January 11, 2021

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID EPA-R06-OAR-0510
Via regulations.gov

Re: Comments on Proposed Notice of MACT Approval (NOMA), Draft Prevention of Significant Deterioration (PSD) Permit, and Draft Title V Permit for Bluewater Texas Terminals LLC

Bluewater Texas Terminal LLC ("BWTX") appreciates the opportunity to provide comments on the three proposed draft permits for which public notice was made on November 12, 2020. As the permit applicant, BWTX agrees with EPA's proposal to issue all necessary authorizations under the Clean Air Act for its project, and commends EPA staff for their considerable efforts in conducting a thorough and detailed review. Further, BWTX believes that EPA could lawfully issue each of the proposed authorizations based on the administrative record before it at the time of the proposal.

Consequently, with the exception of a proposed reduction in the PTE for loading emissions, BWTX does not have any comments on specific conditions of each proposed authorization or permit. Instead, BWTX's comments are intended to: (1) identify additional bases in support of EPA's issuance of all authorizations, (2) identify areas where EPA's reasoning should be strengthened, and (3) request that EPA clarify how it has satisfied the procedural requirements applicable to its review. Specific areas of comment include the following:

- PSD Step 1. EPA did not explain fully why a platform-based control for volatile organic compounds ("VOCs") would or would not redefine the source proposed by BWTX. EPA did not explain why platform-based VOC controls have been "demonstrated." As a result, EPA has not included additional lawful grounds upon which the issuance of the PSD permit could be based.
- PSD Step 2. EPA mistakenly concluded that a control option—platform-based controls for volatile organic compounds ("VOC") routed from a mooring buoy through subsea vapor lines—with no demonstrated application is technically feasible under Step 2 of the top-down BACT process. EPA reached this mistaken conclusion by relying on incomplete, unverifiable, or otherwise non-public information. EPA has not fully disclosed the information upon which it relied in making this finding, and has not fully explained how its decision comports with applicable permitting guidance. As a result of these mistakes, EPA has not included additional lawful grounds upon which the issuance of the PSD permit could be based.
- PSD Step 4. In its economic analysis, EPA mistakenly declined to consider the full costs associated with deploying an innovative and unproven control option for VOCs. EPA also did not explain clearly how the costs for the control options it did *not* select under Step 4 were in excess of the costs incurred by other facilities of the type under review. As a result of these mistakes, EPA has not included additional lawful grounds upon which the issuance of the PSD permit could be based.
- Title V. EPA did not clearly explain its non-applicability determination for MACT Y and for Texas SIP requirements.
- NOMA. EPA did not clearly explain why it is appropriate to issue a Notice of MACT approval, and also did not identify the actual procedures it relied on in setting the MACT emission limitation/work practice.

Considering the level of public interest on the draft permits, it is of special importance for EPA to provide as detailed an explanation as possible of the bases for its decisions. BWTX urges EPA to consider the

enclosed comments (comments specific to a particular permit are clearly captioned) and improve its Statements of Basis by incorporating additional information justifying its decision.

Yours,

chaitalidave

Chaitali Dave

Bluewater Project Manager

Enclosure

Attachment— List of Comments

Comments on PSD Permit

General

1. The draft permit requires application of BACT at each emissions unit at the proposed stationary source. The permit additionally specifies the methods used for determining compliance with its emission limitations, which include instrumental monitoring, recordkeeping designed to serve as monitoring, and other related provisions. The permit imposes a general duty to maintain and operate the facility in a manner consistent with good air pollution control practices at all times. The permit includes malfunction-specific reporting requirements but does not provide for any waiver of its control requirements during periods of malfunction, nor does it create any specific affirmative defenses for excess emissions during malfunctions.

   The permit contains all of the elements required for a PSD permit, and BWTX supports its issuance. BWTX applauds EPA staff for conducting a thorough review.

Potential to Emit

2. The potential to emit (PTE) for VOC was calculated as follows in BWTX's application (fig. 3-1) following EPA Publication AP-42 Sec. 5.2, equation (1), which applies to loading of "petroleum liquids":[1]

$$E = L_L \times Q = \frac{SPM}{RT} Q = \frac{0.2 \cdot 8.44 \cdot 59.37}{0.0019109 \cdot 531.8} \times 384,000 \approx 37\,\mathrm{MMlb/yr} = 18,936\,\mathrm{tpy}$$

   "Petroleum liquids" are defined in EPA regulations to include crude oil as well as most finished and intermediate products manufactured in a petroleum refinery.[2] In addition to this generic methodology, AP-42 Sec. 5.2 also specifies a separate set of equations (equations (2) and (3)) "specifically for loading of crude oil into ships and ocean barges."[3] Using equations (2) and (3) would result in a PTE as follows.

$$\begin{aligned} E = (C_A + C_G) \times Q &= 42 \left[0.86 + 1.84(0.44P - 0.42) \frac{MG}{T} \right] Q \\ &= 42 \left[0.86 + 1.84(0.44 \cdot 8.44 - 0.42) \frac{59.37 \cdot 1.02}{531.8} \right] 384,000 \\ &\approx 25\,\mathrm{MMlb/yr} = 12,500\,\mathrm{tpy} \end{aligned}$$

   This emission rate is approximately 66% of that estimated in BWTX's application. BWTX felt obliged to use equation (1) in preparing its application based on guidance received at a pre-application meeting with EPA Region 6 representatives. EPA Region 6 has attempted to apply TCEQ permitting procedures in its review (for example, by requiring that a state air toxics dispersion modeling analysis be conducted), and TCEQ (the environmental agency for the nearest affected coastal state) requires that equation (1) be used in NSR permit applications that it processes.[4] BWTX offers three reasons why EPA should not require the use of equation (1) as noted in TCEQ Publication APDG-xxx.

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[1] N.B. 0.0019109 MBbl psia/(lbmol °R) and 1/12.46 Mgal psia/(lbmol °R) are equivalent expressions of the ideal gas constant, *R*.
[2] 40 C.F.R. § 60.111a(b).
[3] AP-42 Sec. 5.2 at 5.2-8.
[4] TCEQ Publication APDG-xxx. *Air Permit Technical Guidance for Chemical Sources: Loading Operations.* DRAFT Oct. 2000. At 10. ("Emissions from all loading shall be estimated using the following expression which can be found in AP-42…")

First, as indicated above, equations (2) and (3) are more relevant than equation (1) in estimating emissions from loading crude oil into ships and ocean barges.

Second, BWTX notes that the draft permit (Condition IV.B.3) does not require use of TCEQ Publication APDG-xxx, but instead requires use of AP-42 Sec. 5.2 for use in calculating emissions for compliance purposes.[5] In other words, the draft permit allows use of equations (2) and (3). BWTX also understands that EPA is nearing approval of a separate case-by-case MACT application ("GulfLink application") for which VOC emissions have been calculated using equations (2) and (3) instead of equation (1).[6] BWTX agrees with the relevant factual assertions made in the GulfLink application supporting use of equations (2) and (3).

Third, because federal—not state—law applies on the Outer Continental Shelf, EPA is not bound to use the TCEQ guidance that uses equation (1). Indeed, because the use under APDG-xxx of equation (1) is inconsistent with the more relevant equations (2) and (3) from AP-42, EPA *may not* use the inconsistent state requirement.[7]

For these reasons, BWTX has prepared a complete set of alternate emission calculations (Corresponding to Fig. 3-1 of the PSD permit application), which are included as an appendix to this document. **If EPA approves a calculation methodology involving use of equations (2) and (3), it should update the estimated PTE for the project, and should likewise update the baseline emissions rate employed in Step 4 of its top-down BACT analysis.**

A. EPA should clarify whether it approves the use of equations (2) and (3) for air permitting actions.

B. EPA should clarify whether it interprets § 1518(b) of the Deepwater Port Act to require use of TCEQ guidance on loading operations, even if the TCEQ guidance conflicts with an EPA guidance document. EPA should also clarify whether *Parker Drilling Mgmt. v. Newton* is relevant to its interpretation.

C. To the extent that the PTE or baseline emissions rate materially affects the outcome of any aspect of the PSD review (e.g., economic impacts analysis, air quality analysis), EPA did not take into consideration variability between the two sets of published calculation methodologies, even though it issued a draft permit approving use of the methodology.

Specifically, EPA did not consider that use of equations (2) and (3) would have resulted in proportionally higher average cost effectiveness levels (given below) for EPA's and BWTX's calculations, respectively:

$$\$\,14,444\,/\text{ton} \times \left(\frac{18,936\,\text{tpy}}{12,500\,\text{tpy}}\right) = \$\,21,881\,/\text{ton}$$

$$\$\,34,790\,/\text{ton} \times \left(\frac{18,936\,\text{tpy}}{12,500\,\text{tpy}}\right) = \$\,52,702\,/\text{ton}$$

A complete calculation for the latter figure is included as an appendix to this document.

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[5] "Emissions shall be calculated using the calculation procedures contained in EPA's AP-42: Compilation of Air Emissions Factors, Section 5.2, Transportation and Marketing of Petroleum Liquids (December 4, 2008) [*tout court*]."

[6] *Case-by-Case MACT Application. GulfLink Project. Proposed Deepwater Loading Port Facility*. October 2020. Docket MARAD-2019-0093 (henceforth "GulfLink Application"). At 3-9–3-16. N.B. Items referenced by docket number were accessed via https://www.regulations.gov/.

[7] *See Parker Drilling Mgmt. Serv., Ltd. v. Newton*, 587 U.S. ___ (2019), slip op. at 7–8 ("Because federal law is the only law on the OCS, and there has never been overlapping state and federal jurisdiction there, the statute's reference to "not inconsistent" state laws does not present the ordinary question in pre-emption cases—i.e., whether a conflict exists between federal and state law. Instead, the question is whether federal law has already addressed the relevant issue; if so, state law addressing the same issue would necessarily be inconsistent with existing federal law and cannot be adopted as surrogate federal law. Put another way, to the extent federal law applies to a particular issue, state law is inapplicable."). *Available at* https://www.supremecourt.gov/opinions/18pdf/18-389_4g15.pdf.

D. If EPA approves the use of equations (2) and (3) for air permitting actions, it should reduce the emission limits in Section III of the draft permit consistent with the supplied alternative calculation.

Control Technology Review

3. In the present action, EPA proposes to conduct its control technology review following the familiar five-step "top down" process described in its 1990 *New Source Review Workshop Manual* and its 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases*.[8] ("NSR Workshop Manual" and "GHG Guidance," respectively) Although the Deepwater Port ("DWP") is not subject to any GHG-specific requirements, BWTX understands that Region 6 staff have incorporated elements of the GHG guidance into their BACT analysis, which is understandable in light of Region 6's prior experience reviewing GHG PSD permits while a GHG PSD FIP was in place for the State of Texas. **EPA did not articulate a basis for its reliance on both guidance documents in conducting its BACT analysis.**

4. At Step 1 of the control technology review, EPA identifies six types of potentially applicable controls: (i) submerged fill loading; (ii) two types of add-on vapor combustion technologies (vapor combustor and process flare); and (iii) three types of add-on vapor recovery technologies (refrigeration, adsorption, and vapor balancing). EPA also acknowledges that all of the options involving add-on controls would involve modification to BWTX's proposed design. The processes EPA identified which might enable use of an add-on control device are: (i) subsea vapor pipelines and fixed offshore platform; (ii) subsea vapor pipelines to shore; and (iii) specially designed workboat or shuttle tanker.[9]

A. EPA's top-down framework divides potentially applicable control alternatives into three categories: inherently lower-emitting processes/practices/designs, add-on controls, and combinations of inherently lower emitting processes/practices/designs and add-on controls.[10] **In Step 1 of its analysis, EPA did not clearly distinguish between add-on controls and inherently lower-emitting processes/ practices/ designs. Clarifying this distinction is important—as more fully described below—for the redefining the source analysis, the Step 2 technical feasibility analysis, and the Step 4 economic feasibility analysis.**

BWTX understands that there are sixteen logically possible control options that were evaluated by EPA (5 add-on controls × 3 designs + 1 work practice = 16 control options). EPA has not made these options/combination of options explicit in its Step 1 list of potentially applicable control alternative. Conversely, BWTX *was* explicit in its application (p. 4-8), which identified seven potentially applicable control options (six combinations of control device and design and one work practice).

This lack of explicitness appears to derive from EPA's use of the SPOT Terminal Services PSD Public Notice as a template for the BWTX project.[11] The SPOT project included as a part of its base design an offshore platform (which was required for reasons independent of air pollution control). In the SPOT BACT analysis, no alternative processes were considered by EPA, and it was not critical for EPA's Step 1 analysis to consider all possible combinations of add-on controls and inherently lower-emitting processes/practices/designs.

In contrast to SPOT, the BWTX DWP base design does *not* include an offshore platform (nor subsea lines to shore, nor controlled workboats/shuttle tankers). So that the bases for its decision can be articulated more clearly—and so that additional and alternative grounds for a decision can be more clearly described—**EPA should explicitly list in Step 1 all potentially applicable control alternatives and their various combinations**.

B. BWTX acknowledges that it is possible that EPA did not list all sixteen logically possible control options because EPA believes that an offshore platform (as a foundation for VOC controls) is not an inherently lower-emitting process/practice/design, but is instead simply a part of an add-on control. If this is EPA's

[8] PSD/Title V SoB at 6.
[9] Id. at 7.
[10] Cf. GHG Guidance at 25.
[11] Docket item EPA-R06-OAR-2019-0576-0003 at 10–12.

position, it should be clarified as such. In addition, for the reasons set forth in more detail below, BWTX would respectfully disagree if this actually is EPA's position.

BWTX commented in a June 11, 2020, letter to EPA that offshore "hub platforms" and "junction platforms" exist in the Gulf of Mexico to facilitate pipeline interconnections, maintenance, and other functions necessary for offshore pipeline systems.[12] Where piping systems with different pressure specifications are connected, safety valves are introduced which may be located on a platform.[13] The platform contemplated by EPA would be an offshore hub or junction platform.[14] BWTX is not aware of any example where such a platform has been installed for the primary purpose of controlling air pollution, nor of any example where such a platform would have been omitted from a construction plan in the absence of air quality regulations.[15] Two examples illustrate this:

- The SPOT DWP license application indicates that the primary driver for its proposed construction of a fixed offshore platform is to accommodate a pipeline specification break, which requires construction of a platform based on current engineering discipline in the Gulf of Mexico. The opportunity to control VOC emissions is identified as a secondary consideration.[16]
- In September 2020, a DWP license application was filed by Blue Marlin Offshore Port LLC, describing proposed use of two existing offshore hub platforms and existing offshore pipeline infrastructure as part of a proposed crude oil export facility.[17] The applicant does not identify air pollution control as a factor for its inclusion of the existing platforms in its license application.

Offshore hub or junction platforms are components of offshore pipeline networks. When proposed as part of a deepwater port for crude oil exports (four such proposals have been made in recent DWP license applications), they are necessary to the project design regardless of air pollution control considerations. Such platforms are neither add-on control devices nor appurtenances thereto.

C. BWTX's PSD application (pp. 4-12–4-17) advanced two alternative arguments for rejecting a control option consisting of an add-on control device (vapor combustor) and supporting process (subsea vapor pipelines, fixed offshore platform, and other associated equipment) as BACT at Step 1.

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[12] *Cf.* Genesis Energy, L.P. SEC Form 10-K for fiscal year ending December 31, 2019 ("Offshore Hub platforms are typically used to interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and conduct drilling operations during the initial development phase of a crude oil and natural gas property.").

[13] *Cf.* Minerals Management Service. 2010. Evaluation of High Integrity Pressure Protection Systems (HIPPS). https://www.bsee.gov/sites/bsee.gov/files/tap-technical-assessment-program//623aa.pdf (accessed December 3, 2020).

[14] N.B. an offshore hub or junction platform has little similarity to a "sea island"-type dock with fixed moorings. Cf. BWTX NOMA application at 3-2–3-6. Such a loading operation operated in San Francisco bay prior to 1995 using a control device on the dock itself. Though BAAQMD referred to the dock as a "platform" in its comments to the MACT Y docket, the similarities of that facility to an offshore hub platform more or less end with the word "platform." *See Id*. 3-2–3-6, 5-10. In any case, EPA has not identified "sea island"-type facilities as relevant in either SoB.

