March 4, 2011

Office of Information and Regulatory Affairs
Office of Management and Budget
Attention: Desk Officer for EPA
725 17th Street, NW
Washington, DC 20503

EPA Docket Center (EPA/DC)
Environmental Protection Agency
Mail code 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
a-and-r-docket@epa.gov

Attn:  Docket ID: EPA-HQ-OAR-2010-0682

To Whom It May Concern:

On February 2, 2011 at 76 Fed. Reg. 5804, EPA requested comment on a proposed information collection request (ICR) entitled Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; NSPS and NESHAP for Petroleum Refinery Sector Residual Risk and Technology Review (RTR) (New Collection); EPA ICR No. 2411.01, OMB Control No. 2060–NEW. The American Petroleum Institute (API) and the National Petrochemical and Refiners Association (NPRA) submit these comments on that proposed ICR. Our members own and operate the petroleum refineries that will be required to respond to the ICR, so we have a particular interest in assuring that the ICR is focused on efficiently gathering only those data that EPA reasonably needs to support near-term policy and regulatory decisions.

The Agency’s authority to require the submission of information is carefully constrained under the law. For example, although section 114 of the Clean Air Act (CAA) provides EPA with information gathering authority, EPA’s information collection efforts under section 114 must be reasonable and, in this case, firmly anchored to reasonably foreseeable policy or regulatory needs. Similarly, sections 3506(c)(2)(A)-(C) of the Paperwork Reduction Act (PRA) require that the information has practical utility; (2) is not unnecessarily duplicative of information otherwise reasonably accessible to the agency; and (3) reduces to the extent practicable and appropriate the burden on persons who shall provide information to or for the agency. Each of these requirements is violated by particular requirements in the proposed ICR.
The regulatory need for all of the ICR information is driven by EPA’s intent to review and amend most regulations applicable to refineries and to add new greenhouse gas requirements. President Obama’s recent Executive Order 13563 requires that regulations only be proposed upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify) and that the proposing Agency must identify and use the best, most innovative, and least burdensome tools for achieving regulatory ends. We do not believe such a reasoned determination has been made relative to all of the regulations being developed by the Agency for regulating refineries and that this ICR effort clearly is not the least burdensome approach to addressing any needed revisions to refinery rules. The ICR should be delayed until the reasoned determinations for the proposed set of regulations are completed and the ICR should then be adjusted to reflect any limitations in the rulemakings resulting from those determinations.

As discussed in Attachment 1, the proposed ICR should not be approved by OMB or must be significantly revised and focused to be justifiable under section 114 and to meet the Agency’s obligations under the PRA. In essence, EPA is asking the refining industry to spend significantly more than $70 million dollars to collect data for them that, by their own admission, will not be available in sufficient time for them to use in developing the proposals that they cite as the basis for requesting the data. This is unreasonable and violates the intent of the PRA and the recent executive order on improving regulation. EPA and OMB should focus on the lessons taught by the recent Boiler and Process Heater MACT and Mandatory Greenhouse Gas Reporting rules: that rushing through the collection, tabulation, and analysis of complex, extensive data collected through ICRs is ill-advised and leads to problematic rulemaking and extensive and wasteful rework. Either the ICR should be reduced to only the data that can be properly evaluated in the time EPA’s compressed rulemaking schedule allows before proposal, or the schedule for the proposals should be delayed to allow thoughtful and complete analysis of the immense quantity of data that is being collected. In Attachment 2, we provide specific comments on the ICR draft to identify questions and clarifications that remain to be resolved to minimize confusion and increase the likelihood that the responses will be consistent and useful.

If you have any questions, please contact Matt Todd at (202) 682-8319.

Sincerely,

/s/ Matthew Todd       /s/ David Friedman

Matthew Todd          David Friedman
API                  NPRA
Input@api.org       dfriedman@npra.org
(202) 682-8319       (202) 552-8461
cc Ms. Brenda Shine  
Sector Policies and Programs Division (E143–01)  
Office of Air Quality Planning and Standards  
Environmental Protection Agency  
Research Triangle Park, NC 27711  
shine.brenda@epa.gov
Attachment 1

American Petroleum Institute (API)
And
National Petrochemical and Refiners Association (NPRA)

Detailed Comments to the
Office of Management and Budget
On the Need for and Burden Associated with the
Draft Refinery Information Collection Request

EPA ICR No. 2411.01, OMB Control No. 2060–NEW

Docket ID: EPA-HQ-OAR-2010-0682
OMB should not approve this massive information request\(^1\) because:

1) most of the requested information is already available to EPA under existing Paperwork Reduction Act (PRA) authorizations or from other government sources;
2) much of the information will not be of “practical utility” for the rulemakings cited by EPA;
3) the resources and costs are significantly underestimated and not accurately reflected in the supporting statement; and
4) the policy implications of changing EPA’s historical approach to data collection have not been adequately addressed.

1) EPA already has or can obtain much of the information proposed for collection from delegated authorities under existing approvals. It would be far more efficient for EPA to develop methods to gather and manage that information than to require refiners to submit duplicate information.

a. The combustion and energy portions of the draft ICR should be disallowed since EPA has or is collecting extensive data on combustion sources and emissions, including GHG emissions. OMB should not approve the gathering of refinery combustion and energy information in this ICR or information to support a repetitious review of NSPS J/Ja.

Components 1 and 2 of the draft ICR request extensive and detailed data on combustion sources in refineries and on refinery energy production and use. However, EPA already has or is collecting under other information collection requests extensive data on combustion sources. Except for NSPS J/Ja, combustion sources are not regulated by any of the regulations mentioned by EPA in justifying this data collection in the supporting statement or Federal Register notice. Rather such sources are addressed in combustion-specific rules in both parts 60 and 63, and in particular, combustion efficiency is addressed in the just promulgated Boiler and Process Heater (BPH) MACT, which requires annual tune-ups of refinery units and comprehensive energy audits of refineries. Relative to NSPS J/Ja, EPA recently completed a review of NSPS J and, as a result, promulgated amendments and the new NSPS Ja standard\(^2\). Gathering new data for another general NSPS J review would have no “practical utility” and thus is not allowed by the PRA. The outstanding questions relative to those NSPSs are around the flare requirements, the NOx limits for process heaters during turndown operation, and the possible regulation of Greenhouse Gases (GHG) from refinery sources. None of these three items justify the extensive data collection in the draft ICR. EPA already gathered the data needed for addressing these issues during the NSPS J/Ja rulemaking and/or is gathering GHG information under the GHG Reporting rule. Information on combustion sources in general, including refinery combustion

\(^1\) Attachment 3 summarizes, at a high level what is being requested.
\(^2\) 73 Fed. Reg. 35838 (June 24, 2008)
sources, has been gathered under the extensive BPH MACT ICR effort\(^\text{3}\) and as part of the recent rulemakings applying to turbines and engines.\(^\text{4}\) The recently promulgated BPH MACT is applicable to boilers and process heaters at refineries and thus we do not see why the extensive data requested by EPA in this ICR is necessary. It is also important to note that EPA’s analysis supporting the Boiler and Process Heater MACT rulemaking shows that for gas-fired boilers and process heaters (which comprise the vast majority of refinery units, (1) there are no health benefits to be obtained from additional control of HAPs and (2) there are no health benefits to be obtained from reductions of particulate matter (estimated by EPA at no more than 200 pounds per year).

Component 1 requires extensive information on energy use at the site, including detailed information on steam production and consumption and boiler and process heater energy efficiency steps. In responding to our earlier comments that gathering this information is not justified, EPA states “Process information for GHG emissions is not being reported in the MRR for 2010; Energy management is important for GHG rules.” However, EPA just finalized comprehensive facility energy management requirements in the BPH MACT rule that addresses all energy production and consumption in a refinery. Thus, there is no justification for gathering any data related to boilers or process heaters or facility energy production or consumption. Under the final BPH MACT rule refineries must have an energy assessment performed, identify potential reduction steps, and submit the results to EPA or the delegated authority. In light of those comprehensive requirements, it is hard to see how gathering the detailed energy process information required here will have any “practical utility” in future refinery GHG regulations.

b. OMB should not approve data collection associated with 40 CFR part 63 subpart CC, since the risk and technology review of that subpart has already been met. EPA completed a refinery risk and technology assessment in 2009. EPA has not justified discarding that analysis which was found by the Administrator to be adequate, but even if the analysis is discarded, there is no basis for discarding the database that underlies that effort.

