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Before The Executive Director
Utah Department Of Environmental Quality

In the Matter of: Approval Order – Petroleum Processing Plant Emery Refining L.L.C. Project Number: N14627-0001 DAQE-AN146270001-13	REQUEST FOR AGENCY ACTION July 22, 2013

Request for Agency Action

1. Pursuant to Utah Code Section 19-1-301.5 and §§ 63G-4-201(1)(b), (3) and Utah Admin. Code R305-7-203, the Grand Canyon Trust, Living Rivers, Southern Utah Wilderness Alliance, and the Center for Biological Diversity (collectively "Trust") hereby files its Request for Agency Action with Amanda Smith, Executive Director of the Utah Department of Environmental Quality and Bryce Bird, Director of the Utah Division of Air Quality. The Trust seeks review and remand of the June 21, 2013 decision by the Utah Division of Air Quality and the Director of the Utah Division of Air Quality (collectively "DAQ") to issue an Approval Order ("AO") for

Emery Refining LLC's ("Emery") petroleum processing plant ("plant" or "refinery") near Green River, Utah. In accordance with Utah Code § 19-1-301.5 (7) and R305-7-204, the Trust supports this Request for Agency Action with a separate Petition to Intervene and declarations of members of petitioner organizations, filed herewith.

I. Agency File Number and Date of Mailing

2. The Trust contests the Approval Order signed on June 21, 2013 by Mr. Bryce Bird, Director of the Utah Division of Air Quality, to authorize the establishment of a new petroleum processing plant in Green River, Utah (DAQE-AN146270001-13) (Project Number N14627-0001). This Request for Agency Action is timely hand delivered to the Executive Director of the Utah Department of Environmental Quality, the Director of the Division of Air Quality and the Administrative Proceedings Record Officer on July 22, 2013. In addition, this Request for Agency Action was served on all parties by email. Utah Code § 19-1-301.5(3)(b); Utah Admin. Code R305-7-203 (5).

II. Statement of Legal Authority and Jurisdiction

3. The Executive Director has jurisdiction over this Request for Agency Action pursuant to Utah Code § 19-1-301.5, and § 63G-4-101 *et seq.* The legal authority for this Request for Agency Action is found in: the Utah Constitution, the Clean Air Act, 42 U.S.C. § 7401 *et seq.*, and its implementing regulations, *e.g.* Code of Federal Regulations, Title 40, Chapter 1, subchapter C, and the Utah Air Conservation Act, Utah Code Section 19, Chapter 2, and its implementing regulations. Utah Admin. Code Rule R307 (hereinafter Rule R307 will be referred to as Utah Air Quality Rules). In addition, this Request for Agency Action finds its legal authority in the federally enforceable State Implementation Plans (SIPs) for Utah.

III. Statement of the Relief or Action

4. The Trust requests an order voiding the AO; remanding the AO with instructions that DAQ objectively and independently review the data and analysis provided by Emery, that DAQ otherwise fulfill its obligations under state and federal law, and that any determinations flowing from this review be supported by substantial evidence and documented in the record. The Trust requests any other or additional remedy the Executive Director deems appropriate. In addition to this statement of relief, the Trust provides requests for relief specific to each issue raised below.

IV. Statement Demonstrating that the Trust Met Requirements of 19-1-301.5(4)

5. The Trust has met the requirements of Section 19-1-301.5(4) by submitting two sets of timely comments and exhibits on DAQ's ITA DAQE-IN-146270001-13. The Trust's comment is attached as Exhibit 1. This comment provided the basis for the Trust's legal arguments, and also provided comments on the technical inadequacies of the ITA. The Trust will refer to this comment as "Trust Comment." To provide assistance to DAQ as it evaluated the adequacy of the ITA, Dr. J. Phyllis Fox submitted technical comments submitted on behalf of the Trust. Dr. Fox's comment is attached as Exhibit 2. The Trust will refer to this comment as "Fox Comment." The Trust hereby incorporates and references the Trust Comment and Fox Comment. In addition to, and in clarification of those comments, the Trust sets forth the reasons for its Request for Agency Action below.

6. In accordance with the requirements of R305-7-202 (1)(b) and R305-7-203 (3)(h), the Trust's two comments provided sufficient information and documentation to enable the Director to fully consider the substance and significance of the issues being raised in this Request for Agency Action. Where applicable, the Trust attached supporting documentation of technology

used in similar refineries. The Trust provided reports of documented Clean Air Act violations caused by permit inadequacies similar to those at issue in the AO. The Trust provided relevant legal standards and EPA guidance, and noted instances in which DAQ failed to comply with the mandates of the Clean Air Act, the Utah Air Conservation Act, and the Utah Air Quality Rules. DAQ's own responses to the Trust's comments indicate that the comments were sufficient to enable DAQ to respond to the substance of each issue raised. *See* DAQ Memorandum in Response to Comments (hereinafter DAQ Memorandum), attached as Exhibit 3.

V. Statement of Facts and Reasons

Introduction

7. Representing thousands of citizens of Utah and the Colorado Plateau, local and national environmental groups bring this Request for Agency Action, challenging DAQ's issuance of an Approval Order that enables Emery to construct and operate its new oil refinery in the heart of the Colorado Plateau. Under Approval Order DAQE-AN146270001-13, DAQ has not required Emery to incorporate the best pollution controls nor has it required Emery to ensure that the air blowing to the downwind communities and landscapes – including iconic Arches National Park – will continue to meet national health and visibility standards. Moreover, DAQ exempted Emery from the analysis normally required of large new industrial plants based on an erroneous conclusion that the refinery will be a "minor" source of air pollution, rather than a major emitting source.