[15] Cf. David Solomon (EPA OAQPS) Nov. 27 1995, to Timothy Mohin (Intel Corporation). *Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment*. (discussing distinction in the context of the definition of "potential to emit").

[16] *Deepwater Port License Application. Sea Port Oil Terminal Project. Volume IIa— Offshore Project Components Environmental Evaluation*. Docket item MARAD-2019-0011-0001. At 1-9–1-10.

[17] *Deepwater Port License Application. Blue Marlin Offshore Port (BMOP) Project. Volume I— Deepwater Port Application*. Docket item MARAD-2020-0127-0003. at 1–2.

(1) The process has never been demonstrated in practice.[18]

(2) Modifying BWTX's project to incorporate a process/design involving a fixed offshore platform would interfere with BWTX's business purpose and would impermissibly redefine the source.

EPA's Step 1 analysis mentions that "some alternatives" would entail modifications to the proposed facility, but does not explain why it rejected both of BWTX's Step 1 arguments. **EPA was mistaken in finding—without detailed explanation-- that a combination of technologies that have never been demonstrated in practice is "available." EPA was also mistaken in finding—again, without detailed explanation—that including a platform as a foundation for air pollution controls would not "redefine the source."**

5. At Step 2 of its control technology review, EPA eliminated adsorption, vapor balancing, use of a process flare, as well as any controls not mounted on an offshore platform, as technically infeasible. EPA found the three remaining options (refrigeration system on offshore platform, vapor combustor on offshore platform, and submerge fill) to be technically feasible. A control option is considered to be technically feasible if it "(1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review."[19]

A. BWTX reads EPA's Step 2 analysis as conceding that neither of the two control options involving add-on controls have been demonstrated and operated successfully on the same type of source under review. **BWTX requests that EPA state clearly whether such controls have been demonstrated. In addition, for the reasons set forth in more detail below, BWTX would respectfully disagree if EPA believes that these controls have been demonstrated.**

B. EPA concludes that addition of a fixed platform is the most practical choice for implementing a combustion-based control system.[20] While vapor combustors are add-controls which are in widespread use at onshore terminals, the associated platform-based design/process is not. EPA admits that no such control system actually exists, and that its only knowledge of such a system is derived from its review of the SPOT PSD application,[21] which describes a *sui generis* design for which a permit has not yet been issued.[22] Furthermore, EPA has determined in a separate action that it would not consider any source constructed with an offshore platform as a potentially "similar source" (40 C.F.R. § 63.42).[23]

EPA should clarify that its finding of technical feasibility for the two options involving add-on controls rests on a finding that the options are both <u>available</u> and <u>applicable</u> to the source type under review. In addition, BWTX would respectfully disagree if EPA believes that these controls are available and applicable.

C. EPA correctly sets aside the consideration of technology risk in its short discussion of basic design elements in Step 1 of its analysis. But EPA mistakenly did not include an evaluation of technology risk as required in Step 2. In its Step 1 analysis, EPA quotes from *In re Prairie State Generating Company*: "the business objective of avoiding risk associated with new, innovative or transferable control technologies is not treated as a basic design element."[24] The full quote from Prairie State goes on to state: "but instead is considered under step 2 of the top-down method."[25] However, rather than

[18] See NSR Workshop Manual at B.10. ("Lower-polluting processes should be considered based on **demonstrations** made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels."). Emphasis supplied.
[19] GHG Guidance at 33. Substitution of "or" for "and" in the PSD/Title V SoB (at 8–9) is presumed to be a typographical error.
[20] Id.
[21] Cf. Docket EPA-R06-OAR-2019-0576.
[22] PSD/Title V SoB at 13 ("…we are unaware of an operational offshore SPM buoy system supported by a nearby fixed platform that is currently equipped with vapor emissions control.")
[23] NOMA SoB at 12 ("…EPA decided to consider other similar projects identified by BWTX that did not have a platform.")
[24] PSD/Title V SoB at 7 n. 10.
[25] 13 E.A.D. 1, 23, n.23 (EAB Aug. 24, 2006).

considering technology risk in Step 2, the EPA assumes without discussion that the control technology is 100 percent reliable.[26]

EPA mistakenly did not consider the risks of control technology transfers in assessing whether a control option is <u>commercially available</u> for purposes of Step 2, and in particular, whether transferred controls can be reasonably estimated to be less than 100 percent reliable.

D. EPA comments that BWTX has not developed detailed engineering plans, engaged engineering contractors, or completed other planning for construction of a DWP facility similar to SPOT's. [27] BWTX reads EPA's statement as conceding two problems with its finding of technical feasibility:

(1) **BWTX could commission work for an attempted redesign of its project to correspond more closely to SPOT's, but this would cause it to incur impermissible "extended time delays and resource penalties,"[28] implying a lack of <u>commercial availability</u>.**

(2) As remarked above, **EPA's only familiarity with the control option under consideration is its knowledge of the pending PSD permit application for SPOT**. This fact points to more fundamental problems with EPA's finding of technical feasibility. An implied expectation to reverse-engineer a rival's contemporaneous project appears to cut against the whole notion of a case-by-case control technology review.[29] Because it was not reasonable for BWTX to sponsor expensive and time-consuming original engineering research during the processing of its PSD application (and EPA did not require it to do so), the control options evaluated at Step 4 lack the level of definition traditionally expected. BWTX sees this fact as a sign that EPA is on the wrong track by finding that it is feasible for BWTX to construct a project similar to SPOT's DWP project (which, EPA assumes, incorporates technically feasible pollution controls).

E. The EPA discusses the SPOT PSD application, which describes the use of a vapor combustor on an offshore platform for control of a proposed (but not permitted or constructed) SPM loading facility, and states that the control system was based on a detailed analysis conducted by the permit applicant. The NSR Workshop Manual specifies that non-deployed control technologies may only be treated as <u>applicable</u> if they are "specified in a permit."[30] The same guidance document also states that for process-type control alternatives, "the decision of whether or not it is <u>applicable</u> to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique <u>had been applied previously</u>."[31]

(1) BWTX provided detailed supporting technical information in its permit application in support of a finding that the vapor combustor and platform option is not <u>applicable</u> (and therefore not technically feasible). A similarly detailed analysis has been provided by another permit applicant.[32] EPA has summarized, but not responded to or rebutted BWTX's analysis in any of its particulars. BWTX has not been able to locate EPA's technical feasibility analysis for the

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[26] PSD/Title V SoB at 17.
[27] PSD/Title V SoB at 13.
[28] NSR Workshop Manual at B.18. *Accord In the Matter of Spokane Regional Waste-to-Energy*. 2 E.A.D. 809 (Adm'r Jun. 9, 1989) ("[G]iven the Clean Air Act's emphasis on granting or denying completed PSD permit applications within one year of filing, it would be unreasonable to read "available" as imposing a duty on the permit applicant to conduct time-consuming original research by generating new data for the purpose of discovering whether a potential, but unproven, technology might possibly prove successful.")
[29] *In the Matter of New York Power Authority*. 1 E.A.D. 825, 827 (Adm'r Dec. 6, 1983) ("…BACT determinations for equipment utilized at one site [are] not necessarily [] carried over and applied as precedent at another site. All BACT determinations are site specific.") Accord *In the Matter of Certainteed Corporation*. 1 E.A.D. 743, 747 (Adm'r Dec. 21, 1982). ("…the 'case-by-case' evaluation of economic costs and energy and environmental impacts that has to be performed as part of BACT determination is inextricably tied to a specific set of assumptions regarding the type of pollution control technology that will be in place at each facility.")
[30] NSR Workshop Manual at B.18. *Cf. In the Matter of TEX-USS Corporation* (Adm'r, Jul. 19, 1982) (Region's finding of technical feasibility for an emission limitation based on its inclusion in other PSD Permits was appropriately considered).
[31] Id. B.19. Emphasis supplied.
[32] GulfLink application at 6-2–6-33.

SPOT project. **If it is actually material, EPA did not include its technical feasibility analysis for SPOT in the administrative record, or otherwise provide actual documentation of its decision-making process.**

(2) **EPA was mistaken to the extent it assumed that a technology must be treated as <u>applicable</u> (and technically feasible) when described in a PSD application, even if the permit is never issued, or even if the associated project has no realistic prospect of completion.**[33]

(3) **If it relied on non-public information for a control option that has not been specified in a permit, the EPA was mistaken.**

(4) BWTX acknowledges that EPA's finding of technical feasibility might have been driven by the perceived need for consistency in its decision making under Step 2 for platform and non-platform-based deepwater ports, rather than by its application of the applicable guidance documents on a case-by-case basis. **If the EPA believes that it is important to achieve consistency in decision-making at the expense of following a case-by-case analysis that might yield different outcomes at different projects, EPA should say so explicitly.**

F. EPA refers to "successful demonstration" of the use of subsea vapor pipelines at nearshore terminals employing onshore control devices.[34] T**he two nearshore terminals referred to are GIMT and Ashkelon Oil Port. Information about the vapor recovery systems at neither facility constitutes evidence of successful demonstrations of vapor recovery technology. If additional information exists, EPA has not identified it as a base for its decision-making.**

(1) As noted by EPA,[35] GIMT operated for a total of six months, permanently ceasing operations in 1994. The best available public information describing GIMT's control system was published in 1989, prior to the start of operation of the facility.[36] BWTX has conducted a diligent search and been unable to locate any information describing actual performance of the facility.

(2) Actual information about Ashkelon Oil Port is even more limited. As indicated in BWTX's PSD application (pp. 4-10–4-11), public information about the vapor control system at that facility is limited to a very brief mention in the Port Handbook:[37]

> *A Vapour Combustion Unit (VCU) was installed in Ashkelon Oil Port. Gasses emitted from vessels during loading operations, are transferred to the VCU and are burned in a monitored process.*
>
> *The VCU enables continued loading of vessels without dependence of wind directions.*

The latter statement implies that use of the VCU is in fact optional, and that the terminal operator uses it as needed to prevent high readings at onshore air monitors.[38] BWTX notes that intermittent control of sources is specifically disallowed under the Clean Air Act.[39] Further information about the terminal may be difficult to obtain, since BWTX understands that the site is treated as sensitive by the Israeli government due to its proximity to the Gaza Strip.

BWTX has been unable to obtain more detailed information directly from the terminal. A recently-filed case-by-case MACT application for a separate project reports a similar failure to

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[33] Cf. *In the Matter of New York Power Authority*. 1 E.A.D. 825, 826–827 (Adm'r, Dec. 6, 1983).
[34] PSD/Title V SoB at 13.
[35] NOMA SoB at 11.
[36] DiElsi, Gary J. "Principles of Marine Vapor Recovery." *Marine Technology* 26(1): 34–43, January 1989.
[37] Port of Ashkelon. Information, Operational Procedures and Regulations Handbook. May 2019. Accessed December 1, 2020, at https://www.eapc.com/wp-content/uploads/2013/07/ashkelon-port-regulations.pdf.
[38] The Hebrew-language version of the terminal's website provides access to readings from a government air quality monitor showing concentrations of benzene, among other pollutants. https://www.svivaaqm.net/Online.aspx?ST_ID=160;0;GRID
[39] *See* CAA § 123(a)(2), prohibiting the use of dispersion techniques in setting emission limits.

obtain more detailed information, and comments that the controlled SPM was taken out of service in June 2020.[40]

Since some level of "hard data" is normally expected before a control option can be treated as "available,"[41] **EPA did not adequately disclose the data it considered in concluding that capture and control of loading vapors using subsea lines has been successfully demonstrated.**[42]

6. In its PSD application, BWTX argued that construction of an otherwise unnecessary offshore platform, equipped with a vapor combustion system, would present unacceptable safety risks: among other hazards, it would constitute a manned structure storing and receiving highly flammable materials; it would entail frequent transportation of highly flammable materials; and its design would necessary deviate from US Coast Guard Regulations developed to ensure the safety of marine vapor control systems.[43] In short, it could interfere with BWTX's general duty to "design and maintain a safe facility."[44] **EPA was mistaken to the extent it did not take safety into account (particularly in the case of overt conflicts with safety regulations) in determining whether a control option is "available" (in either the Step 1 or Step 2 sense of the word).**

7. At Step 4 of its control technology review, EPA conducts an economic analysis for one control option (vapor combustor on offshore platform), and comments that economic impacts for a second technology (carbon adsorption on offshore platform) would be more adverse, even if that technology were feasible. EPA concludes that use of a vapor combustor on an offshore platform should be rejected based on its economic impacts.

   A. BWTX agrees with EPA that any add-on control options would have unacceptable economic impacts. Since **EPA has understated these economic impacts**, the following comments should serve to strengthen the basis for EPA's overall finding.

   BWTX provided an economic analysis for the option of a VCU located on a special-purpose offshore platform and estimated an average cost effectiveness of $34,800/ton VOC removed (PSD application tbl. 4-6). EPA does not report this value, and instead presents the results of a cost effectiveness calculation performed by EPA which was determined by altering four key assumptions in BWTX's economic analysis. The result ($14,444/t VOC removed) is given, and is accompanied by a supporting table in the docket.[45] BWTX notes EPA's efforts to develop its own independent economic analysis with supporting documentation, but disagrees with its components and conclusions.[46]

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[40] GulfLink application at 6-34–6-35.

[41] *In the Matter of Spokane Regional Waste-to-Energy*. 2 E.A.D. 809 (Adm'r Jun. 9, 1989). *Accord In the Matter of Brooklyn Navy Yard Resource Recovery Facility*. 3 E.A.D. 867 (Adm'r Feb. 28, 1992).

[42] *Cf. also In re Steel Dynamics, Inc*. 9 E.A.D. 165, 193–194, n. 33 (EAB Jun. 22, 2000) (upholding permitting authority's ignoring data from installation of SCR at Japanese steel mill electric arc furnaces where there was "no information in the record … to substantiate when or how [the NO_X] removal levels were achieved or explain the operating parameters of the steel mills' EAF or SCR systems.") *Accord In the Matter of Mecklenburg Cogeneration Limited Partnership, Clarksville, VA*. 3 E.A.D. 492, 494 n.3 (Adm'r Dec. 21, 1990) (upholding reviewing authority's rejection of a transfer technology [SCR on pulverized coal-fired boilers] based on lack of demonstration: "A rule of reason proportionate to the technology's track record necessarily governs how much detail and documentation must go into consideration of a particular technology.")

[43] PSD application at 4-28–4-31. *Cf. also* GulfLink application at 6-23–6-26, 6-33 (discussing safety issues relating to placement of detonation arrestor).

[44] CAA § 112(r)(1).

[45] PSD/Title V SoB at 15–17.

[46] As noted in a previous comment, had EPA properly considered the differing emission calculation methodologies prescribed by TCEQ's and its own guidance for crude oil loading operations, it would have reported its average cost effectiveness as a range ($14,444–21,881/ton), rather than giving only a point estimate. Moreover, to the extent that EPA believes itself bound to use the TCEQ guidance in its initial estimation of PTE, the NSR Workshop Manual requires EPA to set the baseline emission rate at a level that represents a realistic scenario of upper boundary uncontrolled emissions. NSR Workshop Manual at B.37–B.38. As explained above, AP-42 equations (2) and (3) reflect the realistic scenario of upper bound emissions, and should be used—with a corresponding permit limit on PTE—to make Step 4 calculations.

B. EPA calls into questions BWTX's use of a contingency factor based on 40% of the total installed cost. EPA believes that the factor should be 15% and that the basis should be the total indirect costs, and has incorporated these preferences into its analysis.

(1) EPA states that it considers vapor combustion a mature technology, and that while its application at a DWP is new, the contingencies should not be significantly outside the range provided by EPA's cost manual. The *Air Pollution Control Cost Manual* (APCCM) reads as follows:[47]

> *Contingency can also vary depending primarily on the age of the technology. For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI.*

BWTX does not dispute that vapor combustors standing alone are a mature add-on control technology. However, since the control option in question consists of both add-on controls and a *sui generis* combination of process/design components (offshore platform, subsea vapor pipelines, etc.), **EPA mistakenly ignored the "age" of the control option. EPA has not clearly explained why undemonstrated process/design components should be treated in the same manner as "mature" technologies**.