In attempting to justify discarding its previous eight years of effort on subpart CC, the Agency states in the ICR supporting statement “Preliminary risk analysis results for the petroleum refinery sector (based on the 2005 NATA NEI data sets) indicate that some refineries are projected to present risks above the thresholds for further consideration under the residual risk process;” while that statement is true, it is incomplete. It fails to report that in the recently completed subpart CC analysis, no refineries were concluded by EPA to pose risks that exceed the one-in-100 million criterion for requiring further action and that the Agency has already concluded that with the addition of a cooling tower monitoring and repair work practice and

\(^\text{3}\) In July 2008, the EPA issued a survey, entitled “Information Collection Effort for Facilities with Combustion Units (ICR No. 2286.01).” This ICR was distributed to 3,396 facilities with boilers and process heaters firing any fuel type and other combustion units firing non-fossil solids. In May 2009, the EPA issued a follow-up ICR (ICR No 2286.03) requesting a subset of these facilities to conduct stack testing to fill data gaps.

some requirements for additional storage vessels fittings, that the public is appropriately protected. In its unpublished but signed Jan 2009 final rule preamble, EPA concluded:

“Since the estimated maximum individual cancer risk for the source category is less than 100-in-1 million, and since chronic noncancer risks, multipathway risks, and environmental risks were determined to be negligible, we conclude from this risk assessment that the risks associated with the Refinery MACT 1 source category are acceptable. We recognize that we cannot completely rule out the potential for acute exposures above the AEGL-1 for hydrofluoric acid and the REL for benzene; however, we conclude that risks associated with the Refinery MACT 1 source category are acceptable on the basis that our assessment of such potential impacts is based on a conservative exposure scenario (particularly regarding the simultaneous occurrence of worst-case meteorological conditions and peak emission conditions) and other conservative screening assumptions (particularly regarding the potential for fugitive hydrogen fluoride emissions to peak dramatically in the short-term) and since it identifies only a limited number of facilities and potentially impacted people.5”

Thus, it is clear that the CAA requirement for “further consideration under the residual risk process” mentioned in the supporting statement for this ICR has been met, regardless of whether the results of that analysis are withdrawn or not. Repeating that effort will involve a massive use of EPA and industry resources (starting with this ICR) that can, and should, be directed to more pressing regulatory needs. Effectively calling a “mulligan” on the 2009 subpart CC residual risk and technology rule is particularly difficult to understand given that the Agency has provided no reason why this additional effort will result in any additional risk reduction.

Collecting new information on subpart CC sources on the grounds that it is needed to review a regulation that has recently been reviewed does not have “practical utility” to the Agency and thus does not meet PRA requirements.

EPA has not taken final action on its proposal to withdraw its previous subpart CC actions under CAA 112(d)(6) and (f). Thus, they certainly have no authority to gather information to repeat those reviews or to review their final conclusion that no further action is necessary. However, even if they finalize the proposed withdrawal that does not change the Administrator’s previous conclusion that they already have adequate data for evaluating this source category under the (d)(6) and (f) provisions. Therefore, there is no “practical utility” to gathering additional information and those portions of the draft ICR cannot be approved under the provisions of the PRA.

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5 Page 34 of final rule signed by Administrator Johnson, January 16, 2009 and proposed for withdrawal by EPA (but never withdrawn).
c. **Much of the requested information is already gathered by EPA under other PRA approvals. OMB should limit this ICR to only information that is not already being collected by EPA.**

EPA is already authorized to gather most of the information being requested through Notices of Compliance Status, Periodic Reports, Consent Decree reports, Operating Permits, and other required submissions – including information collected by the Office of Enforcement (e.g., FCCU stack test data), under existing PRA authorizations. EPA states in the ICR supporting statement, the following:

> Although some of the needed information may be included in title V or State air emissions permits, many permits do not contain all of the detail needed and are not readily available from any single source. Furthermore, there are no readily available sources for previously conducted emissions test results (since the mid-1990s) that will provide data for emissions of the variety of pollutants under consideration.

Having information “readily available from any single source” is not a criterion in the PRA. The PRA does not authorize duplicative information collection because an Agency finds it convenient to put the burden on others. In this case, if there are holes in the available permit data for refineries, EPA may use CAA section 114 authority to fill those holes without violating the PRA, but the PRA does not allow use of such authority to require repetitious reporting of information already in EPA’s hands or already provided under PRA authority. The same is true for previously reported emission tests. Most such tests are required to be reported to EPA or the delegated authority and thus have already been made available to EPA under other PRA authorizations. EPA may, under the PRA, request tests that have not been submitted under other PRA authorizations, but, again, may not do so for tests where their submission would be duplicative.

EPA’s authority to require the submission of information is carefully constrained under the law. For example, although section 114 of the CAA provides EPA with information gathering authority, EPA’s information collection efforts under section 114 must be reasonable and, in this case, firmly anchored to reasonably foreseeable policy or regulatory needs. The ICR in its current form goes well beyond what can reasonably be justified. For instance, it is not reasonable to ask for a list of information on applicable requirements when they are plainly listed in the publicly available Title V permits for the affected facilities. Similarly, it is not reasonable to gather information that already is in the Agency’s possession, notwithstanding the fact that the Agency must exert some effort to improve its internal information management practices and systems.

Of particular concern is the information EPA proposes to gather in Component 1, Part II, Section 12 of the ICR on flares. EPA has recently been using CAA section 114 authorities to gather flare information from refineries and to require testing of flares. They also gathered extensive information on flares to support the recently completed NSPS J review and NSPS Ja rulemaking and have been actively involved in flare test programs that are currently underway. Finally, EPA
Attachment 1 - Detailed Comments on the Need for and Burden Associated with the Draft Refinery ICR

has indicated that they plan to propose new flare requirements in June of 2011. Clearly, then the ICR flare data, which is due to EPA at the end of May 2011, will not even be available to EPA before the proposal is submitted for Interagency review. Since representative flare information for refineries appears to be already available to EPA and the proposed ICR flare information will not be available before EPA plans to complete a new flare proposal, OMB should not approve the collection of this information.

2) OMB should not approve ICR elements that have not been demonstrated to be of “practical utility;” without such a demonstration the ICR cannot be approved under the PRA.

a. API/NPRA do not believe it is possible for the extensive ICR results to be tabulated, reviewed and integrated into a proposed rulemaking with interagency review by December 10, 2011. As recently demonstrated in the Boiler and Process Heater (BPH) NESHAP effort, data analysis and integration suffers when rulemaking occurs under short deadlines. In proportion to the number of issues under consideration and the time available, this data integration effort far exceeds the BPH ICR effort.

EPA is committed through a consent agreement to proposing most of the rules cited as the basis for this ICR by December 10, 2011 and finalizing those rules by November 10, 2012. The draft ICR requires responses by May 31, 2011 for Component 1, June 30, 2011 for Component 2 and August 31, 2011 for Components 3 and 4. Due to the scope of EPA’s request, these due dates will be difficult for refiners to meet and it is likely some information will lag and data quality may suffer. Even if these dates are met, it is unclear how EPA can tabulate and credibly analyze this massive amount of data from 152 refineries, diligently consider regulatory actions and alternatives using this information, and develop and fully review proposals for greenhouse gases under NSPS J/Ja, Db, Dc, GGG, QQQ, complete review of Refinery MACT 2 (Part 63 subpart UUU) and resolve a number of outstanding NSPS J/Ja reconsideration items as required by that consent agreement, particularly in light of EPA’s indicated intent to simultaneously propose any other needed revisions to these rules relative to refineries, complete the Refinery MACT 1 review and develop uniform standards for essentially all types of equipment used by refineries.

Along these same lines, some of the requested information is unnecessary because EPA has already developed draft rules on the issue for which the data are being collected. Thus, the data from this ICR would become available at a time when it would not be useful – i.e., after proposal and potentially after final rulemaking. As an example, EPA is well along on developing a new set of generic flare requirements and EPA is close to finalizing refinery-specific flare requirements under NSPS Ja. Thus, there is no apparent reason for collecting refinery flare information when EPA is in the final stages of proposing new flare requirements.
b. The PRA limits this information collection to the refinery equipment, units, and emissions for which the ICR resource estimates were made. Components 1 and 2 of the draft ICR do not correspond with the stated description of the need for the data or the basis for the ICR resources estimates and is not limited to equipment, units, and emissions in petroleum refineries as are the burden and cost estimates.

In Part A1(b) of the supporting statement, EPA states:

This information collection is being conducted by EPA’s Office of Air and Radiation (OAR) to assist the EPA Administrator, as required by sections 111(b), 112(d), and 112(f)(6) of the Clean Air Act (CAA), as amended, to reevaluate emission standards for this source category. The information will also be used to develop greenhouse gas regulations for petroleum refinery sources under CAA sections 111(b) and 111(d).

“This source category” is indicated to be petroleum refineries.