8. There is no identified need to rush forward with an incomplete and inadequate permitting process at the expense of both public health and visibility within Southern Utah's nationally treasured red-rock country. Indeed, the technology necessary to extract the oil shale and tar sands oil that the company intends to process has not yet even been proven commercially viable.

There are many unresolved questions about the refinery, and the consequences of a hasty decision will be borne by the citizens of Utah.

9. Here, the Executive Director stands as the gatekeeper for the health of Utah's people and its environment. As shown below, the Executive Director can decide, as a matter of law, that DAQ's analysis of Emery's "minor" source status was incomplete, and the AO does not otherwise comply with the Clean Air Act, the Utah Air Conservation Act, and the Utah Air Quality Rules. The Trust urges the Executive Director to vacate the AO and remand it to DAQ to correct its errors.

A. Emery's Refinery is Not a Synthetic Minor Source Because the AO Lacks Enforceable Terms and Conditions to Limit VOC Emissions Below Major Source Thresholds

10. The Trust raised this issue in public comment. Trust Comment, 9-12, 17-18.

11. Emery and DAQ identify Emery's refinery as a "synthetic minor source" of VOC emissions, thus attempting to exempt this facility from complying with Title V of the CAA. There are two types of minor sources: (1) a "true minor source" is one in which the facility's potential to emit is below the major source threshold; (2) a "synthetic minor" source is one where the facility's actual uncontrolled emission of a pollutant is in excess of major source emission thresholds, and enforceable limitations on the source's emissions of that pollutant are imposed to keep the source from emitting at or above major source emission thresholds.

12. In order for a synthetic minor permit to be considered legally adequate, the difference between actual uncontrolled emissions and controlled emissions must be guaranteed by enforceable permit conditions. In the absence of enforceable permit conditions, the source is simply a major source masquerading as a minor source – an outcome that the Clean Air Act, the Utah Air Conservation Act, and the Utah Air Quality Rules strictly forbid.

13. Recognizing the essentiality of enforceable emissions limitations, R307-401defines potential to emit as:

> "the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its **design if the limitation or the effect it would have on emissions is enforceable**." (emphasis added).

14. Pursuant to R307-401, a source's potential to emit can be calculated using physical or operational limitations if (1) limitations exist in the AO; and (2) those limitations are enforceable. Absent enforceable limitations, a source's emissions must be assumed to be its actual uncontrolled emissions. If those actual uncontrolled emissions exceed major source threshold and the AO lacks enforceable conditions to limit emissions, then the source must be considered a major source and be made subject to Title V's requirements. *See, e.g., Weiler v. Chatham Forest Products, Inc.*, 392 F.3d 532, 535 (2d Cir. 2004) ("a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act **unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels**.") (emphasis added); *United States v. Questar Gas Mgmt. Co.,* 2011 WL 1793172 (D. Utah 2011) ("limitations on a facility's emissions may only be considered when they **are legally and practicably enforceable** by a governmental entity") (emphasis added); *Sierra Club v. Ga. Power Co*., 365 F. Supp. 2d 1297, 1308 (D. Ga. 2004)(same); *Sierra Club v. Public Serv. Co*., 894 F.Supp. 1455, 1460 (D. Colo. 1995) (same); *In re Peabody Western Coal Company*, 12 E.A.D. 22, 31 (2005) ("In sum, therefore, [potential to emit] reflects a source' s maximum emissions capacity considering the application of any emission control equipment, or other

capacity-limiting restrictions, **that effectively and enforceably limit emissions capacity**”) (emphasis added).

15. Here, the actual uncontrolled emissions of VOCs from Emery’s refinery total 338.38 tons per year, and the controlled VOC emissions are alleged to total 36 tons per year; thus DAQ and Emery allege that Emery’s refinery is a synthetic minor source. However, the administrative record and AO conditions do not support these claims. Instead, as shown below, the AO violates the fundamental principles regarding the creation of synthetic minor permits because the actual potential to emit exceeds the major source threshold and the AO lacks adequate enforceable conditions to ensure that Emery’s emissions of VOCs will remain under major source thresholds.

16. VOC emissions come from four main emission units in the refinery: the storage tanks, equipment leaks, oil-water separators, and loading racks. For each of these four VOC emission sources, there is a discrepancy between actual uncontrolled emissions and controlled emissions. The AO does not provide adequate terms and conditions to justify this discrepancy for any of the four sources.

<u>The AO Lacks Sufficient Enforceable Conditions for Storage Tank VOC Emissions</u>

17. The difference between actual uncontrolled emissions and controlled emissions from Emery’s storage tanks totals 178.38 tpy of VOC. This difference – which alone is enough to render Emery’s refinery a major source – is not supported by enforceable conditions in the AO. The sole enforceable limit on VOC emissions from the storage tanks is a rolling production limit. DAQ’s decision to incorporate rolling production limits into the AO is entirely appropriate; however, additional conditions are required in order for the 178.38 tpy reduction to be found legally adequate.