(2) In addition to the "age" of a control technology, contingency factors also "account[] for inadequacies in cost estimating methods" and are "inversely proportional to the level of accuracy for a cost estimate." For a control option which is mature and for which a study-level cost estimate is available, a contingency factor of 5–15% is appropriate.[48]

BWTX stated in its PSD application that a contingency factor greater than 5–15% was appropriate because the technology in consideration was non-mature (p. A-6). In evaluating the control option under consideration, EPA was unable to perform a "study-level" or "Class 4" cost estimate,[49] and had to use lower-accuracy cost data. Therefore, following APCCM, **EPA was mistaken in not using a contingency factor higher than 5–15%.**

A contingency factor of 5–15% is not appropriate for non-study-level estimates, and alternate contingency factors can be inferred from the sources informing the two cost estimation publications cited in the APCCM.[50] A contingency is a "[s]pecific provision for unforeseeable elements of cost … which previous experience has shown to be statistically likely to occur." Inaccuracies in a cost estimates may be on the high-end or on the low-end, but "there is a greater probability that the actual cost will be more than the estimated cost where information is incomplete … [and] the positive spread is likely to be wider than the negative."[51]

Consistent with this definition of contingency, AACE treats contingency cost as the difference between the initial point estimate of project costs and a pre-selected point on a graphical cumulative probability distribution constructed for the project (most typically 50%), as shown in Figure 1 below.[52]

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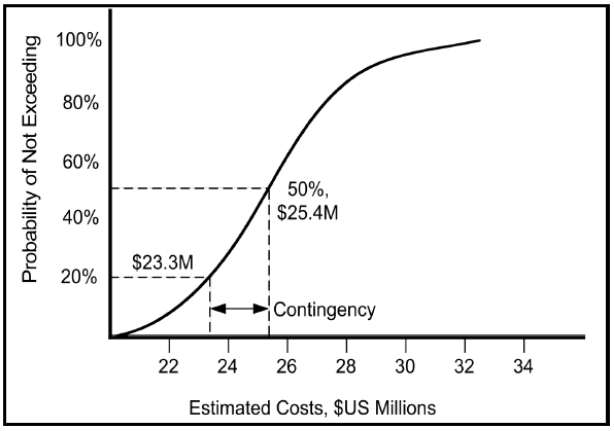
[47] US EPA Office of Air Quality Planning and Standards. *Air Pollution Control Cost Manual* ("APCCM"). Section 1, Chapter 2. *Cost Estimation: Concepts and Methodology*. Nov. 2017. Accessed December 4, 2020, at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf. At 30.
[48] APCCM Sec. 1, Chap. 2, at 30.
[49] *Cf.* APCCM Sec. 1, Chap. 2, at 6. (Specifying the preferred level of estimate for air pollution control cost economic analyses).
[50] Perry and Chilton eds. (1973). Chemical Engineers' Handbook. Fifth Ed. New York: McGraw-Hill. ("Perry's"). At 25-14–25-15. AACE International Recommended Practice 18R-97, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries (March 2016) ("AACE").
[51] Perry's at 25-45, 25-14, respectively.
[52] AACE at 2. ("The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope")

Figure 1— Example determination of contingency factor based on probabilistic cost analysis[53]



Since the probability distribution function for a less accurate, "Class 5" estimate will have a longer high-end tail than that corresponding to a "Class 4" or lower estimate, contingency factors must be higher for less accurate estimates. BWTX believes that a "difference in spreads" approach is an appropriate generalization of APCCM guidance. The difference in spreads for AACE "Class 4" estimates is consistent with the APCCM guideline of 5–15% for mature technologies, and the difference in spreads for AACE "Class 5" estimates captures BWTX's proposed contingency factor of 40%. **BWTX's proposed contingency factor of 40% is consistent with EPA guidance. EPA has not explained why a 40% contingency factor is inappropriate for order-of-magnitude cost estimates for undemonstrated technologies.**

Type of Estimate	Negative spread	Positive Spread	Difference (implied contingency factor)
Class 5	-20% to -50%	+30% to +100%	+10% to +50%
Class 4	-15% to -30%	+20% to +50%	+5% to +20%
Class 3	-10% to -20%	+10% to +30%	0% to +10%
Class 2	-5% to -15%	+5% to +20%	0% to +5%
Class 1	-3% to -10%	+3% to +15%	0% to +5%

(3) EPA states that "the contingency for a mature technology should range from 5 to 15% of the **TIC**, see 2.6.4.2."[54] The original source has "TCI," (total capital investment) not "TIC" (total indirect costs). **EPA's typographical error resulted in a significant understatement of the cost effectiveness of the controls.**

C. BWTX provided a detailed analysis showing the estimated on-stream reliability of a platform-based VCU (pp. A-11–A-15), which was based on a published database of offshore component failure rates[55] and a standard text on reliability engineering.[56] The need to estimate the system's on-stream time in the absence of empirical data from operating installations is a consequence of treating the undemonstrated control option as technically feasible. EPA did not acknowledge BWTX's analysis and concluded (presumably based on the intermittently operated Ashkelon facility) that the on-time reliability of the control option is 100 percent.

[53] Larry R. Dysert, *Estimating, in* SKILLS & KNOWLEDGE OF COST ENGINEERING, A SPECIAL PUBLICATION OF AACE INTERNATIONAL (Scott Amos, ed., 2007) at 9.1, 9.23.
[54] PSD/Title V SoB at 16. Emphasis supplied.
[55] OREDA. Offshore Reliability Data Handbook (4th ed.). 2002. Høvik: Det Norsk Veritas.
[56] Smith, D.J. 2005. Reliability, Maintainability and Risk: Practical Methods for Engineers (7th ed.).

(1) "It is customary to establish emissions limitations based on realistic operating parameters, rather than on results that are only occasionally achievable."[57] No operating results have been identified for any of the controlled loading operations under discussion (SPOT, GIMT, Ashkelon, etc.), and BWTX supposes that EPA's assumption of 100% reliability (and similarly, EPA's finding that BWTX's on-stream time analysis constituted "insufficient support") is an argument from silence. **EPA was mistaken in its analysis because it has no positive, articulated basis for concluding that the system will be 100% reliable.** EPA's approach is also inconsistent with its approach to setting emission limits for a selected technology, which "must … reflect consideration of any practical difficulties associated with using the control technology."[58]

(2) As discussed in BWTX's PSD permit application, the control option under consideration (platform-based VCU) has no demonstrated application. It would consist of a series of system components, each of which has a non-zero probability of failure. When published failure rates for offshore components are used, BWTX estimates that the system would suffer an interruption, on average, after every 13.45 hours of operating time. Based on this calculation, BWTX estimated that the fraction of throughput delivered before a control system service interruption to be 53.8%. **EPA was mistaken in rejecting—without a reasonable basis—BWTX's calculation predicting 53.8% reliability**.

D. BWTX included contractual demurrage fees that would be charged by the vessel owner if loading is delayed because of VCU unreliability. The EPA rejected these charges, commenting as follows:

> *EPA does not include[] costs associated with lost profit, in this case "late fees," that may be associated with the operation not operating on schedule.*

APCCM provides that "If the shut-downs [for installation of a control device] do not occur in a well planned and routine manner, any additional foregone production of goods and products would need to be included as a private cost attributable to the retrofit cost."[59] BWTX has argued in its application that the APCCM guidance on lost production/foregone revenue is reasonably applied to accounting for the costs of operating an undemonstrated technology (pp. 4-43, A-7–A-8). **EPA guidance does allow for consideration of the type of expense EPA refers to as "lost profit." EPA has not adequately explained its rejection of any consideration of foregone production.**

E. BWTX included "reliability services" in its annual costs, to permit continuity of operations at the time the control system was unavailable. EPA rejected these charges, commenting as follows:

> *EPA removed these costs as they were the costs to reverse lighter any crude oil that could not be loaded via the SPM due to unavailability of the vapor control device. EPA assumes that the vapor combustion unit will be available for 100% of the loading time.*

BWTX has questioned the appropriateness of assuming 100% on-stream time in a separate comment. EPA's comment assumes that the control option under consideration would involve a requirement forbidding loading operations to take place unless the control system was on-stream. If uncontrolled loading operations were permitted during service outages (e.g., as they are usually permitted at oil production sites during tank battery vapor recovery unit outages), however, EPA would have an independent basis for rejecting the reliability services charge. Since EPA has not examined this issue, **EPA has not provided an independent basis for rejecting the "reliability services" charge.**

In any case, BWTX believes there is good basis for including the reliability services charge. If a control technology under consideration has a wide range of emission performance levels (as undemonstrated

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[57] *In the Matter of Genesee Power Station*. 4 E.A.D. 832,862 (EAB Oct. 22, 1993). *Accord In the Matter of Pennsauken County, New Jersey Resource Recovery Facility*. 2 E.A.D. 768 (Adm'r Apr. 20, 1999) and *In re Pio Pico Energy Center* 16 E.A.D. 56, 119–120 (EAB Aug. 2, 2013) (and cases cited therein).

[58] *In re Newmont Nevada Energy Investment, LLC, TS Power Plant*. 12 E.A.D. 429,441 (EAB Dec. 21, 2005). *Accord In the Matter of Pennsauken County, New Jersey Resource Recovery Facility*. 2 E.A.D. 768, 769 (Adm'r Apr. 20, 1999) ("The control efficiency of the Commerce facility in California, the only [similar source] with a sustained experience using ammonia injection, has varied from 11 to 62% … The emission limitation for the Pennsauken facility is derived in part from the results of the Commerce study…")

[59] APCCM Sec. 1, Chap. 2, at 30.

technologies must), it is appropriate to estimate all costs associated with compliance with the upper and lower ends of potential emission limitations.[60] At the high end of the performance range (100% availability requirement), costs for mitigating system downtime should be estimated because the system cannot be presumed to function at 100% availability. On the lower end of the performance range (53.8% availability as calculated by BWTX), there would be no need to mitigate system downtime through reverse lightering, so long as the system was at least 53.8% reliable; EPA's analysis would continue to reflect a charge for reliability services of $0, but would specify a VOC emission reduction of 53.8% of 17,989 tpy, and the final cost effectiveness value would have been increased by 86%, other things being equal.

Even if it was appropriate for EPA to reject a "reliability services" charge, EPA was mistaken in not considering system reliability at Step 3 of its analysis.

F. The SoB states that an estimated cost of $14,444/t VOC removed is "excessive in comparison with most upper bound cost effectiveness levels."[61] The NSR Workshop Manual frames the relevant finding as whether the cost is "significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT costs in general) for the pollutant."[62] EPA's own formulation obscures whether it has in fact concluded that the cost is excessive and the basis for that conclusion. **EPA's conclusions would be strengthened by explaining in more detail how it evaluated cost-effectiveness in the case of facilities that lack a cohort for purposes of determining comparative cost effectiveness.**

G. BWTX argued in its application that building a platform based VCU would add 50 percent to the capital cost of the entire project. BWTX asserted that given the absence of any full-scale application of vapor controls at an SPM, it would be appropriate to conclude as an alternative ground that this level of capital cost increase makes the control cost ineffective. **EPA did not explain whether it considered the capital cost of the control system (as a fraction of the project's capital cost) in concluding that the control option was not economically reasonable. If EPA did not consider such information, EPA was mistaken by ignoring analogous permitting guidance for innovative controls in the GHG PSD permitting context.**[63]

Comments on Notice of MACT Approval

8. Based on its finding that the record for Subpart Y does not fully support coverage of the proposed DWP under that standard,[64] EPA has not listed 40 CFR Pt. 63, Subpart Y as an applicable requirement in the Draft Title V permit, and has proceeded with a case-by-case MACT determination.

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[60] NSR Workshop Manual at B.23. ("…in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative … when reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise. Also, a control technology that has been eliminated as having an adverse economic impact at its highest level of performance, may be acceptable at a lesser level of performance.")

[61] PSD/Title V SoB at 17.

[62] At B.45. *Accord In re Steel Dynamics, Inc*. 9 E.A.D. 165, 205 (EAB Jun. 22, 2000) (emphasizing the importance of comparative cost-effectiveness data for similar facilities).

[63] The NSR Workshop Manual expresses a (non-binding) preference for average and incremental cost effectiveness analyses when comparing the costs of controls. However, this is true only for "control alternatives that have been effectively employed in the same source category." (at B.31). The EAB has further stated that where "there is no comparable facility that has installed the candidate technology, the rationale for relying on [average or incremental] cost effectiveness . . . is less compelling." *In re ExxonMobil Chemical Company (Baytown Olefins Plant)*. 16 E.A.D. 383, 399 (EAB May 14, 2014). 2014 WL 1979510 at *13.

[64] NOMA SoB at 5.

A. **EPA must strengthen the procedural elements of its findings by revising the NOMA SoB to include an applicability determination with respect to Subpart Y before issuing the NOMA.**[65]

9. EPA remarks that the proposed submerged fill work practice requirements "do represent the 'MACT floor' for the proposed BWTX DWP," and further remarks that BWTX developed a list of potential technologies for marine loading operations "for further review in a beyond the floor MACT analysis."[66] BWTX believes that EPA's use of the terms "MACT floor" and "beyond the floor," which are normally used in the context of nationwide rulemakings under CAA § 112(d), may lead to confusion in the context of a NOMA proceeding.

A. EPA should not have used the terms "MACT floor" and "beyond the floor," because they imply that case-by-case MACT determinations under CAA § 112(g) are subject to the same substantive procedures as source category-wide rulemakings under CAA § 112(d).

B. To the extent that EPA instead uses the terms simply as shorthand references to the principles at 40 CFR §§ 63.43(d)(1), (2), respectively, it did not clearly explain its use of terminology.

C. Standard setting under CAA § 112(d) involves a familiar two-step process. First, the "MACT floor" is established based on a comprehensive review of sources within the same category or subcategory; and second, "beyond the floor" requirements are evaluated based on cost and other factors.[67] The two steps of the analysis are on equal footing and consider different types of information. For case-by-case MACT determinations under CAA § 112(g), on the other hand, the "similar source" analysis (40 CFR § 63.43(d)(1)) sets the minimum emission limitation, which is based on a consideration of transfer technologies, cost, and other factors, while the "alternatives" analysis (40 CFR §63.43(d)(2)) identifies different options for meeting such emission limitation. **A case-by-case MACT determination does not present any exact parallel to the § 112(d) "MACT floor" or "beyond the floor" steps.**

10. In its NOMA application, BWTX proposed to find that the Louisiana Offshore Oil Port (LOOP), the only crude oil export terminal currently operating in federal waters, was the only "similar source," and therefore the best-controlled similar source.[68] EPA, however, has determined that it would not consider any source constructed with an offshore platform (LOOP was the only such source identified) as a potentially "similar source."[69] While EPA has proposed to approve the MACT requirements recommended by BWTX, 40 CFR § 63.43(d)(1) can be read as requiring the permitting authority to make a determination identifying the best controlled similar source.

A. If not LOOP, **what is the best controlled similar source? EPA has not identified a best controlled similar source; neither has it explained why it need not do so.**

11. In its NOMA application, BWTX commented that several potential "similar sources" should be rejected as a threshold matter. Ellwood Marine Terminal and Gaviota Interim Marine Terminal (GIMT) are not currently in operation. Production platforms on the Norwegian Continental Shelf and the Eilat-Ashkelon Oil Port are not located in the United States.

