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August 2, 2016

U.S. Environmental Protection Agency
Attn: Ms. Brenda Shine
Sector Policies and Programs Division, Refining and Chemicals Group
Office of Air Quality Planning and Standards (OAQPS)
Research Triangle Park, NC 27711

Re: AGA’s Comments on EPA’s Proposed Information Collection Request for Oil and Gas Facilities, 81 Fed. Reg. 35763 (June 3, 2016)

Dear Ms. Shine:

The American Gas Association (AGA) appreciates the opportunity to comment on EPA’s Proposed Information Collection Request (proposed ICR) for oil and natural gas facilities noticed in the Federal Register on June 3, 2016. We are responding to EPA’s request for comments on specific aspects of the proposed ICR as described in the referenced Federal Register notice and supporting documents in Docket ID No. EPA-HQ-OAR-2016-0204, including EPA’s Supporting Statement for Public Comment dated May 12, 2016, the draft worksheets, the updated Attachment 2 with “picklist assignments,” and EPA’s June 30, 2016 memo listing “picklist values” for answering the questionnaire worksheets for natural gas facilities.

The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 72 million residential, commercial and industrial natural gas customers in the U.S., of which 95% – just under 69 million customers – receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas
companies and industry associates. Today, natural gas meets more than one-fourth of the United States’ energy needs.

AGA and our members have devoted significant resources over the years to obtain better natural gas emissions data and to modernize systems and practices to improve both safety and environmental performance. We were founding partners 20 years ago in EPA’s voluntary Natural Gas STAR program, and our members have participated over the past two decades, sharing technologies and innovations for improving the environmental performance of natural gas systems. AGA’s Board of Directors has adopted a Commitment to Enhancing Safety,\(^1\) and has approved voluntary AGA guidelines for reducing natural gas emissions.\(^2\) As a result of our members’ commitment to safety and efforts to modernize their distribution infrastructure, the recent updated EPA Inventory of Greenhouse Gas Emissions issued April 15, 2016 shows that emissions from natural gas distribution have dropped an impressive 74 percent since 1990, even as the industry added over 300,000 miles of distribution mains to serve 17 million more customers, an increase of 30 percent in both cases.\(^3\) Similarly, our members have helped reduce emissions from natural gas transmission pipelines and compression. EPA’s recent GHG Inventory demonstrates that these efforts to modernize and upgrade facilities has helped reduce emissions from transmission and storage by 45 between 1990 and 2014.\(^4\) AGA members also showed up in force to support the launch of EPA’s new voluntary Methane Challenge program in March 2016.\(^5\) All 41 companies that volunteered as Founding Partners are AGA members, and more of our members plan to join later this year. In addition, AGA and its members have supported and participated in peer-reviewed scientific research studies to collect field measurement data on natural gas emissions – including the Lamb, Washington State University (WSU) multi-city distribution study (2015) and the Zimmerle, Colorado State University (CSU) transmission and storage study (2015). AGA and several members are also participating in an ongoing U.S. DOE NETL study comparing and reconciling top-down atmospheric and bottom-up facility methane measurements across the natural gas value chain (production through distribution) based on measurements taken in the same place during the same time period.

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4. Id.
5. See EPA Methane Challenge web site, [https://www3.epa.gov/gasstar/methanechallenge/](https://www3.epa.gov/gasstar/methanechallenge/).
In light of this track record for emission reductions, particularly by gas utilities, EPA excluded gas utility facilities downstream of the local distribution company (LDC) custody transfer station – such as distribution system facilities, natural gas transmission and compression, underground storage, LNG peak shaving storage facilities and other facilities inside that point – from the scope of natural gas facilities subject to the recent GHG new source performance standards (NSPS) under 40 C.F.R. Part 60, Subpart OOOOa and Clean Air Act §111(b). This means that any existing source performance standard (ESPS) under Clean Air Act §111(d) for natural gas facilities would also exclude gas utility facilities located downstream of the LDC custody transfer station. The proposed ICR is intended to obtain data to help EPA develop a proposed ESPS for natural gas facilities, but we understand that EPA proposes to collect data from some facilities that will not be subject to the ESPS. For example, EPA plans to send the ICR to 100% of the liquefied natural gas (LNG) peak shaving storage facilities, even though almost all such facilities are located downstream of the LDC custody transfer station and will thus be exempt from the ESPS. AGA estimates only 2-4 LNG storage facilities are located upstream of the LDC custody transfer station and will potentially be subject to the upcoming ESPS. We question the need to burden 96 otherwise exempt facilities with an extensive data request in order to design regulations to cover approximately 4 facilities that may be subject to the upcoming ESPS. Nevertheless, if EPA can show that this is truly necessary to obtain a ‘statistically valid sample’ that will have practical utility in developing the ESPS, and can take the steps we suggest in these comments to reduce the data collection burdens, our members are willing to assist in collecting data from otherwise exempt facilities in order to support data driven decisions. Given the stringent federal pipeline safety controls at such facilities, we also anticipate that the agency will find that emission rates are extremely low and likely do not warrant additional federal regulation to minimize natural gas emissions.