18. For example, the AO lacks any conditions limiting roof land events. Floating roofs are

an effective method of controlling VOC emissions from storage tanks because they prevent direct contact of the stored liquid with ambient air and limit the creation of a saturated vapor in the headspace of the tank. However, if the liquid level in the tank is lowered to below the surface of the floating roof support legs, the roof will land on its legs, creating a saturated vapor space and limiting the control efficiency of the floating roof. EPA AP-42 methodology now incorporates roof-landing losses, and the Trust expects (although that information is not available in the record) that Emery's use of the Tanks 4.0 program estimates VOC emissions that include roof-landing events.

19. The AO lacks any enforceable terms and conditions to identify, quantify, and control roof-landing events. Therefore, there are no enforceable terms or conditions that limit the occurrence of roof landing events to the number of times included in the Tanks 4.0 emissions estimate. Examples of necessary permit conditions to prevent roof landing events and to control VOC emissions from tanks to below major source threshold include, but are not limited to, submerged or bottom fill requirements, conditions limiting vapor pressure of roof tank contents, and a calculation of emissions from roof landing events. Absent these conditions, there is no legal basis to support Emery and DAQ's contention that the discrepancy between actual uncontrolled emissions and controlled emissions will total 178.38 tpy of VOC. Consequently, the refinery cannot legally be considered a synthetic minor source of VOCs. Instead it is a major source that is subject to Title V requirements of the Clean Air Act.

<u>The AO Lacks Sufficient Enforceable Conditions for VOC Emissions From Equipment Leaks</u>

20. The difference between actual uncontrolled emissions and controlled emissions from equipment leaks is not supported by enforceable conditions. The uncontrolled VOC emissions from equipment leaks from both the distillation plant and the wax plant total 62.06 tons per year.

The controlled emissions of VOCs from equipment leaks from both the distillation plant and wax plant total 6.3 tons per year.

21. There are no enforceable limits in the AO that justify this 55.76-ton per year reduction. The only emissions limitation on equipment leaks within the AO is section II.B, which purports to limit VOC emissions by requiring that the operator shall develop a written leak-detection-and-repair (LDAR) plan that is consistent with certain federal regulations, namely 40 C.F.R. §§ 60.482-2a (g)(2), 60.482-7a (g)(2) & (3), 60.482-10a (j)(2) & (3), and 60.482-11a (e)(2). If a member of the public did not take time to read the referenced regulations, the citations to extensive federal regulations appears to impose substantive requirements on the facility. However, rather than impose federally enforceable limitations, each of the incorporated federal regulations is <u>an exception from monitoring and inspection requirements</u> that would otherwise be imposed by the other sections of 40 C.F.R. § 60.482. For example 40 C.F.R. § 60.482-2(a)(g)(2) provides:

> "Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:
> **(2)** The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

Similarly, § 60.482-7a (g)(2) provides:

> **(g)** Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:
> **(2)** The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

22. 40 C.F.R. §§ 60.482-10a (j)(2) & (3), and 60.482-11a (e)(2) are similar exceptions based on adherence to written plans that require monitoring of valves as frequently as practicable during safe-to-monitor times.

23. The language in these exceptions is not sufficiently precise to allow these provisions to be considered practically enforceable. The EPA has recognized problems with this type of language, and in the 2007 document entitled *Leak Detection and Repair: A Best Practices Guide,* EPA identifies "improperly identifying components as 'unsafe' or 'difficult' to monitor" as a typical compliance problem in current LDAR programs.[1]

24. Compounding the problem, leaks identified under the proposed LDAR program are not taken into account in any way under the terms of the AO. Even if testing showed higher fugitive emission rates or lower control efficiency; even if the final component count is higher than the assumed preliminary estimates; the AO contains no compliance requirements.

25. As a result, there is no consequence to Emery if leaks occur more frequently than assumed in the emission calculations or more components are installed than assumed in the AO. The AO does not require that emissions from leaks above the levels assumed in the AO ever be quantified or tallied. If the number of leaks, concentration of pollutants in the leaks, or the size of the leaks exceeds the AO assumptions, Emery is not even required to identify this problem, nor report it.

26. While Emery is required to carry out an LDAR program, the AO does not require Emery to use this program to determine whether the facility has more leaks or more components or poorer repair efficiency, and, consequently, more emissions than assumed. The emission limits are unenforceable as a practical matter and thus cannot be used to support Emery and DAQ's contention that the refinery is a synthetic minor source.

27. Finally, the Trust takes this opportunity to rebut one of DAQ's comments regarding the monitoring and regulation of fugitive emissions. In response to the Trust's comment that the

[1] US EPA, *Leak Detection And Repair: A Best Practices Guide* (2007) available at http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf

ITA provided inadequate monitoring and regulation of fugitive emissions, DAQ stated "it is not typical to require the same level of monitoring for sources such as Emery, with VOC emissions of 36 tpy, as for much larger sources." Perhaps this comment could be considered logical if Emery was a *true* minor source. However, Emery is a synthetic minor for VOC emissions, and can only hold its permit if the AO controls VOC emissions to below major source thresholds. Thus, enforceable monitoring and regulation is more important for synthetic minors – which Emery is – than for any other source, regardless of its size.