A. The statutory minimum requirement for MACT for new sources refers to "the emission control that **is** achieved in practice by the best controlled similar source, as determined by the Administrator."[70] Congress' use of the present tense obviously implies that the best controlled similar source is one which

[65] *Cf.* CAA § 112(g)(2)(B). ("Such determination shall be made on a case-by-case basis where no applicable emission limitations have been established by the Administrator.")
[66] NOMA SoB at 15–16. Emphasis supplied
[67] *See National Lime Ass'n v. EPA*. 233 F.3d 625, 629 (D.C. Cir. 2000).
[68] BWTX NOMA Application at 6-13.
[69] NOMA SoB at 12 ("…EPA decided to consider other similar projects identified by BWTX that did not have a platform.")
[70] CAA § 112(d)(3). Emphasis supplied.

is in operation at the time the Administrator's determination is made. During the MACT Y rulemaking, EPA disregarded GIMT because it was not in operation.[71]

B. In the NOMA SoB, EPA includes operations occurring outside of the United States as potentially "similar sources," creating an apparent discrepancy with its guidance to exclude such sources from consideration during case-by-case MACT determinations.[72]

While discussion of defunct sources and sources outside the United States is reasonably apt for inclusion amongst the "available information," and adds to the overall level of documentation in the docket, **EPA has not made clear the limitations of its inclusion of such sources in its "similar source" analysis.**

12. In its NOMA application, BWTX argued that construction of an otherwise unnecessary offshore platform, equipped with a vapor combustion system, would present unacceptable safety risks: among other hazards, it would constitute a manned structure storing and receiving highly flammable materials; it would entail frequent transportation of highly flammable materials; and its design would necessary deviate from US Coast Guard Regulations developed to ensure the safety of marine vapor control systems.[73] In short, it could interfere with BWTX's general duty to "design and maintain a safe facility."[74] **EPA mistakenly did not take safety into account (particularly in the case of overt conflicts with safety regulations) in setting case-by-case MACT for a facility.**

13. EPA concludes its "Principle 2" evaluation with the following statement:[75]

> *Therefore, EPA has determined that it is neither technically nor economically feasible at this time to prescribe or enforce any controls beyond submerged fill loading for the BWTX DWP.*

BWTX agrees with EPA's finding, but seeks additional clarification, as the reference to "technical feasibility" is not relevant to a case-by-case MACT determination. EPA's finding that none of the controls are technically feasible appears to conflict with a related finding in the PSD/Title V SoB (that two control options <u>are</u> technically feasible). The statement about economic feasibility is consistent with the draft (but in BWTX's view, incomplete) PSD economic analysis. As noted in a prior comment, since cost and technical compatibility are considered in the "similar source" analysis, **it was unnecessary for EPA to make a separate finding of technical or economic feasibility after it had already conducted its similar source analysis.**

14. If EPA approves the use of AP-42, Section 5.2, equations (2) and (3) for air permitting actions, it should reduce the PTE figure given in NOMA Sec. B.7 consistent with the presently-supplied alternative emission calculations.

<u>Comments on Title V Permit</u>

Applicable Federal and State Air Quality Control Requirements

15. EPA comments that "the applicable requirements [of Texas] include the federally approved portions of 30 TAC Chapter 101, 111, 113, 115, and 116, and 30 TAC Chapter 122 (with EPA serving as the permitting authority)."[76] The draft Title V permit lists these State regulations among the "Applicable Regulations" but does not actually identify any specific State rules as applicable.

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[71] *See* 60 Fed. Reg. 48,388, 48,393 (1995) (referencing a docket entry that lists all similar sources for the MACT floor and that specifically excluded GIMT).
[72] *See* 61 Fed. Reg. 68,395, 68,394 (1996) ("The definition of MACT for new source MACT in this rule does not require consideration of sources outside the U.S.").
[73] NOMA at 7-8–19,
[74] CAA § 112(r)(1).
[75] NOMA SoB at 22.
[76] PSD/Title V SoB at 6.

A. BWTX questions whether the listed Texas regulations are "applicable" in the sense of 33 U.S.C. § 1518(b), as EPA asserts. **EPA does not explain why it believes that the State regulations are "applicable," given that existing Federal air pollution control laws already apply to the DWP.**

B. BWTX believes that the draft Title V permit correctly characterizes the listed State regulations. That is, while they are facially within the scope of "applicable requirements" (40 C.F.R. § 71.2), **no specific TCEQ regulation actually applies to the BWTX DWP source**.

16. Based on its finding that the record for Subpart Y does not fully support coverage of the proposed DWP under that standard,[77] EPA has not listed 40 CFR Pt. 63, Subpart Y as an applicable requirement in the Draft Title V permit.

EPA has not clearly presented its applicability determination for Subpart Y and include all necessary supporting documentation in the docket.

[77] NOMA SoB at 5.

Supporting References (distribution not restricted)

Figure 3-1ALT Emission Calculations for VOC, Total HAP, H_2S, and GHG, Alternate Methodology based on Equations (2) and (3).

Annual Average Emiss. Factor

Quantity	Value	Units
Arrival Component, C_A	0.86	lb/Mgal
Generated Component, C_G	0.69	lb/Mgal
True Vapor Pressure	8.44	psia
Temperature	72.1	F
Vapor Phase MW	59.37	lb/lbmol
C_L	65.1	lb/MBbl

Hourly Average Emiss. Factor

Quantity	Value	Units
Arrival Component, C_A	0.86	lb/Mgal
Generated Component, C_G	0.90	lb/Mgal
True Vapor Pressure	11	psia
Temperature	95	F
Vapor Phase MW	60.32	lb/lbmol
C_L	74.0	lb/MBbl

Carbon Dioxide Emiss. Factor

Quantity	Value	Units
Ideal Gas Constant	0.001910877	MBbl psia / lbmol R
Saturation Factor	1	Dimensionless
True Vapor Pressure	2.058	psia
Temperature	72.1	F
Vapor Phase MW	44.0098	lb/lbmol
L_L	89.1	lb/MBbl

H_2S Weight Fraction, Annual

Quantity	Value	Units
Liquid phase mass fraction	2	ppmw
Liquid phase mol. Wt.	156.75	lb/lbmol
Vapor phase mol. Wt.	59.37	lb/lbmol
K-factor (80 F)	23	y / x
Vapor phase mass fraction	121	ppmw
Implied partition coefficient	106	vppmv/lppmw

H_2S Weight Fraction, Hourly

Quantity	Value	Units
Liquid phase mass fraction	10	ppmw
Liquid phase mol. Wt.	156.75	lb/lbmol
Vapor phase mol. Wt.	60.32	lb/lbmol
K-factor (80 F)	23	y / x
Vapor phase mass fraction	598	ppmw
Implied partition coefficient	106	vppmv/lppmw

Methane Weight Fraction

Quantity	Value	Units
Liq. Phase Mass Fraction	0.4964	ppmw
Liquid phase mol. Wt.	189.92	lb/lbmol
Vapor phase mol. Wt.	58.09	lb/lbmol
K-factor (95 F)	190	y / x
Vapor phase mass fraction	308	ppmw
Methane GWP	25	lb CO_2e/lb

NSR Pollutant Emission Rates

Pollutant	Avg. Period	Emission Rate
VOC	1-hr	5920.74 lb/hr
VOC	Annual	12500.26 tpy
H_2S	1-hr	3.54 lb/hr
H_2S	Annual	1.52 tpy
GHG (mass basis)	Annual	17117.38 tpy
GHG (CO_2e basis)	Annual	17209.89 tpy

HAP Species Emission Rates

Pollutant	ER_lb/hr	ER_tpy
Total HAP	260.51	550.01
n-Hexane	211.37	446.26
Benzene	20.72	43.75
Toluene	19.54	41.25
m-Xylene	5.74	12.13
p-Xylene	3.32	7.00
o-Xylene	1.30	2.75
Ethylbenzene	1.60	3.38
Styrene	0.06	0.13
Xylene (all isomers)	10.36	21.88

Operational Limits

Quantity	Value	Units
Short-term pumping rate	80	MBbl/hr
Annual throughput	384000	MBbl/yr

Notes

1. C_A per AP-42 Tbl. 5.2-3.

Table 4-6ALT. Cost Effectiveness Calculation for Vapor Combustor System (Offshore Platform), incorporating use of equations (2) and (3).

Item	Description	Basis	Estimation Factor	Item Cost
Capital Costs				
Direct Costs				
1	VCU and Associated Equipment			$ 37,142,400.00
2	Instrumentation	APCCM Chap. 3.2, Sec. 2, Tbl. 2.10 ("Tbl 2.10")	10%	$ 3,714,240.00
3	Sales Tax		6.25%	$ 2,321,400.00
4	Freight		6%	$ 2,228,544.00
5	Total Purchased Equipment Cost (PEC)	Sum of Items 1--4		$ 45,406,584.00
6	Foundations (structure reinforcement)	Tbl 2.10	8 % of PEC	$ 3,632,526.72
7	Handling and Erection	Tbl 2.10	14 % of PEC	$ 6,356,921.76
8	Electrical	Tbl 2.10	4 % of PEC	$ 1,816,263.36
9	Piping	Tbl 2.10	2 % of PEC	$ 908,131.68
10	Instrumentation	Tbl 2.10	1 % of PEC	$ 454,065.84
11	Painting	Tbl 2.10	1 % of PEC	$ 454,065.84
12	Direct Installation Costs	Sum of Items 6--11		$ 13,621,975.20
13	Platform	Platform buy & build		$ 191,000,000.00
14	Vapor Handling	Floating & subsea hoses, buoy & PLEM mods for vapor, subsea vapor pipelines		$ 22,000,000.00
15	Total Direct Costs (TDC)	Sum of Items 5,12--14		$ 272,028,559.20
Indirect Costs				
17	Engineering		12.25% of TDC	$ 33,323,498.50
18	Construction and Field Expenses		8% of TDC	$ 21,762,284.74
19	Contractor fees	Tbl 2.10	10% of TDC	$ 27,202,855.92
20	Start-up	Tbl 2.10	2% of TDC	$ 5,440,571.18
21	Performance Test	Tbl 2.10	1% of TDC	$ 2,720,285.59
22	Total Indirect Costs (TIC)	Sum of Items 17--21		$ 90,449,495.93
23	Contingencies	Tbl 2.10, CF = 0.4 for non-mature technology (cf. APCCM Ch. 2 § 2.6.4)	40% of (TDC+TIC)	$ 144,991,222.05
24	Total Capital Investment (TCI)	Sum of Items 15,22		$ 507,469,277.19
Annual Costs				
Direct Costs				
27	Raw Materials			$ -
28	Utilities	Fuel Gas (VCU), diesel (generators), water (potable), etc. (Scaled by % availability)		$ 88,565,117.86
29	Maintenance		10% of TDC	$ 27,202,855.92
30	Subtotal (Lines 27--29)			$ 115,767,973.78
31	Opex Related to Platform & Vapor Recovery System	Salaries, Helicopter, Support Vessels, lease for additional submerged land, etc.		$ 28,403,350.00
32	Demurrage Fees			$ 5,950,714.00
33	Reliability Services	$0.75/Bbl service fee	53.8% on-stream	$ 133,095,213.65
34	Total Direct Annual Costs	Sum of Items 30--33		$ 283,217,251.43
Indirect Costs				
36	Property Taxes	No state taxation per OCSLA 1333	0% of TCI	$ -
37	Insurance and Administrative Charges	3% of TCI (PCCM sec. 2.5.5.8).	3% of TCI	$ 15,224,078.32
38	Capital Recovery	CRF based on i=0.0425 and n=20 yrs (APCCM sec. 1.5.2)	7.52% of TCI	$ 38,171,755.20
39	Total Indirect Annual Costs			$ 53,395,833.52
Recovery Credits				
41	Materials			$ -
42	Energy			$ -
Totals				
44	Total Annualized Costs	Sum Items 34,39		$ 336,613,084.95
Cost Effectiveness				
46	Baseline VOC Emission Rate			12500 tpy
47	VOC Emission Rate (Alternative)	Control during periods of system availability.	95.0 % reduction	6113 tpy
48	VOC Emissions Reduction			6387 tpy
49	Cost Effectiveness (VOC)	Item 44 / Item 48		**$52,701.75 per ton**

October 2000
RG-xxx

Air Permit Technical Guidance for Chemical Sources:
Loading Operations

Air Permits Division

Texas Commission on Environmental Quality

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Disclaimer

This document is intended as guidance to explain the specific requirements for new source review permitting of loading operations; it does not supersede or replace any state or federal law, regulation, or rule. References to abatement equipment technologies are not intended to represent minimum or maximum levels of Best Available Control Technology (BACT). Determinations of BACT are made on a case-by-case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific concerns with off-site impacts concerns may indicate stricter abatement than required by the BACT determination.

The represented calculation methods are intended as an aid in the completion of acceptable submittals; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data.

These guidelines are applicable as of the date of publication date of this document, but are subject to revision during the permit application preparation and review period. It is the responsibility of the applicants to remain abreast of any guideline or regulation developments that may affect their industries.

The electronic version of this document may not contain attachments or forms (such as the PI-1, Standard Exemptions, or Tables) that can be obtained electronically elsewhere on the TCEQ web site.

The special conditions included with these guidelines are for purposes of example only. Special conditions included in an actual permit are written by the reviewing engineer to address specific permit requirements and operating conditions.

Contents

I. OVERVIEW

The purpose of this document is to assist the permit applicant in identifying applicable State and Federal Regulations, in planning air abatement methods, and in preparing a permit application for a project to build or modify a loading rack. This will also be used as a resource document by agency staff.

Loading operations are conducted at almost every terminal (gasoline and bulk or "for hire" terminals), refinery, petrochemical and chemical complex in the state. The loading operations are typically divided into three major categories. These categories include tank truck loading, rail car loading, and marine loading (both barge and ship). Some facilities also use drum loading as a method of transferring product, however this package will concentrate on the major categories of loading operations. This document will describe acceptable methods of calculating these emissions and specify acceptable methods of controlling loading losses.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. The applicant should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying "end-of-pipe" controls can not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

II. PROCESS DESCRIPTION

A. Tank Truck Loading

Tank trucks are loaded with fuel or chemicals at loading racks. When using a control device, the collection header which is usually on top of the truck will be connected to the control device with flexible hoses. With truck loading, there will be losses at the truck for uncontrolled cases, but for controlled cases, there is the potential for losses at the truck and control device. When determining the percent of loss at the truck, the type of truck as well as the type of connection will need to be known.

Tank truck loading operations can be divided into three general categories: A) atmospheric trucks, B) pressure trucks used in atmospheric service, and C) pressure trucks. The type of connection that is used in the loading procedure will be considered to determine the collection efficiency. "Quick connects" are clamp type connections that are not bolted or flanged. "Quick connects" can be used with atmospheric trucks. Hard-piped connections are bolted or flanged to the receiving vessel. Hard-piped connections should be used with pressure trucks to achieve the maximum collection efficiency. Atmospheric trucks need to be leak checked according to NSPS Subpart XX standards when transporting compounds with a vapor pressure greater than 0.5 psia. In the case when a pressure truck is used in atmospheric service, a 100 percent collection efficiency may be obtained if the pressure truck is tested according to DOT standards for pressure rating and pressure stressed type connections are used. Pressure trucks are designed to handle materials with a pressure of 15 psig or greater. When operated in a leak-free manner, DOT certified for pressure rating, and loaded with pressure stressed type connections, 100 percent collection efficiency can be used for loading emissions.

Accepted collection efficiencies (vapor collected to BACT control device) are as follows:

Unenhanced Loading	**65%**
Enhanced Loading	**85%**
Annual Leak Checking (non gasoline)*	**95%**
Semi-Annual Leak Checking (non gasoline)*	**97.5%**
Annual Leak Checking (gasoline)*	**98.7%**
Vacuum Loading	**100%**

*** Leak checking as described in NSPS Subpart XX**

Definitions

Unenhanced and enhanced loading are not BACT for compounds with vapor pressure greater than 0.5 psia. They are a way of decreasing loading losses if the off property impacts are too high.

Unenhanced Loading- Loading loss emissions are sent to a control device, however, the trucks are not leak checked.

Enhanced Loading- Loading loss emissions are sent to a control device, however, the trucks are not leak checked. A positive pressure of +3 to +5 inches of water is not exceeded in the truck cavity. This can be maintained by using a blower.

Vacuum Loading- Hard-piped loading maintaining a vacuum of less than -1.5 inches of water in the truck cavity. Each application containing vacuum loading will be looked at individually. The pressure in the truck must never become neutral or positive when vacuum loading.

Loading fugitive emissions - Uncollected loading emissions are called loading fugitives. These differ from process fugitives which are emissions that escape from valves, pumps, and any type of connections in the piping.