In the February 2, 2011 Federal Register Notice that this ICR has been submitted to OMB for review and approval (hereafter “the Notice”), EPA describes the purpose of Component 1 as “To obtain the information necessary to identify and categorize all units potentially affected by any future revision to a standard.” It describes the “standards” being addressed as follows:

EPA is issuing a single collection of information for sources covered under 40 CFR part 63, subparts CC and UUU and 40 CFR part 60, subpart J so that EPA can, at one time, assess whether additional control strategies are necessary and, if so, which are the most effective for hazardous air pollutants (HAP), regulated under CAA section 112, and criteria air pollutants (such as particulate matter, sulfur dioxide, and nitrogen oxide), regulated under CAA section 111. The data would also allow EPA to evaluate compliance options for startup and shutdown periods and consider ways to consolidate monitoring, reporting and recordkeeping requirements for the different rules under review. The data may also help EPA conduct reviews of other rules specific to petroleum refineries, including Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries (40 CFR part 60, subpart GGG), Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (40 CFR part 60, subpart QQQ), and the National Emission Standard for Benzene Waste Operations (40 CFR part 61, subpart FF).

The Notice then indicates that Component 2 requires an emission inventory for the “facility” and the General Instructions in Component 1 specifies that the requested information in Components 1-3 and, if applicable, Component 4 is to be provided “for the facility listed in the Section 114 letter you received in the mail.” Individual items use similar language. For instance, Component 1, Section 11 states “‘other atmospheric vents’ include any continuous or intermittent process vents located at the facility and under common control…” [Emphasis added]. The terms “facility” and “petroleum refinery” are used somewhat interchangeably throughout the
information request. EPA even appears to be requiring information on operations that are not owned by the refinery. For instance, Question 3 of Component 1, Part II, Section 10 asks for information on “captive” hydrogen plants.

Facility is defined in the draft ICR documents as “Any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control.” A 1995 letter providing a regulatory and expansive definition of common ownership or common control is included in the docket (EPA-HQ-OAR-2010-0682-0027), presumably to support expanding the coverage of this ICR well beyond petroleum refineries. Under this interpretation, it would appear that many operations that are not part of a petroleum refinery and are subject to other standards and data collection activities would have to respond (e.g., separate but contiguous chemical operations, separate but contiguous production facilities, separate but contiguous terminal operations). For instance, while EPA has completed data collection and Clean Air Act (CAA) section 112 residual risk and technology reviews for SOCMI processes (i.e., part 63 subparts F, G and H), the ICR language can be read to be requiring those facilities to respond to this ICR, if they are contiguous with a refinery.

While the ICR facility definition may have a place in new source review, permitting or other regulatory contexts it is improper to use it for this data collection activity and thereby expand the data collection requirement significantly beyond that described in the Notice and that used as the basis for the burden estimate. It is clearly OMB’s and EPA’s responsibility under the PRA to assure only data is collected as described in the ICR supporting statement and for which a valid burden estimate has been provided and we request OMB assure the Agency limits this data collection to that extent by requiring the ICR to explicitly define the “facility” to which the ICR applies as being the petroleum refinery as identified for the EIA 2009 Refinery Capacity Report.

In responding to our comments on this issue in the draft ICR, EPA indicates they believe they need information on chemical and other non-refining operations that are located in a refinery. However, that is not what we object to or what this ICR asks for. We object to using this ICR to gather information on chemical and other operations that are not in a petroleum refinery, but are contiguous to a petroleum refinery.

Following are specific examples of some of the situations in the industry, incorporating these non-refinery operations into the ICR response will significantly increase the burden and cost of responding and could easily double the burdens and costs associated with Component 2 for petroleum refineries with large associated chemical operations.

One large facility includes a petroleum refinery that is a joint venture with a Title V permit of its own and a co-located separately permitted set of chemical operations that include processes that manufacture phenol, butadiene, and aromatics (all SOCMI part 63 subpart F, G and H processes). These chemical operations are not part of the joint venture refinery and are not covered by the refinery permit.
Another large facility includes a petroleum refinery and a separately permitted, contiguous chemical plant that produces over 50 products including ethylene, SOCMI chemicals, rubber products, and other chemicals.

A smaller petroleum refinery is located on property that also contains a crude oil processing plant (where three phase flow (oil, water, and gas) from oil wells is separated and the crude oil sent to a pipeline.

c. Even for equipment within a refinery, there is no regulatory reason for gathering much of the requested data (e.g., heat exchange system information, incident reports, equipment leak component counts by process unit rather than monitoring area) or requiring some of the testing (e.g., crude analyses, cooling tower sampling). Many of the detailed questions appear of no practical utility (e.g., number of open-ended lines and sight glasses, cooling system details, details of every minor process change in the last five years).

Component 1 and 2 items.

1. Section 14 of Component 1 gathers detailed information on heat exchange systems in refineries. Since EPA has already finalized requirements to minimize HAP emissions from refinery heat exchange systems and most refinery heat exchange systems are covered because HAPs are prevalent in refineries, we see no “practical utility” for gathering this information. In responding to our comments on this point, EPA states “We have not deleted the table because we still need information on non-HAP service cooling towers for impacts analysis for possible VOC requirements.” Yet, many of the questions bear no relationship to VOC, for instance the four Table columns devoted to water treatment and the water pressure and make-up water rate questions.

2. Part III of Component 1 requests information on public complaints and reports of each flare, air emission, or odor complaint received in 2010. Refineries are not currently required to keep records of complaints they receive, so the data may not be available. It is unlikely tabulations of public complaint information, even if the basis of the complaint was confirmed by a regulatory agency, will have any use in rulemaking. In the response to comment, EPA claims they need this information for “outreach” purposes, but that is not a reason for collecting data under CAA §114 or the PRA. Furthermore, the details requested are problematic. For instance, Table 2 asks for names and contact numbers of people who submitted complaints. It is questionable that EPA needs this information or that we or they have the right to make this information public (as EPA indicates that ICR responses will be) without the person’s permission. OMB must make EPA explain how they will use this information in ways allowed by the PRA and privacy laws and whether EPA has received approval from the complainants to make their names and contact information public.
If EPA persists in requesting this information, it should only request information on confirmed complaints and it should obtain that information from local regulatory agencies.

3. Section 3 of Component 1 asks for detailed component counts (e.g., valves, pumps, flanges, etc) for each process unit and fuel gas system. Process unit is defined in the ICR as “any segment of the petroleum refinery in which a specific processing operation is conducted. Examples of such units include, but are not limited to, alkylation units, catalytic hydrotreating (or catalytic hydrorefining or desulfurization), catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal (coking) processes, sulfur recovery, and blending, sweetening, and treating processes.” Often this information is not available by process unit, because monitoring is typically done on a geographic area basis and those areas may subdivide or combine equipment from several processes. We see no regulatory reason why this information is needed on a process unit basis, rather than on whatever basis is already available.

Additionally, this section asks for estimates of the number of open-ended lines, sight glasses, and gages, which are not potential leak sources and thus counts are not normally available and gathering estimates will serve no purpose. By regulation and for safety reasons, open-ended lines are not allowed (they must be plugged or be double blocked. Sight glasses and gages are pieces of equipment and not potential leak sources. All three may be connected to a process, but the connections involve valves, flanges, and connectors that are counted under those categories. Thus, we see no purpose for having to estimate the number of these three types of components and gathering that data should not be allowed.

4. Part 4 Table 2 asks for cost data for the thousands of minor process and equipment changes that have occurred in each refinery in the past 5 years. We understand the Agency’s need for real cost data on major emission reduction projects (Table 1) given the unreasonably low cost estimates used in recent rulemakings, but do not understand how the Agency can use information on such minor activities as deleting a few valves from a line, upgrading a pump seal, modifying a drain water seal, adding a fitting to a floating roof or any of the vast multitude of minor emission reduction activities that occur daily in a refinery. OMB should disallow this piece of the ICR, since the data will have no “practical utility.”

5. Component 2 requires emission estimates for all emissions from the petroleum refinery. However, the ICR may require that same refinery to test some of its operations, thereby providing new emission information. If a site is required to perform testing, then providing that portion of the emissions inventory should be delayed until testing is complete so that those results may be used for the emission inventory.
Component 3 and 4 items.

6. Component 3 requires extensive crude oil analyses even though that information cannot be used to calculate emissions and much is already available on crude metal content in the open literature. Metals and sulfur partition as they pass through the refinery. The metals typically end up in the heavy oil fractions. The sulfur proportions among streams and then is removed from some streams and remains in other liquid streams. As a result, there is no correlation between sulfur and metals in crude and air emissions. EPA has provided no clear and specific explanation as to how it might use the sulfur and metals information under NSPS, NESHAP, or any other CAA regulatory program, in light of the fact that it is unrelated to emissions or potential regulation requirements. Thus, we see no “practical utility” for collecting this information and Component 3 is not authorized under CAA section 114 or the PRA.