The AO Lacks Sufficient Enforceable Conditions for VOC Emissions from Oil-Water Separators

28. The difference between actual uncontrolled emissions and controlled emissions from the oil-water separators is not supported by enforceable conditions. The uncontrolled VOC emissions from the oil-water separators in the distillation and wax plants totals 52.56 tons per year. The controlled emissions of VOCs from equipment leaks from both the distillation plant and wax plant total 2.1 tons per year.

29. There are no enforceable limits in the AO that justify this 50.46-ton per year reduction. The calculation of VOC controls was drawn from AP-42 factors, and reflects a 96% control efficiency. In other words the 50.46 ton per year reduction is premised on the idea that the facility's technology will eliminate 96% of VOC emissions from the oil-water separators. Even if DAQ's assumption of 96% VOC removal was appropriate, it was improper for DAQ to rely on that 96% figure in calculating controlled emissions because that level of removal is not legally or practically enforceable under the terms of the AO.

30. There is no provision in the AO that requires the oil-water separators to achieve that level of performance. Indeed, at no point does the AO even mention the 96% VOC removal control efficiency. Instead, II.B.3.b prescribes simply that Emery install "a monitoring device capable of

monitoring and recording the VOC concentration shall be installed and operated in accordance with 40 C.F.R. §§ 60.695 and § 61.354. Even if it was acceptable to incorporate these federal standards by reference –as discussed *infra*, this practice is unacceptable for numerous reasons – neither of these referenced provisions contain compliance standards or enforcement conditions. Accordingly, the 96% removal efficiency is not enforceable and Emery and DAQ's reliance on it invalidates its controlled VOC emission calculations. Because the emission limits are unenforceable as a practical matter, they cannot be used to support Emery and DAQ's contention that the refinery is a synthetic minor source.

The AO Lacks Sufficient Enforceable Conditions for VOC Emissions from Loading Racks

31. The difference between actual uncontrolled emissions and controlled emissions from the loading racks is not supported by enforceable conditions. The uncontrolled VOC emissions from the loading racks total 18.5 tons per year. The controlled emissions of VOCs from equipment leaks from both loading racks totals .882 tons per year.

32. There are no enforceable limits in the AO that justify this 17.618-ton per year reduction. The single condition in the AO related to loading rack emissions is II.B.7.a, which provides that "[t]he product loading rack shall be equipped with a vapor collection system. The collected gases shall use a submersible loading mechanism. Collected naphtha gases shall be routed to the process boilers." This single provision is not enforceable and thus cannot be used to justify a controlled emissions estimate of .882 tons per year. It is important to note that all products will be trucked to the refinery and then the processed petroleum will leave the plant by truck transport; thus, adequate control on loading processes is particularly important. Examples of provisions that should be present in the AO include, but are not limited to, submerged fill or bottom fill loading requirements; requirements that all loading lines have vapor-tight connections

that close automatically when disconnected; numeric pressure controls on the vapor collections system; and CEMS monitoring on the vapor collection system. As is true for the three other VOC sources discussed above, Emery and DAQ's cannot use unenforceable terms in the AO to support the conclusion that the refinery is a synthetic minor source.

33. As demonstrated above, DAQ's conclusion that Emery's refinery is a synthetic minor source for VOCs is erroneous and based on severely flawed and inadequately supported emission estimates and assumptions. Indeed, DAQ's minor source status is premised on calculations for VOC emissions from each source that, at different times, violates up to all three of the definitional features of potential to emit: the AO relies on assumptions that do not reflect Emery refinery's maximum capacity to emit VOCs; the AO credits purported limitations that are not enforceable; and the AO relies on monitoring, rather than "physical or operational limits," to diminish PTE. As the *Weiler* court stated, "a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels." 392 F.3d at 535. The AO contains insufficient legally and practicably enforceable terms and conditions to make certain that VOC emissions remain below 100 tons per year. Therefore, it must be considered a major source and made subject to Title V permit obligations.

34. The Trust requests an order voiding the AO, declaring that the refinery is a major source of VOC emissions that is subject to Title V of the Clean Air Act, remanding the AO to the DAQ with instructions that it fulfill its obligations under federal and state law and that this effort be documented in the record. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

B. The AO Is Premised on an Underestimation of VOC Emissions

35. The Trust preserved this issue by raising it in public comment. Trust Comment, 17-18; Fox Comment, 2-4

36. The problem of the AO lacking enforceable conditions on VOC emissions is exacerbated by the fact that the AO underestimates VOC emissions. As a result of this underestimation, it is likely that the actual uncontrolled emissions of VOCs far exceeds 338.38 tons per year. Because the AO lacks enforceable conditions, and emissions are underestimated, Emery's VOC emissions could significantly exceed its 36-tpy emissions estimate.

37. First, fugitive component leaks from valves, pumps, compressors, and connectors in the Emery facility are a source of VOC emissions. The conventional estimation method for fugitive VOC emissions requires: (i) an accurate count of the number of fugitive components such as valves, connectors, pumps, sampling connections, etc.; (ii) information about the design of such components such that appropriate assumptions can be made regarding the likely emissions from each such component; (iii) selection of the proper emission factor, which in turn depends on the measurement of the level of VOC emissions near each component; and (iv) the effect of the applicable LDAR program in minimizing such emissions.