AGA is committed to supporting fact-based policy decisions, and thus we support the agency’s overall goal of collecting good quality data to guide its regulatory decisions. However, some of the information EPA is proposing to collect (1) would impose unnecessary burdens, (2) would require far more time and labor costs than EPA estimates, particularly in the timeframe EPA proposes, and (3) would have no practical utility for EPA’s regulatory purposes. AGA believes the alternatives we suggest will better serve EPA’s goals while imposing less burden and cost on facility operators.

1. **EPA Should Allow At Least Through the End of June 2017 for ICR Response**

Winter months are the busiest time of year for natural gas utilities, pipelines and storage facilities, due to peak demand during the winter heating season. The first quarter of every year is also when environmental reporting personnel must collect data to report on all environmental media – including their Subpart W GHG reports that are due by the end of March. And yet, that is precisely when EPA plans to ask our members to respond to a very detailed questionnaire, and
send employees or contractors out in the field to count components and conduct tank sampling. The proposed schedule calls for EPA to send the ICR questionnaires to facility operators at the end of October and to require responses within 120 days – i.e. EPA is asking natural gas utilities and transmission pipeline companies to collect all the data and submit their completed ICR worksheets during November, December, January and February – during the holidays, the winter peak demand season and the first quarter environmental reporting crunch period. Companies are already stretched during this time of year. Our members say they would most likely have to hire outside contractors to perform the ICR work, as the company personnel are already more than fully occupied - especially during that time of year. It takes time to draft contracts, obtain legal review and get contracts in place, which would further reduce the time available to perform the ICR work. This would also increase costs, particularly if many operators are trying to hire the same limited pool of expert contractors at the same time. Moreover, even if the outside contractors have the requisite professional expertise, they will not be as familiar with company facilities and operations as internal personnel. So, EPA’s proposed schedule could also result in a greater error rate in the data unless internal personnel are allowed time to better review and guide the contractors’ work.

In addition, EPA’s proposed 120 day schedule (November through February) will largely preclude the opportunity to use Subpart W data for 2016 – particularly data that will be reported for the first time by March 31, 2017 – including for example, transmission pipeline blowdowns, and emissions data from the gathering and boosting segment. Adjusting the schedule will allow operators to use this new Subpart W data.

There is no need to impose such an artificial time crunch, unnecessarily driving up costs and reducing data quality. Simply extending the ICR response from early November 2016 through the end of June 2017 – would allow facility operators to use Subpart W data, spread out the required work, and use more internal personnel (once they are freed up from the winter peak operational tasks and first quarter reporting deadlines). This would also help address safety concerns by allowing operators to avoid sending personnel out during the cold and icy conditions of winter to count and assess equipment that would otherwise remain untouched. To the extent contractors are needed, the longer time frame would make it easier and less costly to obtain outside assistance. AGA therefore urges EPA to allow from November 2016 through June 30, 2017 to respond to the ICR.

2. EPA Underestimates Time and Costs for Responding to the ICR

In Attachment 3B to the Supporting Statement, EPA estimates the “Industry Burden and Cost for Responding to the Part 2 Questionnaire” based on the estimated number of hours EPA believes would be required to perform the required tasks by an engineer, operator, manager and/or clerical worker. Rates for an engineer are estimated to be $148.95 per hour, while the cost for an operator are estimated to be $65.10 per hour. EPA estimates each task would take approximately 1-6 hours per equipment type worksheet per facility ICR.
In contrast, our member company environmental engineers evaluated the tasks called for in Part 2 and estimated that it would require 2 to 60 hours depending on the type of facility and information requested. These estimates consist primarily of engineering time, with an estimated average total number of hours of 70 hours per facility ICR, as summarized in the following table.