The control device may be a flare, an incinerator, a carbon adsorption system or a scrubber. An approved flare has 98 percent destruction efficiency. An approved incinerator has 99.9 percent destruction efficiency. The recovery efficiency of a carbon adsorption system will be evaluated on a case-by-case basis; the Texas Commission on Environmental Quality (TCEQ) would like to see <100 ppm organic escaping the bed. Scrubber efficiency is estimated by the applicant. Scrubbers are usually used to control inorganics. The applicant may refer to the standardization packages for flares, absorber units, carbon absorption systems, and fugitive sources for methods of calculating these emissions.

There are many emission sources to consider when loading chemicals. Uncontrolled loading fugitives, process fugitives from piping and components, tank emissions, and emissions from the control device that is controlling the collected loading emissions must all be considered. Process fugitive emissions are emissions that result from leaking valves, pumps, flanges, and

compressors. Fugitive emissions from equipment and piping that is associated with the loading procedure must be accounted for.

B. Railcar Loading

Railcar loading operations are reviewed on a case by case basis. In most cases, railcars are pressure stressed (there are few atmospheric railcars) and use hard-piped and/or bolted connections. Simple "quick connects" like those used for gasoline tankers are not acceptable for railcars. Information on the type of connections being used needs to be submitted. If the railcar is pressure tested or involved in a leak checking program (company requirement or Department of Transportation (DOT) requirement), this information needs to be included in the application. If no leak checking can be documented, or the use of hard-piped or bolted connections cannot be verified, assume that 5 percent of the vapors from the railcar are uncollected.

C. Marine Loading [1]

Marine loading can be broken down into two categories: barge and ship (also known as parcel tankers). Marine loading is not subject to BACT review, however, the TCEQ does look at impacts on the shoreline associated with emissions from the marine loading operation. Marine emissions are also considered to be a primary source of emissions by the EPA for PSD/Non-Attainment applicability determinations.

1. **Barge Loading: Much of the barge loading operations that occur along the gulf coast is uncontrolled. Barge loading is becoming easier to control since more vessels are equipped with vapor return headers as required by state and federal regulations. When reviewing barge loading operations for permitting and impact evaluation purposes, applicants will often try uncontrolled loading as a first pass (unless specific controls are required by federal regulations, such as National Emission Standards for Hazardous Air Pollutants (NESHAPS) Subpart BB for benzene or state regulations, such as Regulation V). If the shoreline impacts cannot pass a Health Effects review, then the applicant needs to modify his operations in such a way that acceptable impacts can be achieved. These modifications can include reducing the pumping or filling rate of the barge, increasing the dispersion of the emissions from a barge during loading, or controlling the barge emissions.**

(1) The issue of permitting of marine sources is currently under review by the TCEQ and changes may result.

For applicants that wish to control their barge loading operations, calculations should include uncollected emissions (loading fugitives) unless the barges are loaded under vacuum conditions. The barge itself is usually not considered to be vapor tight. The collection efficiencies used for truck loading are also used for barges. Unless the barge is leak tested, the emission collection efficiency is 65 percent. If the barge is leak tested according to NESHAPS Subpart BB requirements, then a 95 percent collection efficiency can be used. The applicant also has the option of using a vacuum loading system (100 percent collection efficiency).

2. Ship Loading: There are various facilities along the gulf coast which load product or transfer material into ships. Uncontrolled emissions are usually proposed by the applicant as a first pass. If impact problems result, the applicant needs to see what can be done to reduce the shoreline impacts associated with ship loading. Most ships are equipped with vapor recovery headers and the emissions can be routed to a control device, but in some cases, the ships are not equipped with any vapor control equipment. A review of the option of reducing the loading or filling rate of the ship should be made. In some instances, it may be possible for the applicant to install some type of temporary containment or collection system.

In addition to considering a vapor recovery system that vents to a thermal destruction or recovery device, the following practices should also be considered for reducing emissions from ship loading:

- **Utilizing segregated ballast tanks and vacuum regeneration, and avoiding ballasting or steam stripping operations;**
- **Ensuring that vessels are vapor tight;**
- **Monitoring vapor recovery systems, flare, and valves to ensure proper function;**
- **Equipping vessels with pressure control devices so that over- and under-pressurization does not occur;**
- **Equipping vessels with level monitoring alarms systems so that overfilling of vessels does not occur: and**
- **Cargo gauging and sampling.**

The loading frequency and magnitude of the screening level exceedance is also something that can be of value in a more detailed Health Effects review.

III. APPLICABLE STATE AND FEDERAL REQUIREMENTS

With regards to loading, the applicant must demonstrate compliance with all applicable State Regulations:

Regulation V Loading and Unloading of VOCs §115.211-§115.219

Comments on Regulation V:

§115.211 specifies the maximum emissions allowed from gasoline terminals in non-attainment areas. This section also specifies the maximum VOC emissions allowed from marine terminals in the Houston/Galveston area.

§115.212 requires sending emissions to a control device when loading VOC with a true vapor pressure equal to or greater than 1.5 psia before November 15, 1996 and equal to or greater than 0.5 psia after November 15, 1996 in certain non-attainment areas.

§115.214 requires leak testing of trucks loading or unloading gasoline or VOCs with a vapor pressure greater than 0.5 psia, after May 31, 1995.

NSPS Subpart XX is used as a guideline for leak checking trucks for all VOCs.

NESHAPS Subpart BB is used as a guideline for leak checking ships and barges for all VOCs.

DOT has guidelines for pressure testing trucks.

Applicable Permits by Rule (formerly known as Standard Exemptions (SE))

When the requirements of the Permits by Rule contained in Chapter 106 (30 TAC 106) Sections 106.261 (previously SE 106), 106.262 (previously SE 118), 106.472 (previously SE 51), or 106.473 (previously SE 53) are met, they may be used for authorizing loading operations.

IV. BACT GUIDELINES

Tank truck loading operations can be subdivided into three general categories: atmospheric trucks, pressure trucks used in atmospheric service, and pressure trucks.

A. When loading compounds with a vapor pressure >0.5 psia, the collected emissions must be routed to a control device with a minimum of 98 percent destruction efficiency or 95 percent removal efficiency.

The BACT for atmospheric type tank trucks consists of annual leak checking according to NSPS Subpart XX standards (which provides for a 95 percent collection efficiency of loading emissions) for compounds with a vapor pressure greater than 0.5 psia. Splash loading is not BACT. Submerged or bottom loading is required.

Even though trucks loading chemicals other than gasoline are not subject to the NSPS subpart, the leak testing requirements outlined in Subpart XX are used as a BACT leak-testing benchmark for atmospheric trucks. Trucks which contain compounds with vapor pressures less than 0.5 psia are not required to be controlled; however, impact review does still apply. There may be cases where trucks handling material less than 0.5 psia may need to be controlled because of unacceptable off property impacts.

If off-property impacts are found to be unacceptable, the applicant may decide to either leak test two times per year (which would provide for a 97.5 percent collection efficiency) or proceed with a vacuum loading type system (100 percent collection).

Process fugitive emissions from loading operations should be controlled through appropriate equipment design, modification, and Leak Detection and Repair (LDAR) programs. This includes: design, modification and/or LDAR for piping and piping components such as connectors, valves, relief valves, pumps, and compressors. Acceptable BACT and LDAR for process fugitive emissions can be found in the TCEQ technical guidance document for "Equipment Leak Fugitives".

B. In some cases, applicants may use pressurized trucks in atmospheric type loading situations (for example, a pressure truck used to transport Jet A or gasoline). It is possible for the applicant to obtain 100 percent collection efficiency in terms of estimating emissions if the following is applied:

1. **Pressure truck certification: Is the pressure truck certified? Most pressure trucks are required to undergo DOT testing in order to maintain their pressure rating. If the truck is not pressure certified, a 100 percent collection efficiency should not be allowed (unless vacuum loading is being used).**

2. **Are pressure rated connections being used? A complete description of the loading and vapor recovery connections must be provided for a determination of collection efficiency. Loading into a pressurized truck without using pressure-stressed type connections cannot be given 100 percent collection efficiency. The efficiency will be determined on a case-by-case basis.**

3. **A 100 percent collection efficiency can be given to those applicants that are loading a pressurized material into tank trucks designed to handle a pressure of 15 psig or greater. Materials loaded into these types of tanks tend to be vapor at atmospheric temperature and pressure (the trucks are specifically designed for this type of service). NOTE: Recent permitting experience has indicated that not all pressure trucks are operated in a leak-free manner. Some trucks are equipped with what is known as a spew gauge. This is not considered to be BACT.**

   A spew gauge is a method of determining the liquid level inside a tank truck. If a truck is equipped with a spew gauge, the vapor tightness of the tank truck is compromised during the loading operation. Although the tank truck may be tested and pressure certified to operate at 15 psig or greater, the spew gauge will still allow emissions to the atmosphere. The truck is no longer vapor tight, and the loading operation itself is no longer BACT.

   Depressurizations of trucks must be routed to a control device. Hoses used during loading must be purged and are not allowed to drip liquid. Spills must be properly attended to.

V. SAMPLE CALCULATIONS

The AP-42 loading equation listed in Chapter 5.2 is typically used to calculate emissions from loading operations. Emissions are broken down into short-term emissions (lb/hr) and annual emissions (tons/year). Short-term emissions should be estimated by using the maximum expected vapor pressure and temperature of the compound being loaded and the maximum expected pumping rate being used to fill the container (truck, rail car, ship). Annual emissions should be estimated by using the average annual temperature and corresponding vapor pressure of the compound and the expected annual throughput of the compound.

Emissions from all loading shall be estimated using the following expression which can be found in AP-42, Fifth Edition, Section 5.2, dated January 1995. Loading fugitive emissions are estimated at the proper collection efficiency. The captured emissions from the loading rack shall be vented to a control device with at least 98 percent destruction efficiency or 95 percent removal efficiency.

$$L_L = 12.46\ SPM/T$$

where:

L_L = Loading Loss (lb/10^3 gal of liquid loaded)

S = Saturation factor from AP-42, Table 5.2-1

P = True vapor pressure of liquid loaded (psia)

M = Molecular weight of vapors (lb/lb-mol)

T = Temperature of bulk liquid loaded (^oR)

Example 1. The following example is based on truck loading 5,500,000 bbl of gasoline (RVP-13) at a loading rack. It is submerged loading with dedicated normal service. The true average vapor pressure of the liquid loaded is 8.3 psia; the vapor molecular weight is 62 lb/lb-mol; and the annual temperature of the bulk liquid loaded is 70ºF.

Annual Loading Losses

$$L_L = 12.46 \text{ SPM/T}$$

S = 0.6 for submerged loading, dedicated normal service
P = 8.3 psia
M = 62 lb/lb-mol
T = 530ºR (70ºF)

$$L_L = 12.46\ (0.6)(8.3)(62)/530 \quad = 7.26 \text{ lb}/10^3 \text{ gal liquid loaded}$$

Total Gasoline Uncontrolled Emissions =

$$\frac{7.26 \text{ lb}}{1000 \text{ gal}} \times \frac{5{,}500{,}000 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{\text{ton}}{2000 \text{ lb}} = 838.39 \text{ tons/yr}$$

Loading fugitive gasoline emissions = 0.05 (838.39 tons/yr) = 41.92 tons/yr

Short-Term Uncontrolled Loading Losses

Use the maximum filling rate and maximum true vapor pressure to calculate the maximum short-term emissions. At 100ºF, the maximum vapor pressure is 13.8 psia. At this terminal, 50,000 gallons of gasoline can be loaded in one hour.

$$L_L = 12.46\ (0.6)(13.8)(62)/560 \quad = 11.42 \text{ lb}/1{,}000 \text{ gal}$$

Uncontrolled Emissions =

$$\frac{11.42 \text{ lb}}{1000 \text{ gal}} \times \frac{50{,}000 \text{ gal}}{\text{hr}} = 571.11 \text{ lb/hr}$$

Short-term loading loss emissions = (0.05)(571.11 lb/hr) = 28.56 lb/hr

Flare Emissions

Annual: (838.39 tons/yr)(0.95)(0.02) = 15.93 tons/yr
Short-term: (571.11 lb/hr)(0.95)(0.02) = 10.85 lb/hr

Example 2. The following example is based on railcar loading 3,000,000 gal/yr of ammonium sulfide. Hard-pipe connections are used with submerged loading, dedicated normal service. The annual vapor pressure of ammonium sulfide at 70ºF is 1.29 psia. Its vapor molecular weight is 64 lb/lb-mol. There will be no loading fugitives since 100 percent collection efficiency is given for hard-piped loading of railcars. The only emissions associated with this loading operation are emissions from the control device and process fugitives.

Annual Loading Losses

L_L = 12.46 SPM/T

S = 0.6 for submerged loading, dedicated normal service
P = 1.29 psia
M = 64 lb/lb-mol
T = 530ºR (70ºF)

L_L = 12.46 (0.6)(1.29)(64)/530 = 1.16 lb/ 10^3 gallon ammonium sulfide loaded

Annual emissions =

$$\frac{1.16\ \text{lb}}{1000\ \text{gal}} \times \frac{3{,}000{,}000\ \text{gal}}{\text{yr}} \times \frac{\text{ton}}{2000\ \text{lb}} = 1.74\ \text{tons/yr}$$

Short-Term Loading Losses

The maximum filling rate of 200 gal/min and the maximum vapor pressure of 2.34 psia at 100ºF are used to calculate short-term emissions.

L_L = 12.46(0.6)(2.34)(64)/560 = 2.00 lb/10^3 gal ammonium sulfide loaded

Short-term loading emissions =

$$\frac{2.00\ \text{lb}}{1000\ \text{gal}} \times \frac{200\ \text{gal}}{\text{min}} \times \frac{60\ \text{min}}{\text{hr}} = 24.0\ \text{lb/hr}$$

Thermal Oxidizer emissions

Annual: (1.74 tons/yr)(0.001) = 0.002 ton/yr
Short-term (24 lb/hr)(0.001) = 0.024 lb/hr

Be sure to account for the sulfur dioxide which will be formed from the burning of a sulfide and any additional nitrogen oxides from burning a nitrogen-bound vapor.

Example 3. The following example is based on ship loading 2,500,000 barrels per year of furfural. Submerged loading with dedicated normal service is used. The true annual vapor pressure at 70°F is 0.035 psia. The molecular weight is 96.08 lb/lb-mol. Furfural is being loaded without controls since its maximum vapor pressure is 0.096 psia at 100°F which is <0.5 psia.

Annual Loading Losses

L_L = 12.46 SPM/T

S = 0.6 for submerged loading, dedicated normal service
P = 0.035 psia
M = 96.08 lb/lb-mol
T = 530°R (70°F)

L_L = 12.46(0.6)(0.035)(96.08)/530 = 0.05 lb/10^3 gal furfural loaded

Annual emissions =

$$\frac{0.05\ \text{lb}}{1{,}000\ \text{gal}} \times \frac{2{,}500{,}000\ \text{bbl}}{\text{yr}} \times \frac{42\ \text{gal}}{\text{bbl}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = 2.63\ \text{tons/yr}$$

Short-Term Loading Losses

The maximum filling rate of 1,000 bbl/hr and the maximum vapor pressure of 0.096 psia at 100°F are used to calculate short-term emissions.

L_L = 12.46(0.6)(0.096)(96.08)/560 = 0.12 lb/10^3 gal furfural loaded

Short-term loading emissions =

$$\frac{0.12\ \text{lb}}{1000\ \text{gal}} \times \frac{1000\ \text{bbl}}{\text{hr}} \times \frac{42\ \text{gal}}{\text{bbl}} = 5.04\ \text{lb/hr}$$

VI. EXAMPLE PERMIT CONDITIONS

Example Special Conditions are given in the pages that follow. A Maximum Allowable Emission Rate Table, Chemical List, General Conditions, and a fugitive monitoring program are also included with the permit when it is issued.

