors transfers gas from an out-of-service system that would otherwise be vented to the atmosphere to an operating system.	X				X
10	**Use recycle line to recover displaced gas during condensate loading -** Captures methane that would otherwise be vented to the air by directing CH_4 vapor to a vapor recovery line.	X				X
11	**Route vented gas from compressor rod packing to fuel line -** This design change prevents fugitive emissions from rod packing.				X	X
12	**Route vented emissions to flare** – Flaring reduces the direct venting of gas and reduces CH_4 emissions by conversion of the CH_4 to CO_2 by combustion. CO_2 has a lower global warming potential than CH_4.		X			X
13	**Recover methane released from pipeline system liquid storage tanks -** Capture and flare flash gases from atmospheric condensate storage tanks.		X			X
14	**Use of stop-off fittings to reduce pipeline blowdowns for pipe repair** – A device that allows bypass of the repair area without shutting the system down. It avoids the need to vent gas and avoids CH_4 emissions.				X	X
15	**Convert gas-driven chemical pumps to instrument air** – Eliminates methane and associated carbon dioxide emissions from venting of natural-gas-driven pumps by conversions to air driven pumps.				X	X
16	**Install electric starters on compressor engines** – More efficient starting with a reduction in un-combusted fuel emissions from engine exhaust during start-up.				X	X
17	**Automate systems operation to reduce venting** – This refers to any number of automation techniques to improve operational efficiency such as reducing energy consumption and emissions from process upsets.				X	X
18	**Replace ignition on engine systems** - Reduce unnecessary engine operation and false starts.				X	X
19	**Replace natural gas starters with air or nitrogen** – Venting emissions from the gas starts are avoided with this substitution.				X	X
20	**Replace bi-directional orifice metering with ultrasonic meters** – Replacing bi-directional orifices with ultrasonic meters reduces the need to vent gas for orifice plate cleaning and changeout.				X	X
21	**Convert pneumatic controls to mechanical controls** – This is one technique of avoiding venting from pneumatic controls by substituting another actuation mechanism.				X	X
22	**Insert gas main flexible liners** – The use of liners can reduce the potential for internal corrosion and associated potential fugitive and venting emissions associated with repairs.			X	X	**May be difficult to quantify**

Table 1. Design Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions: Capture	Vented Emissions Reductions: Flare	Vented Emissions Reductions: Reduce Venting	Fugitive Emissions Reductions	Accurate Quantification Methods Exist
23	**Internal pipeline coating** – Internally coated pipe reduces the potential for leaks from internal corrosion. It also reduces the potential for associated maintenance that would require venting the line.			X	X	**May be difficult to quantify**
24	**External Protective Coating Improvements for Pipelines –** Using better protective coatings can take the form of directly applied coatings to steel lines that reduce potential external corrosion and associated leak or repair venting emissions. For river and canal crossings this can also refer to protective concrete coatings of a line to prevent external force damage and the venting emissions associated with the damage and necessary repairs.			X	X	**May be difficult to quantify**
25	**Installation of additional block valves on pipelines** – By segmenting a system with additional block valves, the total line pack per section is reduced. This reduces the volume of gas that would be vented from a section of line for maintenance.			X		X
26	**Pre-plan and pre-install stubs, lock-o- ring flanges, stopple tees, etc.** – During pipeline construction, install fittings for future connections and avoid the need to blowdown main pipeline.			X		X
27	**Pipeline crossovers** – Reduce the need for venting from maintenance of a line section by allowing transfer of the gas to another line section.			X		X
28	**Move fire gates in to reduce venting at compressor station** – The relocation of emergency block valves at a compressor station to reduce the volume of gas vented.			X		X
29	**Automatic Combustion Control Systems for Gas Engines -** Improves engine efficiency and reduces emissions. Automated controls improve system and efficiency improvements on rich burn, high-speed, turbocharged engines and can reduce the rate of catastrophic failure.			X		X
30	**Replace Gas-Engines With Electric Motor Drives For Pumps And Compressors** – Emissions from gas engines are avoided by this substitution.			X		X
31	**Discharge Gas Coolers** – Cooling compressor discharge gas reduces its volume and velocity. The pressure drop between compressor stations decreases and creates a higher inlet pressure at the next compressor station. That station uses less fuel to compress the incoming gas, reducing GHG emissions.			X	X	X
32	**Gas Sampler Orifice Reduction** – An orifice size reduction, by restricting flow rate in gas sampling, reduces the amount of emissions that would be vented during execution of the sampling procedure.			X		X

Table 1. Design Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions: Capture	Vented Emissions Reductions: Flare	Vented Emissions Reductions: Reduce Venting	Fugitive Emissions Reductions	Accurate Quantification Methods Exist
33	**Replace snap acting relief valves with modulating relief valves** – Changing the type of relief valve can reduce to total volume of gas releases upon functional relief valve discharges.			X		X
34	**Line Heater System Modifications –** Modify heaters for better efficiency in preventing potential hydrate formation and risk of damage leading to accidental gas release emissions.			X		**May be difficult to quantify**
35	**Turbine Drive Installation at Compressor Stations in lieu of Reciprocating Engines** – Turbine drives have lower emissions than gas engines and can be substituted where feasible.			X		X
36	**Replace dehydrators with lowered emissions potential designs -** For example, replace glycol dehydrator with a desiccant dehydrator or with separators and in-line heaters. By substituting technology to achieve water removal, CH_4 emissions from the glycol dehydrator are avoided.			X		X
37	**Use level gauges on separators** - Level gauges allow operators to visually inspect liquid levels in separators and therefore vent liquid and small amounts of gas only when necessary.			X		X
38	**Installation of linebreak block valves -** Reduces volume of gas emitted during pipeline failure as valves shut-in at detection of sudden pressure reduction (pipeline failure).			X		X
39	**Install pressurized condensate storage to eliminate atmospheric tank venting** - Avoids vented releases by keeping condensate pressurized when transported to a gas plant for recovery.			X		X
40	**Install excess flow valves -** Excess flow valves automatically shut off flow in the event of a line break or large leak and limit the release quantity and associated CH_4 and CO_2 emissions.			X		X
41	**Install electronic flare ignition devices** - Replacing flare pilot flames with electrical sparking pilots, which can be remotely started with a small electric supply such as solar, reduces releases of methane from flare pilots which emit gas when blown out by wind until they are relit or shut off.				X	X
42	**Cathodic Protection** – Reduces potential corrosion of metal equipment and components. It is a standard and common protection for pipelines and tankage. One application is the upgrade of unprotected bare steel pipe.				X	**May be difficult to quantify**
43	**Replace compressor cylinder unloaders** – Faulty unloaders leak methane from o-rings, covers, and other areas. Failing unloaders cause unscheduled reciprocal compressor shut downs.				X	X

Table 1. Design Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions			Fugitive Emissions Reductions	Accurate Quantification Methods Exist
		Capture	Flare	Reduce Venting		
44	**Reduce methane leaks from compressor rod packing systems** – CH_4 can leak through packing-rod interfaces as the packing ages. Installing new packing will reduce fugitive emissions.				X	X
45	**Install static seal systems on reciprocating compressors** – A static seal has inherently less emissions than other seal technologies.				X	X
46	**Convert gas pneumatic controls to instrument air** – By substituting compressed air for pressurized natural gas, instrument air systems eliminate the constant bleed of natural gas from controllers.				X	X
47	**Replace high-bleed with no-bleed pneumatic controls** – No-bleed pneumatic devices do not emit methane Replacement should occur before end of life to ensure additionality.				X	X
48	**Design for Lower Operating Pressure** – Designing a pipeline for lower operating pressure involves the design of a pipeline network as well as a potential trade-off between increased capital cost of larger pipe to achieve a given flow capacity and the smaller diameter pipe to achieve that capacity a higher pressure. This is a complex design optimization that will vary according to estimated temporal conditions over the operating life of the system, the local conditions, and current conditions.				X	**May be difficult to quantify**
49	**Fully welded regulating stations** – Minimization of flanged or threaded fittings (where maintenance requirements allow) reduces the chance for leaks and associated emissions. Regulating stations is one example application.				X	X
50	**Consolidation of regulating boxes at distribution stations** – This reduces the total number of leak sources and hence fugitive emissions.				X	X
51	**Replace Relief Valves Pressure Switches, Control Valves, or Worker/Monitor Regulator Set-ups at Gate Stations and Other Locations –** Emissions from relief valve seat leakage or from functional discharges are avoided.				X	X
52	**Replace wet seals with dry seals in centrifugal compressors** - Use wet seals rather than dry seals whenever seals are replaced or installed in centrifugal compressors. Dry seals permit significantly less natural gas fugitive emissions than wet seals, and improve performance and maintenance requirements.				X	X
53	**Use seal oil trap vents and dry seals on compressors** - improve sealing system and modify compressor seal technology. Seal oil trap vents return leaking gas to the pipeline.				X	X

Table 2. Maintenance Projects in the Natural Gas Transmission and Distribution Sectors

ID	Project Description	Vented Emissions Reductions			Fugitive Emissions Reductions	Accurate Quantification Methods Exist
		Capture	Flare	Reduce Venting		
54	**Replacement of old distribution mains and lines** – Replacement reduces the potential for leakage emissions and venting emissions associated with frequent maintenance repairs. A common practice in the distribution sector for old steel, cast iron, and plastic mains. It can be applied to any sector if leak frequency is a problem.			X	X	May be difficult to quantify
55	**Replace Compressor Rod Packing Systems** – Replace worn compressor rod packing rings and rods results in operational benefits, reduced methane emissions, and cost savings.				X	X
56	**Use composite wrap for non-leaking pipeline defects** – Using composite wrap to repair non-leaking pipeline defects as an alternative to pipeline replacement avoids the venting of the damaged pipe. This reduces methane emissions from venting.			X		May be difficult to quantify
57	**Adjust Bleed Rate on Pneumatic Devices –** Optimal adjustment of the bleed rate, where allowed according to the type of device, can be used to lower emissions.				X	X
58	**Implement lineheater efficiency, optimization and/or design and operation program** - Examples of operations and maintenance programs to optimize operational efficiencies or replace conventional equipment with more efficient technologies as lineheaters approach their scheduled maintenance.			X		X
59	**Reduce frequency of replacing modules in turbine meters** – Associated venting frequency and the associated emissions are reduced.			X		X
60	**Reduce gas blowdown volumes prior to service by customer use as a fuel gas** – This is an operational measure based on planning to allow the timing of service to a line for maintenance to correspond to the demand cycle. This permits the pressure to be lowered from use of the gas and reduces the volume of line pack that has to be vented.			X		X
61	**Directed Inspection and Maintenance for all Gas and Pipeline System Facilities** – Implementing a DI&M program for all assets is a proven, cost-effective way for companies to detect, measure, prioritize, and repair leaks to reduce methane emissions. DI&M programs can include an entire system or focus on select elements of a system. Example elements are gate valve stations, compressor stations, pressure safety valves, compressor station blowdown valves, and high-bleed devices. DI&M programs can use optical detection and measurement technologies or other technologies.				X	X

Table 2. Maintenance Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions			Fugitive Emissions Reductions	Accurate Quantification Methods Exist
		Capture	Flare	Reduce Venting		
62	**Purge and retire low pressure gasholders** – Rather than vent gas to inflated storage tanks, route to thermal oxidizer and convert methane to carbon dioxide.	X				X
63	**Reduce emissions when taking compressors off-line** - Examples of practices that can be employed when compressor's are off line: keep compressors pressurized which reduces emissions by avoiding "blowdown"; connect blowdown vent lines to the fuel gas system to allow normally vented gas to be used; or install a static seal on a pressurized compressor's rods to eliminate rod packing leaks.			X		X
64	**Lower frequency of orifice plates inspection** – Reducing the frequency of inspection reduces methane emissions from purging the line or venting from the plate assembly when opened for inspection.			X		X
65	**Blowdown System and Emergency Shutdown Devices (ESD) Practices Modifications to Reduce Venting and Purging Emissions** – These systems would employ the same approach as described to reduce emissions from compressor shut downs.	X	X			X
66	**Lower purge pressure for shutdown controls** – This is a form of reducing the bleed rate for gas actuated pneumatic devices by reducing the pressure to the minimum required to actuate the device.			X		X
67	**Cool-Stop Operation for Compressors** – Idling a compressor at no load prior to shut down reduces venting volumes and associated emissions by allowing natural depressurization through the system before venting. This reduces the amount of gas that vents from the system.			X		X
68	**Use/ reduce compressor station cyclic purging** – A procedural practice for reducing the total volume of gases from required system purges in the operating cycle of a compressor.			X		X
69	**Use inert gases, plugs and pigs to perform pipeline purges** – The substitution of an inert gas such as nitrogen rather than using natural gas for moving plugs and pigs in pipeline cleaning reduces the amount of vented natural gas and associated methane and carbon dioxide emissions.			X		X
70	**Use hot taps for in-service pipeline connections -** This method of making connections to a pipeline reduces the need for venting large volumes of gas and reduces venting emissions associated with maintenance or pipeline modifications			X		X

Table 2. Maintenance Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions: Capture	Vented Emissions Reductions: Flare	Vented Emissions Reductions: Reduce Venting	Fugitive Emissions Reductions	Accurate Quantification Methods Exist
71	**Using pipeline pump-down techniques with portable compressors to lower gas line pressure before maintenance (i.e., Drawing Down Line Pressure Using Downstream Stationary Compressor Facility Equipment)** – Reducing the pressure and line pack prior to maintenance by using a transfer compressor, either portable or permanently installed for the purpose, allows the transfer of gas to local fuel service or to reinjection into another pipeline. This reduces the quantity of gas that has to be vented. Methane emissions are avoided. Non-productive carbon dioxide emissions are also avoided.	X				X
72	**Reduce distribution system pressure** – This reduces the emission rate from leakage and from maintenance venting.				X	May be difficult to quantify
73	**Sweep instead of pig pipeline** – For cleaning pipelines the use of a sweeping tool for removal of dirt and debris reduces the volume of gas that is vented as part of the procedure. The use of a sweeping rather than pigging tool depends on the historically proven condition of the line based on its specific service.			X		X
74	**Encourage utilities to pre-install sewer and water line stubs to reduce third party damages to gas mains** – Work with underground utility companies to pre-install sewer and water line stubs as third party damage prevention measure in pipeline damage prevention programs.			X		May be difficult to quantify
75	**Outage planning and coordination** – A formal program that coordinates activities with periods of low demand, and hence low system inventories and pressures, can reduce vented gas emission volumes.			X		May be difficult to quantify
76	**Pipeline Survey Frequency Increase** – More frequent surveys increase the probability of earlier detection of leaks and reduce the associated GHG emissions.				X	May be difficult to quantify
77	**Perform leak repair during pipeline replacement** – An operational practice that applies to adjacent piping where sections of pipe are being replaced. It takes advantage of scheduling leak repairs when field crews are already mobilized and reduces the cost of emissions control by leak reduction.			X	X	May be difficult to quantify
78	**Gas Quality Control** – Require improvements in the quality of gas received from producers. Tighter specifications reduce the amount of moisture, sulfur compounds and carbon dioxide in the gas. The specification reduces the corrosivity of the gas and the potential for corrosion induced leakage in equipment and associated maintenance. Potential GHG emissions from leaks and maintenance activities are reduced.				X	May be difficult to quantify

Table 3. Procedural Projects in the Natural Gas Transmission and Distribution Sectors