<table>
<thead>
<tr>
<th>Section</th>
<th>Equipment Type</th>
<th>Hours</th>
<th>Comments - Tasks per Facility</th>
</tr>
</thead>
<tbody>
<tr>
<td>2F*</td>
<td>Storage Tank Separators</td>
<td>5-50</td>
<td>See AGA Comments below on Tanks / Separators</td>
</tr>
<tr>
<td>2G</td>
<td>Pneumatic Devices</td>
<td>10-40</td>
<td>Inventory and classify each device under the respective pneumatic device categories; this estimate could vary widely since the device categories are not the same as those specified in Subpart W under the GHGRP</td>
</tr>
<tr>
<td>2I</td>
<td>Dehydrators</td>
<td>2-8</td>
<td>Most information should be available from Glycalc and other process simulation software used for permitting</td>
</tr>
<tr>
<td>2J</td>
<td>Equipment Leaks</td>
<td>1-16</td>
<td>Hours may vary widely dependent on the existence of an internal program/procedure which already tracks as a result of other regulations such as Subpart W under the GHGRP; LNG storage facilities under Subpart W threshold would have to review leak logs to attempt to quantify</td>
</tr>
<tr>
<td>2J</td>
<td>Component Counts</td>
<td>34-60</td>
<td>Operators will either conduct their own counts or accompany contractor to conduct count; number of components and burden related to size and type of facility</td>
</tr>
<tr>
<td>2K</td>
<td>Compressors</td>
<td>5-16</td>
<td>Majority of time consumed will be looking for the rod-packing and wet seal replacement information for the individual compressors</td>
</tr>
<tr>
<td>2L</td>
<td>Blowdowns</td>
<td>12-40</td>
<td>Hours may vary widely depending on the existence of an internal program/procedure which already tracks blowdowns as a result of other regulations (i.e. GHGRP, if applicable); Review logs, maintenance tasks; quantify blowdowns.</td>
</tr>
<tr>
<td>2M</td>
<td>Control Devices</td>
<td>2-60</td>
<td>Hours may vary widely depending on the age and data availability of the specified control device in place at the natural gas facility</td>
</tr>
</tbody>
</table>

*Note: EPA’s Attachment 3B erroneously refers to the storage tanks/separators worksheet collection activity as “2C.” This a confusing but probably inadvertent error. The EPA burden and cost table would be less confusing if it referred to the actual worksheet section number for tanks and separators – 2F.

The above table includes estimates of actual hours that are based on ranges estimated for AGA member facilities. AGA believes these burdens could be reduced or at least the cost could
be reduced by allowing more time and by reducing the scope of requested information as we suggest in these comments.

### 3. Eliminate Requirement to Count Total Number of Components

EPA should eliminate the requirement in the equipment leak questionnaire worksheet 2J to count the total number of components at a natural gas facility that come into contact with 5% or more methane by weight, and the total number of components monitored for leaks in the most recent monitoring survey. Pipeline quality natural gas is 95% or more methane, so this requirement in effect requires counting all the thousands of components at a natural gas transmission compressor station, natural gas transmission line, underground storage facility, LNG peak shaving storage facility, or LNG import/export terminal, even if none of them are leaking. This information is not currently available, and collecting it would be a seriously unnecessary waste of time and money. EPA provides no explanation why the agency needs to know the total number of components at a facility or why this could possibly have any practical utility for developing regulations to monitor and reduce methane emissions at existing natural gas facilities. A similar proposed requirement to count components was dropped from EPA’s Subpart OOOOa methane NSPS.

Although a detailed list of components might provide a large data base on which the agency could perform a statistical review to estimate emissions, this data would have no practical utility without an extensive campaign to quantify the amount of emissions (if any) from each component. Further, it is questionable how useful such a massive undertaking would be, given that components are upgraded, repaired and replaced on a regular basis--not only to reduce or avoid gas loss, but also for planned maintenance, improved operation or system upgrades.