- **This facility shall comply with all applicable requirements of U.S. Environmental Protection Agency (EPA) Regulations on Standards of Performance for New Stationary Sources promulgated for Liquid Storage Tanks and Bulk Gasoline Terminals in Title 40 Code of Federal Regulations Part 60 (40 CFR 60), Subparts A, Kb, and XX.**

- **These facilities shall comply with all requirements of EPA Regulations on NESHAPS promulgated for Benzene in 40 CFR 61, Subparts A and BB.**

- **All lines and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service until they are repaired to a leak-free state.**

- **Operations shall cease immediately upon detection of any liquid leaking from the lines or connections. Operations shall not be continued until the lines and connections are repaired to a leak-free state.**

- **Emissions from the Vapor Recovery Unit (VRU) are limited to XX pounds volatile organic compounds (VOC) per 1,000 gallons of gasoline transferred as determined using testing procedures in 40 CFR 60, Subpart XX or equivalent methods.**

- **Annual throughput for each compound is limited to the following through the loading racks:**

Compound	Millions of Gallons
Gasoline and Raffinate	xx
No. 2 Fuel Oil	xx
Jet A Fuel	xx
Ethanol	xx

Annual rack throughput records of each product shall be maintained at the plant site and shall be made readily available to TCEQ personnel or any local air pollution control program having jurisdiction upon request to show compliance with this condition.

- **Loading operations at these facilities are limited to the handling of the chemicals appearing on the attached lists or chemicals that are covered by one of the TCEQ standard exemptions. Loading of other chemicals is prohibited unless prior approval is obtained from the Executive Director of the TCEQ. It will not be necessary to obtain reapproval for chemicals previously approved for handling at these facilities.**

- **Upon start-up of the vacuum vapor collection system, each tank truck shall pass vapor-tight testing every 12 months using the methods described in 40 CFR 60, Subpart XX. The permittee shall not allow a gasoline tank truck to be filled or emptied unless the tank being filled or emptied has passed a leak-tight test within the past year as evidenced by a prominently displayed certification affixed near the Department of Transportation certification plate which:**

  A. Shows the date the tank truck last passed the leak-tight test required by this condition, and

  B. Shows the identification number of the gasoline tank truck.

- **Tank truck loading vapors shall be routed through a vacuum-assisted loading rack to a vapor recovery unit (VRU) or backup mobile vapor combustor unit (VCU) equivalent. Tank trucks shall not be loaded unless the vapor collection system is properly connected and the entire collection and recovery system (or destruction system in the case of the backup VCU) is working as designed.**

- **Prior to the start-up of the vacuum vapor loading system, all collected emissions shall be routed to the vapor recovery unit (VRU) operating at no less than 95 percent abatement efficiency and xx mg of VOC emissions per liter of VOC loaded on a six-hour average.**

- **After the start-up of the vacuum vapor loading system, the emission rate at the VRU exhaust stack shall not exceed xx pounds of VOC per 1,000 gallons of liquids transferred across the loading rack (or xx mg of VOC per liter of liquid transferred) using the methods described in 40 CFR 60, Subpart XX, or equivalent methods.**

- **Flares shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity and pilot flame monitoring. If necessary to insure adequate combustion, sufficient fuel gas shall be added to make the gases combustible. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.**

- **Tank truck loading vapors shall be routed to a vapor combustor with not less than 98 percent combustion efficiency.**

- **A blower system shall be installed which will produce a vacuum in the tank truck during all loading operations. Should the vacuum system cease operating for any reason, loading operations shall cease immediately. The vacuum system shall be repaired before loading operations can resume. It is not permissible to load tank trucks at any time without the vacuum system in operating condition. A pressure/vacuum gauge shall be installed on the suction side of the loading rack blower system to verify a vacuum. Records of all vacuum system downtime and repairs shall be maintained for a period of two years and made available to representatives of the TCEQ and appropriate local programs upon request.**

- **The holder of this permit shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of VOC from the CAS.**

  A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specifications No. 1 through 7, 40 CFR 60, Appendix B. If there are no applicable performance specifications in 40 CFR 60, Appendix B, contact the TCEQ Office of Air Quality, New Source Review Program in Austin for requirements to be met.

  B. The system shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in 40 CFR 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days, unless the monitor is required by a subpart of New Source Performance Standards or NESHAPS, in which case zero and span shall be done daily without exception.

  Each monitor shall be quality-assured at least quarterly in accordance with 40 CFR 60, Appendix F, Procedure 1, Section 5.1.2. For non-NSPS sources, an equivalent method approved by the TCEQ may be used.

  All cylinder gas audit exceedances of +15 percent accuracy and any CEMS downtime shall be reported to the appropriate Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate Regional Manager.

  C. The monitoring data shall be reduced to ( ) average concentrations at least once every ( ), using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in ( ) at least once every ( ).

  D. All monitoring data and quality-assurance data shall be maintained by the source for a period of two years and shall be made available to the Executive Director or his designated representative upon request. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

- **Carbon Sampling on a Non-Continuous Basis. At all times, the loading rack shall vent through a carbon adsorption system (CAS) consisting of at least two activated carbon canisters that are connected in series.**

  A. The CAS shall be sampled and recorded (FREQUENCY) to determine breakthrough of VOC. The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sampling shall be done during operating

conditions, reflecting maximum emission venting to the CAS. (Example: during loading, tank filling, process venting)

B. The method of VOC sampling and analysis shall be by flame ionization detector (FID), or a TCEQ-approved equivalent. On each day that sampling is required, the FID shall be calibrated prior to sampling with a certified gas mixture at 0 ppmv ±10 percent and at _____ ppmv ±10 percent.

C. Breakthrough shall be defined as a measured VOC concentration of _____ ppmv. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister immediately. Within four hours of detection of breakthrough, a fresh canister shall be placed as the new final polishing canister. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frames.

D. Records of the CAS monitoring maintained at the plant site, shall include (but are not limited to) the following:

(1) Sample time and date.
(2) Monitoring results (ppmv).
(3) Corrective action taken including the time and date of that action.
(4) Process operations occurring at the time of sampling.

These records shall be made available to representatives of the TCEQ and local programs upon request and shall be retained for at least two years following the date that the data is obtained.

E. The holder of this permit may request a change in frequency of breakthrough sampling after completing at least one year of sampling as specified above. The request shall include a copy of the CAS monitoring records specified in Paragraph D of this condition and shall be submitted to the TCEQ, Office of Permitting, Remediation & Registration, Air Permits Division in Austin for review and response. The permit holder may not change the sampling frequency until written approval is received from the Executive Director of TCEQ.

- **Storage and Loading of VOC**

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.5 psia at the maximum expected operating temperature or (2) to storage tanks smaller than 25,000 gallons.

B. An internal floating roof or equivalent control shall be installed on all tanks.

C. An open-top tank containing a floating roof which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank

provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

D. For any tank equipped with a floating roof, the integrity of the floating roof seals shall be verified annually and records maintained to describe dates, seal integrity and corrective actions taken.

E. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650, Appendix C or an equivalent degree of flotation, except that an internal floating cover need not be designed to meet rainfall support requirements.

F. Uninsulated tank exterior surfaces exposed to the sun shall be white.

G. For purposes of assuring compliance with VOC emission limitations, the holder of this permit shall maintain a monthly record for all storage tanks and loading operations. The record shall include tank or loading point identification number, control method used, tank or vessel capacity in gallons, name of the material stored or loaded, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC true vapor pressure at the monthly average material temperature in psia, VOC throughput for the previous month and year-to-date in gallons and total tons of emissions including controls for the previous month and year-to-date. This record shall be maintained at the plant site for at least two years and be made readily available to representatives of the TCEQ upon request.

H. Emissions for tanks and loading operations shall be calculated using: (a) the February 1996 Supplement D to the fifth edition of AP-42, "Compilation of Air Pollutant Emission Factors", Chapters 5.2 and 7 and (b) the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks" and © the TCEQ publication titled "Technical Guidance Package for Chemical Sources -Loading Operations".

● Each tank truck shall pass annual leak-tight testing as follows:

A. The permittee shall not allow any tank truck to be filled or emptied unless the tank being filled or emptied has passed a leak-tight test within the last year as evidenced by a prominently displayed certification affixed near the Department of Transportation certification plate which shows:

(1) The date the tank truck last passed the leak-tight test required by this condition, and,

(2) The identification number of the tank truck.

B. Tank tightness testing shall be conducted as follows:

(1) Pressure in the tank must change no more than 3 inches of water (0.75 kPa) in five minutes when pressurized to a gauge pressure of 18 inches (4.5 kPa) or when evacuated to vacuum of 6 inches of water (1.5 kPa).

(2) Any tank failing to meet the testing criteria of Special Condition No. XX above shall be repaired and retested within 15 days.

(3) The owner or operator of the tank truck shall maintain records of all certification testing and repairs. Records covering a period of not less than two years at any time shall be maintained.

(4) The record of each certification test required by this condition shall, as a minimum, contain:

a. Company name.
b. Date and location where the test was carried out.
c. Name and title of the person conducting the test.
d. Tank identification number.
e. Initial test pressure and the time of the reading.
f. Final test pressure and the time of the reading.
g. Initial vacuum and the time of the reading.
h. Final vacuum and the time of the reading.

(5) Copies of all records required by this condition shall be maintained at the plant site for at least two years and be made available to representatives of the TCEQ upon request.

- **A record of the following parameters shall be maintained. These parameters are to be checked and recorded on a daily basis, Monday through Friday, excluding holidays.**

A. Pressure to the upper and lower spray nozzles in the absorber.

B. Suction and discharge temperature of each of the vacuum pumps.

Readings on these parameters shall be compared to the following ranges:

A. A pressure range in the upper spray nozzle of XX to XX psig;

B. A pressure range in the lower spray nozzle of XX to XX psig; and

C. A difference in temperatures of XX to XX ^{o}F.

The permittee shall initiate corrective actions upon determining that the above readings are outside the acceptable range.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK. NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

NOV 27 1995

Mr. Timothy J. Mohin
Government Affairs Manager
Environment, Health and Safety
Intel Government Affairs
888 17th Street Northwest, #860
Washington, DC 20006-3939

Dear Mr. Mohin:

Thank you for the additional information you provided regarding the exhaust conditioners used in tool operations in the semiconductor industry. We agree with your assessment that, for potential to emit calculations, the exhaust conditioners should be considered as an inherent part of the process.

Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment

For purposes of determining a source's potential to emit, it is necessary to calculate the effect of air pollution control equipment. Current Environmental Protection Agency (EPA) regulations and policy allow air pollution control equipment to be taken into account if federally enforceable requirements are in place requiring the use of such air pollution control equipment. There are, however, situations for which case-by-case judgements are needed regarding whether a given device or strategy should be considered as air pollution control equipment, or as an inherent part of the process. The EPA believes that the following list of questions should be considered in making such case-by-case judgements as to whether certain devices or practices should be treated as pollution controls or an inherent to the process:.

1. Is the primary purpose of the equipment to control air pollution?

2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

3. Would the equipment be installed if no air quality regulations are in place?

If the answers to these questions suggest that equipment should be considered as an inherent part of the process, then the effect of the equipment or practices can be taken into account in calculating potential emissions regardless of whether enforceable limitations are in effect.

Analysis of the criteria for the semiconductor tools listed

No information supplied to date by Intel suggests that product recovery by the exhaust conditioners is significant. That EPA believes that the first and third criteria are satisfied.

Criteria 1. The exhaust conditioners described in your letter are small treatment systems that are local to the point-of-use of process tools such as etching and deposition processes. The primary purposes are to: (1) increase the uptime of the process tools, (2) to minimize safety hazards, and (3) to prevent impurities from entering other processes.

Criteria 3. The information you have provided suggests strongly that air quality regulations are not the driving factor for installation of the equipment. Moreover, the fact that they are "interlocked" with the process chambers suggests that the process cannot operate unless the exhaust conditioner is in use.

Therefore, based upon a review of the information presented the exhaust conditioners are considered by the EPA to be inherent to the process and can be considered in potential emission calculations without federally enforceable requirements.

Cautions

The above determination regarding the use of the localized exhaust conditioners in the semiconductor industry is case-specific. This determination is not intended to set a precedent for localized pollution control equipment for other source types without a similar case-specific review.

While many types of point-of-use and interlocked treatment device may be considered as "inherent," there does exist, of course, air pollution control equipment at semiconductor facilities that may not meet the above criteria. For example, a remote water scrubber located at the roof of a building would generally be considered an air pollution control device.

If you have any further questions regarding this matter, please call Timothy Smith at (919) 541-4718, or Tony Wayne at (919) 541-5439.

sincerely,

David Solomon
Acting Group Leader
Integrated Implementation Group

cc: Chief, Air Branch, Regions I-X
Regional PTE Contacts

5.2 Transportation And Marketing Of Petroleum Liquids[1-3]

5.2.1 General

The transportation and marketing of petroleum liquids involve many distinct operations, each of which represents a potential source of evaporation loss. Crude oil is transported from production operations to a refinery by tankers, barges, rail tank cars, tank trucks, and pipelines. Refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by these same modes. From the fuel marketing terminals, the fuels are delivered by tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is usually a motor vehicle gasoline tank. Similar distribution paths exist for fuel oils and other petroleum products. A general depiction of these activities is shown in Figure 5.2-1.

5.2.2 Emissions And Controls

Evaporative emissions from the transportation and marketing of petroleum liquids may be considered, by storage equipment and mode of transportation used, in four categories:

1. Rail tank cars, tank trucks, and marine vessels: loading, transit, and ballasting losses.
2. Service stations: bulk fuel drop losses and underground tank breathing losses.
3. Motor vehicle tanks: refueling losses.
4. Large storage tanks: breathing, working, and standing storage losses. (See Chapter 7, "Liquid Storage Tanks".)

Evaporative and exhaust emissions are also associated with motor vehicle operation, and these topics are discussed in AP-42 *Volume II: Mobile Sources*.

5.2.2.1 Rail Tank Cars, Tank Trucks, And Marine Vessels -

Emissions from these sources are from loading losses, ballasting losses, and transit losses.

5.2.2.1.1 Loading Losses -

Loading losses are the primary source of evaporative emissions from rail tank car, tank truck, and marine vessel operations. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded. The quantity of evaporative losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo;
- Method of unloading the previous cargo;
- Operations to transport the empty carrier to a loading terminal;
- Method of loading the new cargo; and
- Physical and chemical characteristics of the new cargo.

The principal methods of cargo carrier loading are illustrated in Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4. In the splash loading method, the fill pipe dispensing the cargo is lowered only part way into the cargo tank. Significant turbulence and vapor/liquid contact occur during the splash

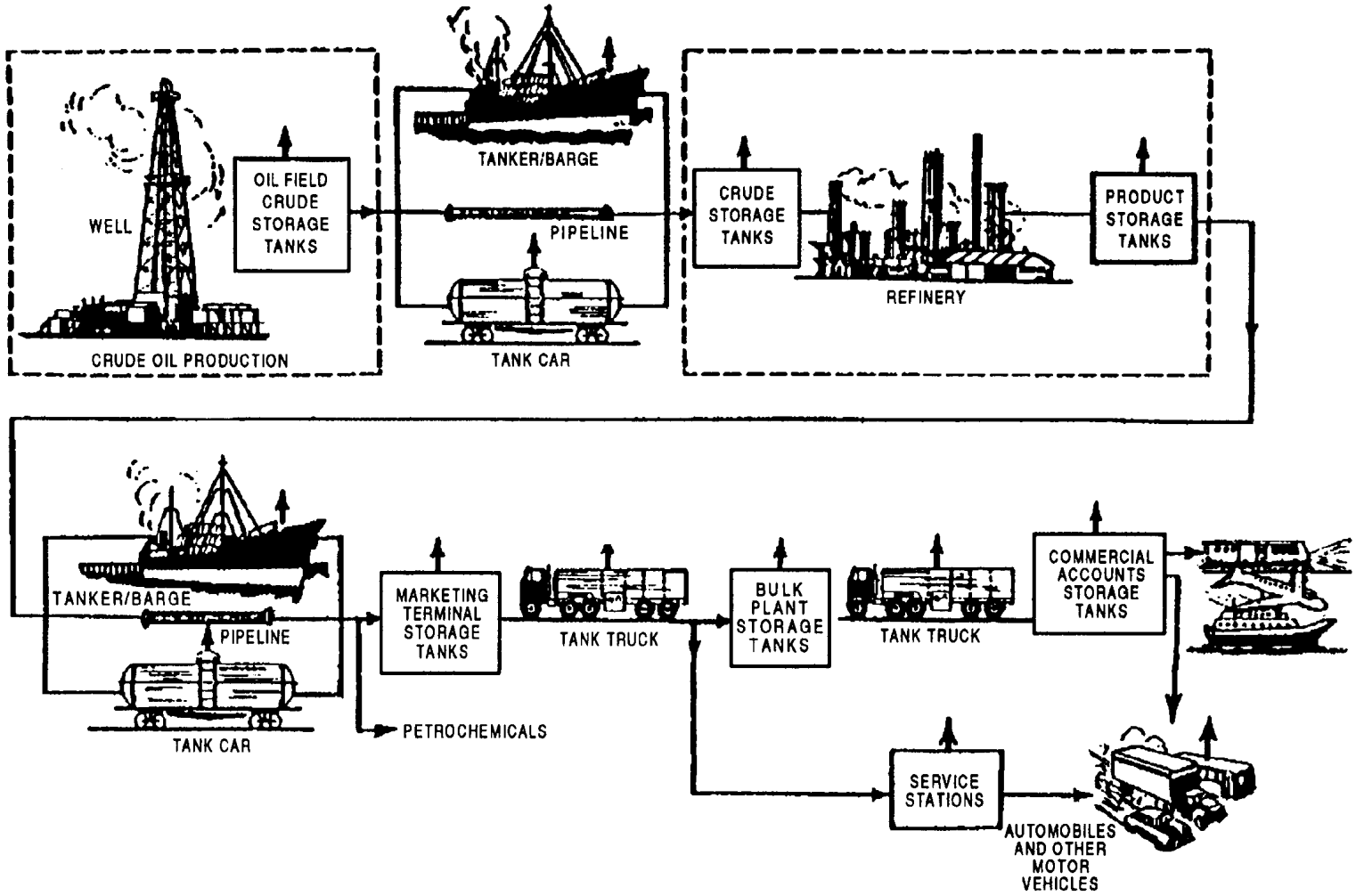

Figure 5.2-1. Flow sheet of petroleum production, refining, and distribution systems.
(Points of organic emissions are indicated by vertical arrows.)