ID	Project Description	Vented Emissions Reductions			Fugitive Emissions Reductions	Accurate Quantification Methods Exist
		Capture	Flare	Reduce Venting		
79	**Test gate station pressure relief valves with nitrogen** – Avoids the venting of methane by substituting nitrogen for natural gas for valve testing.			X		X
80	**Close main and unit valves prior to blowdown** – This prevents inadvertent overpressuring and venting form parts of the system that otherwise could be isolated.			X		**May be difficult to quantify**
81	**Compressor Shut-down Emissions Reductions** – This is a generic procedural action that can be accomplished by any of several means. Reduction in line pressure prior to shut down to reduce the volume of gas in systems that must be vented. Venting to a flare system or thermal or catalytic oxidation system rather than directly to the atmosphere. Venting to a vent gas collection system with a portable compressor to route gas to a fuel gas system for other equipment or back to a gas line.	X	X	X		X
82	**Pipeline "Burn-Down" with Downstream Compressor Station to Lower Gas Line Pressure before Maintenance (i.e., Using NG As Fuel To Downstream Stationary Compressor Facility Equipment)** – This is the specific application of using the gas that would otherwise be vented as a fuel. It directly reduces methane emissions.	X				X
83	**Replace Orifice Flow Measurement with Reduced Inspection Frequency Methods** – Various electronic metering methods are available that will minimize the need for venting GHG for plate change-out and orifice plate inspections.			X		X
84	**Damage Prevention Programs –** These programs comprise a variety of procedures and practices to prevent damage to the assets from anthropogenic activities near the assets or from natural outside forces. One-Call programs are one form of damage prevention measure that requires notification of pipeline operators in advance of activity potentially on a right-of-way and allows the operator to respond appropriately to protect the assets. Another example is the use of ground or aerial surveys to look for unreported activities that could affect the asset. The potential for damage and emissions from accidental releases, and from emissions from associated emergency and repair procedures is reduced. Damage prevention programs are typical for transmission and distribution pipeline systems, but such formal programs can also be applied to facility assets such as compressor, metering and regulator stations and storage facilities.			X		**May be difficult to quantify**
85	**Emergency Shutdown Policy Revision** – Procedural changes are a means that can potentially alter the quantity of emissions associated with upset or emergency venting.			X		**May be difficult to quantify**

Table 3. Procedural Projects in the Natural Gas Transmission and Distribution Sectors, continued

ID	Project Description	Vented Emissions Reductions: Capture	Vented Emissions Reductions: Flare	Vented Emissions Reductions: Reduce Venting	Fugitive Emissions Reductions	Accurate Quantification Methods Exist
86	**Install meter protection posts** – Meter protection posts are a form of vehicle barrier to prevent vehicle damage of pipeline system and facility equipment in areas where motor vehicles or other moving equipment may be present. The potential for gas releases from damage and the maintenance activities associated with that damage is reduced.			X		May be difficult to quantify
87	**Purging / Flaring Standard** – A purging and flaring standard is the procedural basis for the various technical practices of controlled venting such as flaring rather than direct atmospheric discharge; use of portable or permanent compressors for transfer of otherwise vented gas to fuel gas systems and re-injection into the pipelines.	X				X
88	**Service riser valve change procedure** – Use a tool that can be inserted through the service valve to block flow of gas while valve is being replaced. Vented emissions are avoided.			X		X
89	**Reduce the frequency of engine starts with natural gas** - An example of maintenance practices targeting reduced frequency of unignited gas, or startup natural gas, venting to the atmosphere. O&M schedules dictate how frequently such turbine engines are restarted.			X		X
90	**Inspect flowlines with increased frequency** - Methane leakage from flowlines is one of the largest sources of emissions in the gas industry. Regular survey and repair of underground leaks will prevent small leaks from increasing in volume over time.				X	May be difficult to quantify

1.1 Vented Sources

Venting is the release of natural gas either during planned activities or unplanned events such as emergencies that mandate a drop in system pressure. In many cases, venting due to maintenance or emergencies can be considered non-routine. Maintenance activities can require a reduction in system pressure ("blowdown") to increase worker safety. Following maintenance work, the system may need to be purged with natural gas before being repressurized to force out oxygen that could be a flammability risk. Alternatively, emergencies and upsets often trigger an automatic system blowdown. Pressure relief valves and emergency shutdown devices play an important role in this procedure.

> Distinguishing between vented and fugitive emissions is important. As an example, pipeline blowdown events (planned or unplanned) are vented emissions. Valve blow-by, which occurs after an overpressure event when valve surfaces are not properly re-seated, results in gas escaping from the valve and is a fugitive emission.

The volume, duration, location, and frequency of venting events vary widely. Appendix A provides selected case studies of projects that reduce venting emissions. The case studies illustrate projects that may lead to the most significant emissions reductions from the NGTD sector or to illustrate how project types can achieve reductions beyond regulatory requirements.

1.2 Fugitive Sources

For NGTD operations, fugitive emissions are commonly defined as, "unintentional leaks at sealed surfaces, as well as from underground pipelines" (API, 2009). Essentially, any pressurized component can leak CH_4 and, in fact, some are designed to do so continuously. Table 4 provides a summary of typical fugitive emission sources in the NGTD sector [AGA, 2008].

Table 4. Typical Fugitive Emissions Sources Associated with the NGTD Sector

• Threaded connector	• Open-ended line
• Valve	• Tubing connectors
• Control valve	• Pump seal,
• Pressure relief valve	• Sampling connections
• Pressure regulator	• Sight glass
• Orifice meter	• Threaded union
• Other flow meter	• Threaded check valve
• Compressor seals	• Diaphragms
• Drains	• Flanges
• Hatches	• Meters
• Instruments	• Fin fan cooler tube ends

Fugitive emissions are quite significant in the distribution sector, constituting 97 percent of CH_4 emissions [U.S. EPA, 2009b]. (The emission sources that comprise Figure 3b are equipment that release fugitive CH_4 emissions.) In the transmission sector, venting emissions are greater than fugitive emissions (as shown in Figure 3a).

There are many approaches to reducing fugitive emissions. Leaking components can be repaired, retrofitted, or replaced. Further, directed inspection and maintenance (DI&M) or leak detection and repair (LDAR) programs can enable a company to become more effective at identifying, quantifying, and remedying fugitive emissions. A case study for reducing fugitive emissions is presented in Appendix A. Many more projects are included in Tables 1-3.

Fugitive emissions can be difficult to quantify as this issue paper discusses in Section 8.3, where quantification methodologies for both above- and below-ground fugitive CH_4 emissions are presented.

2.0 Additionality

For the Reserve, addionality is a two-tiered test of a project against regulatory requirements and industry performance standards. In the case of NGTD offset projects, regulations that directly or indirectly limit GHG emissions and non-regulatory aspects influence additionality. While some air quality regulations directly or indirectly affect GHG emissions from the NGTD sector, no current regulations dictate mandatory efficiency standards for equipment or operational procedures in the NGTD system. In terms of performance standards, individual NGTD installations vary widely in design, age, and operational characteristics, complicating the determination of performance standards.

As the Reserve points out in its Program Manual, additionality is the aspect of a project that is the most critical to determining its eligibility. It is also, however, the most difficult aspect to define and apply.

In simple terms, a project that is additional would not have occurred without an offset market; market incentives must have motivated the project. This approach ensures that the GHGs removed or prevented from entering the atmosphere as a result of the project can truly offset other emissions.

This section addresses regulatory requirements and potential performance standards applicable to NGTD systems. In addition, two NGTD project types are presented as case studies for establishing additionality criteria, based on the United Nations Framework on Climate Change Clean Development Mechanism (UNFCCC CDM) approved methodologies.

2.1 Regulatory Aspects

Reductions of GHG emissions resulting directly or indirectly from compliance with federal, regional, state, local standards, regulatory limits on GHG emissions, or other legally binding agreements (such as consent decrees) are not additional. The following is a summary of regulatory requirements that may affect NGTD project additionality. The summary begins with regulations that indirectly reduce GHGs through their limitation of VOC emissions.

2.1.1 Indirect regulation of GHGs through VOC limits

- **National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Oil and Natural Gas Production and Natural Gas Transmission and Storage (40 CFR Part 63 Subpart HHH).** This regulation reduces HAP emissions associated with processes that could also release CH_4. Specifically, it requires glycol dehydration unit vents and storage tanks with HAP emissions that exceed a gas throughput and liquid throughput threshold value be connected to a closed-loop emissions control system. This system must cut emissions by 95%.
  In addition, gas processing plants are subject to a requirement to implement leak detection and repair (LDAR) programs. However, this requirement does not apply to transmission and distribution facilities.
- **New Source Performance Standards (NSPS)**. Fugitive VOC emissions are regulated by the NSPS regulations for "**Equipment Leaks of VOC From Onshore Natural Gas Processing Plants"** (40 CFR part 60 Subpart KKK). This rule, however, does not apply to natural gas transmission and distribution facilities unless they are also part of a gas processing plant.
- **49 CFR Part 92.** This United States Department of Transportation regulation lays out requirements for design, maintenance, and construction of NGTD systems. These requirements are aimed at ensuring safe operation of pipelines. To

- **State VOC Rules.** – Many states have VOC emission rules that apply to NGTD facilities. Through the process of complying with VOC limits or standards, CH_4 emissions could also be reduced (at times through combustion to form CO_2). These rules could be included in state implementation plans (SIP). These state regulations must be assessed for their impact on project additionality. The Reserve may wish to develop a catalogue of state rules and their potential impact on project additionality.
- **State Construction and Operating Permit Conditions.** State permitting requirements at times exceed underlying applicable requirements (state or federal) in restricting pollutant emissions levels, including VOC emissions. These limits can also indirectly limit CH_4 emissions. The permitting requirements affecting each project will need to be reviewed to determine their affect on project additionality.

2.1.2 GHG-Related Regulatory Programs

As of the date of this publication, there are no existing federal, regional, state, or local air regulations that specifically and directly limit GHG emissions from the NGTD industry. The following discussion summarizes potential federal, regional, and state programs that could affect the additionality of natural gas transmission and distribution offset projects.

<u>Federal Programs</u>

The US EPA could use several aspects of the Clean Air Act (CAA) to directly or indirectly limit GHG emissions. Many of these avenues for regulation at the federal level depend on the determination that GHGs are "regulated air pollutants." This determination has not yet been officially made by the US EPA (or courts). An example of how this determination could affect NGTD projects is through the federal construction permitting process, which could establish GHG limits in permits. In the recently published Proposed PSD and Title V Tailoring Rule, EPA acknowledges that when it finalizes the pending GHG vehicle emissions rule [74 FR 24007; May 22, 2009], it will establish CO_2 and other GHGs as regulated air pollutants. According to the report, EPA Administrator Lisa Jackson made this assertion in an August 12, 2009, reply to an environmentalist petition asking her to reject a power plant air permit issued by Kentucky regulators that did not include CO_2 limits. While EPA is not requiring the permit at issue to limit CO_2 emissions, Jackson does say that power plant permits may need to limit CO_2 as soon as March of 2010, when EPA is expected to finalize the vehicle GHG rule.

Current EPA and Congressional efforts to develop regulations to either directly limit GHGs or reduce them through a cap-and-trade program could affect NGTD offset projects. The same is true for state regulations.

<u>Regional Programs</u>
Regional programs such as the Regional Greenhouse Gas Initiative (RGGI), Midwest Greenhouse Gas Reduction Accord (MGGRA) and Western Climate Initiative (WCI) have developed or intend to develop GHG reduction strategies (such as a cap-and-trade program) for which participating states would develop corresponding state requirements for program implementation. None of these programs are currently in effect with the exception of RGGI, which does not include the NGTD sectors. At present, it does not seem that these programs will set GHG limits or emission standards for certain sectors or equipment. The federal definition of regulated pollutant does not constrain them and they may include elements beyond a cap-and-trade program.

<u>State and Local Air Authorities Programs</u>
Although all but a few states are developing GHG regulations, currently no state GHG rules or regulations directly limit GHG emissions from NGTD vented or fugitive sources. Some states such as California and Washington are well along in developing regulations that impact specific sources. None of the state programs to date except California have suggested regulating NGTD sources outside of a cap-and-trade program.

- California – The Global Warming Solutions Act of 2006 (AB32) establishes a comprehensive program of regulatory and market (cap-and-trade) mechanisms to achieve reductions of GHGs. The rule designates the Air Resources Board (ARB) as the agency responsible for regulating many GHG emission sources to reduce state GHG emissions to 1990 levels by 2020. A NGTD GHG emissions reduction measure is being developed as part of the rule's early implementation measures. Details of the measure have not yet been specified, but could include standards or emission limits for individual emission sources at these facilities in addition to general participation in the market driven (cap-and-trade) portion of the rule. This measure is scheduled to be adopted in late 2010.
- Other developing state GHG programs are either cap-and-trade-based programs that may or may not include the NGTD sector, or include only large fossil-fueled power generation or other large combustion sources within the state.
- State Construction and Operating Permit Conditions – Although limits on GHG emissions are not currently regulated through federally enforceable permit conditions, states are free to add these conditions to construction and operating permits according to their own rules and regulations. Many state permitting authorities are already considering GHG emissions as part of their review process under general pollution prevention provisions. Several pending projects have already been rejected from the permitting process for not addressing GHG emissions as part of their applications. If states choose to directly limit GHG emissions through state permitting programs, NGTD emission reduction projects will need to assess permitting impacts on project eligibility. The Reserve should

Consent Decrees and other Binding Agreements

Consent decrees and other similar court orders can come as a result of regulatory enforcement or other legal actions, e.g., law suits. These agreements are legally binding and have the same affect on additionality as regulatory requirements. These agreements can specify general or specific reductions in emissions that can exceed legal requirements. Agreements that limit VOC emissions could also reducing CH_4 emissions. Recent developments indicate consent decrees that limit GHG emissions are beginning to be issued by the courts. A recent example is the inclusion of a first-time mandate to reduce GHG emissions in a proposed consent decree with an Ohio Edison power plant. The August 11, 2009, proposed decree will require the company to reduce GHGs at the power facility by 1.3 million tons per year.

No such consent decrees have been issued to date for the NGTD sector; however, agreements that reduce VOC emissions have been issued. Consent decrees and other similar agreements will need to be reviewed for additionality impacts when they are applicable to a specific operation, site, or company.

Other Regulatory Program Issues

Regulatory programs for GHG emissions at the federal, regional and state levels are not only developing emission limits but are also developing their own emissions calculation methods and procedures. Many of the proposed and developing regulations include provisions related to how GHG emissions are to be calculated (for example the proposed federal mandatory GHG reporting rule). These procedures may or may not agree with the baseline and emissions reduction calculation methodologies developed for creditable emission reductions for another program. Developing calculation methods outside of or in conflict with regulatory required methods will be problematic, potentially requiring two separate emission estimates for some sources.

In addition to the federal reporting rule, as of this date, the following states have developed mandatory reporting and have varying decrees of prescriptive methods for calculating GHG emissions.

- California
- Connecticut
- Colorado
- Delaware
- Hawaii
- Iowa
- Massachusetts
- Maryland
- Maine
- North Carolina
- New Jersey
- New Mexico
- Oregon
- Virginia
- Washington
- Wisconsin
- West Virginia

2.2 PERFORMANCE STANDARDS

In general, the performance standard must be developed to ensure that eligible projects exceed business-as-usual and industry standard practices. This development of an industry-wide performance standard is a distinguishing feature of the Reserve's program. One example of a project that should not be the subject of protocol development is cast iron pipe replacement. This project type would likely not be considered additional because these pipelines are being phased out of gas distribution systems [AGA, 2008].

The industry associations (AGA, INGAA and API) are useful sources of industry standard information. EPA's Natural Gas STAR program literature provides an indication of what NGTD members of that program are doing. In addition, the United Nations Framework Convention on Climate Change Clean Development Mechanism (UNFCCC CDM) methodologies outline types of documentation that a company could submit to demonstrate their business-as-usual activities. While the CDM approach is quite different from the Reserve's approach of developing an industry-wide performance standard, information that the CDM program examines on a project-by-project basis could also be used in the development of an industry-wide standard.

Under the CDM approach, to prove that a project activity exceeds business-as-usual activities at an individual company, that company must produce records such as maintenance logs, equipment replacement schedules, and manufacturer equipment lifetime specifications. For example, replacing equipment that produces CH_4 emissions with non-emitting equipment must occur at a rate greater than that under business-as-usual conditions. A project developer should provide evidence of the useful life of the equipment that could be replaced during the project as part of the additionality demonstration. The Reserve would need to gather this information for a sufficient number of companies and technology vendors to establish an industry-wide standard.

Table 5 outlines possible performance standards and the associated benefits and drawbacks of adopting them. For some comments in the table, projects are discussed by type (design, maintenance, procedural).

Table 5. Performance Standard Evaluation

Performance Standard	Example(s)	Benefits	Drawbacks	Stringency Considerations
Emissions Intensity or Production-Based	• GHG emissions per throughput • GHG emissions per pipeline mile	• Could apply to all three project types (design, maintenance, procedural) • Could use existing industry emission factors as reflecting industry standard. Stringency level must then be determined.	• If existing emission factors are not used, a significant data gathering effort is required (e.g., typical equipment types and operating characteristics) to determine baseline emissions intensity.	• Could set stringency based on emission factors for new equipment. • Wide range of equipment, operating practices complicates establishing a stringency level.