If EPA wishes to have a measure of the size of a facility in relation to its number of leaking components or level of emissions, there are less burdensome alternatives using data readily available in a company’s records, such as asking for the volume of natural gas throughput at the facility or storage capacity or amount of natural gas actually stored in a given year. We would be happy to work with EPA to develop alternatives that work for both operators and EPA.

### 4. AGA Supports Requesting Information on Routine Inspections, with Minor Revisions

AGA does not object to the request in worksheet 2J asking whether the operator conducts routine inspections at a given facility, and if so, the inspection frequency and monitoring method used. However, we have a few suggestions to improve this portion of the ICR. Pick list 38 (monitoring method) should allow an operator to pick more than one method, as sometimes more than one method can be used to detect and/or measure methane emissions. Hi-Flow equipment should be added to pick list 38, as this is sometimes used to measure flow rate of a detected leak. EPA should also retain the option to pick “other” and allow the operator to specify another method. The pick list options for “leak definition” (pick list number 39) are currently
limited to parts per million volume (ppmv) levels from 500 ppmv up to 10,000 ppmv, plus “any visible emissions using OGI.” An option should be added allowing a facility operator to pick 12,500 ppmv if they used a methane detector set to alarm (for safety purposes) at 25% of the lower explosive limit (LEL), which is equivalent to 12,500 ppmv. In case an operator has data based on Hi-Flow measurements, AGA suggests adding a pick list option for cubic feet per second or minute (i.e. a flow rate measured with a Hi-Flow device).

5. **EPA Should Reduce Reporting Burden for Low-Emitting LNG Facilities**

AGA especially urges EPA to eliminate the burdensome total component counts for Liquefied Natural Gas (LNG) facilities, because the burden so far outweighs any practical utility for EPA’s goal of developing existing source performance standards (ESPS) pursuant to Clean Air Act 111(d) for natural gas facilities. First, more than 95% of existing LNG peak shaving storage facilities will be excluded from the source category subject to the ESPS, because they are inside the LDC custody transfer station, and this type of facility (when new or modified) is excluded from the source category subject to the 111(b) NSPS. Second, due to their inherent operations as well as stringent requirements under federal pipeline safety regulations, greenhouse gas emissions from both LNG peak shaving storage facilities and LNG import/export terminals are already extremely low, as we explain below.

a. **LNG Leaks, if any, Are Visible as Small Vapor Clouds and Promptly Fixed**

By their very nature, LNG facilities make it easy to spot and address any leaks promptly. LNG storage facilities and LNG import/export terminals operate at cryogenic temperatures (< -100 degrees Fahrenheit). Leaks are obvious to the naked eye, because a small vapor cloud develops at the point of leakage as the moisture in the air condenses.

b. **Frequent Leak Surveys and Repairs Are Already Required by Federal LNG Rules**

The Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has adopted regulations for LNG facilities under 49 CFR Part 193, section 2013, that are even more stringent than those for transmission lines under Part 192. Natural gas transmission pipeline operators are required under 49 C.F.R. Part 192 Section 706 to perform leak surveys as often as two to four times per calendar year, and section 711 requires transmission operators to make permanent repairs to discovered leaks when feasible. Manned facilities are patrolled at least once per shift during the day, and unmanned satellite facilities that are only used during seasonal peak operations are still patrolled at least twice per month. Personnel conducting these on foot patrols check for visible vapor clouds and use hand-held methane detection devices.

c. **Federal LNG Safety Regulations Require Continuous Fixed Point Gas Detection**

Due to stringent federal safety regulations, LNG facilities are monitored constantly by fixed point gas detection equipment which can set an alarm in the LNG facility control room – in addition to the regular foot patrols described above. PHMSA’s LNG regulations under 49 C.F.R.
Part 193 adopt by reference provisions from the 2001 version of the National Fire Protection Association (NFPA) 59A, Standards for the Production, Storage, and Handling of Liquefied Natural Gas (LNG) to require all LNG facilities (peak shaving storage and vaporization, satellite, and import terminals) to install fixed point leak and flammable gas detection systems, to monitor those fixed point systems continuously, and to repair any leaking or defective component.₆ NFPA 59A is an American National Standards Institute (ANSI) accredited consensus standard developed by the NFPA, subject matter experts, government regulators, industry stakeholders, manufacturers, insurance industry representatives, fire fighters, and the public. The NFPA 59-A Standard is revised and updated every 3-4 years to ensure that it reflects the latest technology and practices, and PHMSA periodically amends 49 C.F.R. §193.2013(g) to adopt provisions added in more recent iterations of NFPA 59-A. Pursuant to this federal regulation, LNG facility operators have installed gas/leak detection equipment that performs continuous monitoring of field conditions and upon detection is required to alarm in the field and at an attended control room at 25% of the lower flammable limit (or lower explosive limit – LEL) of methane. The LEL is 5% methane in air; 1.25% (25% of LEL) or 12,500 ppmv is the required gas detection alarm limit pursuant to the NFPA 59A LNG Standard.