38. By its own admission, neither Emery nor DAQ has an accurate count of fugitive components. No engineering design drawings, which would allow for the verification of the number of components underlying Emery's emissions counts, were provided. Thus, DAQ could not possibly have verified any of the component counts. Nor was the public able to review such counts or to even compare and contrast such counts with those from other comparable facilities that are currently operating. As such, this fundamental input to the fugitive VOC calculations

was unverifiable. Compounding its error, DAQ has not made the counts enforceable in the AO. In addition, no engineering design details for any of the components are found in the record. Without this data and detail, it is impossible to determine whether the average emission factors that Emery has used in estimating emissions are even appropriate.

39. Next, the emission factors used by Emery, as noted in its very own calculations, are taken from a 1995 EPA document, which is now over 17 years old. The emission factors were derived from surveys conducted at various chemical plants and refineries in the late 1980s and early 1990s. Subsequently, EPA audits have shown that actual emissions from fugitive sources can be significantly greater than previously believed.

40. The EPA has acknowledged, and scientific studies show, that the AP-42 emission factors for flares, tanks, and wastewater treatment systems significantly underestimate VOC emissions from these processes. *See, e.g.*, Office of Inspector Gen., EPA, 2006-P-00017, EPA Can Improve Emissions Factors Development and Management 11-12 (2006) (explaining that for refineries "[t]he under-reporting was caused largely due to the use of poor quality emissions factors"); Memorandum from Brenda Shine, EPA, to EPA (July 27, 2007) at 1, Docket ID No. EPA-HQ-OAR-2003-0146-0010 ("This document provides the basis for our hypothesis that there is a systematic low bias in reported emissions of VOC and air toxics from petroleum refineries.").

41. Considered together, Emery and DAQ's estimates for VOC emissions from the facility are unverifiable, use 1995 emission factors that have been shown to underestimate fugitive emissions, and more likely than not, severely underestimate the emissions of VOCs.

C. DAQ Erred as a Matter of Law By Issuing an Exemption for Flare Emission Limits During Malfunction Events

42. The Trust preserved this issue by raising it in public comment. Trust Comment, 17; Fox Comment, 6.

43. AO Condition II.B.5.b, which allows Emery a blanket exemption from flare emission limits during unavoidable upsets and process emergency is illegal. DAQ contends that "by definition, a breakdown is random and not expected. There is no way to include such emissions in an annual emissions estimate." DAQ Memorandum at 6. This position cannot be maintained in light of EPA's conclusion that emissions at flares may be monitored and regulated as the agency specified at length in the NSPS Subpart Ja rules. *See* 60 C.F.R. 100a-109a. Moreover, courts and EPA have long held the view that malfunction events are expected, regular emissions, and cannot be exempted or ignored. *See, e.g.*, *Michigan DEQ v. Browner*, 230 F.3d 181, 183 (6th Cir. 2000) (SIP provisions cannot automatically exempt violations from startup, shutdown, and malfunctions); *Sierra Club v. EPA*, 551 F.3d 1019, 1027-28 (D.C. Cir. 2008) (vacating rule exempting violations from startup, shutdown, and malfunction violations); *In re Indeck-Elwood LLC*, 2006 WL 3073109 at *33 (E.A.B. 2006) ("EPA has, since 1977, disallowed automatic or blanket exemptions for excess emissions during startup, shutdown, maintenance, and malfunctions…"). Clearly, there is no legal basis or evidence in the record to support the Director's authorization of an AO that does not put limits on or require monitoring of the flares during unavoidable upsets and process emergency at the Emery refinery.

44. Next, while it is impossible to know if and when problems will arise, emissions associated with malfunctions must nonetheless be included in the facility's potential to emit. As discussed in detail above, "potential to emit" is the "maximum capacity of a stationary source to emit a pollutant under its physical and operational design." This is essentially the worst case scenario of potential emissions, which includes emissions during unexpected malfunctions. Moreover, startup, shutdown and malfunction events are unquestionably regulated under the Clean Air Act. *See, e.g.,* 65 Fed. Reg. 70,792, 70,793 (Nov. 28, 2000) (EPA rulemaking

"reiterate[ing] that, under the Act, all excess emissions during startups, shut down, or malfunction episodes are violations of applicable emission limitations."). Despite the legal requirements to calculate and regulate these emissions, the AO's emissions estimate does not account for emissions from the flare during malfunction events. This is basis for remand of the AO. *See, e.g., In the Matter of Cash Creek Generation, LLC*, Petition No. IV-2010-4, Order Granting in Part and Denying in Part Petition for Objection to Permit, June 22, 2012 ("EPA grants the petition…due to KDAQ's failure to provide a reasoned explanation regarding how the PTE calculation for total HAPs accounts for flaring emissions associated with operations other than standby and startup.").

45. DAQ's failure to account for malfunction events in flare emissions or monitor those emissions renders the potential to emit estimates for all pollutants emitted from the flare legally inadequate. This is particularly problematic for CO and GHG emissions, both of which already approach major source thresholds. DAQ must go back and include malfunction emissions estimates for all pollutants emitted from the flare in the AO's potential to emit estimations.