7. Component 4 requires analysis of the vents from eight delayed coker coke drums. However, there are no demonstrated methodologies for obtaining representative samples from this short duration, turbulent flow, constantly changing, wet source and no demonstration that the prescribed analyses, which were developed for stack testing sources of constant and particular compositions would yield valid results. Similarly, there is little experience among stack testing companies with this testing. The wide variability demonstrated in the test work done on these sources during the NSPS Ja rulemaking, demonstrates that without further testing methodology development characterization of these vents with a quality adequate for rulemaking is unlikely. If EPA persists in proceeding on the current basis, each facility will have to obtain approval for use of modified methods. Each method modification may be different from others resulting in more varied results that cannot be relied on for rulemaking. Thus, these analyses will have no “practical utility” for rulemaking and should not be required by Component 4.

8. Component 4 requires 12 petroleum refineries to test their cooling towers using the modified El Paso Method for HAPs, formaldehyde, THC, methane, HCl and Cl₂. Cooling tower monitoring and repair provisions were added to part 63 subpart CC on October 28, 2009 for all cooling towers where HAP may be present (a large percentage of all refinery cooling towers). Compliance is required by October 28, 2012. Additionally, EPA concluded in its residual risk and technology review of part 63 subpart Q that no revisions were justified for the Industrial Cooling Tower NESHAP (71 FR 17729 (April 7, 2006)). Thus, there is no regulatory need or justification for testing cooling towers, since there is no regulatory need to review or change any rules addressing cooling towers. Even for methane, which is not a HAP or VOC, this testing will serve no purpose. As EPA claimed in the subpart CC rulemaking, the new CC requirements will lead to significant reductions in cooling tower emissions and thus any information collected in 2011 will not be representative of future cooling tower emissions.
3) EPA significantly underestimates the cost of responding to the ICR.

   a. EPA estimates a total cost of approximately $5 million for Components 1 and 2 (process and emission information). We estimate a cost of approximately $49 million (510,000 hours versus EPA’s 56,000 hour estimate). For instance, the required equipment leak information could take hundreds of hours to gather and/or recast into process unit and fuel gas system groupings versus EPA’s estimate of 5 hours. In a large refinery, the wastewater emission estimate alone could require all or most of the 200 hours EPA estimates for the entire emission inventory effort.

On page 5805 of the Notice, EPA reports that “The annual public reporting and recordkeeping burden for this collection of information is estimated to average 256 hours per response” and that the request will be issued to 152 “refineries.” EPA estimates the total annual burden hours as 69,342 hours and the estimated total annual burden cost as $30,924,069, which includes $912 in O&M costs. The hours per response figure in the Notice does not agree with the total burden hours estimate in the Notice or with the 456 hours per response estimated in the ICR Supporting Statement and is apparently a typographical error.

Assuming the 456 hours per refinery is EPA’s actual estimate of the burden associated with this ICR, of which 374 hours is attributable to Components 1 and 2, it is clear to us that this estimate is unreasonably low and does not represent a valid estimate of the burden as required by the PRA. Based on a in-depth review of the ICR requirements and detailed information from seven refineries, we estimate a minimum of 2,300 hour to respond to Components 1 and 2 for the 96 small to medium sized refineries (defined as less than 125,000 barrels per day throughput) and 5,400 for the 56 larger refineries (greater than 125,000 barrels per day throughput), assuming the ICR is revised to apply only to refinery facilities and reasonable interpretations of the ICR questions. This would result in a cost estimate (using EPA’s labor rates) of approximately $51 million dollars for responding to Components 1 and 2, versus EPA’s estimate of approximately $5 million. The summary of our analysis is shown in the following Table and Figures.
Comparison of Refinery Sector ICR Estimated Costs to EPA Assumptions

<table>
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<th>ICR Component 1, 2, 3 &amp; 4 Descriptions</th>
<th>EPA Costs1</th>
<th>Subtotal Small to Medium Refineries2 Sector Costs</th>
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<tr>
<td>Part I</td>
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<td>Part III</td>
<td>Incident Reports</td>
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**Estimated Response Cost Totals - All Components**

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<th>Component</th>
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<td>Source Testing Analytical</td>
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<td><strong>Totals Including Analytical Costs</strong></td>
<td><strong>$32,375,488</strong></td>
<td><strong>$77,255,843</strong></td>
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</table>

_EPA Costs_ based on 56,000 EPA estimated hours in Supporting Statement @ $95/hr including 5% and 10% management and clerical assumptions

1. Small to Medium Refinery Sector response estimated at 239,328 hours (2,493 hours at the 96 refineries with <125,000 bbl/day processing throughput)
2. Large Refinery Sector response estimated at 301,168 hours (5,378 hours at the 56 refineries with >125,000 bbl/day processing throughput)
3. Total Refinery Sector Costs based on 516,450 hours @ $95/hr including 5-10% management clerical assumption and 20% uncertainty
4. contingency
Attachment 1 - Detailed Comments on the Need for and Burden Associated with the Draft Refinery ICR

**Small to Medium Refinery Costs**

- Part I, $723,672, 3%
- Part VI, $3,536,554, 17%
- Part V, $2,101,795, 10%
- Part IV, $2,013,696, 9%
- Part III, $251,712, 1%

**Large Refinery Costs**

- Part I, $484,546, 2%
- Part VI, $6,188,969, 22%
- Part V, $7,987,661, 29%
- Part IV, $1,174,656, 4%
- Part III, $146,832, 1%
Even our overall burden estimate probably underestimates the actual hours needed. For instance, one company reports it will take 300 hours per refinery to provide equipment leak information for which the Agency estimated 5 hours and that just data entry for Table 4-1 (Storage Tanks) will take much longer than the 5 hours EPA estimates for completing all of Section 4, because their refineries have 75 to 800 tanks each.

Even something as apparently simple as identifying units requires considerable burden (not considered by EPA) since sources are required to use the unit identification used in the EPA National Emission Inventory (NEI) database. Since most sources are not familiar with that EPA database and unit identifications in that database are often cryptic or unclear, it can take many hours to determine the “correct” unit identifications. Furthermore, those NEI identifications may or may not be accurate and it may take many hours for sources to identify and correct NEI misidentifications. Even more of an issue is the required assignment of SCC codes to individual emission points (another burden EPA has not addressed.) Sources will have to sort through long lists of SCC codes, which, again, are unfamiliar, to determine the best fit for each of the hundreds of emission points on which they are reporting. The EPA burden estimates do not seem to reflect these requirements.

Section 11 of Component 1 calls for including analyzer vents in the required “other atmospheric vents” category. Since only the analyzer outlet is allowed to go to the atmosphere (sample purges must be controlled) these are miniscule emission sources, but because there are as many as several hundred such vents in a refinery, providing data on them as required by Section 11 will take many tens of hours, rather than the 4 hours EPA allows for all of Section 11. Even more hours will be wasted because Section 11 explicitly requires including analyzers and other vents that are not part of a petroleum refinery.

Part V of Component 1 asks for CEMS data, but requires that data be handled in a particular way (e.g., exclude all days when one hour of data is unqualified) and to be provided in a spreadsheet and with extensive additional information. The two hours per occurrence EPA estimates is inadequate to provide that spreadsheet because of the large amount of manual effort that it requires. We would conservatively estimate a minimum of 10 hours per occurrence, raising the total technical burden hours from 2462 to at least 12,312, even assuming EPA’s underestimated assumption of nine (9) CEMS data responses per refinery, and the associated cost from $268,548 to close to $1.2 million. One large refinery reports that there are 78 CEMS/CMS units that would require data reporting under the ICR.

Part III of Component 1 requests information on each “non-routine emission event” at the petroleum refinery (which is defined to include each startup and shutdown event) and information on public complaints and reports of each flare, air emission, or odor complaint received in 2010. The ICR Supporting Statement assumes two hours per refinery for responding to Part III and apparently assumes only reports to the National Response Center are required, despite what the ICR instructions specify. Rather than two hours per refinery, Part III could take

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6 The definitions document defined “non-routine emissions” as “Emissions that occur during periods of start-up, shutdown, or equipment or component malfunction.” Thus, Part III is apparently asking for information on the large number of such events, whether or not there were any unusual emissions.
hundreds of hours per refinery if a diligent effort is undertaken to extract detailed estimates of emissions for every startup, shutdown, malfunction and process upset that occurred in 2010 from overall emission estimates.