Performance Standard	Example(s)	Benefits	Drawbacks	Stringency Considerations
Emissions Threshold (projects would need to achieve emission reductions in excess of a threshold)	• Design projects must reduce natural gas releases to the atmosphere by emissions by 100 MM scf per year	• Similar pros as efficiency level performance standard	• Similar cons as efficiency level performance standard	• Difficult to establish a blanket stringency, even within broad project types.
Efficiency Level (proposed project would need to achieve a specified efficiency level)	• Design projects must reduce GHG emissions by 10%	• Could adopt a simplified approach such as identifying high-achieving Natural Gas STAR projects and setting the average percent emission reductions from those projects as the performance standard • Could apply to all three project types (design, maintenance, procedural)	• Very difficult to develop a general efficiency threshold, even for the broad project types of design, maintenance, and procedural. • Determination of the baseline is not straightforward because of the variety of project types, even within the broad categories of design, maintenance, and procedural. • Could exclude additional projects if the percent reduction is too small.	• Difficult to establish a blanket stringency level, even within broad project types.
Technology-Based[1] (performance standard would define a minimum acceptable technology)	• A project must use a specified technology type (e.g., compressor, valve, pump model) that can achieve a certain emissions level to pass the performance standard.	• Any sized project can pass the performance standard if it uses the mandated technology.	• Only applicable to design projects • Certain technology types may not be feasible to implement at certain facilities, rendering those facilities unable to participate in Reserve projects • A good deal of information gathering regarding technology types in use in the industry and trends in adopting new technologies would be needed.	• Best-performing equipment can aid in setting stringency level.

To adopt any of these performance standards, a detailed understanding of the current industry equipment fleet and how it is operated is essential. Industry groups (e.g., AGA,

[1] See discussion of WRI protocol [World Resources Institute, 2005] in Section 4.0 for an example of how this performance standard could be developed.

INGAA, API) and U.S. EPA's Natural Gas STAR program are sources of information that can build this understanding. Note that the Gas STAR program only has detailed information about some project types, and that information is only available for certain Natural Gas STAR partners; therefore, it may not be representative of the industry. Due to the unique characteristics and number of the potential project types (identified in Tables 1 through 3), further development of specific performance standards for particular projects is not possible within the context of this issues paper.

2.3 Examples from the United Nations Framework Convention on Climate Change Clean Development Mechanism Methodologies (UNFCCC CDM)

The UNFCCC oversees CDM projects that reduce GHG emissions. These projects help countries meet their GHG emission reduction targets established in the Kyoto protocol.

There are two methodologies established by the CDM program for the NGTD sector. The first deals with leak detection and repair programs [UNFCCC CDM Executive Board, 2005]. The second establishes a methodology for quantifying the benefits of replacing leaking iron or steel pipes with plastic pipes in natural gas pipelines [UNFCCC CDM Executive Board, 2007].

In this discussion, it is important to clarify that the CDM program establishes additionality on an individual project basis. This approach generally requires more effort to evaluate each project, whereas the performance standard method of determining additionality that the Reserve uses takes more effort up front to establish the industry-wide performance standard. The discussion below therefore addresses what CDM evaluates on an individual project basis to establish additionality. Additional information in these project methodologies is provided in Appendix A.

2.3.1 Leak Detection and Repair (LDAR)

This methodology [UNFCCC CDM Executive Board, 2005] is based on a project in Moldova that aimed to reduce fugitive emissions from compressor gate stations. It is applicable to projects that "reduce leaks in natural gas pipeline compressor stations and gate stations in natural gas long-distance transmission systems by establishing advanced leak detection and repair (LDAR) practices."

Specific considerations for additionality, drawn from the CDM's "Tool for the Demonstration and Assessment of Additionality" [UNFCCC CDM Executive Board, 2008] include whether similar efforts to reduce fugitive emissions due to leaks have been implemented. If such measures have been taken, the project would be ruled out on the basis of being business-as-usual. In the CDM program, a project can be ruled out as non-additional if the project developer would undertake the project even in the absence of the program.

Only the types of leaks that are detected and repaired beyond current practice are eligible for project inclusion under the UNFCCC methodology. The project developer is requested to identify different types of leaks such as those that need to be repaired for safety reasons, those that will only be repaired if they can be easily accessed by maintenance staff, and those that will only be repaired if the leak can be detected by noise, sight, or smell. The project developer must indicate the types of technologies used to detect leaks and which of the types of leaks are addressed in any existing LDAR program. If the project will use more advanced leak detection technologies than any existing LDAR program, the case for additionality is boosted. Much of this information can be gathered from staff interviews and can also be used in determining the baseline scenario.

For the Reserve, the systematic determination of leak repairs that are beyond business as usual is complicated, particularly for some types of leaks. For example, identifying fugitive leaks that are easily accessible is location specific and not conducive to establishing an industry-wide additionality standard.

For other leak types, a general approach to establishing business as usual is possible, such as for leaks that pose a safety risk. These leaks would not qualify as additional, as they would be expected to be repaired. Similarly, repairing leaks that can be detected without the use of detection equipment should also be established as business-as-usual.

Regarding financial incentives, the CDM methodology argues that a pipeline operator is analogous to a delivery service and is not penalized for lost gas or rewarded for conserved gas. The pipeline operator would therefore not have an incentive to reduce leaks beyond what is required for safety and maintenance reasons and would not undertake a project to reduce leaks beyond business-as-usual in the absence of the CDM program. The project developer, however, must prove that the operator of the compressor and gate stations has no economic incentive to reduce leaks. They must also prove that the pipeline operator will not get paid more to move the increased quantity of gas through the pipeline. This proof could be found in publicly available documents, or in the case that these are not available, letters from the pipeline company explaining the contract. Staff interviews may also be necessary. In this case where the pipeline operator has no financial incentive to reduce emissions, the "simple" cost analysis outlined in CDM's additionality tool [UNFCCC CDM Executive Board, 2008] can be used. But, if the project developer does have a financial incentive to reduce CH_4 emissions, that analysis will not prove additionality. The methodology does not instruct which analysis to use in this case.

Under the CDM methodology, project developers must also submit a common practice analysis. This analysis indicates peer company activities regarding using leak detection and repair equipment in compressor and gate stations. It can include staff interviews and/or letters from other pipeline operators. Leak detection and repair projects require the following documentation:

- Historical written protocols and leak repair records;
- Internal procedures for identifying and repairing leaks;
- Staff interviews concerning LDAR techniques; and
- Documentation of technologies used in the LDAR program.

The above-listed documentation could be requested from a representative sample of companies to determine an industry-wide performance standard for current LDAR practice. These examples can be extended to documentation that could be requested for other procedural or maintenance projects that rely on implementation of procedures rather than the installation of new technology.

2.3.2 Pipe Replacement

This UNFCCC CDM methodology [UNFCCC CDM Executive Board, 2007] is based on a project in Rio de Janeiro. It applies to projects in which polyethylene pipes replace cast iron pipes or steel pipes without cathodic protection in the natural gas distribution grid. Although this specific project type is not recommended for protocol development by the Reserve (because U.S. industry practices are phasing out the use of cast iron pipe), the considerations have application to other projects involving equipment replacement.

Only projects that replace cast iron or steel pipes without cathodic protection with polyethylene pipes are eligible. Further, pipe replacement must exceed repairs made under normal maintenance/upgrading practices. The following points also relate to eligibility for this project type:

- No supply interruptions occur related to the gas leakages the project activity covers;
- The project activity does not change the total gas supply capacity; and
- The distribution system is not undergoing nor has undergone within the past three years a change in distributing other gases that would cause the pressure or other operational parameters to change.

These requirements relate to establishing an industry-wide performance standard for this and other project types because it will be essential to gather information from a representative sample of industry that will reveal what business-as-usual replacement rates are for pipelines or other equipment (e.g., high-bleed valves) that could be part of a Reserve project. The CDM approach further guides that, in terms of a regulatory review, all regulations that limit gas losses from gas distribution pipes and those that affect distribution system safety should be assessed for their impact on additionality.

To determine whether the project would have occurred without the financial incentive of the CDM program, an investment analysis should be conducted based on costs and revenues relevant to the project activity. The analysis should include the following points:

- The investment cost of replacing the pipelines.
- Savings from conservation of saleable product. This analysis should use the price that the distribution company expects to pay for the gas. The methodology suggests a sensitivity analysis to determine the effect of this price.
- Savings in repair costs that will result from using new pipes.

3.0 Baseline Quantification

3.1 Baseline Scenario Determination

Greenhouse gas emission reductions must be quantified relative to a reference level of GHG emissions, referred to as the baseline scenario. Potential candidates for the baseline scenario represent situations or conditions that plausibly would have occurred in the absence of the reduction project. In general, identifying baseline candidates should

consider existing and alternative project types, activities, and technologies that result in a product or service identical (or nearly identical) to that of the project activity, and should be credible over a range of assumptions for the duration of the baseline application
The baseline emissions are those that would have occurred in the absence of the project.

Identifying the baseline scenario can be challenging. Table 6 identifies three options for determining the baseline, which are accompanied by a discussion of how they could be applied to projects in the NGTD sectors.

Table 6 Baseline Scenarios and Considerations

Baseline Scenario	Considerations for NGTD Projects
Actual emissions from the continuation of existing practices	Existing pre-project emissions can be determined through measurement (Section 8) and/or calculation techniques (Section 8) for a particular reduction project. This provides a highly accurate determination of pre-project emissions.
Emissions from a technology that represents an economically attractive course of action, considering barriers to investment	This option, as described by API [API, 2004], would involve using forecast data to determine emission reductions through new technology adoption. The emissions intensity of the baseline scenario technology is used to determine what emissions would be throughout the project period if that technology remained in operation.
Average emissions of similar project activities that occurred in the past five years in similar social, economic, environmental, and technological circumstances, and whose performance is among the top 20% of their category.	US EPA Natural Gas STAR data that is available for some project types could be used to determine expected emission reductions for a given project type.

In the CDM methodology for leak reduction from compressor and gate stations [UNFCCC CDM Executive Board, 2005], the baseline is determined in part through the same steps used to determine additionality. The developer must determine what efforts are underway to reduce CH_4 leaks from key equipment such as unit valves, blowdown valves, rod packings, and pressure relief valves. The technology used to detect these leaks is also a consideration. If more than one baseline alternative exists, project developers are to use the most conservative baseline. Further, the methodology applies if, "the likely baseline scenario is the continuation of the current leak detection and repair practices." In other words, the baseline calculations must account for business-as-usual efforts to reduce CH_4 leaks.

This CDM approach, however, is different from the Reserve's. The Reserve addresses these issues on an industry-wide level in developing the baseline determination as part of the protocol for each project type.

The CDM methodology for pipeline replacement [UNFCCC CDM Executive Board, 2007] lays out baseline calculations that result in the most "reasonable, conservative replacement rate for the cast iron pipes or steel pipes without cathodic protection." The two cases that are considered in determining the baseline are planned replacements as documented *ex ante* in the draft project design document (PDD) and business-as-usual replacement activities. The latter may be motivated by safety or operational factors and is determined by annual *ex post* monitoring. The baseline chosen is the greater of these two options (*ex ante* and *ex post*). Further description of baseline determination and calculation for this method is provided in Appendix A.

The API, in a document that presented case studies of emission reduction projects [API, 2007], used as a baseline the emissions from pre-project technologies. For the LDAR project example, baseline emissions from valves are defined as the measured pre-project emissions. Similarly, for the glycol dehydrator project, baseline emissions are those that would have been emitted from gas-assist pumps that, in the case study, will be replaced with electric pumps. For both of these examples, the pre-project emissions can be measured.

3.1.2 Performance Standard for Determining Baseline Scenario

The World Resources Institute, in its Protocol for Project Accounting [WRI, 2005] presents a relevant case study project: the installation of high-efficiency compressors. The case study outlines the process of selecting a performance standard and establishing the baseline based on that standard. The performance standard approach was chosen because it was assumed that compressor technology in the commercial market is relatively uniform. Compressor stations in the geographic area and temporal range of the case study were analyzed to determine the year the compressors began operating, the number of compressors at each station, the station capacity, and the design fuel usage of the compressor (MJ/kWh). All baseline candidate compressors can provide the same quality and quantity of service as the high-efficiency compressors that would be installed as the project activity. The design fuel usage of compressors depends on the load. To be conservative, the case study assumes a 100% load and calculates GHG emissions from each baseline candidate using an IPCC emission factor in units of kg CO_2eq/MJ. The load is equal to the maximum rated capacity in kW. The GHG emissions intensity of each baseline candidate is calculated in terms of MJ/kWh.

Once all GHG intensities are calculated, the stringency must be selected. The baseline scenario could be selected as:

- The lowest emitting compressor in the analysis;
- The mean intensity of all compressors in the analysis;
- The median intensity of all compressors in the analysis; or
- A percentile (10th, 25th) of the data set.

The case study selects the 10th percentile stringency level because it reflects the trend of decreasing emissions from newer compressor stations. The baseline emissions are then set as this level of emissions multiplied by the project activity level of service (kWh of compressor capacity).

> To summarize, the WRI protocol case study is instructive because this approach of identifying candidate technologies that are high-performing could be used to establish the performance standard and baseline scenario for Reserve projects. However, for many of the potential NGTD projects, continuation of current practices is a feasible baseline scenario and provides for accurate determination of baseline emissions.

3.2 BASELINE EMISSIONS QUANTIFICATION

Calculation methods described in Section 8 are the same for baseline and project emission reduction quantification. The baseline emissions apply to the equipment within the project boundary, which may encompass the entire system (refer to the discussion in Section 5.).

4.0 Magnitude and Cost Effectiveness of Potential Reductions

The cost effectiveness of an emissions reduction project depends on the amount of emissions reduced, equipment and/or labor costs, and the price of natural gas. Several publicly available studies provide an indication of the cost effectiveness of such projects and how cost effectiveness can vary by project type. For example, the emissions reductions achieved as a result of measures implemented through EPA's Natural Gas STAR program provide a basis for evaluating potential emissions reductions for some of the NGTD sector project types identified in this paper.

4.1 NATURAL GAS STAR PROGRAM

Natural Gas STAR industry partners operate in all natural gas industry sectors (production, processing, transmission and distribution) and represent 60 percent of the industry in the United States [U.S. EPA, 2009a]. Emissions reductions reported by this voluntary program through 2007 demonstrate that the implementation of different technologies and practices can result in significant CH_4 emissions reductions. From 1993 to 2007, Natural Gas STAR partners reduced CH_4 losses by approximately 677 Bcf. Also, since the start of the program in 1993, the overall success of the program has steadily increased to emissions reductions of 92.5 Bcf in 2007. In 2007, most of the reductions were achieved in the production sector (73%), followed by transmission (19%), gathering and processing (7%) and distribution (1%). Natural Gas STAR reported that with the avoided natural gas emissions achieved in 2007, the natural gas industry accrued nearly $648 million in additional natural gas sales (assuming a 2007 average natural gas price of $7.00 per thousand cubic feet) [p. 2].

Table 7 illustrates trends in CH_4 emission reductions in the four natural gas system sectors as reported in the Natural Gas STAR Program [p. A-143, Table A-114].

Table 7. Methane Reductions Derived from the Natural Gas STAR Program (Gg) [U.S.EPA, 2009b]

Process	1992	1995	2001	2002	2003	2004	2005	2006	2007
Production	0	75	383	420	565	917	1,308	1,336	1,667
Processing	0	5	29	34	65	60	123	135	133
Transmission and Storage	0	121	336	344	330	416	512	505	450
Distribution	0	19	33	161	110	95	34	108	28

Natural Gas STAR identified several project types/technologies in the four sectors that represented the top opportunities for reduction as reported by industry partners. Approximately 195.1 Bcf of CH_4 emissions have been avoided since 1993 in the transmission sector. Top CH_4 emission reduction opportunities in the transmission sector since 1993 include:

- Directed Inspection and Maintenance (DI&M) at compressor stations (21% of total reductions or approximately 41 Bcf);
- Use of fixed/portable compressors for pipeline pumpdown (17% or 33 Bcf);
- Installation of vapor recovery units on pipeline liquid/condensate tanks (14% or 27 Bcf);
- Use of turbines at compressor stations (11% or 21 Bcf);
- Replacement of wet compressor seals with dry seals (10% or 20 Bcf);
- DI&M at surface facilities (7% or 14 Bcf);
- Use of composite wrap repair (5% or 10 Bcf); and
- Other (15% or 29 Bcf).