46. The Trust requests an order voiding the AO, declaring that DAQ erred by allowing a blanket exemption for flare emissions during malfunction events, remanding the AO to the DAQ with instructions that it remove this condition, recalculate PTE for all pollutants emitted from the flare, and fulfill its obligations under federal and state law. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

D. The AO is Legally Inadequate Because It Does Not Limit Emery's Greenhouse Gas Emissions To Less than 100,000 Tons per Year

47. The Trust preserved this issue by raising it public comment. Fox Comment, 1-2.

48. The Trust reserves the right to supplement the record at a later point on this argument based on DAQ's failure to provide the full record when the AO was issued. In its comments on

the ITA, the Trust noted that Emery applied the wrong formula when it calculated GHG emissions and, therefore, underestimated emissions. DAQ noted in it its response to comment that the Trust correctly identified this mistake. DAQ Memorandum at 7 ("Emery Refining used an incorrect reference for the calculations" of GHG emissions). As a result of the Trust raising this issue in public comment, Emery recalculated GHG emissions to total 90,096 tons per year.

49. The Trust was not provided with the data, emissions formulas, or assumptions underlying this recalculation until 17 days into the 30-day period to seek administrative review. Particularly given the complexity of GHGs, these revised estimates were not provided in sufficient time for the Trust to comment on them. After all, the public is entitled to comment on the agency action and the evidence that supports it and, at a minimum, is entitled to at least 30 days to submit a request for agency action based on the administrative record.[2] With this ongoing barrier to public participation noted, the Trust submits the following arguments.

50. The AO entirely lacks an enforceable mechanism to limit GHG emissions to fewer than 100,000 tons per year. DAQ itself recognizes this need. In an internal email, Tim Andrus stated "I expect we will add a CO2e limit to the AO of 99,000 tons to make sure this isn't PSD for GHG." Exhibit 4. Regrettably, DAQ did not act on Mr. Andrus's suggestion and the AO entirely lacks emission limitations for all sources of GHG emissions.

51. It is possible that Emery's refinery will emit GHGs in excess of the major source threshold for several reasons. First, the AP-42 emission factors that produced the 90,096 ton per year estimate are widely recognized to underestimate GHG emissions. Second, as discussed *supra*, malfunction events from flaring are excluded from the GHG emission estimate. This

[2] DAQ has repeatedly refused the Trust's requests to extend the public comment period, to provide additional public hearings, and to extend the 30-day window in which to request administrative relief. Given that the process of commenting on an oil refinery is extremely complex, these repeated denials violate the Due Process Clause, the Equal Protection Clause, and the Open Courts Clause of the Utah Constitution.

leads to an underestimation of all GHGs, including methane. Methane is a potent greenhouse gas that is twenty-one times more powerful at warming the atmosphere than CO_2. Finally, the flare – which is a source for methane emissions – is exposed to wind. Wind exposure significantly reduces combustion efficiencies, resulting in much higher emissions that assumed in the emission inventory. At no point does the record justify the 98% destruction efficiency claimed from the flare. Given these factors, it is possible that Emery's refinery may exceed the major source threshold for GHG. Thus, it is essential and legally required that the AO contain an enforceable limit on GHGe, which it does not. Because the AO entirely lacks limits on GHG emissions, much less enforceable limits, it must be revoked and remanded.

52. The Trust requests an order voiding the AO, declaring that the AO lacks enforceable limits on GHG emissions, and remanding the AO to the DAQ with instructions that it fulfill its obligations under federal and state law, that this effort be documented in the record, and that any reissued AO reflect this analysis. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

E. The AO Is Legally Inadequate Because It Does Not Contain Sufficient Emission Limitations and Does Not Protect Short Term NAAQS

53. The Trust raised these issues in public comment. Trust Comment, 12, 14.

54. Utah Admin. Code Rule R307-401-8 (1)(a) establishes that the Director may only issue an approval order if the director determines that the pollution control for emissions is at least Best Available Control Technology (BACT). Rule R307-401-2 (1) provides a definition of BACT as follows:

> " 'best available control technology' **means an emissions limitation** (including a visible emissions standard) based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed stationary source or modification which the director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or

> modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an **emissions standard** infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." (emphasis added).

55. As the definition makes clear, BACT is an emissions limitation that results from a process that is often called a BACT analysis. Explaining this often-confused point, the EPA New Source Review Manual[3] states:

> To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. * * *
> * * * **BACT emission limits** or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of **short term** ambient standards (limits written in pounds/hour), and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). *See* EPA's Draft New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" B-56, (EPA OAQPS, October 1990) (hereinafter NSR Manual).

56. BACT is an emissions limitation that is based on the maximum emissions reduction capable of being achieved from a chosen technology. An example facilitates understanding of this less than intuitive concept. In *Utah Chapter of the Sierra Club v. Division of Air Quality*, the Utah Division of Air Quality selected selective non-catalytic reduction (SNCR) as the appropriate control technology to limit sulfur dioxide emissions from a combustion source within a power plant. *Utah Chapter of the Sierra Club v. Division of Air Quality*, 2009 UT 76, ¶ 47.

[3] Although this guidance is denoted as Draft, nonetheless it has been and continues to be widely used by air quality professionals both within the EPA (such as permit writers) and others for PSD analysis. The Utah Supreme Court has relied on this source as being authoritative with regard to air quality permits. *Utah Chapter of the Sierra Club*, 2009 UT 76, ¶ 4.