Part IV of Component 1 asks for detailed cost data for thousands of emission reduction activities and would seem to include such minor activities as removing a few valves, upgrading a pump seal or a single tank fitting gasket. It would involve thousands of hours of effort to try to gather all of the requested detail for those thousands of minor activities. The 20 hours EPA estimates for completing the cost section wouldn’t even be enough to begin gathering data for Table 2. We understand the Agency’s need for real cost data, but believe only the major reduction activities as covered in Table 1 of this section of the ICR, should be addressed and that the hundreds of hours of burden associated with even providing that data should be included in the burden estimate. OMB should understand exactly how information on thousands of duplicative, minor emission reduction activities will be used and why the vast effort to collect such information is justified before it authorizes Table 2 of Part IV.

Part V of Component 1 asks for stack test reports from the last five years and daily average 2010 analyzer data. The burden estimate is based on two source test reports per refinery (499 hours, $46,380) and nine analyzer reports (2831 hours, $268,548). These occurrence assumptions are unrealistic and grossly underestimate the number of reports and the burdens and cost. Because many refineries are in non-attainment areas, are in Texas Highly Reactive VOC areas, and because of the refinery NSR consent decree and Title V permit requirements, there has been an extensive amount of source testing performed in the last five years, particularly for NOx. Rather than assuming two reports per refinery, EPA should have assumed at least twenty reports. Similarly, there are a large number of CEMS in most refineries, particularly criteria pollutant CEMS, but also hydrocarbon and BTU analyzers. Rather than assuming nine CEMS per refinery EPA should have assumed at least 20. On this basis the burdens for Part V should have been at least 11,281 hours and $1,060,567.

In responding to comments on the burden imposed by the first draft ICR, EPA indicated that they did not include most of the burdens for the emission estimates (Component 2) in the PRA burden estimate because the TRI emission inventory is due at the same time and could be used for responding to the ICR. Unfortunately that is not true. EPA requires use of methods for much of this emission inventory that are not used for TRI. In this inventory EPA also requires emission estimates for many species not addressed by TRI (e.g., five different particulate emission types, many individual VOCs). While the information developed for TRI and State emission inventories will be of some help, it will not alleviate much of the burden associated with Component 2. Even the spreadsheets used for TRI and State emission inventories will be of little benefit, since they are not based on the ICR required estimating methodologies, do not include many of the species required and are not organized as required by the ICR. Thus, EPA should have assumed burdens close to those needed for an entirely new emission inventory.
Of particular concern in Component 2 is the requirement to use EPA-provided spreadsheets to perform the wastewater emission calculations. There is one spreadsheet for each type of wastewater treatment component. Facilities will have to gather the required input data (some of which is not readily available) for each spreadsheet and manually integrate the results of one spreadsheet with the next. In a large, complex refinery it will take much iteration to develop an estimate of even marginally reasonable quality using this approach. EPA estimates 200 hours to complete Component 2, we believe just the wastewater estimates can take 200 hours, because of the requirement to use this new, untested set of spreadsheets.

Because 1) this ICR schedule overlaps the Toxics Release Inventory (TRI) schedule and the recently delayed Mandatory Greenhouse Gas Reporting Rule (MRR) schedule, 2) this ICR requires using estimating methodologies that in many cases differ from those used for the TRI and for State emission inventories, preventing the use of existing estimating tools, 3) this ICR requires emission estimates for many species not normally estimated individually, and 4) this ICR requests large quantities of information to be organized differently than it is for other emission inventories, much of the response to this ICR will have to be handled manually. In addition, since experienced emission estimating personnel will be busy with MRR, TRI and State emission inventory work, much of the ICR response will be handled by less experienced individuals. As a result, extra time will be required to develop, review and QA/QC the ICR responses than would otherwise be necessary. No allowance for this extra effort is included in the burden estimate. These considerations alone are likely to add 40-400% to the hours needed to respond to this ICR.

b. The number of tests, and the resources and costs associated with adapting the test methods required by Components 3 and 4 appear significantly underestimated. Additionally, the time and costs associated with installing sample ports, sample probes and, in some cases, the associated process and refinery outages are not included in EPA’s cost estimates.

Our detailed cost analysis indicates that the burdens associated with Components 3 and 4 are likely to be somewhat larger than EPA estimates. We estimate 115 hours per refinery versus the EPA estimate of 65 hours, for a total burden cost of $2.3 million versus the EPA estimate of $1.1 million. However, much more significant than the burden underestimate that the Agency appears to have significantly underestimated the Component 4 out-of-pocket costs, primarily by underestimating the number of tests required and ignoring the capital costs and production impacts of the test program.

Component 4 specifies the sampling and analysis methodologies that are required. Those methodologies require particular sampling probes and, in many cases, multiple sampling ports or sample ports of a certain size (e.g., a six inch port rather than a standard four inch port may be needed to meet the ICR requirements for collecting simultaneous samples.) These sampling facilities are often not in place and will require significant planning and engineering, which does not appear to be accounted for in the time period allowed or in the cost and burden estimates. Additionally, installation of some of these facilities will require unit shutdowns and, in some
cases, shutdowns of entire refineries or sections of refineries. Nothing in the ICR supporting analysis reflects those significant costs, production disruptions, or emission and other environmental impacts of extra unit or refinery startups and shutdowns or the impact of such shutdowns on fuel supply or cost. OMB should require that the Agency delay any testing where an extra process outage is required until the next planned unit outage or that the costs and burdens associated with such outages, including product value losses, be reflected in the ICR if delays are not allowed.

EPA appears to have based its cost estimate of $777,000 for the required fuel gas testing on testing one fuel gas system per refinery for 21 refineries, yet most refineries have many fuel gas systems, some reporting up to 10. For cooling towers, the cost estimate of $50,000 is based on one cooling tower at each of 12 refineries being tested, but refineries usually have many cooling towers, with many large refineries having 10 or more cooling towers. Furthermore, many cooling towers have multiple return headers and thus would require multiple tests just to characterize that single cooling tower. Even for large, expensive tests (e.g., fluid cat crackers, delayed cokers), the burden estimate has assumed one test per refinery, but many refineries have two of that type of unit. Nothing in the Component 4 draft indicates that testing is required for only one of a particular equipment type at a listed test site or provides information on how to select that one, if that is EPA’s intent. If OMB approves this testing, it should limit the number of tests to the number used by EPA in the Supporting Statement basis (i.e., one per site) and should require EPA to clearly identify how to select the source to be tested.

As discussed in Item 7 of Section 2.b of these comments testing coke drum emissions from delayed cokers will present challenging methodology issues. The additional costs incurred for facilities to develop modifications to all EPA test methods in order to test this source, in addition to the time necessary to obtain EPA approval, is not reflected in the ICR estimates. In addition, the listed analytes in the ICR is extensive and will require installation of 5 test ports, which is not typical for any source, particularly a Delayed Coker drum vent. Stack testing facilities of this magnitude are not likely to be currently available for any Coker.

Finally, Component 4 requires that some testing be performed at island refineries, but the ICR does not reflect the extra costs for doing tests in such remote locations. Typically, in such situations stack test equipment and personnel must be brought from the mainland and samples must be transported to the mainland for analysis. Costs and burdens are typically at least twice what they would be for mainland refineries and this should be reflected in the ICR estimates.

4) OMB should required EPA to return to the traditional approach of gathering representative data verses seeking data from all U.S. refineries.

   a. In a precedent-setting move, EPA seeks to gather data from all sources at all 152 US refineries, rather than from a representative set of emission points in the refinery source category. EPA has not justified these changes from established practice, nor did they indicate in the 1999 Residual Risk Report to Congress that such an approach might be employed.
EPA should be required to provide an estimate on how this new approach (i.e., all sources, Agency-specified emission calculations) will impact EPA and industry resources and costs as it is applied to other source categories. If this is not an approach that EPA plans to use generally, it should be required to demonstrate why this approach should be applied to petroleum refineries; particularly in light of the extensive amount of information already available.

As EPA reports in the ICR Supporting Statement “A data set derived from the EPA’s 2005 National Scale Air Toxics Assessment (NATA) National Emissions Inventory (NEI) and supplemented with data supplied by about 20 individual refineries were used for a previous residual risk assessment for Refinery MACT 1.” In its previous evaluation, EPA had high quality data on 20 of 152 refineries and NEI data for most of the other 132 refineries. Such a level of information is typical for rulemaking. Concluding that the Agency must have comprehensive data on every source in a source category and from many operations that are not even part of the source category but are located nearby is unprecedented and not justified. Acceptance of this approach would greatly increase Agency and public burdens associated with EPA rulemaking and thus should be carefully weighed. OMB should require EPA to explain the reasons for the change and how it will impact all future rulemakings.