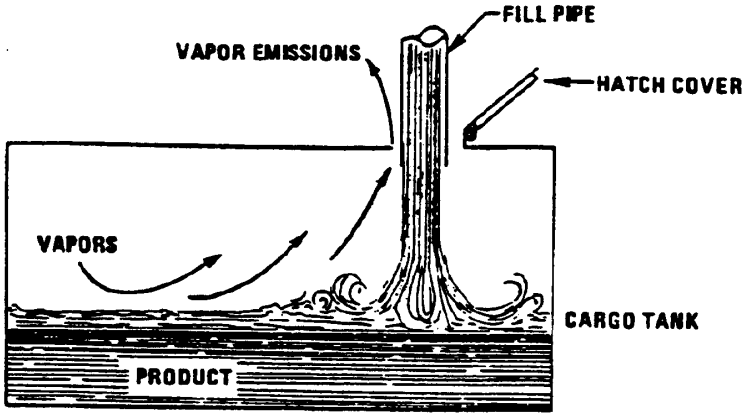

Figure 5.2-2. Splash loading method.

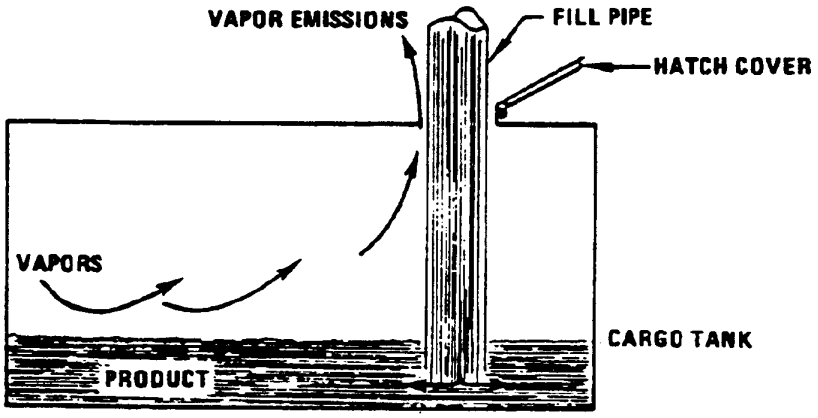

Figure 5.2-3. Submerged fill pipe.

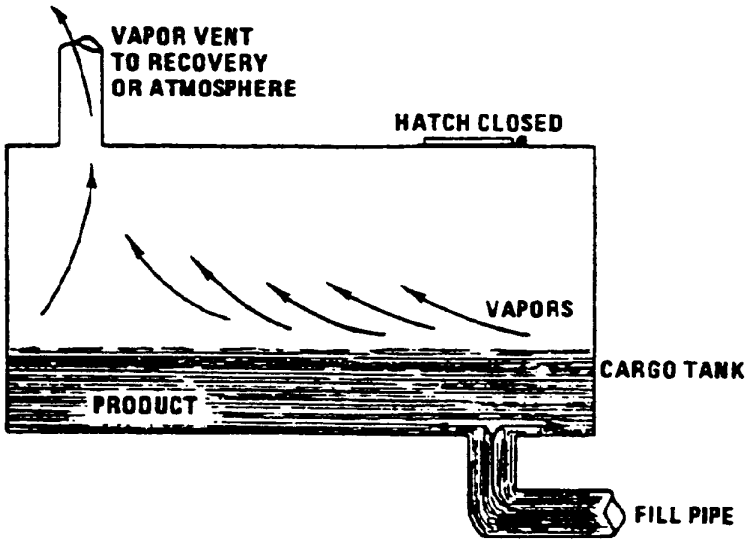

Figure 5.2-4. Bottom loading.

loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ±30 percent)[4] using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \qquad (1)$$

where:

L_L = loading loss, pounds per 1000 gallons (lb/10^3 gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Section 7.1, "Organic Liquid Storage Tanks")
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Section 7.1, "Organic Liquid Storage Tanks")
T = temperature of bulk liquid loaded, °R (°F + 460)

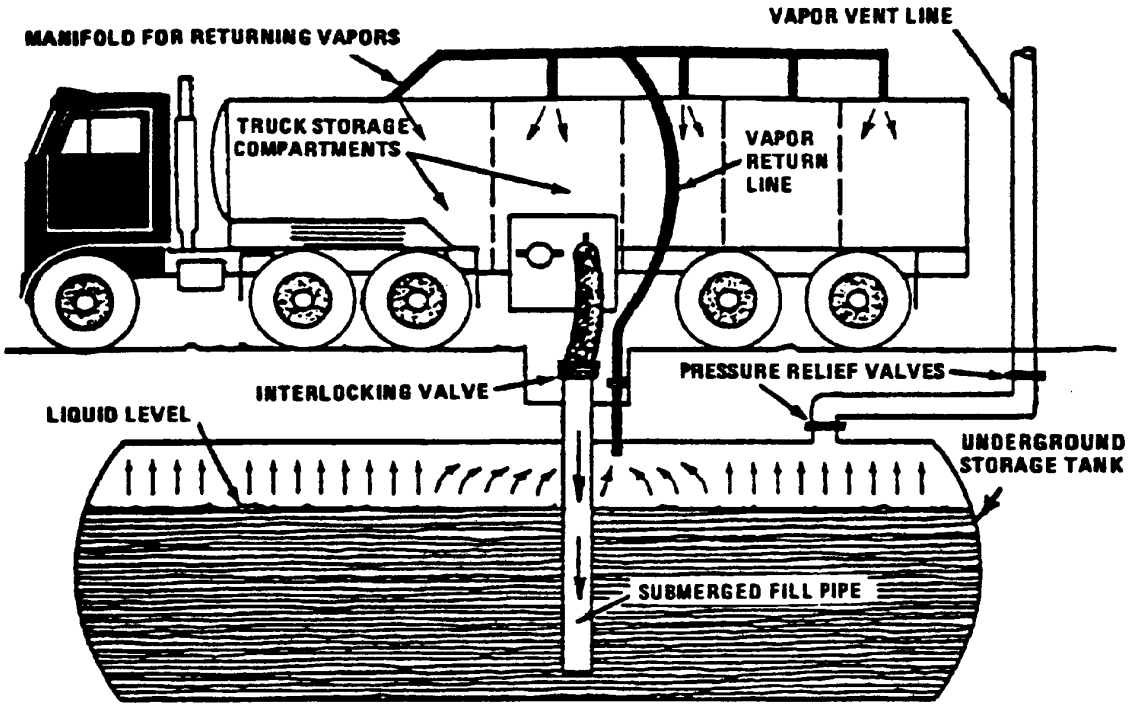

Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

Table 5.2-1. SATURATION (S) FACTORS FOR CALCULATING PETROLEUM LIQUID LOADING LOSSES

Cargo Carrier	Mode Of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels[a]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

[a] For products other than gasoline and crude oil. For marine loading of gasoline, use factors from Table 5.2-2. For marine loading of crude oil, use Equations 2 and 3 and Table 5.2-3.

The saturation factor, S, represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100}\right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.[5-6] However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).[7] A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change) A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests[6].

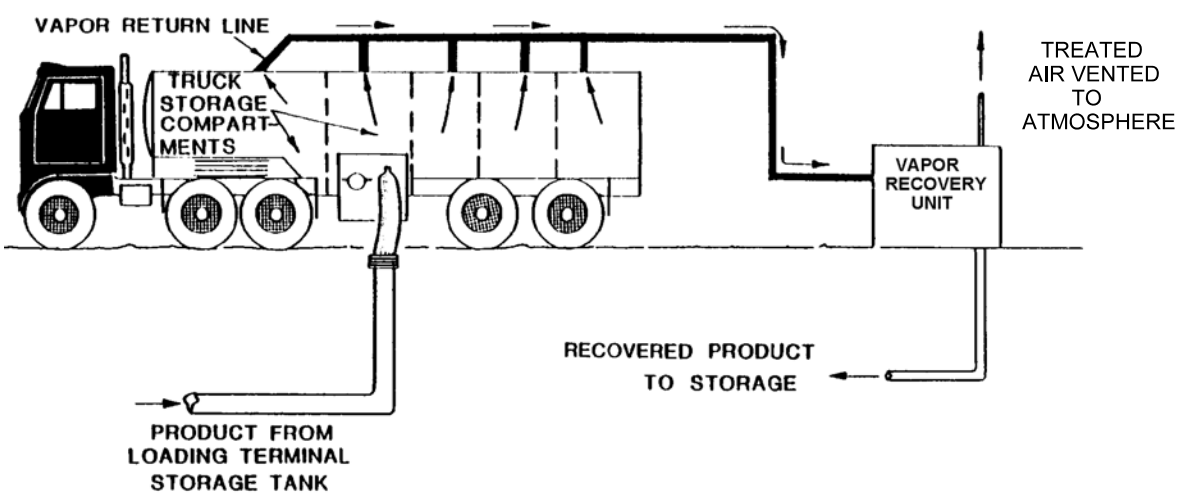

Figure 5.2-6. Tank truck loading with vapor recovery.

Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T} \left(1 - \frac{eff}{100}\right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline = 6.6 psia
M = molecular weight of gasoline vapors = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540} \left(1 - \frac{94}{100}\right)$$

$$= 0.60 \text{ lb}/10^3 \text{ gal}$$

Total loading losses are:

$$(0.60 \text{ lb}/10^3 \text{ gal})(8.0 \times 10^3 \text{ gal}) = 4.8 \text{ pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.[8] These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10^3 gal).

Table 5.2-2 (Metric And English Units). VOLATILE ORGANIC COMPOUND (VOC) EMISSION FACTORS FOR GASOLINE LOADING OPERATIONS AT MARINE TERMINALS[a]

Vessel Tank Condition	Previous Cargo	Ships/Ocean Barges[b]		Barges[b]	
		mg/L Transferred	lb/10^3 gal Transferred	mg/L Transferred	lb/10^3 gal Transferred
Uncleaned	Volatile[c]	315	2.6	465	3.9
Ballasted	Volatile	205	1.7	—[d]	—[d]
Cleaned	Volatile	180	1.5	ND	ND
Gas-freed	Volatile	85	0.7	ND	ND
Any condition	Nonvolatile	85	0.7	ND	ND
Gas-freed	Any cargo	ND	ND	245	2.0
Typical overall situation[e]	Any cargo	215	1.8	410	3.4

[a] References 2,9. Factors are for both VOC emissions (which excludes methane and ethane) and total organic emissions, because methane and ethane have been found to constitute a negligible weight fraction of the evaporative emissions from gasoline. ND = no data.
[b] Ocean barges (tank compartment depth about 12.2 m [40 ft]) exhibit emission levels similar to tank ships. Shallow draft barges (compartment depth 3.0 to 3.7 m [10 to 12 ft]) exhibit higher emission levels.
[c] Volatile cargoes are those with a true vapor pressure greater than 10 kilopascals (kPa) (1.5 psia).
[d] Barges are usually not ballasted.
[e] Based on observation that 41% of tested ship compartments were uncleaned, 11% ballasted, 24% cleaned, and 24% gas-freed. For barges, 76% were uncleaned.

In addition to Equation 1, which estimates emissions from the loading of petroleum liquids, Equation 2 has been developed specifically for estimating emissions from the loading of crude oil into ships and ocean barges:

$$C_L = C_A + C_G \tag{2}$$

where:

C_L = total loading loss, lb/10^3 gal of crude oil loaded
C_A = arrival emission factor, contributed by vapors in the empty tank compartment before loading, lb/10^3 gal loaded (see Note below)
C_G = generated emission factor, contributed by evaporation during loading, lb/10^3 gal loaded

Note: Values of C_A for various cargo tank conditions are listed in Table 5.2-3.

5.2-3 (English Units). AVERAGE ARRIVAL EMISSION FACTORS, C_A, FOR CRUDE OIL LOADING EMISSION EQUATION[a]

Ship/Ocean Barge Tank Condition	Previous Cargo	Arrival Emission Factor, lb/10^3 gal
Uncleaned	Volatile[b]	0.86
Ballasted	Volatile	0.46
Cleaned or gas-freed	Volatile	0.33
Any condition	Nonvolatile	0.33

[a] Arrival emission factors (C_A) to be added to generated emission factors (C_G) calculated in Equation 3 to produce total crude oil loading loss (C_L). Factors are for total organic compounds; VOC emission factors average about 15% lower, because VOC does not include methane or ethane.
[b] Volatile cargoes are those with a true vapor pressure greater than 10 kPa (1.5 psia).

This equation was developed empirically from test measurements of several vessel compartments.[8] The quantity C_G can be calculated using Equation 3:

$$C_G = 1.84\ (0.44\ P - 0.42)\ \frac{M\,G}{T} \qquad (3)$$

where:

P = true vapor pressure of loaded crude oil, psia
M = molecular weight of vapors, lb/lb-mole
G = vapor growth factor = 1.02 (dimensionless)
T = temperature of vapors, °R (°F + 460)

Emission factors derived from Equation 3 and Table 5.2-3 represent total organic compounds. Volatile organic compound (VOC) emission factors (which exclude methane and ethane because they are exempted from the regulatory definition of "VOC") for crude oil vapors have been found to range from approximately 55 to 100 weight percent of these total organic factors. When specific vapor composition information is not available, the VOC emission factor can be estimated by taking 85 percent of the total organic factor.[3]

5.2.2.1.2 Ballasting Losses -

Ballasting operations are a major source of evaporative emissions associated with the unloading of petroleum liquids at marine terminals. It is common practice to load several cargo tank compartments with sea water after the cargo has been unloaded. This water, termed "ballast", improves the stability of the empty tanker during the subsequent voyage. Although ballasting practices vary, individual cargo tanks are ballasted typically about 80 percent, and the total vessel 15 to 40 percent, of capacity. Ballasting emissions occur as vapor-laden air in the "empty" cargo tank is displaced to the atmosphere by ballast water being pumped into the tank. Upon arrival at a loading port, the ballast water is pumped from the cargo tanks before the new cargo is loaded. The ballasting of cargo tanks reduces the quantity of vapors returning in the empty tank, thereby reducing the quantity of vapors emitted during subsequent tanker loading. Regulations administered by the U. S. Coast Guard require that, at marine terminals located in ozone nonattainment areas, large tankers with crude oil washing systems contain the organic vapors from ballasting.[10] This is accomplished principally by displacing the vapors during ballasting into a cargo tank being simultaneously unloaded. In other areas, marine vessels emit organic vapors directly to the atmosphere.