Cumulative sector reductions in the distribution sector totaled 39.8 Bcf since 1993. Top opportunities in the distribution sector since 1993 include:

- DI&M at surface facilities (55% of total reductions or approximately 22 Bcf);
- Identification and rehabilitation of leaky distribution pipe (21% or 8 Bcf);
- DI&M survey and repair leaks (4% or 2 Bcf);
- Use of automated systems to reduce pressure (2% or 1 Bcf);
- DI&M at compressor stations (non-mainline transmission) (1% or 0.4 Bcf);
- Injection of blowdown gas into low pressure systems (1% or 0.4 Bcf); and
- Other (4% or 2 Bcf).

4.2 COST EFFECTIVENESS

As noted above, the cost effectiveness of a project varies from system to system. This is because the variation in each system's technologies and practices can affect the quantity of CH_4 emissions reductions an individual project achieves. In addition, the payback period for a project varies depending not only on the amount of CH_4 emissions reductions achieved, but also the price of natural gas.

With information provided by program participants, the Natural Gas STAR Program compiled a report on the average capital costs, annual operations and maintenance (O&M) costs, CH_4 emissions reductions achieved (in Mcf per year), and the payback period for many of the projects included in the program. The payback period was based on the 2007 average cost of natural gas ($7.00/Mcf). The results are presented in Table 8.

Table 8. Natural Gas STAR Average Project Cost Effectiveness [U.S. EPA, 2009a]

Project Type	Capital Costs	O&M Costs (Annual)	Methane Savings (Mcf/Year)	Payback Period (Years)
VENTED SOURCES				
Using pipeline pump-down techniques with portable compressors to lower gas line pressure before maintenance (i.e., drawing down line pressure using downstream stationary compressor facility equipment)	>$10,000	NA	200,000	0-1
Use "Zero Emissions" dehydrators	>$10,000	>$1,000	31,400	0-1
Use hot taps for in-service pipeline connections	>$10,000	>$10,000	24,400	0-1

Project Type	Capital Costs	O&M Costs (Annual)	Methane Savings (Mcf/Year)	Payback Period (Years)
Reroute glycol skimmer gas	<$1,000	$100-$1,000	7,600	0-1
Close main and unit valves prior to blowdown	<$1,000	$100-$1,000	4,500	0-1
Use composite wrap for non-leaking pipeline defects	$1,000-$10,000	NA	3,960	0-1
Pipe glycol dehydrator to vapor recovery unit	$1,000-$10,000	>$1,000	3,300	0-1
Replace natural gas starters with air or nitrogen	<$1,000	$100-$1,000	1,350	0-1
Reduce emissions when taking compressors off-line	$1,000-$10,000	NA	1,200-4,00	0-1
Replace compressor rod packing systems	$1,000-$10,000	NA	865	0-1
Convert pneumatic controls to mechanical controls	<$1,000	$100	500	0-1
Inject blowdown gas into low pressure mains	<$1,000	<$100	150	0-1
Reduce the frequency of engine starts with natural gas	<$1,000	<$100	132	0-1
Reduce frequency of replacing modules in turbine meters	<$1,000	<$100	27	0-1
Replace ignition - reduce false starts	$1,000-$10,000	<$100	21	0-1
Automate systems operation to reduce venting	$1,000-$10,000	$100-$1,000	20	0-1
Redesign blowdown systems and alter emergency shutdown devices (ESD) practices to reduce venting and purging emissions	<$1,000	<$100	<100-72,000	1-3
Recover vented gas from pipeline pigging operations	>$10,000	>$1,000	21,400	1-3
Install pressurized condensate storage to eliminate atmospheric tank venting	>$10,000	>$1,000	7,000	1-3
Install electric starters on compressor engines	$1,000-$10,000	<$100	1,350	1-3
Install ejector	$1,000-$10,000	<$100	700	1-3
Replace dehydrator with lowered emissions potential designs	>$10,000	<$100	130	1-3
Replace bi-directional orifice metering with ultrasonic meters	>$10,000	<$100	20	1-3
Install automated air/fuel ratio controls on compressor engines	>$10,000	Reduced	128 per unit	1-3
Move fire gates in to reduce venting at compressor station	>$10,000	<$100	1,700	3-10
Lower purge pressure for shutdown controls	$1,000-$10,000	<$100	500	3-10
Use recycle line to recover displaced gas during condensate loading	$1,000-$10,000	$100-$1,000	100	3-10
Recover methane released from pipeline system liquid storage tanks	<$1,000	$100-$1,000	160	>10
Use inert gases, plugs and pigs to perform pipeline purges	<$1,000	$100-$1,000	90	>10
Install excess flow valves	>$10,000	<$100	16	>10
Test gate station pressure relief valves with nitrogen	<$1,000	$100-$1,000	8	>10
Purge and retire low pressure gasholders	<$1,000	>$1,000	500	None
FUGITIVE SOURCES				
Replace compressor cylinder unloaders	>$10,000	<$100	3.5M	0-1
Replace wet seals with dry seals in centrifugal compressors	$325,000	$14,000	45,000	0-1
Convert gas pneumatic controls to instrument air	>$10,000	NA	2,500	0-1

Project Type	Capital Costs	O&M Costs (Annual)	Methane Savings (Mcf/Year)	Payback Period (Years)
Directed inspection and maintenance of compressor station blowdown valves	<$1,000	$100-$1,000	2,000	0-1
Insert gas main flexible liners	$1,000-$10,000	<$100	225	0-1
Perform leak repair during pipeline replacement	<$1,000	$100-$1,000	2,500	1-3
Pipeline Survey Frequency Increase	$1,000-$10,000	>$1,000	1,500	1-3
Install electronic flare ignition devices	$1,000-$10,000	<$100	1.68	1-3
Gas quality control	<$1,000	$100-$1,000	500	3-10
Directed inspection and maintenance of pressure safety valves (PSV)		$100-$1,000	170	3-10
Replace gas-fired with electric compressors	>$10,000	>$1,000	6,440	>10
Use of improved protective coating at pipeline canal crossings	>$10,000	<$100	44	>10

NA = Not Available

As exact project and anticipated O&M costs are unknown, the cost of achieving reductions from project activities ($/tonne of CO_2-equivalent) cannot be predicted in this paper. However, payback period information provided in the table above serves as an indicator of project cost-to-savings efficiency.

Results of the Natural Gas STAR assessment show that many projects have relatively low implementation and operating costs with a payback period of less than one year. This is a key reason the Gas STAR program has been so successful. In terms of quantifying creditable emission reductions, this has implications in the assessment of additionality. It is difficult to establish that a reduction activity would not have occurred when the payback period is minimal. However, companies and investors operate under capital constraints and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives.

5.0 Project Boundary and Leakage

The emission reductions projects in this issues paper either conserve CH_4 or convert it to CO_2 through combustion. In conserving CH_4, the project involves essentially a material balance on CH_4, and drawing the project boundary is relatively straightforward. (Project IDs 1 and 21 are examples.) If the project converts CH_4 to CO_2 through combustion, the project boundary must be expanded beyond the source where CH_4 is captured to include the combustion source. Whether the project involves design, maintenance, or procedural activities, the project boundary should include the equipment that the project affects. This is the approach the WRI case study takes [WRI, 2005]. Alternatively, to ensure leakage is avoided, the boundary can be expanded, encircling all elements, even those unforeseen, that the project could impact.

The UNFCCC CDM methodology for LDAR projects [UNFCCC CDM Executive Board, 2005] is a helpful example of setting a project boundary for a NGTD sector project. In this case, the project boundary is the compressor and gate stations. Only CH_4 emissions from non-intentional releases, such as fugitive emissions from valves, are valid for inclusion.

One-time effects could also be included in the project boundary. These could include emissions from construction equipment that could be used in the installation of new plastic pipeline segments, for example.

The World Resources Institute case study is informative when considering options for establishing the project boundary. It determines that capture of previously released CH_4 will not alter the end user's demand for natural gas. Table 9, reproduced from the WRI document [WRI, 2005], contains the WRI assessment of primary and secondary effects from the high-efficiency compressor installation project. The conclusion of the assessment was that only primary effects are included in the project boundary.

Table 9. Primary and Secondary Effects of High-Efficiency Compressor Installation Project

PRIMARY EFFECT	SECONDARY EFFECTS	
	ONE-TIME EFFECTS	UPSTREAM AND DOWNSTREAM EFFECTS
Reduction in combustion emissions from generating off-grid electricity from reduced fuel use by compressors (per unit of natural gas transported).	**Considered:** • GHG emissions associated with the manufacture, installation, and decommissioning of compressors. **Magnitude/Significance:** The project activity will cause GHG emissions associated with the manufacture, installation, and decommissioning of compressors. However, these same activities would have occurred in the baseline scenario, producing GHG emissions from the same GHG sources. The result is zero net change between project activity GHG emissions and baseline emissions, so there are no one-time GHG effects.	**Considered:** • Reduced GHG emissions associated with reduced mining/extraction of natural gas. • Reduced GHG emissions associated with reduced transportation of natural gas. **Magnitude/Significance:** The project will cause an absolute reduction in demand for natural gas, leading to reductions in GHG emissions associated with extracting and transporting natural gas. Such GHG reductions would constitute positive secondary effects; to be conservative, these GHG reductions are assumed to be zero. No other inputs or outputs are associated with the project that might cause secondary effects.

Another issue to consider when establishing a project boundary is market effects. Market responses generally occur when the project prompts providers or users of an input to a project (in this case natural gas) to react to a change in market supply or demand. These effects are minimal when the product or service produced or consumed by the project has few substitutes or can have few alternate suppliers. This is the case with NGTD as the only fuel source entering and leaving the transmission and distribution system is natural gas. Further, end users are unlikely to change their energy supply (to, for example, grid electricity) as a result of the project. Market effects are therefore expected to be insignificant for the project types discussed in this issue paper.

In developing the project boundary, it is important to minimize risk of leakage. This phenomenon occurs when GHG emissions reductions or sequestration is undermined by increased emissions outside the project boundary.

It is possible that in implementing an emissions reduction project that resources could be shifted from emissions reductions efforts or general maintenance efforts that minimize GHG emissions in another part of the system. To prevent this phenomenon, a project developer could be required to submit proof of ongoing emissions reductions measures at other points in the system that are not in the project boundary. Alternatively, the project boundary could include the entire system as discussed above. Required documentation could include maintenance manuals and records for the entire facility before the project period and during the project period, calibration records, metering system logbooks, and independent audit reports (internal or external). This is a similar approach that the urban forestry protocol takes where a project developer must submit a tree maintenance plan to show leakage has been guarded against by maintaining the level of maintenance on all trees in non-project resources.

If a project conserves CH_4 by replacing gas-driven equipment with electric-powered equipment, the project boundary could include power plant emissions associated with powering the new equipment. If the boundary does not include the power plant, the emissions at the power plant could be considered leakage. It is possible, however, that the electric-powered devices could run from a solar-powered battery or other non-GHG emitting device, eliminating potential leakage.

In summary:

- The project boundary should include the equipment that the project affects.
- The WRI provides precedence for including only the primary effects in the project boundary.
- The amount of CH_4 captured from most of the projects identified in this paper is not sufficient to impact the market or end use consumption.
- The risk of leakage is manageable for NGTD projects. For projects impacted by maintenance activities, leakage can be monitored through mechanisms established by the Reserve for other project types (e.g. urban forestry).

6.0 Ownership

Ownership may not be straightforward to establish for the projects described herein. Several different ownership scenarios are possible including one company owning a transmission or distribution system and another operating it. More than one company may own or operate at a given transmission or distribution installation.

It could be possible for the transmission or distribution system owner, operator, GHG project financiers or project developers, or utilities to be considered the project developer in the eyes of the Climate Action Reserve. This suite of potential owners is similar for other project types including urban forestry and coal mine CH_4 emissions reduction projects.

One method of determining ownership would grant climate reserve tonnes (CRT) only to the entity who owns the equipment that will be subject to the emissions reduction project. Alternatively, if the emissions reduction project is initiated by an entity that carries out maintenance work at a facility but does not own the equipment, that entity should have the ability to claim ownership for the reductions.

To eliminate ambiguity in project ownership, the roles and responsibilities of the entities who own equipment impacted by the project and those who will carry out labor related to the project must be clearly defined. Further, ownership of the GHG reductions must be specified and documented *a priori* as is the case with other project types for which the Reserve has existing protocols.

7.0 Permanence

For the project types described herein, a given parcel of natural gas is prevented from escaping to the atmosphere. That gas parcel can have one of two fates. Either it is combusted in a flare or it is retained in the transmission and distribution system and delivered to an end user where it is combusted. If the gas is combusted in a flare, the overall GHG emissions from the process are reduced by the difference in global warming potential between CH_4 and CO_2. These emissions reductions can not be reversed because the natural gas has undergone a chemical change and will not revert to the greater global warming potential it had before it was combusted. In the event that the gas parcel continues on in the system, it will reach the end user and be either combusted or used in a chemical synthesis process. The trapping of the parcel of natural gas, however, will not translate into increased combustion or chemical production at the end user. From this discussion, it is possible to conclude that the primary effects of NGTD projects can not be reversed.

8.0 Quantification Methodologies

This section gives a broad overview of methodologies and emission factors for quantifying GHG emission reductions for NGTD projects and refers the reader to the appendices and the following three protocols where the factors and methodologies are published.

- The American Petroleum Institute's Compendium *of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* [API, 2009b], a comprehensive resource of emission estimation methods for the entire oil and natural gas industry. This issue paper discusses only the portions of the Compendium that apply to the transmission and distribution sectors.
- The Interstate Natural Gas Association of America's (INGAA*) Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage* [INGAA, 2005], which applies only to the transmission sector.
- The American Gas Association's (AGA) *Greenhouse Gas Emission Estimation Methodologies, Procedures, and Guidelines for the Natural Gas Distribution Sector* [AGA, 2008] applies solely to the distribution sector. Many of the AGA emissions factors rely heavily on Canadian data. Canadian-derived emission

These three documents were written with the aim of assisting oil and natural gas companies in developing GHG inventories. They were not written with the intent of assisting companies with quantifying project-level emissions, although API has published a series of documents to assist companies in using the emission factors and engineering calculations in the Compendium on a project level [API, 2007].

An additional source of quantification methodologies is the Mandatory Greenhouse Gas Reporting Rule Subpart W, as it was published in draft format in the April 10, 2009 Federal Register [EPA, 2009]. Onshore transmission compression facilities were subject in the proposed rule; distribution facilities were not. Engineering calculation methods are described in Section 98.233 while monitoring methods are described in Section 98.234.

8.1 Emission Factors

The emission factors in the three resource documents (API, INGAA, AGA) are in many cases derived from a 1996 study conducted by the Gas Research Institute (GRI) and U.S. EPA (GRI/EPA, 1996]. As a part of this study, component counts and component/equipment leak rates were measured and associated uncertainty confidence bounds were quantified. Regarding the EPA/GRI study, AGA states that,

> "*the purpose of the GRI/EPA Study was identification of sources and quantification of U.S.* ***national*** *methane emissions. These data were* ***not*** *intended to be used to develop default emission factors or industry averages for the gas industry. This issue is similar to the concept of applying an EPA AP-42 emission factor for NOx to a piece of equipment such as an internal combustion (IC) engine. Typically a company would not consider using the AP-42 emission factor for a NOx emission limit because of the factor's "average' nature, and the potential for the generic emission factor to not be representative of the specific equipment of interest."*

In addition, the emission factors likely overestimate emissions because natural gas systems have reduced emissions since 1996 due to improvements in technologies and management practices which have been encouraged in part by EPA's Natural Gas STAR program. As a result, if project developers used these emission factors, the emissions reductions stemming from the project would be overestimated. Further, the lowest precision value (expressed as 95% confidence intervals) associated with an emission factor, as cited in the API Compendium, is 20% for a residential gas meter. Typical precision values are over 50%, many exceed 100%. While similar uncertainties accompany emission factors in other Reserve protocols (e.g., for nitrous oxide emissions in the livestock protocol), it is recommended that the Reserve not allow project developers to use emission factors in the development of project emission reduction estimates. This recommendation is made because direct measurement methods are available that provide more accurate data and using the default emission factors will result in overestimating emission reductions.