Furthermore, these facilities are required to have trained and qualified operating personnel who monitor the installed detection systems and conduct regular facility inspections several times each day, including process post-cool down field checks to confirm that system integrity has been maintained. Due to notification by the monitoring system to the attended control room, if leakage does occur, operating personnel are alerted immediately and the leak is quickly addressed by adjusting the equipment or stopping the process, thereby avoiding any significant emissions.

d. LNG Valves by Design Have Minimal to No Leakage

Due to the combined conditions of extreme temperature and pressure, valves (gate, ball, butterfly, etc.) in LNG service are typically designed with extended bonnets and utilize multiple rings of V-ring style stem packing, made typically of PTFE (Teflon). This style of packing is very resilient and has high sealing qualities, thereby greatly minimizing if not eliminating fugitive emissions.

e. LNG Safety Relief Devices Minimize or Eliminate Emissions

Due to extreme operating conditions, the majority of safety relief valves in LNG service are soft seated style valves, which greatly minimize or eliminate premature leakage at pressures below the valve opening set point. Additionally, relief valves in the LNG industry in the U.S. are maintained at a very high level of performance, as each relief valve at LNG facilities is required by the federal LNG code, 49 C.F.R § 193.2619, to be inspected and tested annually for lift pressure and positive reseating, which indicates that it operates properly and is not leaking. PHMSA inspects safety valve testing records to confirm that the facility’s annual testing of valves has met the regulatory requirements for test frequency and valve performance.

f. LNG Compression Equipment Differs Internally and is Far Lower Emitting

LNG facilities use reciprocating and centrifugal compressors for a limited number of purposes, which include boil-off compression, and as refrigerant and boost compression in liquefaction processes. Compressors are not used (and not needed) to compress vaporized LNG in order to move natural gas from LNG storage facilities to the distribution send-out system.

From a cursory inspection on the outside, reciprocating compressors at LNG facilities may appear similar to reciprocating compressors more familiar to EPA, such as those located at transmission compressor stations. However, reciprocating compressors at LNG storage facilities are quite different internally, due to the materials utilized to seal piston rod packing to limit leakage past the piston rods. Reciprocating compressors used at LNG facilities for boil-off compression, liquefaction refrigeration compression and liquefaction stream boost generally utilize non-lubricated cylinders and rod packings to eliminate the risk of lubricants being introduced into the process gas stream, causing contamination of the stream with oil residue, which would freeze the oil in critical components such as heat exchangers, operating at temperatures as low as minus 260 degrees Fahrenheit. These non-lubricated applications typically utilize piston ring, and rod packing materials of varying graphite, PTFE (Teflon) blends which are very resilient and have high sealing qualities, thereby greatly minimizing fugitive leak emissions from the compressor rod packing cases.

Centrifugal compressors are typically utilized at LNG facilities as liquefaction process refrigerant compressors. Again, while externally they may resemble typical centrifugal compressors that are becoming more common in gas transmission compressor stations, these centrifugal refrigerant compressors are typically quite different internally with respect to their shaft sealing design, using very sophisticated oil film (wet) sealing or dry elements, which greatly reduce or eliminate leakage. The outer case seal areas and the seal oil drains are directed back to the compressor suction after demisting takes place. Because the outer case seal area and seal drains lead back to the compressor suction, there are no gases purposely vented to the atmosphere.
g. LNG Pump Design Precludes Emissions