Equation 4 has been developed from test data to calculate the ballasting emissions from crude oil ships and ocean barges[8]:

$$L_B = 0.31 + 0.20\ P + 0.01\ PU_A \qquad (4)$$

where:

L_B = ballasting emission factor, lb/10^3 gal of ballast water
P = true vapor pressure of discharged crude oil, psia
U_A = arrival cargo true ullage, before dockside discharge, measured from the deck, feet; (the term "ullage" here refers to the distance between the cargo surface level and the deck level)

Table 5.2-4 lists average total organic emission factors for ballasting into uncleaned crude oil cargo compartments. The first category applies to "full" compartments wherein the crude oil true ullage just before cargo discharge is less than 1.5 meters (m) (5 ft). The second category applies to lightered, or short-loaded, compartments (part of cargo previously discharged, or original load a partial fill), with an arrival true ullage greater than 1.5 m (5 ft). It should be remembered that these tabulated emission factors are examples only, based on average conditions, to be used when crude oil vapor pressure is unknown. Equation 4 should be used when information about crude oil vapor pressure and cargo compartment condition is available. The following sample calculation illustrates the use of Equation 4.

5.2-4 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS FOR CRUDE OIL BALLASTING[a]

Compartment Condition Before Cargo Discharge	Average Emission Factors			
	By Category		Typical Overall[b]	
	mg/L Ballast Water	lb/10^3 gal Ballast Water	mg/L Ballast Water	lb/10^3 gal Ballast Water
Fully loaded[c]	111	0.9	129	1.1
Lightered or previously short loaded[d]	171	1.4		

[a] Assumes crude oil temperature of 16°C (60°F) and RVP of 34 kPa (5 psia). VOC emission factors average about 85% of these total organic factors, because VOCs do not include methane or ethane.
[b] Based on observation that 70% of tested compartments had been fully loaded before ballasting. May not represent average vessel practices.
[c] Assumed typical arrival ullage of 0.6 m (2 ft).
[d] Assumed typical arrival ullage of 6.1 m (20 ft).

Sample Calculation -

Ballasting emissions from a crude oil cargo ship would be calculated as follows, using Equation 4:

Design basis -

Vessel and cargo description: 80,000 dead-weight-ton tanker, crude oil capacity 500,000 barrels (bbl); 20 percent of the cargo capacity is filled with ballast water after cargo discharge. The crude oil has an RVP of 6 psia and is discharged at 75°F.

Compartment conditions: 70 percent of the ballast water is loaded into compartments that had been fully loaded to 2 ft ullage, and 30 percent is loaded into compartments that had been lightered to 15 ft ullage before arrival at dockside.

Ballasting emission equation -

$$L_B = 0.31 + 0.20\ P + 0.01\ PU_A$$

where:

P = true vapor pressure of crude oil
= 4.6 psia
U_A = true cargo ullage for the full compartments = 2 ft, and true cargo ullage for the lightered compartments = 15 ft

$$L_B = 0.70\ [0.31 + (0.20)\ (4.6) + (0.01)\ (4.6)\ (2)] + 0.30\ [0.31 + (0.20)\ (4.6) + (0.01)\ (4.6)\ (15)]$$

$$= 1.5\ \text{lb}/10^3\ \text{gal}$$

Total ballasting emissions are:

$$(1.5\ \text{lb}/10^3\ \text{gal})\ (0.20)\ (500{,}000\ \text{bbl})\ (42\ \text{gal/bbl}) = 6{,}300\ \text{lb}$$

Since VOC emissions average about 85 percent of these total organic emissions, emissions of VOCs are about: (0.85)(6,300 lb) = 5,360 lb

5.2.2.1.3 Transit Losses -

In addition to loading and ballasting losses, losses occur while the cargo is in transit. Transit losses are similar in many ways to breathing losses associated with petroleum storage (see Section 7.1, "Organic Liquid Storage Tanks"). Experimental tests on ships and barges[4] have indicated that transit losses can be calculated using Equation 5:

$$L_T = 0.1\ PW \qquad (5)$$

where:

L_T = transit loss from ships and barges, lb/week-10^3 gal transported
P = true vapor pressure of the transported liquid, psia
W = density of the condensed vapors, lb/gal

Emissions from gasoline truck cargo tanks during transit have been studied by a combination of theoretical and experimental techniques, and typical emission values are presented in Table 5.2-5.[11-12] Emissions depend on the extent of venting from the cargo tank during transit, which in turn depends on the vapor tightness of the tank, the pressure relief valve settings, the pressure in the tank at the start of the trip, the vapor pressure of the fuel being transported, and the degree of fuel vapor saturation of the space in the tank. The emissions are not directly proportional to the time spent in transit. If the vapor leakage rate of the tank increases, emissions increase up to a point, and then the rate changes as other determining factors take over. Truck tanks in dedicated vapor balance service usually contain saturated vapors, and this leads to lower emissions during transit because no additional fuel evaporates to raise the pressure in the tank to cause venting. Table 5.2-5 lists "typical" values for transit emissions and "extreme" values that could occur in the unlikely event that all determining factors combined to cause maximum emissions.

Table 5.2-5 (Metric And English Units). TOTAL UNCONTROLLED ORGANIC EMISSION FACTORS FOR PETROLEUM LIQUID RAIL TANK CARS AND TANK TRUCKS

Emission Source	Gasoline[a]	Crude Oil[b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations[c]						
Submerged loading - Dedicated normal service[d]						
mg/L transferred	590	240	180	1.9	1.7	0.01
lb/10^3 gal transferred	5	2	1.5	0.016	0.014	0.0001
Submerged loading - Vapor balance service[d]						
mg/L transferred	980	400	300	—[e]	—[e]	—[e]
lb/10^3 gal transferred	8	3	2.5	—[e]	—[e]	—[e]
Splash loading - Dedicated normal service						
mg/L transferred	1,430	580	430	5	4	0.03
lb/10^3 gal transferred	12	5	4	0.04	0.03	0.0003
Splash loading - Vapor balance service						
mg/L transferred	980	400	300	—[e]	—[e]	—[e]
lb/10^3 gal transferred	8	3	2.5	—[e]	—[e]	—[e]

Table 5.2-5 (cont.).

Emission Source	Gasoline[a]	Crude Oil[b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Transit losses						
Loaded with product						
mg/L transported						
Typical	0 - 1.0	ND	ND	ND	ND	ND
Extreme	0 - 9.0	ND	ND	ND	ND	ND
lb/10^3 gal transported						
Typical	0 - 0.01	ND	ND	ND	ND	ND
Extreme	0 - 0.08	ND	ND	ND	ND	ND
Return with vapor						
mg/L transported						
Typical	0 - 13.0	ND	ND	ND	ND	ND
Extreme	0 - 44.0	ND	ND	ND	ND	ND
lb/10^3 gal transported						
Typical	0 - 0.11	ND	ND	ND	ND	ND
Extreme	0 - 0.37	ND	ND	ND	ND	ND

[a] Reference 2. Gasoline factors represent emissions of VOC as well as total organics, because methane and ethane constitute a negligible weight fraction of the evaporative emissions from gasoline. VOC factors for crude oil can be assumed to be 15% lower than the total organic factors, to account for the methane and ethane content of crude oil evaporative emissions. All other products should be assumed to have VOC factors equal to total organics. The example gasoline has an RVP of 69 kPa (10 psia). ND = no data.
[b] The example crude oil has an RVP of 34 kPa (5 psia).
[c] Loading emission factors are calculated using Equation 1 for a dispensed product temperature of 16°C (60°F).
[d] Reference 2.
[e] Not normally used.

In the absence of specific inputs for Equations 1 through 5, the typical evaporative emission factors presented in Tables 5.2-5 and 5.2-6 should be used. It should be noted that, although the crude oil used to calculate the emission values presented in these tables has an RVP of 5, the RVP of crude oils can range from less than 1 up to 10. Similarly, the RVP of gasolines ranges from 7 to 13. In areas where loading and transportation sources are major factors affecting air quality, it is advisable to obtain the necessary parameters and to calculate emission estimates using Equations 1 through 5.

5.2.2.2 Service Stations -

Another major source of evaporative emissions is the filling of underground gasoline storage tanks at service stations. Gasoline is usually delivered to service stations in 30,000-liter (8,000-gal) tank trucks or smaller account trucks. Emissions are generated when gasoline vapors in the underground storage tank are displaced to the atmosphere by the gasoline being loaded into the tank. As with other loading losses, the quantity of loss in service station tank filling depends on several variables, including the method and rate of filling, the tank configuration, and the gasoline temperature, vapor pressure and composition. An average emission rate for submerged filling is 880 mg/L (7.3 lb/1000 gal) of transferred gasoline, and the rate for splash filling is 1380 mg/L (11.5 lb/1000 gal) transferred gasoline (see Table 5.2-7).[5]

Table 5.2-6 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS FOR PETROLEUM MARINE VESSEL SOURCES[a]

Emission Source	Gasoline[b]	Crude Oil[c]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations						
Ships/ocean barges						
mg/L transferred	—[d]	73	60	0.63	0.55	0.004
lb/10^3 gal transferred	—[d]	0.61	0.50	0.005	0.005	0.00004
Barges						
mg/L transferred	—[d]	120	150	1.60	1.40	0.011
lb/10^3 gal transferred	—[d]	1.0	1.2	0.013	0.012	0.00009
Tanker ballasting						
mg/L ballast water	100	—[e]	ND	ND	ND	ND
lb/10^3 gal ballast water	0.8	—[e]	ND	ND	ND	ND
Transit						
mg/week-L transported	320	150	84	0.60	0.54	0.003
lb/week-10^3 gal transported	2.7	1.3	0.7	0.005	0.005	0.00003

[a] Factors are for a dispensed product of 16°C (60°F). ND = no data.
[b] Factors represent VOC as well as total organic emissions, because methane and ethane constitute a negligible fraction of gasoline evaporative emissions. All products other than crude oil can be assumed to have VOC factors equal to total organic factors. The example gasoline has an RVP of 69 kPa (10 psia).
[c] VOC emission factors for a typical crude oil are 15% lower than the total organic factors shown, in order to account for methane and ethane. The example crude oil has an RVP of 34 kPa (5 psia).
[d] See Table 5.2-2 for these factors.
[e] See Table 5.2-4 for these factors.

Emissions from underground tank filling operations at service stations can be reduced by the use of a vapor balance system such as in Figure 5.2-5 (termed Stage I vapor control). The vapor balance system employs a hose that returns gasoline vapors displaced from the underground tank to the tank truck cargo compartments being emptied. The control efficiency of the balance system ranges from 93 to 100 percent. Organic emissions from underground tank filling operations at a service station employing a vapor balance system and submerged filling are not expected to exceed 40 mg/L (0.3 lb/1000 gal) of transferred gasoline.

Table 5.2-7 (Metric And English Units). EVAPORATIVE EMISSIONS FROM GASOLINE SERVICE STATION OPERATIONS[a]

Emission Source	Emission Rate	
	mg/L Throughput	lb/10^3 gal Throughput
Filling underground tank (Stage I)		
Submerged filling	880	7.3
Splash filling	1,380	11.5
Balanced submerged filling	40	0.3
Underground tank breathing and emptying[b]	120	1.0
Vehicle refueling operations (Stage II)		
Displacement losses (uncontrolled)[c]	1,320	11.0
Displacement losses (controlled)	132	1.1
Spillage	80	0.7

[a] Factors are for VOC as well as total organic emissions, because of the methane and ethane content of gasoline evaporative emissions is negligible.
[b] Includes any vapor loss between underground tank and gas pump.
[c] Based on Equation 6, using average conditions.

A second source of vapor emissions from service stations is underground tank breathing. Breathing losses occur daily and are attributable to gasoline evaporation and barometric pressure changes. The frequency with which gasoline is withdrawn from the tank, allowing fresh air to enter to enhance evaporation, also has a major effect on the quantity of these emissions. An average breathing emission rate is 120 mg/L (1.0 lb/1000 gal) of throughput.

5.2.2.3 Motor Vehicle Refueling -

Service station vehicle refueling activity also produces evaporative emissions. Vehicle refueling emissions come from vapors displaced from the automobile tank by dispensed gasoline and from spillage. The quantity of displaced vapors depends on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rate. Equation 6 can be used to estimate uncontrolled displacement losses from vehicle refueling for a particular set of conditions.[14]

$$E_R = 264.2\ [(-5.909) - 0.0949\ (\Delta T) + 0.0884\ (T_D) + 0.485\ (RVP)] \qquad (6)$$

where:

E_R = refueling emissions, mg/L
ΔT = difference between temperature of fuel in vehicle tank and temperature of dispensed fuel, °F
T_D = temperature of dispensed fuel, °F
RVP = Reid vapor pressure, psia

Note that this equation and the spillage loss factor are incorporated into the *MOBILE* model. The *MOBILE* model allows for disabling of this calculation if it is desired to include these emissions in the stationary area source portion of an inventory rather than in the mobile source portion. It is estimated that the uncontrolled emissions from vapors displaced during vehicle refueling average 1320 mg/L (11.0 lb/1000 gal) of dispensed gasoline.[5,13]

Spillage loss is made up of contributions from prefill and postfill nozzle drip and from spit-back and

overflow from the vehicles's fuel tank filler pipe during filling. The amount of spillage loss can depend on several variables, including service station business characteristics, tank configuration, and operator techniques. An average spillage loss is 80 mg/L (0.7 lb/1000 gal) of dispensed gasoline.[5,13]

Control methods for vehicle refueling emissions are based on conveying the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space through the use of a special hose and nozzle, as depicted in Figure 5.2-7 (termed Stage II vapor control). In "balance" vapor control systems, the vapors are conveyed by natural pressure differentials established during refueling. In "vacuum assist" systems, the conveyance of vapors from the auto fuel tank to the underground storage tank is assisted by a vacuum pump. Tests on a few systems have indicated overall systems control efficiencies in the range of 88 to 92 percent.[5,13] When inventorying these emissions as an area source, rule penetration and rule effectiveness should also be taken into account. *Procedures For Emission Inventory Preparation, Volume IV: Mobile Sources*, EPA-450/4-81-026d, provides more detail on this.

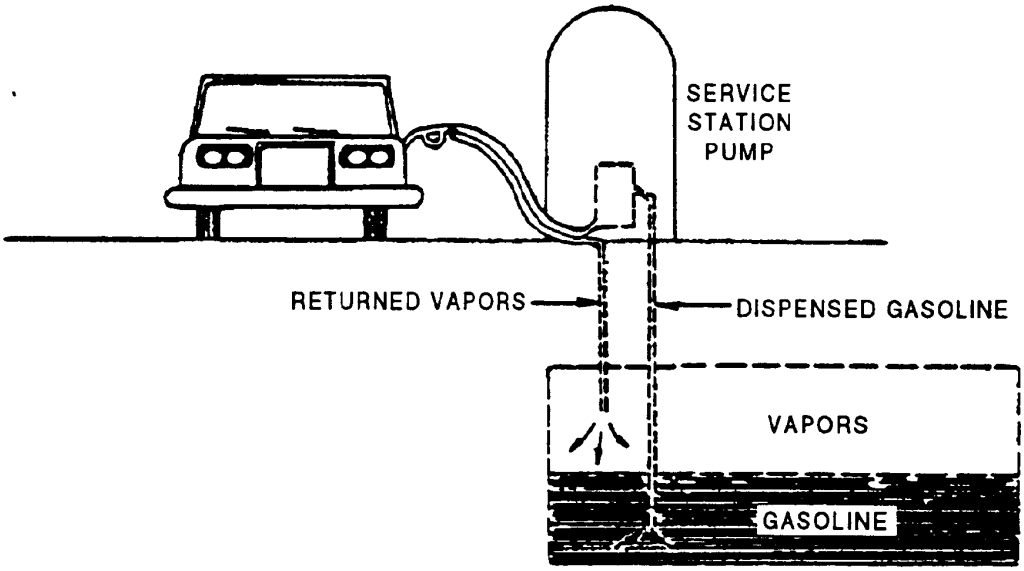

Figure 5.2-7. Automobile refueling vapor recovery system.

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