This was the first step in its BACT determination. After identifying SNCR as the appropriate technology, the Division of Air Quality then advanced to the second step of a proper BACT determination, and imposed an emission limit of 0.1 lb/MMBtu on a twenty-four hour basis as the BACT for sulfur dioxide from combustion sources. *Id*. This emission limitation was derived from the emission reduction achievable through the use of SNCR technology. The description of the process of establishing BACT provided in *Utah Chapter of the Sierra Club* illustrates that BACT is the emission limitation (there, the 0.1 lb/MMBtu per twenty-four hours), and not the use of a specific technology (there, the SNCR technology).[4]

The AO Does Not Contain Sufficient Emissions Limitations

57. The BACT analysis underlying Emery's AO is legally inadequate because it does not result in **an enforceable emission limit** for **each subject emission unit** at the source and for **each pollutant subject to review that is emitted from the source**. For example, there are no emission limits for VOCs, NO_x, TRS, or CO from the flare system. The process boilers do not have emission limits for VOCs, CO, NO_x, or $PM_{2.5}$. There are no emission limits for any pollutant on the cooling towers. There are no practically enforceable emission limits on the internal combustion engine. There are no emissions limits on the atmospheric distillation heater. There are no emission limits on either of the wax plant distillation heaters. There are no emission limits on the compressors. The issuance of the AO without BACT for pollution controls for each of these emission sources constitutes a violation of the Clean Air Act and the Utah Air Conservation Act.

[4] Importantly, the *Utah Chapter of the Sierra Club* case also stands for the concept that when a permitting authority adopts BACT that is not the lowest emission limitation achievable, the permitting authority's decision will be remanded unless it is supported with substantial evidence in the record. See Utah Chapter of the Sierra Club, 2009 UT 76, at ¶ 48.

58. DAQ's occasional incorporation of NSPS subparts, and the emissions limitations buried within those subparts, into the AO does not constitute BACT. For example, provision II.B.3. states "all applicable provisions of 40 CFR 60, NSPS Subpart QQQ…apply to this installation. Similarly, subpart II.B.6.a. states "[s]ubpart IIII, found at 40 CFR 60.4200 to 60.4219 (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)…apply to this facility. At no point did DAQ or Emery interpret the NSPS standards, extract the relevant provisions, and expressly include them into the AO.

59. The incorporation of NSPS standards by reference flies in the face of R307-401-8(1), which provides that "the director will issue an approval order if the following conditions have been met…the proposed installation will meet the applicable requirements of…National Standards of Performance for New Stationary Sources." R307-401-8(5) prevents the Director from issuing an AO "[i]f the director determines that a proposed stationary source, modification or relocation does not meet the conditions established in (1) above." R307-401-8 establishes that the director **must make a determination** that the source will meet the conditions established in NSPS standards. The record available to the public does not indicate that the director made a reasoned determination, or that anyone – not Emery, not DAQ, not EPA, and certainly not the public – even understands which NSPS standards apply to various emissions units, much less whether those standards have been met.

60. Incorporation by reference is particularly inappropriate for a set of standards as complex and multi-faceted as NSPS, where there are multiple compliance options available to a facility, and different standards that could apply. For example, Condition II.B.6.a of the AO provides that "all applicable provisions of…40 CFR 60, NSPS Subpart IIII, found at 40 CFR 60.4200 to 60.4219 (Standards of Performance for Stationary Compression Ignition Internal Combustion

Engines)…apply to this facility." The AO provides no interpretation of the applicability of the various provisions contained within this NSPS nor does it explicitly list the applicable requirements in the AO text. Without consulting the regulations, determining which of the numerous provisions in Subpart III apply to the internal combustion engines (which requires the highly specific and technical knowledge of whether the engines have a displacement of greater or less than 30 liters per cylinder), and calculating emissions based on the relevant formula, it is impossible to determine whether the applicable limits on NO_x and PM emissions are satisfied. It is therefore impossible for the public to determine whether NO_x and PM emissions from internal combustion engines within Emery's Refinery comply with this emission limitation. Again, NSPS is a complicated rule that requires interpretation and therefore the results of that interpretation – the actual standards that apply to any emissions units in any given facility – must be in the AO. *See, e.g.*, *In the Matter of Citgo Refining and Chemicals Company L.P.,* Petition No. VI-2007-01 (May 28, 2009), p. 11 ("Generally, EPA expects that title V permits will *explicitly* state all emission limitations and operational requirements for all applicable emissions units at the facility") (emphasis added). Finally, as discussed at length *infra*, the choice of these NSPS emissions limits as BACT must be supported on the record with an analysis that considers energy, environment, and other costs.

<u>The AO Does Not Protect Short-Term NAAQS</u>

61. Next, the AO does not contain emissions limitations sufficient to protect the short-term National Ambient Air Quality Standards ("NAAQS"). Utah Supreme Court has found that one of the goals of a BACT emission limitation is the protection of short-term ambient standards. *Utah Chapter of the Sierra Club*, 2009 UT 76, ¶ 62. Similarly, the EPA Environmental Appeals Board ("EAB") has held that permits must contain emissions limitations sufficient to protect the

short-term NAAQS. *In Re: Mississippi Lime*, PSD Appeal No. 11-01 (August 9, 2011), 2011 WL 3557194 at 17. Finding that a permit did not define a maximum allowable hour emission limitation for NO_x to protect the one-hour NO_2 NAAQS, the EAB remanded the permit with directions that the authority must "either include maximum allowable hourly emissions limitations for SO_2 and NO_x and explain how it concluded that the limitations are protective of the respective one-hour NAAQS or provide sufficient rationale for not including such emissions limitations. In either case, IEPA must reopen the public comment period to provide the public with an opportunity to submit comments." *Id.* at 18.