If this is not a general policy change for the Agency, OMB should require EPA to explain publicly why it is singling out the refining industry for the comprehensive new regulation that is the justification for this ICR, in light of the 1) extensive regulations already in place, 2) the recently promulgated regulations (e.g., NSPS Ja, GGGa, Boiler and Process Heater MACT) and, 3) the planned new regulations that are not required under the CAA (e.g., revisions to part 61 subpart FF, new control device requirements under the new “Uniform Standards” program).
American Petroleum Institute (API)
And
National Petrochemical and Refiners Association (NPRA)

Detailed Comments on the Language and Content
of the
Draft Refinery Information Collection Request
And
Associated Documents

EPA ICR No. 2411.01, OMB Control No. 2060–NEW

Docket ID: EPA-HQ-OAR-2010-0682
We appreciate the many clarifications and corrections made to the initial ICR draft in response to our comments. However, there are still some items that are unclear and a few technical concerns. This Attachment tabulates items that are unclear or confusing to our members and which need to be clarified if accurate and consistent responses to the ICR are desired. This tabulation is based on the draft ICR, though we believe many of the items should be deleted from the final ICR as discussed in Attachment 1.

**General**

As discussed in our comments on the draft ICR\(^7\), the ICR already requests responses on an unrealistic timeline, and additional time is needed to allow a full and high quality response. In addition to the overall timing of the ICR, due dates for various components should not be based on a specific calendar date as in the current draft. Due dates should be based on 60, 90, 180 days from the date of the individual Refinery ICR request letters. As currently written, any delay in EPA issuing the request to refineries unfairly shortens the response time allowed.

It needs to be made VERY clear in the instructions that if data are not readily available the owner/operator is not required to generate a response. For example, there is typically no data on natural gas component counts. It can be estimated, but it would take at least a month for a smaller facility and longer for a larger facility. This level of effort is not reflected in the burden estimate, is not justified, and this level of effort should not be required. Furthermore, clear instructions are needed on how to indicate where data is not readily available. It is important for those situations to be clearly identified and not have it be assumed that a blank response means zero. We address these items in more detail below.

Please confirm in the general instructions that none of the responses include third party units located at a refinery, such as a hydrogen plant or cogeneration unit that is dedicated to the refinery but not owned or operated by the refinery owner/operator and not under common control.

We anticipate a large number of questions and requests for approval of alternatives and modifications will be directed to EPA. Given the short timeframe for responding, we request EPA establish a telephone hotline to facilitate rapid responses to these requests.

**Component 1**

**Part 1, Overall** - Questions 15 and 16 assume refineries may have ethylene, propylene, acrylonitrile, aromatics and other chemical units, however, the Part II tables do not consistently include chemical rules in the lists of potentially applicable regulations (e.g., Ethylene MACT, HON, MON, Polymer and Resins MACTs, NSPS DDD, III, NNN, RRR). Additionally, some typical refinery rules are not represented in Part II, such as Organic Liquid Distribution MACT, Hazardous Waste Combustor MACT and the various Part 61 benzene NESHAPS, other than

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\(^7\) Docket document EPA-HQ-OAR-2010-0682-012.1
BWON. This should be corrected. Any regulation potentially applicable to the processes and products identified in Questions 15 and 16 of Question 1 should be represented in Part II.

Clarification is needed on how Unit IDs are to be assigned if the NEI identifications are incorrect, duplicative or include multiple units. All of these situations are common in the NEI database.

**Part II, General** - What do we put in the cell if no data is available? N/A? Leave blank? It is critical “not available” responses be fully identified so that those responses are not taken as indicating “zero” and thereby falsely bias the use of the data and the standards developed from the data.

**Part II, Section 1** – Clarify if waste heat boilers on process heaters should be included as part of Table 1-2 or included in Section 2. If they are included in Table 1-2, footnote 2 needs a “none” option, since most waste heat boilers are not supplementary fired.

Table 1-3 (Steam Demand by Process Unit) requires reporting average steam demand for each process unit during normal operation, assuming the processing unit is operating at maximum capacity. There are many issues with this request. EPA needs to explain what they want averaged (i.e., is this an annual average?) and what they mean by “normal operation” in the context of operating at maximum capacity. In general, operating at maximum capacity does not represent normal operation. Maximum capacity of a process unit also needs to be defined, is it maximum feed rate or maximum product rate and is it maximum annual capacity, maximum seasonal capacity, or maximum hourly capacity? Steam demand is different for these cases. For whichever parameter (i.e., feed or product) capacity is to be based on, is it permitted capacity, maximum sustained capacity, or design capacity?

EPA needs to clarify for steam production and electricity. Should these be net production or gross production.

EPA needs to clarify the term “captive hydrogen plant”. It seems like EPA intends for facilities to include 3rd party hydrogen plants that are located onsite in this ICR for Part I Question 16 as well as Part II Section 10. We do not believe that emissions from 3rd party hydrogen plants located onsite should be included in overall emission estimates for the ICR. These are not included in TRI reports or other emission inventories for these facilities because the hydrogen plants are not included in operating permits and not operated by the refinery. Data being requested would have to be provided by the 3rd party as well.

**Part II, Section 2** - Table 2-1 (Process Heater General Information), Footnote 4 asks for types of energy efficiency measures used. The instructions need to clarify if ALL items that apply are to be reported or only the most significant energy efficiency item. This is another item that is an issue in many tables and we recommend EPA clarify every case where they expect all applicable items to be included in the response. This table also asks for hours of turndown operation, but turndown is not defined and thus the responses will be meaningless. We recommend turndown be defined as ≤25% of design firing, since emissions become significantly impacted for most
process heaters below this point, though for some designs impacts begin at higher firing rates than that.

**Part II, Section 3** - Table 3-1 (Equipment and Leak Detection Information for Process Units) requests component counts for open-ended lines. There are no open-ended lines allowed under current regulations, so there is no reasonable basis for requesting this information, since there are no potential emissions. If EPA wants a count of the number of plugged or double blocked open-ended lines it should be clear that is what it is being requesting and understand this count is generally not readily available, since these are not emission points and EPA should not use this information to estimate emissions.

Table 3-1 also asks for additional component separation that is not typically readily available (e.g. flanges versus connectors, hatches, gages, sight glasses, etc.). Furthermore, some of these, as with open-ended lines, are not potential emission sources (e.g., gages, sight glasses\(^8\)), so it is unclear if even the effort to estimate their number is justified and that counting them is not duplicative of the connector and valve counts. Since flanges are often not identified separately from connectors, EPA could avoid many “not available” responses if they simply asked for the total connector count and we recommend that simplification. Finally it should be noted that heavy liquid components are typically only an estimate in most refineries.

Tables 3-2 (Equipment and Leak Detection Information for Fuel Gas and Natural Gas Systems) and 3-3 (Pressure Relief Devices) request natural gas and fuel gas component counts. These are generally not available and would be very time-consuming to estimate. It would take hundreds of hours of effort, depending on the size of refinery, to review P&IDs and walk the lines to get natural gas and fuel gas component counts. EPA should revise the instructions for these tables to be clear that such an effort was not included in the burden estimate, which is five hours for all of Section 3, and it is therefore **not required** that sites develop the requested component counts, as the current instructions seem to suggest.

In fact, we would suggest EPA simplify this request significantly. For fuel and natural gas systems, valves and compressor seals will account for the majority of equipment leak emissions and the number of other component types will be typical of gaseous VOC systems in general. Thus, we suggest the Agency simply request a count of compressors and an estimate of the number of valves in these services and then use the data from Table 3-1 and the atmospheric PRV data from Table 3-3 to develop estimates of the number of other component types using the ratios of that component to valves for gaseous systems from Tables 3-1 and 3-3.

**Part II, Section 4** - Please define “maximum liquid height” for Table 4-1 (Storage Tank General Information). Is this the physical height of the tank wall or the maximum height as determined by a high level shut-off, maximum floating roof limit, or some other criterion?

Table 4-1 requires listing of all storage tanks down to 10,000 gallons (238 barrels) and storing a material with a vapor pressure greater than 0.1 psi. Wastewater or waste storage and waste management units such as oil-water separators, equalization basins, etc. would appear to be to be

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\(^8\) The connection where a gage or sight glass connects with the process may involve “connectors” and/or valves, but those potential emission points are already counted in those component counts.
included as tanks under this definition, but we believe these are more appropriately addressed in the wastewater and solid waste sections of the questionnaire and we suggest they be excluded from the storage tank definition.

**Part II, Section 7** - Clarification is needed on cycle times, water height, and coke drum pressure. None of these values is constant. Is the Agency looking for averages, typicals, maximums, or something else? If averages, is that the annual average for 2010, averaged across all coke drums for that unit. Additionally, guidance should be provided on how to account for maintenance and other extended drum outages.

**Part II, Section 10** - Need clarification on what is meant by hydrogen production. Does this include recovered and purified hydrogen or only the production of purity hydrogen?

**Part II, Section 11** - Is EPA expecting EVERY analyzer vent to be included in this list? What is the definition of analyzer? This will be an extensive list (e.g. several hundred).