The majority of LNG pumps at LNG facilities are not open to the atmosphere, either vertical turbine multistage pumps installed in pump wells submerged within the LNG tank, or pumps for which the motor and the pump are fully enclosed and submerged in LNG in the pump can. These pump types do not require pump shaft seals and are not open to the atmosphere, so they generate no fugitive emissions. For those facilities utilizing LNG pumps with external motors not enclosed within the pump can, and with pump shaft sealing, the seals are closely monitored, and if leakage were to occur, the pump would be shut down and repairs to the seal performed. Due to the level of redundancy of systems and equipment, LNG facilities are generally equipped with a number of spare pumps, allowing shutdown of any pump experiencing a seal failure, while maintaining facility operations.

h. Based on LNG Design and Safety Regulations, EPA should Reduce ICR Burdens at LNG Facilities

In light of these design differences and the overlapping, stringent LNG monitoring and repair requirements under federal pipeline safety regulations, there does not seem to be any practical utility in collecting such extensive data from over 90 LNG facilities that will not even be subject to the ESPS, to develop emission standards for the few remaining LNG facilities outside the LDC custody transfer station — particularly since it is unlikely any such ESPS would result in any significant emission reductions beyond those already achieved through stringent LNG design standards and federal pipeline safety regulations. Given the heavy resource burdens for sending personnel to count all equipment components in all LNG facilities, and the low practical utility of the resulting data for developing an ESPS for the few LNG facilities outside the LNG custody transfer station, AGA urges EPA at a minimum to eliminate from the ICR any requirement to count total components at a facility or the number of components monitored.

6. EPA Should Reduce the Burden for Sampling Tanks with Separators

In worksheet 2F (“Tanks Separators”) question 4 (rows 73 – 75), EPA proposes to ask facility operators to provide “direct measurement data for each atmospheric tank and for each separator for which the separated gas is not recovered for sales.” This appears to call for information about tanks and separators at production well sites only, but the worksheet is not clear on this issue. We ask EPA to clarify what types of facilities would be expected to respond to worksheet 2F, and recommend that this worksheet be limited to upstream tanks in production operations. In transmission and storage facilities downstream of gas processing, natural gas is pipeline quality, the potential emissions from tanks with separators are insignificant, and sampling is not warranted.

Worksheet 2F question 4 asks for data “in hand” if an operator has already performed testing of the “feed material composition using the California Environmental Protection Agency Air Resources Board’s Test Procedure for Determining Annual Flash Emission Rate of Methane
from Crude Oil, Condensate, and Produced Water (CARB Method) within the last 12 months.” If the facility operator has not done so, then the draft ICR worksheet 2F states that the operator “must sample and analyze the tank/separator feed material according to the CARB Method and report the results of the test” in the table provided.

One of our members that has operations across the value chain, including production, reports that some of their tanks and separators are not equipped to be sampled. To comply with worksheet 2F, they would have to install a sampling port which would require a number of resources including, engineering for design, contractors to x-ray the vessel, contract welders, natural gas loss (i.e. emissions) from the blowdown, and the internal resources to isolate the system and bring it back online. All told, the costs to install a port are estimated to be at least $5,000 per separator. Based on information obtained by one of the few vendors across the country that perform flash gas sampling and analyses, our member estimates the minimum cost for performing the lab analysis at $1,700 and the cost of a technician to obtain the sample at $2,000. A single sample could cost anywhere between $3,700 and $8,700. Since there is no way to predict how many ICR’s (for how many facilities) the company will receive, it is difficult to predict the total costs. However, the total cost could easily exceed $100,000 for sampling alone. With many of the associated separators and tanks located after initial gas separation and processing steps (i.e., after gas flashing occurs), a significant portion of these costs would be associated with insignificant emission sources. While EPA may be concerned that data is not in hand to document insignificant emissions in downstream operations, a basic understanding of the processes associated with the natural gas value chain can inform this question. AGA can provide additional background and descriptions if needed.

These costs clearly exceed EPA’s cost estimate of for tank feed sampling, found in Attachment 3B to EPA’s Supporting Statement for Comment regarding “Industry Burden and Cost for Responding to the Part 2 Questionnaire.” The EPA costs from rows 3C and 4 in Attachment 3B indicate $1,000 for each sample analysis and labor costs of about $477 per facility. The example above indicates higher sample analysis costs ($1,700 versus EPA’s estimate of $1,000 per sample) plus related labor and sample preparation costs about an order of magnitude higher than EPA’s estimate.