Some studies to update specific emission factors have been conducted or are planned in the near future. The results of these studies may lend themselves to using emission factors on a project-level basis.

This issue paper discusses emission factors presented in the three resource documents in Appendix C.

8.2 Vented Emissions

Section 1.1 describes the type of emissions that constitute vented emissions. While emission factors (reviewed in Appendix C), process modeling, and engineering calculations can be used to quantify these types of emissions, engineering calculations and process modeling provide more accuracy but may not be applicable to all emission source types. Direct measurements are the most reliable.

8.2.1 Engineering Calculations and Process Simulators

Engineering calculations or process simulators provide higher accuracy than generic emission factors for calculating project emissions. Below are considerations and methods of using these techniques to estimate vented CH_4 emissions. Note that these approaches can be used both to calculate baseline and post-project emissions. Appendix B describes these calculations in more detail.

Glycol Dehydrator Emissions

In determining dehydrator vent emissions, test data taken directly from the glycol dehydrator vent provides a high degree of accuracy. If these test data are not available, it is possible to use process simulation software to model the emissions. One such simulator software is GRI-GLYCalc, which estimates air emissions from glycol units that use triethylene glycol, diethylene glycol, or ethylene glycol to quantify emission project reductions. To use the simulator, the following parameters must be known before and after project implementation: wet gas flow rate, wet gas temperature and pressure, existence of a gas-driven glycol pump, wet and dry gas water contents, glycol flow rate, whether stripping gas is used in the regenerator, and the temperature and pressure of the flash tank (if applicable).

Emission estimates from the GLYCalc model are of sufficient quality to support regulatory reporting of other air emissions. The model parameters do enable the quantification of emission reductions associated with dehydrator improvements.

Pneumatic Devices

INGAA posits that the most accurate emissions estimates can be obtained from device specifications and site-specific data. This information can be used to quantify emissions from projects such as numbers 21, 46 and 47 from Table 1. Necessary characteristics include the following.

- Equipment stroke rate;
- Volume specifications; and
- Average natural gas CH_4 content.

The API Compendium (Section 5.6.2) provides equations for calculating vented emissions from pneumatic pumps based on manufacturer pump curves.

Cold Process Vents and Non-Routine Activities
The term "Cold Process Vent" describes the release of gases without combustion, meaning that these vents release primarily CH_4. As there is no prescribed frequency, volume, or equipment type for these emission sources, there are no standard emission factors or default values for quantifying the GHG emissions that result from reducing or capturing cold process vents. Rather, the approach to their quantification is a material balance.

Engineering calculations (categorized as Tier 4 methods by INGAA) can be used to estimate the volume of gas released based on the internal volumes of the equipment. Characteristic parameters of the events include pipeline segment volume, size of the unit that is blown down, system pressure, gas composition, and event frequency. To determine an annual emissions rate, the emissions per event must be multiplied by the number of events per year. If the venting is continuous, Equation 5-14 in the Compendium applies.

Engineering calculation methods can be used to accurately quantify baseline and project emissions for activities such as project IDs 25 through 28 from Table 1.

8.2.2 Direct Measurement

Direct measurement can be used to accurately quantify vented emissions for a number of reduction project types. Vented emissions, such as from pneumatic devices and pumps, can be measured by the methods described in Section 8.4. When using direct measurements for these devices, it is important to ensure the duration of the measurement is representative of the annual device usage, which can vary significantly for some applications.

Even emissions during unplanned events can be quantified. For example, a system can be set up at a pressure relief valve to measure CH_4 concentration and overall flowrate during these events. These data can be used to quantify emissions during the event.

8.3 Fugitive Emissions

Fugitive emissions are a significant portion of the overall CH_4 emissions for NGTD facilities. As Tables 1 through 3 illustrate, there are many projects that have the potential to reduce fugitive emissions of CH_4 at these facilities. Fugitive emissions can result from:

- Leaks from process and pipeline equipment components such as valves, compressors, pumps, relief valves, flanges, open end lines, meters, pressure gauges, and other connectors;
- Integrity leaks from aging underground pipelines; and
- Open organic material storage vessels and open processing of wastewater, such as process drains. Wastewater treatment facilities are not commonly present at NGTD facilities. A protocol for emissions reductions projects for the NGTD

Reduction of fugitive emissions from component leaks are based on reducing the number and intensity of leaks of CH_4 from various equipment and connector fittings (referred to as components). The identification of leaks to be fixed and determination of the number of leaking components can use a variety of screening techniques. Quantification of the fugitive emissions, once they are identified, employs a smaller number of methods.

Fugitive component leak emissions can be estimated in four basic ways:

1. Facility-level average emission factor approach;
2. Equipment-level average emission factor approach;
3. Component-level average emission factor approach; and
4. Site-specific measurements.

Appendix C provides background information on the three emission factors approaches. In general, the uncertainty associated with these approaches is not suitable for emission reduction quantification. Site-specific measurement methods are described further below.

8.3.1 Site-specific measurements

Facility measurements of CH_4 concentrations and leak flow rates can provide site-specific emission factors with improved accuracy. Three approaches can be applied to developing site-specific emission factors.

<u>Screening Approach</u>

A screening approach can be used to quantify both pre- and post-project emissions. Electronic "sniffing" devices are used in this approach to measure the concentration of CH_4 in fugitive emissions from each device. Based on this measurement and a threshold concentration that, when exceeded, identifies a component as leaking, components are either classified as leaking or not leaking. Threshold values vary by program, but a typical CH_4 concentration value for the threshold is 10,000 ppm. Then, an emission factor for leaking components (in units of emissions per time per component) is multiplied by the number of leaking components. Similarly, a non-zero emission factor for non-leaking components is multiplied by the number of non-leaking components. These two values are summed to obtain the total emissions.

There are a number of sources for emission factors, including U.S. EPA's Method 21. INGAA provides leak/no-leak emission factors with 95% confidence limits [INGAA, 2005, Table 4-6]. One disadvantage to this approach is that much information on the intensity of the leak is lost in applying these simple factors.

Initial screening data can be developed for approximately \$10 - \$50 per component measured. These costs can drop to an industry average of approximately \$1 per component in an ongoing screening program. The screening analytical measurements can introduce uncertainties of 50% - 80%. However these uncertainties are lower than the uncertainties introduced by the assumed generic emissions factors. Studies of the various generic emissions factors have found that they introduce uncertainty of 200% or more to a calculation of emissions. Leak/no-leak factors, like average emission factors, also conservatively include a high leak intensity for both the leak and non-leak factors and as a result the emissions are generally overestimated. Using this approach would therefore overestimate the emission reductions a project would achieve.

<u>Correlation Approach</u>
The correlation approach employs the concentration values detected in the screening process in correlations that relate these concentrations to predict the mass emission rate from the component. The correlation used is generally based on many studies (for example the USEPA correlation equations in Method 21), but not necessarily for NGTD industry components. Correlation equations have been developed for each of the major component types, such as flanges, and are applied to individual components rather than to large groups of equipment, resulting in greater accuracy than the above-described procedure. Despite this improvement, INGAA points out that concentration is a poor surrogate for the actual leak rate. Leak-based correlation equations can have uncertainties within two orders of magnitude of the estimated emissions rate. Figure 4 illustrates this point [AGA, 2008].

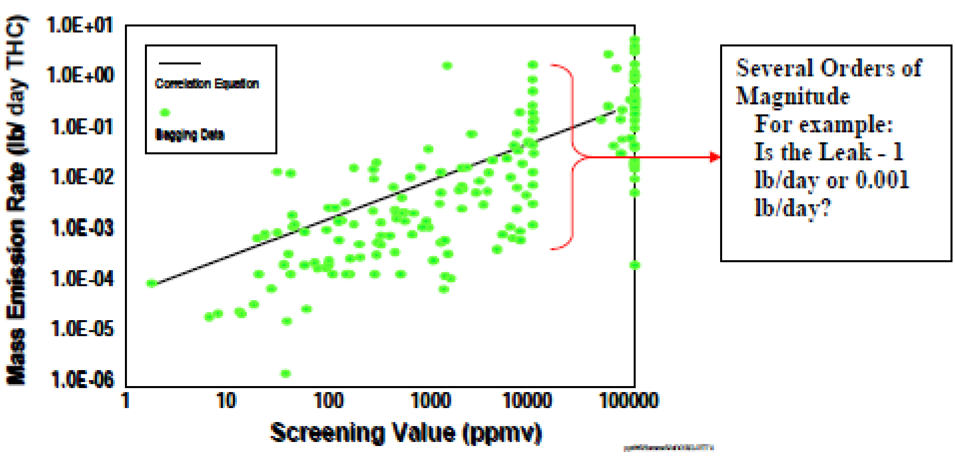

Figure 4. Leak Rate Versus Concentration and Correlation Equation Estimate

Current measurement and data recording instrumentation allow for routine collection of this individual data with the same equipment used for leak/no-leak determinations. Screening data can be therefore developed for approximately $1 per component measured, roughly the same cost as for leak/no-leak data.

<u>Unit-Specific Correlations</u>
The third approach uses unit-specific leak rate correlations with direct measurement of the leak rate in addition to concentration measurements. A component is enclosed and the leak rate measured directly with bagging or high volume sampler techniques as described in Section 8.4. These bagging studies can cost upwards of $500 per component bagged plus screening costs for the remainder of the components. The time and expense of

bagging studies preclude them from being conducted for every component on a frequent basis.

It is possible to develop leak rates only for a limited number of each type of component. These rates can then be applied across a site to equipment that has similar specifications and operating characteristics.

The uncertainty associated with this approach is dependant on the experimental technique of the measurement crew (as well as the accuracy and precision of the analytical method used to measure CH_4 concentration, which also applies to all of these emission quantification methods). Typical measurement uncertainties are 2 - 5%. Higher uncertainties however can be expected for emissions correlations developed from these measurements and applied across other components. As the number of components bagged and screened increases, the uncertainties associated with these correlations decreases. Emissions calculated by site-specific factors can be 10 times or more lower than those calculated by application of average emission factors. For emission reduction quantification applied to a facility level fugitive measurement program, the unit-specific correlation approach provides higher accuracy than other means of quantifying fugitive emissions.

Direct Measurements

Measurement instrumentation can be used to measure emission rates for fugitive source emissions (and also for single event venting measurements such as valve purge events where it is not possible to capture the emissions in a vent or stack). This technique measures total CH_4 concentration in the area around a leak. Direct measurement methods can be used to sample a subset of equipment. Statistical or other calculation methods can then be applied to the sampled data to develop an emissions profile of the entire emissions source population. Many instruments are portable for field use.

Direct screening instrumentation makes use of the same analytical technologies as continuous analyzers. The analyzers' accuracy and precision, like the continuous analyzers, are dependant on the calibration methods used. For CH_4 concentration measurements, a CH_4 calibration standard would be used to calibrate the response of the screening instrument.

Fugitive measurement usually applies to leaks from components, such as valves, compressors, and connection fittings. EPA standard Method 21 - Determination of volatile organic compound leaks (40 CFR Part 60 Appendix A-7) is generally accepted as the standard procedure for monitoring leaks from components. Method 21 specifies requirements for instrumentation in the rule. These are given as performance standards rather than mandates to use specific equipment types. Among other requirements, the measurement instrumentation must address the following:

1. The instrument detector shall respond to the compounds being processed. Method 21 is applied for VOC emissions but can be used to determine CH_4 emissions based on the composition ratio of CH_4 to VOC. Detector types that may meet this requirement include, but are not limited to: catalytic oxidation, flame ionization,

4).

2. The instrument shall be capable of measuring the leak definition concentration specified in the regulation.
3. The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration.

The CDM-Approved baseline methodology AM0023 for "Leak reduction from natural gas pipeline compressor or gate stations" includes the following instrumentation, which is representative of the options available:

- Electronic Gas Detectors equipped with catalytic oxidation and thermal conductivity sensors;
- Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) hydrocarbon detectors, OVAs and TVAs which use flame ionization detectors (FID);
- Acoustic Leak Detection which uses portable acoustic screening devices designed to detect the acoustic signal that results when pressurized gas escapes through an orifice;
- High volume or hi-flow samplers that capture all emissions from a leaking component to quantify leak flow rates; and
- Rotameters and other flow meters used to measure extremely large leaks that would overwhelm other instruments.

There are several manufactures of each of these types of instruments. Individual differences may or may not make a significant difference for the specific measurement to be made. Careful review of the manufacturer's specifications should be done before selecting a particular instrument. The price ranges listed in the following discussion were developed from an internet-based current instrument survey.

Direct screening instruments are generally less sensitive than portable continuous analyzers. FID-based analyzers are best suited for CH_4 concentrations 10 ppm or greater. Uncertainties in a calibrated instrument response of ±2.5% are less than the uncertainties introduced by the field measurement procedures and by the application of emission factors or correlation equations. Total uncertainties can be calculated from the combined uncertainties of each part of the calculation.

In December of 2008, EPA finalized a rule on alternative work practices for determining leaks from equipment. This rule allows the use of infrared (IR) video cameras in addition to Method 21 instruments for regulatory screening requirements. IR cameras merely confirm whether a component is leaking. This information can be used in applying leak/no-leak emissions factors, but a count of fugitive components is required to apply the emission factors.

The cost of component leak screening activities is generally benchmarked at approximately $1 per component analyzed for large facilities' ongoing programs, inclusive of monitoring instrumentation (assumes FID based instruments) and labor costs.

Use of IR camera techniques have significantly higher instrumental costs (currently around $20,000-$50,000) compared to other screening instruments such as FIDs ($4,000-$5,000). However, screening with IR cameras is a relatively rapid process. IR cameras are currently appropriate for screening components as part of a leak identification and repair program rather than as an emission quantification measurement, providing quick identification of leaks.

8.3.2 General Considerations

Without question, the large differences among the mass emissions rates predicted by the three site-specific measurement techniques necessitate that the same technique be used for baseline and post-project emissions quantification.

Bagging studies give the most accurate and precise measurement for an individual component at a point in time. It is therefore important to consider how frequently a project developer would need to measure emissions rates from components since fugitive emission reductions can be temporary, i.e., the same component can begin to leak again. The emissions reduction is only valid for the time period that the fugitive components are demonstrated not to be leaking. (See Appendix A for a discussion of how the UNFCCC methodology addresses these topics.)

8.3.3 Integrity-Based Leaks in Underground Pipelines

Leaks from underground pipelines can develop from corrosion, temperature cycling, limited maintenance, and other factors due to limited access for inspection. Leaks from underground pipelines are more difficult to accurately calculate than leaks from above-ground pipes. Direct or screening measurements are not available, and even determination of component counts or the rate at which cracks form cannot be determined without inspection. This type of fugitive emission has been studied and emissions factors have been developed based on different types of pipeline materials. Potential emission reductions for replacing one type of material with another can be compared with these factors.

The uncertainties associated with emission factors for this project type range from 63% to 261% for the different pipe materials used in NGTD operations (API Compendium, 2009, Section 6). These emission factors appear to be the only current viable quantitative method available for these types of emissions calculations. It is therefore recommended that the Reserve not develop a protocol for this project types involving the replacement of pipe.

8.4 Parametric Measurements

Emissions reduction calculations for NGTD projects require non-chemical, parametric data, in addition to measurements of CH_4 concentrations. Methods for measuring CH_4 concentrations are well established and documented. Therefore, this section focuses on parametric measurements. These measurements can include: flow rate, cumulative flow amount, pressure, and temperature.

Parametric measurement devices have application to continuous or discreet sampling. Continuous measurement instruments (such as flow meters or pressure gauges) that are located in the operating units are particularly subject to performance degradation from environmental effects. These parametric measurements are generally used by the facility for purposes other than calculating CH_4 releases, but may have application to the measurement of baseline or project emissions.