**Part II, Section 12** - For the stayed portions of NSPS Ja, there is no answer to give regarding NSPS Ja applicability to flares. In light of the ongoing reconsideration process, EPA cannot expect refineries to speculate with respect to which flares might ultimately trigger NSPS Ja. Thus, NSPS Ja should be specifically excluded from consideration under this section of the ICR.

**Part II, Section 13** - Clarify this section only applies to units whose primary purpose is sulfur removal from fuel gas.

Table 13-1 (Fuel Gas Treatment Unit Information) asks for the Unit ID for each process unit that generates fuel gas treated in the treatment unit. However, one treatment unit can be receiving streams from multiple process units and treatment units can be interchangeable for maintenance reasons. Some sites have a main line for treatment that receives gas from many process units and then can be treated in different treatment units. It is very difficult to know which process unit offgas is being treated where. Clarification is needed how to handle such flexible operations. In addition, it is not clear this information has any use in developing regulations and the Agency should seriously consider deleting this question.

Clarify that the total sulfur and H₂S data requested in Table 13-1 is for the exit of the fuel gas system mix drum (NSPS J compliance point), not the treatment unit outlet as currently specified. If EPA insists on requesting this data from the fuel gas treatment unit, most of the respondents will not have this data available.

**Part II, Section 14** - Table 14-1 (Cooling Water System Information) Footnote 2 should contain a 4th code - “Services at least one heat exchanger in which the process fluid contains at least 5 wt% VOC and 5 wt% HAP”

Please clarify that this section is asking for information on each cooling tower system and not on each heat exchanger in the refinery.
Part II, Section 15 - Table 15-2 requests average HAP and VOC concentration in wastewater. Most refineries will not have this data since the BWON regulations only require the reporting of benzene emissions. Also, if refineries have estimates they may not be on a process unit basis.

EPA needs to clarify that individual process drains should not be listed separately in Table 15-3 (Wastewater Vent Information). If EPA would like a total drain estimate then that should be specified. There can be thousands of drains in a large refinery.

Part II, Section 16 - Clarify that waste loading operations are NOT included. The description of containers down to 250 gallons makes this confusing.

The definition of submerged fill for the ICR does not correspond to the regulatory definition in some rules (e.g., marine vapor MACT, gasoline distribution GACT). Thus, the results for the submerged fill question will be misleading. In this case, we recommend that no submerged fill definition be provided and sources be allowed to fall back on the regulatory definitions.

Part II, Section 17 - Question No. 2 asks “Describe any pollution prevention methods used to reduce the quantity of solid waste disposed on-site and the percent and/or quantity of waste reduced.” Clarify if cafeteria, office, medical, or other non-industrial wastes are included.

Also, provide further explanation of the question. Is the baseline assumption that all solid waste is disposed of onsite or is this question only dealing with solid wastes that have been disposed of to onsite active landfills, land application units, waste piles, or composting operations? If the latter, a time limit is needed, since some petroleum refineries have been in operation for many decades and it is unreasonable to require them to try to determine practices from the distant past. We recommend the question be limited to reduction activities that have been put in place during the last five years for solid wastes previously disposed of onsite.

“Quantities” of waste reduced by various prevention methods are often not known (since what doesn’t get produced, doesn’t really get measured), an estimates from different refineries may be quite different for the same activity simply because they are strictly guesses. For example, good housekeeping, or street cleaning to keep sediments out of sewers, are commonly used waste prevention measures, but it is difficult to estimate how much waste is reduced by these activities. So, at a minimum, the question should be revised to say something like “…..and if known, the percent and/or quantity of waste reduced.”

Part III – This part is misleadingly titled “Incidence Reports” but requests massive amounts of information on “non-routine emissions,” which are defined as “Emissions that occur during periods of start-up, shutdown, or equipment or component malfunction.” The title should be changed to reflect the real purpose of this section and the instructions for Table 1 should clearly include the definition of non-routine emissions event, rather than having that definition in another document.

Table 1 (Untitled) asks for extensive information on “non-routine” emissions, but nothing in the instructions or definition of non-routine emissions limits the request to events where emissions are different from routine emissions. Thus, for instance, EPA appears to be asking for
information on startup and shutdown events even if the emissions are the same or less than as during normal operations, which is the usual case. This request should be limited to only non-routine events where emissions are higher than normal emissions or where normal controls are bypassed or their effectiveness reduced. Furthermore, the request should be limited to releases to the atmosphere. If a release occurs to the fuel gas system, is captured by a flare gas recovery system, or is sent to a process, there is no reason for the Agency to gather information on that release. Further clarification of “non-routine emissions” is also needed to provide more detail on what events should be included in this part. Does EPA intend for facilities to calculate emission estimates (lbs/hr) for events where NSPS J standards were exceeded (i.e. SO$_2$ concentrations at an SRU during a startup event)? Where monitoring is not required, does EPA intend for facilities to estimate emissions for startup/shutdown events (e.g., NOX, CO emissions from flaring) if estimates are not already available? If so, has that time been incorporated into the burden and cost estimates? EPA should also clarify whether, for events with excess emissions, only reportable events (i.e., where RQs are exceeded) are to be included or all events.

Table 2 (Untitled) asks for names and contact numbers of people who submitted complaints. EPA has no regulatory basis to request this information. In addition, EPA can request information about public complaints from state agencies. Furthermore, EPA needs to explain how they will use this information and how they will obtain approval from the complainants to make their names and contact information public, since ICR responses will be posted to the docket. If EPA persists in requesting information about citizen complaints, EPA should seek that information from local regulatory agencies and then, only those complaints that were confirmed.

Also, Table 2 does not allow the owner/operator to supply information on the validity of the complaint or if the facility was responsible for the complaint. This was in the previous version and should be included in the final. Sources should be allowed to comment on how the complaint was handled.

**Part IV** – Clarify if projects companies were required to install under the NSR consent agreements are included in Tables 1 (Cost Data for APCD) and 2 (Cost Data for Process and Equipment Changes). Clarify footnote 10 of Table 1 on how to handle APCD where maintenance is performed on a longer than annual cycle. Should those activities by annualized?

Table 2 needs clarification on level of changes EPA expects to include. For instance, there will be thousands of minor process and equipment changes, such as pump seal upgrades, tank seal upgrades, water seal upgrades, removal of a few valves, remove a few feet of pipe, etc. that reduce emissions, but only in a minor way. It would involve thousands of hours of effort to try to gather all of the requested detail for those thousands of minor activities. The 20 hours EPA estimates for completing the cost section wouldn’t even be enough to begin gathering data for Table 2, unless those minor activities are excluded and we recommend EPA do so.
**Part V - Question 2 requires the reporting of daily averages - Is this midnight to midnight?**

Questions 2 and 3 call for daily average data for 2010 from qualified CEMS and CMS analyzers, though the introductory paragraph to the part only indicates CEMS data is being requested. These questions do not make clear that they are limited to the pollutants and measurements listed in the questions. Of particular concern is Question 3 and the need to clarify in the instructions for that question that CMS does not include parameter monitors or H₂S, reduced sulfur, total reduced sulfur, hydrocarbon, and BTU analyzers other than those used to monitor fuel and flare gas. Traditionally, CMS is a comprehensive term that covers parameter monitors. The listed analyzers, with perhaps the exception of the BTU analyzers, would normally be considered CEMS. Clearly, the burden and cost estimates did not include providing data on the multitude of parameter monitors present in a refinery or inclusion of all hydrocarbon analyzers, such as those used for product quality and process control, since the burden and cost estimates assumed only nine responses per refinery. EPA should be clear that Question 3 only requires data from the listed types of analyzers being used to monitor fuel and flare gas is required to be submitted.

For some of the types of analyzers listed, daily averages may not reflect the operation because they may include time periods where they are not representative. For instance, flare BTU analyzers may not be representative of the BTU content of flared gas, because the average may include time periods where there was no waste gas flow. In fact, that may represent the bulk of the time for particular flares. Similarly, some combustion stack analyzer results may provide incorrect information if the combustion device only operates intermittently (e.g., regeneration heaters). We recommend these situations be handled by specifying that daily averages not include periods when the device was not operating or when flares were not receiving process waste gas.

Question 4 asks about a “biodegradation rate test” or a “complete mixing test on a biological treatment unit.” Please define or provide a reference for these tests. Also, clarify if Question 5 includes fence line monitoring or community monitoring installed by companies?

Questions 4 and 5 request data back to January 2000, when Question 1 only asks for source tests from January 2005. Is this difference intentional? Older data may not be reflective of the current operation and the data provided in Part II, and the increased burden to provide information back to 2000 is unjustified.

In Attachment 2 of Part V, the second Note “1” indicated should be Note “2.”