We submit that there is a less burdensome and less costly alternative that would still give EPA a statistically valid sample. First, AGA urges EPA to eliminate the requirement to sample tanks located downstream of initial separators associated with natural gas production. Second, if sampling is retained for other downstream facilities, AGA urges EPA to eliminate the requirement to sample tanks that are not already equipped to be sampled. Third, AGA urges EPA to require that no more than 25% of the facilities that receive an ICR should be required to complete Attachment 2F question 4 regarding Feed Material Composition.
7. **Company Data Subject to Non-Disclosure Agreement in Academic Studies should be Protected as Confidential Business Information (CBI)**

Several AGA members provided access to their facilities to academic researchers for peer-reviewed scientific studies, for example for the Lamb WSU distribution study and the Zimmerle CSU study. The data was subject to strict non-disclosure agreements (NDAs) and was made available in journal publications and supplemental information only in aggregated form that did not identify specific locations. To the extent that a company has company-specific data collected in such studies, our members would require that the data be protected as Confidential Business Information (CBI). Any requirement to disclose such data without CBI protection would place a serious and debilitating barrier to future participation in academic research, which would not serve EPA’s goal for obtaining reliable data for data-driven regulatory decisions on methane emissions. AGA urges EPA to make provision to protect such data as CBI.

8. **EPA Should Send ICR Letter to the e-GGRT Designated Representative**

It is not clear from EPA’s proposal where the agency plans to mail ICR letters. We agree with the Interstate Natural Gas Association of America (INGAA) that the ICR letters should not be mailed to individual facility locations – such as individual LNG facilities or transmission compression stations. Environmental compliance and reporting staff are typically located at corporate or subsidiary headquarters, not at individual field locations. To ensure that these letters do not go astray, particularly at unmanned facilities, EPA should mail or email each ICR letter to the appropriate company e-GGRT Designated Representative for the company that operates the facility targeted by the ICR. This will increase the probability of a high response rate to the ICR letters.

9. **ICR definitions Should be Consistent with Methane NSPS and GHGRP**

In several instances, EPA has used terms that are either not defined or are defined in a manner that conflicts with the definitions EPA has used in the GHGRP regulations and/or the methane NSPS final rule, 40 C.F.R. Part 60, Subpart OOOOa. This makes it difficult or impossible to use data already gathered and logged following other established EPA GHG definitions. Obviously, this would result in unnecessarily increasing costs and burdens for responding to the Part 2 survey. To reduce the burdens of this ICR, AGA urges EPA to provide clear definitions for all key terms that align with GHGRP definitions if available, or if not, then with definitions used in the OOOOa NSPS. This will allow operators to use available data as much as possible to respond to the ICR. Clear definitions that set clear boundaries regarding what is in and what is excluded from a source or type of equipment will also help save time, as operators will not have to waste time trying to decipher the meaning of undefined or otherwise ambiguous terms. For example, EPA’s proposed ICR adds several new categories of definitions for pneumatic devices. That is a minimal emissions source for transmission and storage operations (based on data from the 2011 – 2014 Subpart W reports) and will add significant burden. At most, the ICR should
request counts for the three pneumatic device categories already listed and defined in Subpart W.

10. **Blowdown Reporting Should Apply Only to “Natural Gas Transmission Pipeline Facilities”**

The “boundary” for the “natural gas transmission pipeline facilities” is unclear. If pneumatic device and equipment leak ICR worksheets also apply to transmission pipeline facilities that include ancillary equipment such as metering or pressure regulating equipment located along a pipeline, it would become exorbitantly costly to gather that pneumatic device and equipment leak data for 10’s of thousands of pipeline miles. EPA should clarify that the pneumatic device and equipment leak worksheets do not need to be completed for transmission pipelines.

11. **EPA Should Clarify and Revise the Data Elements in the Part 2 Survey to Reduce Burdens**

Many of our member companies may receive multiple Part 2 surveys, magnifying their reporting burdens. AGA agrees with the comments filed by INGAA at pages 10-11 and the detailed analysis in INGAA’s Attachment 2. In order to reduce the ICR burdens, EPA should take care to ensure that each requested data element is truly needed, cannot be obtained from another source such as the March 2017 GHGRP reports, has practical utility to guide ESPS development, and is clearly defined and explained.

AGA appreciates the opportunity to comment. Please contact me if you have any questions.

Respectfully Submitted,

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