Orifice meters are the most prevalent flow meter type used in the oil and gas industry, and are used for metering products during custody transfer as well as for process control and internal accounting. Recommended practices for the installation, calibration and calculation of flows for these custody meters are provided in Section 3 of Chapter 14 of API's MPMS [API, 2005]. This standard was developed through a collaborative effort by members of API, AGA, and the Gas Processing Association, with contributions from the Canadian Gas Association, American Chemical Council, the European Union, Norway, Japan and others. The standard recognizes that many factors contribute to the overall measurement uncertainty associated with many metering applications. Table 10 summarizes the factors that should be considered in evaluating the uncertainty of flow measurements used for GHG emission calculations [API, 2009a].

Table 10. Factors to Consider When Evaluating Uncertainty Of Flow Measurements Used for GHG Emission Calculations

Confidence range of the measurement instrument − Manufacturers' anticipated measurement errors for common flow meters could be used if on-site calibration data are not available
Errors associated with "context-specific" factors Such factors may include the following considerations: − Are measurement instruments installed according to the manufacturer's requirements? − Is the measurement instrument designed for the medium (gas, liquid, solid substance) for which it is being used? − If manufacturer's data are not available, are the instruments operated according to the general requirements applicable to that measurement principle? − Are there any other factors that can have adverse consequences on the uncertainty of the measurement instrument? (i.e., how the measurement instrument is used in practice).
Pressure and temperature corrections for gas meters − Pressure and temperature corrections are only applicable to the determination of the amount of gas and not to the measurement of liquids or solid substances. − The actual amount of gas flow has to be corrected for pressure and temperature to the specified standard conditions in order to avoid major systematic errors.
Determination of total uncertainties − Individual uncertainties determined in a), b), and c) above ought to be summed up to determine the total uncertainty of the individual quantity measured.

The measurement of flow to flares is distinctly different than other flow measurements. Flares are designed as safety relief systems and typically are capable of handling highly variable flow rates of widely varying gas compositions. Therefore, some of the practices that are generally applicable to process control flow measurements have to be modified when addressing flows to flares. API published a measurement standard addressing gas or vapor flare flow measurements, which also includes cautionary details about the effects of fouling (due to entrained liquid droplets, aerosol mists, or other contaminations) on the measurement [API, 2005].

Table 11 [API, 2009a] presents a comparison of flow meter specifications and corresponding meter errors.

TABLE 11. Compilation of Specifications for Common Flow Meters [a]

METER TYPE	MEDIUM	TECHNICAL DESCRIPTION	MANUFACTURERS' REPORTED ERRORS [b]
Rotary meter	Gas	The rotary flow meter is a type of positive displacement (PD) flow meter that is widely used for utility measurements of gas flow. Rotary flow meters have one or more rotors that are used to trap the fluid. With each rotation of the rotors, a specific amount of fluid is captured. Flow rate is proportional to the rotational velocity of the rotors. Rotary meters are used for industrial applications.	0-20% of the measurement range: 3% 20-100% of the measurement range: 1.5%
Turbine flow meter	Gas	Turbine flow meters have a rotor that spins in proportion to flow rate. Many of those used for gas flow are called axial meters. Axial turbine meters have a rotor that revolves around the axis of flow. Axial meters differ according to the number of blades and the shape of the rotors. Turbine meters are used as billing meters to measure the amount of gas used at commercial buildings and industrial plants.	0-20% of the measurement range: 3% 20-100% of the measurement range: 1.5%
Bellows meter	Gas	The bellow gas meter performs volumetric measurement via its bellows. The measurements are based on the principle that the flexible bellows is periodically filled and emptied. A major problem with the bellows system is the residue in the pipe. The internal mechanisms fail to perform their tasks due to such residue, causing the meter to dysfunction and fail to perform a sound measurement.	0-20% of the measurement range: 6% 20-100% of the range: 4%
Venturi meter	Gas and Liquid	Venturi meters are another example of differential pressure flow meters, as described under orifice meters above. In this case, the primary element is a Venturi flow nozzle. Venturis are especially suited to high-speed flows. They are also used for custody transfer of natural gas.	20-100% of the measurement range: 1.5%
Orifice meter	Gas and Liquid	Orifice meters belong to the category of differential pressure flow meters that consist of a differential pressure transmitter, together with a primary element, such as the orifice plates. The orifice plates place a constriction in the flow stream, and the differential pressure transmitter measures the difference in pressure upstream and downstream of the constriction. The transmitter or a flow computer then computes flow using Bernoulli's theorem. Orifice plates are the most widely used type of primary elements. Their disadvantages are the amount of pressure drop caused, and the fact that they can be knocked out of position by impurities in the flow stream. Orifice plates are also subject to wear over time.	30-100% of the measurement range: 1.5%

TABLE 11. Compilation of Specifications for Common Flow Meters, continued

METER TYPE	MEDIUM	TECHNICAL DESCRIPTION	MANUFACTURERS' REPORTED ERRORS [b]
Ultrasonic meter	Gas and Liquid	There are two main types of ultrasonic flow meters: transit time and Doppler. The transit time meter has both a sender and a receiver. It sends two ultrasonic signals across a pipe at an angle one with the flow, and one against the flow. The meter then measures the "transit time" of each signal. The difference between the transit times with and against the flow is proportional to flow rate. Doppler flow meters rely on having the signal deflected by particles in the flow stream and the frequency shift in proportion to the mean fluid velocity.	1-100% of the measurement range: 0.5%
Coriolis meter	Gas and Liquid	Coriolis flow meters contain one or more vibrating tubes. These tubes are usually bent, although straight-tube meters are also available. The fluid to be measured passes through the vibrating tubes. It accelerates as it flows toward the maximum vibration point, and slows down as it leaves that point. This causes the tubes to twist. The amount of twisting is directly proportional to mass flow. Position sensors detect tube positions.	1-100% of the maximum measurement range: 1%
Vortex meter	Gas	Vortex flow meters are one of the few types of meters, besides differential pressure, that can accurately measure the flow of liquid, steam, and gas. Vortex flow meters operate on the von Karman principle of fluid behavior, where the presence of obstacles in the fluid path generates a series of vortices called the von Karman street. To compute the flow rate, vortex flow meters count the number of vortices generated.	10-100% of the measurement range: 2%
Gas Meter with Electronic Volume Conversion Instrument	Gas	An electronic device designed for the primary purpose of converting a volume of gas measured at one set of conditions to a volume of gas expressed at another set of conditions. The device incorporates integral (internal or external) temperature and/or pressure measurement transducers. It may be directly mounted onto a single meter (with mechanical drive or magnetic drive coupling) or connected to a remotely located meter from which it is fed volumetric pulses. The device may perform additional functions such as super compressibility correction, meter accuracy curve correction (linearization), and energy calculations.	For 0.95-11 bar and -10 – 40°C: 0.5%

Notes:
a Based on material presented in Appendix I of the ETSG, July 2007 survey summary document and sources cited.
b The error levels specified are those reported by the manufacturers when instruments are calibrated under laboratory conditions.

In addition, API recently published a valuable guide to assessing uncertainty in measuring parameters required to quantify pre- and post-project emissions: **Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: *Technical Considerations and Calculation Methods, 2009*** [API, 2009a]. The document provides technical background and specific calculation methods to determine uncertainties associated with measurements and emission factors and determine how to aggregate these individual terms to derive uncertainty ranges. The document comments on each piece of an emission calculation, including sampling, measurement (analytical and parametric), emission factor derivation, and error propagation of the calculation itself. Discussion of the statistical methods used to generate uncertainty is beyond the scope of this document.

8.5 Quantification Methods Conclusions

- Emission factors as published by industry groups over predict emissions reductions because they were developed as conservative industry average factors to be used in facility GHG inventories and are therefore not appropriate for quantifying emission reductions.
- Direct measurement and engineering calculations are the recommended means of quantifying baseline and post-project emissions.
- Fugitive emissions are more difficult to quantify than vented emissions. Direct measurement of leak rates and CH_4 concentration in the leaked gas is the most accurate approach of those described in Section 8.3.1.
- Projects involving underground pipeline leaks should not be eligible given the difficulties inherent in quantifying baseline and post-project emissions from this project type.
- Uncertainties associated with measurement devices have been well characterized by the oil and gas industry.

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Appendix A: Project Case Studies

The case studies in this section are provided to illustrate projects that may lead to the most significant emissions reductions from the NGTD sector or to illustrate how project types can achieve reductions beyond regulatory requirements.

A.1 Compressors and Engines

In the transmission sector, compressors (reciprocating and centrifugal) constitute approximately 43 percent of CH_4 emissions [U.S. EPA, 2009b]. For this reason, the Reserve may wish to develop protocols for projects that reduce emissions from these sources. The quantification methodologies described in Section 8 can be used to calculate both baseline and post-project emissions.

Compressor vented emissions largely stem from what can be considered non-routine activities that require system depressurization [API, 2009b]. For example, if maintenance work will be done at a facility, system pressure will be reduced to create a safer work environment. After maintenance work is complete, purging the lines or equipment with process gas can be necessary to push oxygen from the system and prevent the formation of a flammable methane-oxygen mixture. Case studies of these project types, which indicate the corresponding project IDs in Tables 1 through 3, are presented below.

- **Reduce Emissions when Taking Compressors Off-Line [Project ID 63].** Compressors may be taken off line when demand is low or when maintenance is necessary. Standard practice is to vent the compressor to the atmosphere. Methane-conserving alternatives include venting the natural gas to the fuel gas system and leaving the compressor pressurized. In the latter case, additional measures can be taken to minimize fugitive emissions. One potential barrier to this project type is if compressors are not depressurized for maintenance events, additional safety precautions are critical.
- **Alterations to Compressor Start Up [Project IDs 16, 19].** Methane emissions can be vented at several points during engine start up. For example, each time a compressor starts up, the discharge header is unloaded by depressurizing gas and venting to the atmosphere. Then, a gas-expansion turbine starter motor turns over the engine, which also vents CH_4. If there is a false start, these emissions occur more than once until the compressor starts. Updating the starting technology, perhaps to an electric ignition system that a solar recharged battery could power, can reduce vented CH_4 emissions. It would also reduce maintenance time. Alternatively, compressed air rather than natural gas could be used in the starter turbine rather than natural gas.
- **Redesign Blowdown Systems and Alter Emergency Shutdown Devices (ESD) Practices to Reduce Venting and Purging Emissions [Project ID 65].** Emergency shutdown systems automatically remove hazardous vapors during emergencies and shutdowns at compressor stations. The system could release the vapors (which would include CH_4) to the atmosphere. An emission reduction technique is to route the vapors to a flare, the sales line, the fuel box, or lower pressure mains for non-emergency use.

A.2 Pneumatic Devices

Many pneumatic devices such as valve actuators and controls use natural gas pressure as the force for movement. By design, the devices release (bleed) natural gas to the atmosphere both continuously and intermittently. Most of the following projects could be used to reduce emissions from the NGTD sector. Because of the significance of this emission type in the distribution sector, the Reserve may want to focus on developing protocols for these project types. The following examples of projects to reduce CH_4 emissions from pneumatic devices are generally very cost-effective.

- **Replace high-bleed with no-bleed pneumatic controls before end of life [Project ID 47].** Gas-driven pneumatic devices release gas with each actuation or continuously if equipped with a pilot. Certain models of pneumatic devices are designed as low-bleed. The incremental costs of these devices are low (under $300) and replacing high-bleed devices with these more efficient devices can result in a pay back of less than one year. High-bleed devices can also be retrofitted to reduce their emissions.
- **Change driving force of pneumatic devices [Project ID 46].** These devices can be driven by instrument air or mechanical controls, eliminating the CH_4 emissions that stem from using gas-driven pneumatics.

A.3 Natural Gas Dehydrators

Natural gas dehydrators (Figure A.1) are used in the transmission sector but not the distribution sector. They are a less significant contributor to the transmission sector's CH_4 emissions than compressors and pneumatic devices. They remove water from natural gas through absorption of the water into liquid glycol. In a reboiler or regenerator, the water is driven from the glycol. Methane, however, is also entrained in the glycol and is emitted along with water from dehydrator vents. Other pollutants including volatile organic compounds (VOC) and hazardous organic pollutants (HAPs) are also in the dehydrator vent effluent and these emissions are regulated. Section 2.1.1 discusses how these regulations may affect the additionality of a project to reduce CH_4 emissions from dehydrators.

There are a number of projects that can reduce CH_4 emissions from this equipment, one of which is profiled below.

- **Use Zero Emissions dehydrators [Project ID 1].** Implementing a zero emissions dehydrator addresses many emission points within the dehydration system. It is also possible to implement only elements of this overall project and obtain CH_4 emissions reductions. First, rather than being emitted to the atmosphere, gases leaving the regenerator can be condensed. Non-condensable gases, including CH_4, serve as fuel in the reboiler. Second, electric-driven pumps can replace energy exchange pumps (also called gas-assisted glycol pumps). Electric pumps are more efficient and enable lower glycol circulation rates.

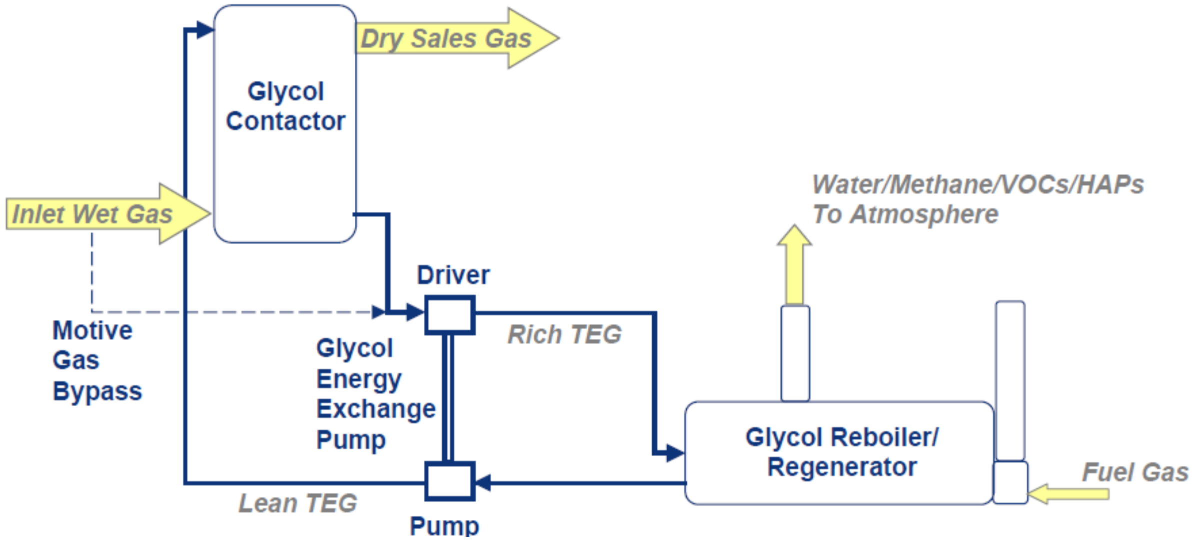

Figure A.1 Basic Glycol Dehydrator System Process Diagram [U.S. EPA, 2009a]

A.4 United Nations Framework Convention on Climate Change Clean Development Mechanism Methodologies

In the following two sections, additional details on the two CDM methodologies described in Section 2.3 are presented. These methodologies provide insight into eligibility aspects (e.g., additionality, baseline determination) of NGTD emission reduction projects and provide equations for quantifying pre- and post-project emissions.

A.4.1 Leak Detection and Repair

The methodology states that electronic screening ("sniffing") devices, organic or toxic vapor analyzers, or acoustic devices can be used to detect leaks [UNFCCC CDM Executive Board, 2005].

The following components in compressor and gate stations require an initial survey and regular subsequent analysis of emissions:

- Unit valves on blown down compressors;
- Blow down valves on pressurized compressors;
- Rod packings on pressurized compressors;
- Power gas vents for compressor unloaders; and
- Engine crankcase vents.