**Component 2**

Speciation procedures for the emission inventory must be clarified. Methodology Rank 5 of the Refinery Emission Estimating Protocol requires use of a default value if no site specific data is available. Does that mean a refinery must use the Rank 5 methodology if it lacks site-specific data for one or a few minor species required by the Protocol? For instance, if a refinery has site specific data for 90% of the HAPs in a stream and it has the other data needed to use a Rank 2 or 3 methodology, does the Agency really want the refinery to use the Rank 5 methodology instead of the Rank 2 or 3 methodology? Sites have speciation data from multiple sources; site specific,
PERF data, other sources. All emission inventory and TRI emission estimates use a mix of site-specific and non-site specific data for speciation. If sites cannot use current methods of speciation and must use site specific only, there will be a lot of blanks in the data reported or only default values reported if they are in the Protocol.

The ICR requires use of the Refinery Wastewater Emissions Tool spreadsheets for the wastewater emission estimates. All of the information needed to use those spreadsheets is not available. Would the Agency like those emissions to be reported as not available in the inventory or for sites to provide estimates developed using other models?

Component 2 asks for a listing of annual and hourly permit limits. Some sites have individual limits, some have only annual limits, and some have caps in varying forms. How does EPA want caps shown in reporting tool? Just noted in the comment column?

It appears that Component 2 excludes steam generating equipment identified in Part I. Is it EPA’s intent to exclude refinery cogeneration units and boilers from the emission inventory?

Component 3

Clarify if Component 3 requires triplicate sampling and triplicate analysis or just triplicate sampling and one composite analysis? Also, clarify if this analysis should be performed per month or on a composite of the 3 months of samples.

The Note to Component 3 states “If you have multiple distillation columns and the feed to all of them is not the same, you must sample the feed from those that have significantly different feed streams.” Clarify how much difference is significantly different. A 5% difference is not likely to have much impact on the concentrations of the metals and other species being measured, but a 25% difference potentially could impact concentrations. We would suggest a 25% difference as the basis for this determination, though as discussed in Attachment 1, none of this information has anything to do with emissions and thus its collection is not justified under either the CAA or the PRA.

Clarify where these samples need to be collected. It is infeasible and unsafe to collect crude samples from the inlet to the distillation column due to the high temperature (in excess of 600 °F) as well as the high pressure. In order to obtain representative samples safely we believe these samples should be collected prior to the desalter.

EPA has specified that ASTM D-4057 be used for the manual collection of the crude samples. However, ASTM D-7482 should be used instead. This method is specifically for mercury analysis but can also be used to analyze for other metals. The ASTM D-7482 method is preferred for mercury analysis because it provides more reliable results.

Component 3 specifies the use of SW-846-6020, -6020A, SW-846-6010B, SW-846-7740 for Se, and SW-846-7060 or -7060A for As for determining metals (except Hg) in the crude oil samples. SW 846 is for solid waste products and groundwater. It does not make sense that the same preparation or analyses will apply to crude oil. For instance, you don’t need to digest the crude
oil samples to aqueous form as done in SW 846 for solid wastes and wastewaters. Additionally, these analysis methods only detect metals in the ppm range. There are reliable methods that are able to be reported out in ppb and avoid the sample preparation problems and these should be specified instead. Specifically, we recommend specifying ASTM D-7343, an x-ray fluorescence method, for determining metals in crude oil.

**Component 4**

By fixing the backend due date for testing, EPA has likely reduced the time allowed for executing and completing the required Component 4 testing from 180 days in the initial draft ICR. The exact amount of reduction depends on the when the ICR actually issues, but is likely to be in the range of 30 days. This is not adequate and, at a minimum, EPA should return to the 180 days, with allowance as discussed below for extensions when needed.

While a few of the stack tests EPA requires will be straightforward, most will not be and time will be needed to develop and receive approval for alternates or revisions to the specified sampling and analytical methods. If EPA is does not respond quickly to alternate requests, the August 31 reporting deadline, which is already potentially infeasible in some cases, cannot be met. We believe the schedule can stand no more than a short delay while waiting on EPA, particularly relative to sampling alternatives, since they involve facilities. To that end, EPA should extend the due date for any stack test by the time it takes for EPA to respond to alternate requests.

Additionally, some of the required stack tests will require hardware additions to complete (e.g. test ports, platforms) and, in some cases, unit and even partial refinery outages to allow safe sample port installation. Extensions to the stacked test reporting deadline should be allowed so process outages can be coincided with planned maintenance outages where outages are necessary to install facilities. Since extra process shutdowns will increase emissions to the environment, impact fuel supplies, and were not included in the burden or cost estimates, EPA should not require such outages.

Sometimes stack tests are done for method and process development purposes. These tests may use non-standard methods or be run at unusual operating conditions or involve stack flow and concentration conditions for which the standard methods are not suited. EPA should clarify that Component 4 Question 1 does not include these unusual stack tests.

EPA should clarify how it intends to address units which have been chosen for testing but which 1) are no longer in operation, 2) do not have atmospheric vents, or 3) do not have the equipment specified to be tested.

Section 1.0 of Component 4 indicates that if you have completed a substantially similar test within the past five years and have submitted that test, new testing is not required. Since EPA is requiring testing of obscure species, normal tests are likely not to have included every species EPA is requiring. In such a case, would the old test be considered substantially similar?
Table 1.1 indicates what species must be measured for each type of process unit. EPA should make clear that if a cell is empty in that Table, testing for the indicated specie is not required for that process unit.

Component 4 calls for testing of delayed coker coke drum vents. However, some delayed cokers do not vent to the atmosphere for more than a few minutes. Testing requires at least an hour to complete a test run. If the coker does not vent for an hour, test results will not be accurate or representative and EPA should not require testing in those situations.

Some refineries supplement mixed fuel gas with natural gas downstream of the mixing drum and CEMS. EPA should clarify that they still want the sampling from the mixing drum, rather than after the natural gas addition in such situations.

Section 1.4 of Component 4 specifies testing requirements for Enhanced Biodegradation Units (EBU). EBU is defined in BWON (and is not included in the ICR definition list) as a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. Some sites listed have biological treatment but those biological treatment units are not BWON EBUs. Do those sites still have to test and using what procedures?

**Summary of Comments and Responses**

The discussion on the cost of completing Component 2 in the summary of comments and responses suggests that EPA expects that refineries will be using Refinery Emission Estimating Protocol (Protocol) version 2.1 to complete the TRI and State Emission Inventories for 2010 data and thus will only need to supplement the those inventories in order to respond to this ICR request. EPA needs to clearly state that they are not requiring use of the Protocol for TRI or State Emission Inventories, changes that would require notice and comment rulemaking.
Attachment 3

Summary of Refinery Information Collection Request (ICR)

Four Components of the Refinery ICR:

**Component 1 (92 pages + 32 pages of definitions)** - Information to be collected by all 152 refineries (Submit to EPA by May 31, 2011) [EPA Estimate – 18,000 hours, $1.7 million]

a. Detailed facility information, including detailed energy production and use information
b. Detailed design and operating information on process equipment, controls, applicable regulations, etc.
   - Process units
   - Process heaters
   - Fuel gas and natural gas systems
   - Storage tanks
   - Other atmospheric vents
   - Equipment leak components
   - Cooling water systems
   - Flares
   - Wastewater treatment
   - Loading operations
   - Solid waste management
   - Annual and hourly permit limits required
c. Incidents and non-routine emission events for 2010, including startups and shutdowns
d. Cost and other information of all emission reduction activities within last 5 years
e. Emission monitoring and source test data - stack tests after January 1, 2005; CEMS data from 2010

**Component 2** - Complete emissions inventory from all 152 refineries using EPA Refinery Emission Estimating Protocol (250 pages) and new, untested Wastewater Emission Estimating Tool (Submit to EPA by June 30, 2011) [EPA Estimate – 35,000 hours $3.3 million]

**Component 3** - Sampling and analysis of the feed to the first distillation column(s) (crude atmospheric tower) from all 152 refineries (Submit to EPA by August 31, 2011) [EPA Estimate – 0 hours, $9.7 million]

a. Three sets of samples taken 30 days apart
   i. Multiple crude units requires multiple tests
   ii. Must indicate if crude slate is “significantly different” than what was used in 2010

**Component 4** - Stack and other testing (e.g., fuel gas systems, cooling towers) (Submit to EPA by August 31, 2011) [EPA Estimate – 16500 hours, $16.2 million]

a. Specific facilities must conduct specific tests
b. Deviations from prescribed test method must be approved
c. CEMS data can be used instead of testing where available - CEMS data should correlate to same times as other stack testing completed

EPA Estimated Total Burden and Cost – 69,000 hours, $30.9 million
API/NPRA estimate - >540,000 hours, >$77 million