The CDM methodology permits bagging techniques, high-volume or high-flow samplers, or rotameters to be used to measure leak flow rates. Bagging techniques enclose the leaking component or opening in a bag or tent. Nitrogen or another inert carrier gas flows through the bag at a known flow rate. When the carrier gas reaches equilibrium, a gas sample is taken from the bag. The sample is analyzed for CH_4 concentration. The leak flow rate is calculated with Equation A.1.

$$F_{CH4,i} = F_{purge,i} \times w_{CH4} \qquad [A.1]$$

where:

$F_{CH4,i}$	=	the leak flow rate of CH_4 for leak i from the leaking component [m^3/hr]
$F_{purge,i}$	=	the purge flow rate of the clean air or nitrogen at leak i [m^3/hr]
w_{CH4}	=	the measured concentration of CH_4 in the exit flow [volume percent]

High-volume or high-flow samplers capture all emissions from a leaking component. A vacuum sampling hose pulls in a large volume of air around the leak source and, separately, a sample of the leaked gas. The high-volume sampler must be calibrated against a range of standards. These devices can prevent interference from nearby emissions sources. These samplers have dual hydrocarbon detectors to measure the hydrocarbon content of each of these two samples. Sample measurements are corrected with respect to the ambient hydrocarbon concentration. The leak rate is the product of the flow rate of the measured sample and the difference between hydrocarbon concentration in the sample and ambient air as in Equation A.2.

$$F_{CH4,i} = F_{sampler,i} \times \left(C_{sample,i} - C_{back,i}\right) \qquad [A.2]$$

where:

$F_{CH4,i}$	=	the leak flow rate of CH_4 for leak i from the leaking component [m^3/hr]
$F_{sampler,i}$	=	the sample flow rate of the sampler for leak I [m^3/hr]
$C_{sample,i}$	=	the concentration of CH_4 in the sample flow from leak I (volume percent)
$C_{back,i}$	=	the concentration of CH_4 in the background near the component (volume percent)

Rotameters (or other flow meters) can be used to measure significantly large leaks that would overwhelm other instruments. They route gas flow from a leak source through a calibrated tube. A float bob within the tube rises and indicates the leak rate. The methodology points out that rotameter data could be used to supplement data gathered during bagging or high-volume sampling.

If a rotameter is used, Equation A.3 is used to calculate the CH_4 leak flow rate.

$$F_{CH4,i} = 3600\frac{\sec}{hr} \times w_{CH4,gas} \times k \times A \times \sqrt{g \times h} \qquad [A.3]$$

where:

$F_{CH4,i}$	=	the leak flow rate of CH_4 for leak i from the leaking component [m^3/hr]
$w_{CH4,i}$	=	the measured concentration of CH_4 in the exit flow [volume percent]
k	=	a constant of the measurement equipment (manufacturer-provided)
A	=	the annular area between the float and the tube wall [m^2]
g	=	the acceleration of gravity [9.8 m/s^2]
h	=	the pressure drop across the float [as height in m]

To quantify the emissions reductions that have occurred, it must be assumed that a leak that was detected and repaired as part of the project would have continued to leak at the same rate the component leaked prior to the repair until it was replaced. It is conservative to estimate a constant leak rate as most leak rates grow over time.

The methodology prescribes the following assumptions.

- If a repair malfunctions, the leak resumes at the same flow rate exhibited either the day of the most recent inspection or during the pre-project measurement of the leak rate (which ever date was most recent).
- Emissions from a specific component are included in the calculations until
  - The equipment is replaced for reasons unrelated to the leak reduction project,
  - The replacement date for a piece of equipment arrives, or
  - The end of the crediting period or project activity period arrives.
- The uncertainty of the measurement is conservatively estimated with the flow rate at the lower end of the measurement uncertainty range at a 95% confidence interval. The methodology gives an example of a leak flow rate of 1 m^3/hr with an uncertainty range of the measurement method of ±10%. For this case, the emissions reductions calculations would be based on a leak rate of 0.9 m^3/hr. UNFCCC cites Chapter 6 of the IPCC Good Practice Guidance as a resource for determining the confidence intervals.

Equation A.4 is used to calculate emission reductions for this methodology.

$$ER_y = ConvFactor \times \sum \left[F_{CH4,i} \times T_{i,y} \times (1 - UR) \right] \times GWP_{CH4} \qquad \text{[A.4]}$$

where:

ERy	=	the CH_4 emission reductions of the project activity during the period y [tCO2 Equivalents]
ConvFactor	=	the factor to convert m³ CH_4 into t CH_4. At standard temperature and pressure [0° C and 1,013 bar] this factor amounts to 0.0007168 t CH_4/m³ CH_4.
i	=	all leaks eligible towards accounting of emissions reductions
$FCH_{4,i}$	=	the leak flow rate of CH_4 for leak i from the leaking component [m³CH_4/h]
UR_i	=	the uncertainty range for the measurement method applied to leak i,
$Ti,_y$	=	the time the relevant component for leak i has been operating during the monitoring period y [hr]
$GWPCH_4$	=	the global warming potential for CH_4 [tCO_2eq/tCH_4]

Table A.1 provides a description of the data that must be monitored throughout the project period to enable calculation of emission reductions. The UNFCCC methodology also provides Table A.2, which outlines quality assurance and quality control procedures for this project type.

Table A.1. Monitoring Requirements for UNFCCC CDM LDAR Projects

Data	Source	Unit	Recording Frequency	Fraction of Data to be Monitored	Archiving Method	Comment
Number, i	Number of leak identified, repaired and then resurveyed	Number	Once	100%	Electronic	Each leak will be tagged with a number and monitored after repair for any additional leaks
Time, T_i	Hours of equipment operation for each leak	Number of hours per reporting year	Continuous	100%	Electronic	Hours of operation will end when the equipment concerned is replaced for a non-leak related reason (i.e. it breaks down), or when the date of predicted replacement as identified in the PDD is reached (whatever is earlier).
Date	Repair and monitoring log	Date of repair and monitoring	Continuous	100%	Electronic	Date of repair will be used along with hours of operation of equipment to determine total hours. In cases of re-emerging leaks, the re-emerging leak will be assumed to have occurred the day after the most recent check which showed no leak.
Ratio	Leak rate of CH4 for each leak detected	m^3 CH4/hr	Annual	100%	Electronic	Recorded at the high end of the leak detection equipment's margin of error. (if equipment measure .070 m^3/hr and has a ± ten percent margin of error then the project developer would use .063 m^3/hr)
Temperature and pressure	Thermocouples, pressure gauges, calculations	°C, bar	Continuous or Periodic	100%	Electronic	Measured to calculate the density of the CH4. Note: Although these variables will be measured, it is not expected that there will be much variance because the pressure and temperature within stations are expected to be basically constant.
Uncertainty Factor for Leak Measurement Equipment	Manufacturer data and/or IPCC GPG	Fraction	Periodic	100%	Electronic	Estimated where possible, at a 95% confidence interval, consulting the guidance provided in Chapter 6 of the 2000 IPCC Good Practice Guidance. If leak measurement equipment manufacturers report an uncertainty range without specifying a confidence interval, a confidence interval of 95% may be assumed.

Table A.2. Quality Control and Quality Assurance Procedures for UNFCCC CDM LDAR Projects

Data	Degree of Uncertainty	QA/QC Procedure
Number, i	Low	Each leak will be tagged with a number and monitored after repair for any additional leaks.
Time, T_i	Low	Data loggers will be installed wherever possible for machines that turn off frequently to measure hourly usage.
Date	Low	Work orders, receipts and other records will be kept in addition to repair logs.
Ratio	Low	Leak rates will be measured and double checked before repair-major discrepancies will warrant a third test. In other words, if a hi-flow sampler is used to measure the rate of a leak, if the results of two tests are far apart, the testing should continue until two measurements have results very close together (to reduce any inaccuracies in the testing process). Should the hi-flow sampler or other equipment need recalibration or adjustment to ensure their accuracy, the project participants will take the necessary action to do so.
Temperature and Pressure	Low	Data recording equipment will be calibrated and double checked on a regular basis.
Uncertainty Factor for Leak Measurement Equipment	Medium/Low	The IPCC Good Practice Guidance will be consulted in compiling uncertainty estimates.

For each leak that is detected and repaired, the following information must be recorded:

- Whether the leak would have been repaired in the absence of the project considering safety, accessibility of the component, method of leak detection (e.g., visual versus electronic device), and use of advanced leak detection technologies beyond any technologies previously used;
- Date of detection;
- Date of repair;
- Exact leak location;
- Leak flow rate;
- Measurement method and uncertainty range; and
- If replacement occurs, date replacement would have occurred in absence of program relying on either the planned replacement schedule or the manufacturer's estimated equipment lifetime.

A.4.2 Steel and Iron Pipeline Replacement

This section discusses emission quantification techniques that the CDM methodology mandates for pre- and post-project emissions [UNFCCC CDM Executive Board, 2007a]. Although pipe replacement projects are not recommended for protocol development by the Reserve, the methodologies for baseline, emission quantification, and monitoring provided in this example may have application to other NGTD projects dealing with equipment replacement.

Baseline Determination
The methodology lays out baseline calculations that result in the most "reasonable, conservative replacement rate for the cast iron pipes or steel pipes without cathodic protection." The two cases that are considered in determining the baseline for this methodology are planned replacements as documented *ex ante* in the draft project design document (PDD) and business-as-usual replacement activities. The latter may be motivated by safety or operational factors and are determined by annual *ex post* monitoring. The baseline chosen is the greater of these two options.

Determining Ex Ante Baseline Replacement
The value of this baseline is determined before the crediting period begins. It is chosen as the most conservative replacement option among the following options:

- Historical average annual length of replacement for the three years prior to the start of the crediting period;
- Documented planned replacements; or
- Estimated replacement based on a linear correlation between year and length of pipeline replaced over their full remaining lifetime.

Equations to calculate the *ex ante* baseline are provided in the CDM document.

Determining the Ex-Post Baseline Replacement
If the *ex post* baseline option is selected, its value is calculated as follows.

First, the project developer, for each year of the project, must determine what fraction of the pipeline replacements that occurred are due to business as usual. This determination is based on internal safety and operational procedures related to pipeline replacement. It likely prescribes a survey of a portion of the total grid annually with pipelines that are identified as not meeting safety or operational standards being slated for replacement. The length of the pipeline selected for replacement will decrease annually as the overall grid becomes younger. The ratio of "unsafe" pipeline to the length of original pipeline could be considered constant but also could increase with the age of the grid.

This proportion must be calculated for the first three years of the project activity. In the remaining years, its highest value during the project period must be used. Beginning in the fourth year of the project activity, the proportion of "unsafe" pipeline to the total original grid is updated annually with an ageing coefficient.

The methodology outlines calculations for baseline determination in the *ex post* scenario. To determine this baseline, the project developer must know the total pipeline that will be replaced in the crediting period, the *ex ante* planned replacements, the actual replacements that occurred in any year, and the length of replacements that occurred because of procedural requirements (e.g., safety, maintenance). Please refer to the methodology for equations used to determine the *ex post* baseline.

Emissions Reductions Quantification
The CDM methodology prescribes certain emission factors with no reported uncertainty estimates. The emission factors are multiplied by the mass fraction of CH_4 in natural gas,

which must be monitored. It is critical to use the same emission factors for old and new pipe in the baseline and project emission calculations.

One source of emission factors is Gas Natural SDG's study to estimate annual leakage from their Spanish distribution network.[2] According to the Gas Natural SDG website,

> *"Gas Natural is the leader in the Spanish gas distribution market, operating through 10 distribution companies across 13 autonomous communities, and two sales companies. The company is the third biggest operator in the Spanish electricity sector, with over 3.5 million customers, according to the National Energy Commission (CNE).."*

The University of Zaragoza, Spain sought to update the Gas Natural SDG emission factors in 2005. They conducted field tests in Spain and measured the volume of fugitive emissions from the existing polyethylene distribution network with the pressure variation method. These new emission factors, however, were less conservative than the original factors for some pipeline types, in which case the CDM methodology uses the original factors. The CDM methodology present emission factors and distinguishes among the two data sources for the emission factors. For all pipeline types, the methodology allows that project developers can use emission factors not listed in the CDM methodology if the rationale for using other emission factors is properly documented.

<u>Monitoring</u>
The following parameters are to be determined at the beginning of the crediting period through a variety of sources including technical specifications, planning documents, and maps. These parameters are not monitored throughout the project period.

- Estimated lifetime of remaining pipeline at the start of the crediting period.
- Length of operational distribution main pipeline section expected to be replaced.
- Historical lengths of pipeline replaced during each of the three years prior to the crediting period.
- Planned pipeline replacement in each year.

The following parameters are monitored throughout the project.

- Methane fraction in pipeline gas (continuous).
- Pipeline pressure (continuous).
- Length of pipeline replaced, which must be distinguished as either procedural or related to the project activity. To demonstrate replacements are high-quality, the project developer must conduct a 24-hour pressure test in which all valves are closed and air is pumped into the system. System pressure must not drop for the 24 hours of the test.
- Grid operation continuity (verified through operational protocols and maps cross-checked with bills from local households).
- Service line replacement. The choice of emission factor is dependent upon whether these lines have been replaced.

[2] Natural Gas SDG is an energy company operating primarily in Spain.

Appendix B: Selected Quantification Equations for Vented Emissions

Equation B.1 provides a material balance approach for quantifying emissions based on measured vent rates.

$$E = V \times Y \times N \times \frac{MW}{C} \qquad \text{[B.1]}$$

where:

E	=	Emissions of CH_4 [tonnes/yr]
V	=	Gas volume released per event [scf/event]
Y	=	Mole percent of CH_4 in gas
N	=	Number of events per year
MW	=	Molecular weight of CH_4 [16 lb/lbmol]
C	=	Conversion from molar volume to mass [379.3 scf/lbmole or 23.685 m^3/kgmole at 60°F and 14.7 psia]

The gas volume released per event (V) is event-specific and must be measured in the baseline time span for each event. The number of events, N, will differ between baseline and project periods. N could increase but if V decreases, the project will still reduce emissions.

The volume of gas released can also be quantified with reasonable accuracy using engineering equations. This volume may be calculated from equipment internal volume parameters or the volume of gas a pipe section contains. In the latter assumption, one assumes the entire contents are released. These volumes could be converted from actual cubic feet of gas to standard cubic feet with the density of the gas. In the case of a pigging operation, the volume is based upon the segment of pipeline that was depressurized and the volume of the pig catcher or launcher.

The density of gas can be determined with Equation B.2, which is a rearrangement of the ideal gas law adjusted by a compressibility factor.

$$n = \frac{PV}{zRT} \qquad \text{[B.2]}$$

where:

N	=	Number of moles
P	=	Pressure [psia or atm]
V	=	Volume
R	=	Gas constant with units chosen according to the selected units for volume, temperature, and pressure
z	=	Compressibility factor [values provided in Perry's Chemical Engineer's Handbook Tables 3-172 in the 1984 version of the publication].

V is typically based on equipment design specifications for the system of interest. If no design data is available, the Canadian Associated of Petroleum Producers (CAPP) document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas*

Facilities provides volume estimation guidelines for several vessel types including horizontal and vertical cylinders, hemispherical and ellipsoidal end caps. This document is a good resource for vessel volume calculations.

Once the number of moles is known, Equation B.3 can be used to quantify emissions.

$$E = M \times Y \times MW \times N \qquad \text{[B.3]}$$

where:

E	=	Emissions of CH_4 [tonnes/yr]
M	=	Moles of gas released per event
Y	=	Mole percent of CH_4 in gas
N	=	Number of events per year
MW	=	Molecular weight of CH_4 [16 lb/lbmol]

It is most practical to use the gas law to estimate the number of moles when the entire volume of the vessel that is blown down is known and the volume of gas released is finite. If only a portion of the vessel contents are released, more rigorous calculation methodologies, such as those described in the Canadian Association of Petroleum Producers (CAPP) document cited above. Parameters necessary for these calculations, which model the gas release as isentropic flow of an ideal gas through a nozzle, include the open cross-sectional area of the release, wellhead pressure, and the gas specific heat ratio. Cross-sectional area data are available in the CAPP document.

Appendix C. Emission Factors

C.1 General Discussion

The INGAA and AGA documents apply a tier-based approach to organize emission estimation methods and factors. Tier levels indicate the level of accuracy that can be expected from the calculation with higher tier numbers indicating a higher degree of accuracy. Tiers 1 through 4 in the INGAA document are outlined in Table C.1.

Table C.1 INGAA Guidance Document Tier Definitions

Tier	Definition
1	General estimate with minimal inputs required. These factors are based on an aggregate of average emissions from a number of emission source types. These emission factors lack granularity for quantifying emissions reductions at an equipment or emission source level.
2	Data requirements and emission factors based on facility-level data or the largest emission sources at a site. These factors assume an average population of equipment for a representative facility and average emission factors for the represented equipment. As with Tier 1, these emissions factors may lack the level of granularity needed to quantify emission reductions for a particulate emission source.
3	Data requirements and emissions based on process operation or equipment-level information at a site. These factors are based on industry average emission estimates, which may or may not be representative of a given emission source.
4	This tier could also be called 3+. It involves emission determinations that require additional data. These determinations are generally not used for inventory development. They may be the most appropriate for quantifying the benefits of emission reduction projects.

INGAA points out that, “the Tier rating scheme is not an absolute indicator of the fidelity of an estimate, but rather an indicator of progressively better emission factors within an individual source category for a specific GHG.” The guidance document advises that it is common to use tiers below tier 3 for non-combustion emissions, which generally have less well-defined emission factors. However, the focus of the INGAA document is on GHG inventory development, not emission reduction project quantification.

Like INGAA, AGA describes a tier-based approach to calculating emissions but it is more specific. AGA presents distribution sector fugitive emissions sources and the corresponding activity data for Tiers 1 through 3 and for several Tier 3+ emission sources in a table that is reproduced below as Table C.2. A majority of the sources rely on the length of pipeline mains as the activity data, but other activity data (e.g., device count, station count, services count) are also very important for calculating emissions from this sector.

Table C.2 refers to Sections 5.2.4 and 5.2.5 of the AGA report, which discuss screening based methods for determining Tier 3+ emission factors and other approaches to developing Tier 3+ emission factors.

Table C.2. Distribution Sector Fugitive Emission Sources and Activity Data [Reproduced from AGA, 2005]

Tier 1[A]	Tier 2[A]	Tier 3[A]	Tier 3+[A]
Distribution Sector CH_4 (Main Pipeline Length)	Customer Meters CH_4 (Device Count)	Residential Customer Meters CH_4 (Device Count)	Refer to Section 5.2.4 and Section 5.2.5.
		Commercial/Industrial Meters CH_4 (Device Count)	
	M&R Stations CH_4 (Station Count)	M&R Stations CH_4 Categorized by Inlet Pressure, Location, and M&R or Pressure Reg. (Station Count)	
	Main Pipeline Leak CH_4 (Mains Length)	Cast Iron Main Pipeline CH_4 (Mains Length)	
		Plastic Main Pipeline CH_4 (Mains Length)	
		Protected Steel Main Pipeline CH_4 (Mains Length)	
		Unprotected Steel Main Pipeline CH_4 (Main Length)	
	Services Pipeline Leak CH_4 (Services Count)	Copper Services Pipeline CH_4 (Services Count)	
		Plastic Services Pipeline CH_4 (Services Count)	
		Protected Steel Services Pipeline CH_4 (Services Count)	
		Unprotected Steel Services Pipeline CH_4 (Services Count)	
Distribution Sector Leak CO_2 (Main Pipeline Length)	Main Pipeline Leaks CO_2 Leak (Mains Length)	Cast Iron Main Pipeline CO_2 Leak (Mains Length)	
		Plastic Main Pipeline CO_2 Leak (Mains Length)	
		Protected Steel Main Pipeline CO_2 Leak (Mains Length)	
		Unprotected Steel Main Pipeline CO_2 Leak (Mains Length)	
	Services Pipeline Leaks CO_2 Leak (Services Count)	Copper Services Pipeline CO_2 Leak (Services Count)	
		Plastic Services Pipeline CO_2 Leak (Services Count)	
		Protected Steel Services Pipeline CO_2 Leak (Services Count)	
		Unprotected Steel Services Pipeline CO_2 Leak (Services Count)	
Distribution Sector Oxidation CO_2 (Main Pipeline Length)	Main Pipeline Leaks Oxidation CO_2 (Mains Length)	Cast Iron Main Pipeline Oxidation CO_2 (Main Length)	
		Plastic Main Pipeline Oxidation CO_2 (Main Length)	
		Protected Steel Main Pipeline Oxidation CO_2 (Main Length)	
		Unprotected Steel Main Pipeline Oxidation CO_2 (Main Length)	
	Services Pipeline Leaks Oxidation CO_2 (Services Count)	Copper Services Pipeline Oxidation CO_2 (Services Count)	
		Plastic Services Pipeline Oxidation CO_2 (Services Count)	
		Protected Steel Services Pipeline Oxidation CO_2 (Services Count)	
		Unprotected Steel Services Pipeline Oxidation CO_2 (Services Count)	

A. Emission Source (Activity Data)

C.2 Venting Emission Factors

INGAA points out that, "many venting events are directly tied to company practices." AGA describes several factors that contribute to the overestimation of and large uncertainty associated with emissions from the distribution sector when using emission factors derived from the EPA/GRI data.

- Sources can be double counted, included in both aggregated activity data and within another emission factor category.
- Devices can be categorized into an incorrect gas pressure ranges.
- Using system-wide emission factors ignores significant system-to-system differences such as pipeline material (e.g., steel v. plastic).

AGA posits that a good deal of information is needed before emission factors can be updated and contain less uncertainty, such as how sources are grouped within emission factors and a better understanding of the operational changes that have occurred since the EPA/GRI study.

The remainder of this section discusses vented emission factors available for use in quantifying emissions from equipment in the transmission and distribution sectors. This information is provided as background for understanding issues associated with default emission factors.

C.2.1 Glycol Dehydrator Emissions

Emission factors are not the preferred approach for quantifying emissions from glycol dehydrator vents because greater accuracy can be achieved through engineering calculation approaches. Emission factors are available in the API Compendium along with precision estimates that were developed from site data and computer simulations. Because the precision ranges from 191-257 percent, these emission factors do not have the degree of certainty necessary for quantifying emission reductions from offset projects and the emission factors are not presented here.

The INGAA guidance document also contains emission factors for glycol dehydrator-vented CH_4 emissions, similar to those provided in the API Compendium.

C.2.2 Glycol Pumps

Gas-assisted glycol pumps associated with glycol dehydrators can be a significant source of CH_4 emissions. The API Compendium cites emission factors for these pumps based on manufacturer technical data and assumptions about typical dehydrator operation. However, the table does not include factors for the NGTD sector because the GRI/EPA study that developed the emissions factors did not observe active gas-assisted glycol pumps in these sectors. The applicability of these emission factors to the transmission and distribution sector is therefore limited. Project developers may not want to rely on these factors and should instead use manufacturer-specific information or field test data to determine emissions from glycol pumps.

C.2.3 Transmission-Related Non-Routine Emissions

INGAA echoes API in pointing out that it is difficult to use default emission factors for non-routine events like maintenance-related blowdowns because these events can be quite unique. Although INGAA provides Tier 3 emission factors, they recommend Tier 4 emission factors as an alternative.

The INGAA emission factors are facility-level, which is generally considered a Tier 2 approach. These emission factors are derived from the 1996 GRI/EPA study.

API provides emission factors for “maintenance and turnaround” and “other releases” from non-routine activities in Table 5-26 of the 2009 Compendium. The precision for these emission factors, when available, range from 64.3 to 346 percent.

API notes that the gas compressor station blowdown emission factor includes compressor blowdowns, compressor starts, pressure release valve releases, emergency shutdown device activation, and other venting activities. For meter and pressure regulation stations, the data are derived from Canadian company information. The pipeline venting emission factor is based on transmission pipeline blowdowns from maintenance activities such as pipe repairs or pigging.

Gas storage station emission factors in the API Compendium apply to both below- and above-ground liquefied natural gas facilities. They have similar non-routine practices to the compressor stations, and are therefore grouped with transmission sector emission factors.

These emission factors are not appropriate for Reserve offset projects because of the high uncertainties and they do not provide granularity for the specific venting sources.

C.2.4 Distribution-Related Non-Routine Emissions

The API Compendium (Table 5-27) and AGA Guidelines (Table 4-2) include vented emission factors for the gas distribution segment.

Meter and regulating station blowdown emission factors in Table 4-2 of AGA include emissions from station blowdowns, purges, and pneumatic isolation valve venting. The pipeline blowdown emission factor is based on gas distribution pipeline blowdowns from maintenance events like pipe repairs, abandonment, or installation. Like the emission factors for transmission-related non-routine events, they are not applicable to quantifying project emissions.

C.2.5 Gas Pneumatic Devices

The API Compendium ranks emission factors as the least preferred option to calculate vented emissions from gas pneumatic devices. The Compendium does provide simplified CH_4 emission factors by industry segment in Table 5-15. Precision data, however, are not available for pneumatic devices in the distribution sector. The precision in emission factors for two types of valve operators in the transmission sector (pneumatic/hydraulic and turbine valve) are over 100 percent.

INGAA provides emission factors for pneumatic actuators/controllers in Table 3-3, based on the 1996 GRI/EPA study. The Tier 3 factors differentiate among different device types. INGAA provides Tier 3 emission factors for pneumatic isolation valves and station control loops based on Canadian data [INGAA Table 3-4]. The meter and regulation station control loop emission factor in this table was developed for the distribution sector but can be applied to the transmission sector. INGAA does not cite confidence intervals for these emission factors.

It is essential to know the number of devices a project effects to calculate emissions because emission factors are on a per device basis. INGAA provides two methods for determining device counts. The first is based on first principles and depends greatly on the engine age and pneumatic control driver gas (natural gas or air). It assumes five pneumatic devices per engine ±5 engines, which results in a 100 percent uncertainty. This approach is based on typical design and usage of three-stage compressors.

The second uses data from the GRI/EPA study and is representative of diverse engine types and ages. It assumes ten pneumatic devices per engine ±5 engines which translates to 50 percent uncertainty. INGAA describes how this device count can be estimated in Section 3.3.3 of its guidelines document.

C.2.6 Pneumatic Pumps

The INGAA guidelines document (Table 3-5) and API Compendium (Table 5-16) present emission factors derived from the 1996 GRI/EPA study. These factors are based on production segment natural gas that has a typical volume percent methane of 78.8 percent by volume. Note, however, that the precision for these emission factors is at times unknown and in the best case is 77 percent.

C.2.7 Tank Flashing Losses

The API Compendium states that CH_4 emissions from condensate flashing can be calculated with a simplified flashing loss emission factor. The Compendium presents emission factors for the transmission segment that were derived from EPA Gas STAR PRO Fact Sheet number 504 on p. 5-55. Confidence intervals are not available for these factors.

C.3 Fugitive Emissions

C.3.1 Facility-level average emission factors

To use an average facility-level emission factor approach, a project developer would need only to apply the correct emission factor to facility throughput or major equipment counts. Facility-level emission factors are presented in the API Compendium as Table 6-2. For the transmission and distribution sector, they are based on miles of pipeline.

The use of facility-level emission factors lacks the granularity needed for quantifying emissions reductions at an equipment or emission source level. For example, the precision of the API emission factors, when available, range from 62.7 to 113 percent (based on a 95 percent confidence interval). These factors are better suited for facility GHG inventory development than for quantifying project-specific emission reductions.

AGA's document noted the following difficulties associated with the application of facility-level emission factors.

- AGA's Tier 1 emission factors are based solely on pipeline length. Omitting the many other factors that will impact fugitive emissions from distribution sector projects, such as component counts, will result in unsatisfactory emission reduction estimates.
- AGA's Tier 2 emission factors were developed from a weighted average of emissions from the M&R stations.
- The fraction of plastic pipeline transmission systems has greatly increased since the EPA/GRI study. Many high-bleed devices have been replaced with low- or no-bleed pneumatic devices since EPA/GRI study.

- The average number of components per station and other parameters that were representative of the industry during the EPA/GRI study are no longer representative.
- Leak detection and repair practices have modernized since the EPA/GRI study.
- Simple, pipeline-length-based emission factors have large associated uncertainty.
- Although lost and unaccounted for (LAUF) data is typically readily available, meter accuracy and the relatively small volume of fugitives compared to overall facility throughput limit its use.

The above discussion supports the conclusion that average emissions factors should not be used to quantify the benefits of reduction. If equipment replacement with low-leak or no-leak components is involved in a project, the new equipment would not be accurately described by the leak rates built into the average emission factors. Direct measurement of leak rates and CH_4 concentration in the leaked gas is the most accurate approach for quantifying fugitive emissions.

C.3.2 Equipment-level average emission factors

This approach estimates fugitive emissions based on the population of major equipment at a facility (e.g., compressor stations). It is slightly more accurate than the facility-level approach. The emission factors discussed in this section derive from extensive component monitoring and emission measurement data. These data were aggregated with activity factors that characterized the number of each minor component per major equipment system. For example, in the transmission sector, the emission factor could be in terms of CH_4 emissions per compressor station.

The following points discuss the calculation methodology for these emission factors and limitations in calculations with these factors.

- Customer meters include the meter and associated piping and fittings. AGA notes that leaks typically occur at the valve, the regulator and inlet/outlet pipe connectors.
- Pipeline emission factors for distribution mains and services were developed from leak rate and frequency data as determined in the 1996 GRI/EPA study. Pipeline emission factors do not reflect differences between protected and unprotected steel and are applied to all non-cathodically protected steel pipeline.
- Table 5-4 in the AGA document presents M&R station emission factors. In general, emission factors increase with station inlet pressure. Vault stations are enclosed and regulators in these stations are no-bleed to limit explosion risks. The AGA document reminds that these factors include pneumatic control loops and isolation valve *vented* emissions, which results in conservative emissions estimates. The downside of using conservative emissions estimates for a Reserve project is that emissions reductions may be overestimated.

The precision of equipment-level emission factors in API Compendium range from 20.6 percent for residential meters to 1500 percent for meter and regulation stations. Most precision values fall between 50 and 150 percent based on a 95 percent confidence interval from the data used to develop the original emission factor.

Considering the large uncertainties associated with equipment-level emission factors, their conservative nature which leads to over prediction of project emissions reductions, and their reliance on data that does not well reflect current industry practice, these types of emission factors are not appropriate to quantify project-level emissions.

C.3.3 Component-level average emission factors

This approach is based on the number of fugitive components in an NGTD facility. These emission factors have been developed for specific component types such as ball/plug valves, pressure relief valves, and open-ended lines. Although this approach provides more accurate estimates than the previous two approaches, the uncertainties associated with these emission factors remain high. The lowest uncertainty (±19%) is associated with the emission factor for connectors in the transmission sector. Table C.3 lists the tables in the API Compendium that contain emission factors relevant the NGTD sectors and the range of uncertainty values in each table.

Table C.3 API Compendium Tables Containing Component-Level Emission Factors Relevant to the NGTD Sector

Table	Lowest Precision Value	Highest Precision Value
6-17. Natural Gas Transmission Compressor Station Component Emission Factors	±33%	±167%
6-18. Natural Gas Transmission and Storage Average Emission Factors	±19%	±127%
6-19. Natural Gas Distribution Meter/Regulator Stations Average Emission Factors	±53.0%	±162%
6-20. Natural Gas Distribution Commercial and Residential Sites Average Emission Factors	±48.3%	±200%

Even for the component-level emission factors, the uncertainties exceed the materiality expectations of emission reduction quantification.

C.3.4 Other Emission Estimation Approaches

AGA provides several possible methods of increasing emission factor reliability. One is to *selectively* incorporate field data for significant equipment with Tier 3 estimates, which are based on process operation or equipment-level information at a site. (See Appendix D for a further discussion of emission factor tiers.) This approach is most applicable for large projects that would involve many components and equipment. Significant equipment could either be defined as certain equipment types (AGA suggests compressor seals and vents, fuel gas systems and scrubbers, gas-operated starters) or equipment that leaks more than a threshold rate as identified by direct measurements. Alternatively, specific leak rate data for *all* fugitive sources could be determined and used to develop equipment-specific emission factors, as described above. Developing these factors and using them in a system in which they are representative of the remaining elements in the system in terms of age, operating characteristics, design, and other factors would result in less uncertainty than using generic Tier 3 factors. These types of emission factors may become inaccurate after a certain period after their development because the equipment that was used as the data source for their development will age and change. To evaluate emissions ex-post, however, it would be possible to use this approach given that no significant system changes occurred since the development of the factors.