62. Here, the AO lacks short-term emission limits necessary to protect short-term PSD increment and short term NAAQS. For example, there are no hourly emission limits on the flare necessary to protect the one-hour NO_2 and SO_2 NAAQS. Indeed, the AO entirely fails to limit NO_x emissions from the flare. Moreover, there are no short-term emission limits sufficient to protect the secondary, three-hour SO_2 NAAQS or the eight hour ozone NAAQS, or even the 24 hour $PM_{2.5}$ and PM_{10} NAAQS. There are no limits on $PM_{2.5}$ in the AO. The shortest-term emissions limits in the AO are the 3-hour rolling average for SO_2 for the process boilers, and the 3-hour rolling average for SO_2 for the flare system. There are no short-term NO_2 emissions limits anywhere in the AO. Moreover, flare emissions from "upsets" are not limited despite being the most likely cause of exceedances of the short-term NAAQS. Without such emission limits, the AO fails to protect short term and medium term NAAQS and increment.

63. Three-hour averages are insufficient to protect 1-hour NAAQS. A 3-hour average can mask shorter-term emission spikes that would violate the 1-hour SO_2 NAAQS. A 3-hour average, for example, would allow all of the emissions to occur during one hour, effectively tripling the mass emission rate assumed in the 1-hour modeling. This type of event is hidden by

a BACT limit based on a 3-hour average. Thus, the averaging time for the BACT limit must be no longer than the shortest NAAQS averaging time, which is 1 hour for NO_2 and SO_2. The AO must be revised to require a 1-hour averaging time to protect short-term ambient standards, in particular the 1-hour NO2 and SO_2 NAAQS.

64. The Trust requests an order voiding the AO, declaring that the AO is not adequately supported by the record, enjoining Emery's refinery, and remanding the AO to DAQ with instructions that it undertake and apply defensible BACT analysis that results in sufficient emission limitations for each emission source of each regulated pollutant, that those limitations protect short-term NAAQS, and that it otherwise fulfill its obligations under federal and state law, that this effort be documented in the record, and that any reissued AO reflect this analysis. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

F. The Record Does Not Support DAQ's BACT Determination

65. The Trust preserved this issue by raising it in public comment. Trust Comment, 16-17; Fox Comments, 5-6.

66. The BACT analysis and resulting emission limitations for Emery's refinery are legally inadequate because they are unsupported by justification in the record. The Utah Supreme Court has held that a BACT determination must be supported by sufficient evidence in the record. *Kennon v. Air Quality Board*, 2009 UT 77, ¶ 28. There, the *Kennon* court found that a BACT analysis is legally adequate when a reasonable person would find that the review "was sufficiently rigorous to ensure that an approval order implemented best available control technology." *Id.* Applying the standard to the permit at issue in that case, the *Kennon* court

remanded the permit, finding that the record "merely rehearsed that a review took place," and was legally inadequate to support a BACT analysis. *Id*.

67. Similarly, the EAB has emphasized the importance of adequately documented BACT determinations, stating that they are "one of the most critical elements in the PSD permitting process and thus 'should be well documented in the record, and any decision to eliminate a control option should be adequately explained and justified.'" *In re Desert Rock Energy Company, LLC*, PSD Appeal Nos. 08-03, 08-04, 08-05, & 08-06, Slip Op. at 50 (September 24, 2009). The Board has remanded permits where the permitting authority's BACT analyses were "incomplete or the rationale was unclear." *Id*.

68. Emery's BACT analysis and DAQ's uncritical adoption of that analysis[5] are legally inadequate under the standards established by the Utah Supreme Court, the Utah Air Quality Rules, and the EAB. First, in contravention of the Clean Air, the Utah Air Conservation Act, and the Utah Air Quality Rules, the record and AO **entirely lack** BACT analysis for emission units that both Emery and DAQ recognize will emit air contaminants. For example DAQ and Emery fail to provide a BACT analysis for the oil-water separators, the flare, and the cooling towers, and there is no BACT emission limitation for these emission sources. Based on Emery's own reporting, both of these units will emit air contaminants. Pursuant to state and federal law, a BACT analysis and consequent emissions limitation is required for each contaminant. DAQ's

[5] Court decisions and Utah Regulations establish that the permit-issuing authority is ultimately responsible for the emission limitation that results from a proper BACT analysis, and for providing an adequate record to support the choice of an emissions limitation. The EAB has held that while the applicant has a duty to supply a BACT analysis and supporting information in its application, reviewing authorities make clear that "the ultimate BACT decision is made by the permit-issuing authority." *In re Genesee Power Station Ltd. Partnership*, 4 E.A.D. 832, 835 (EAB 1993). Division of Air Quality Rules require the Director to issue an approval order based on his assessment of whether the conditions for the AO have been met. See e.g. R307-401-8(1)(a) ("**Director** may issue an approval order only if the degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology"); R307-401-8(5)("If the **director determines** that a proposed stationary source, modification, or relocation does not meet the conditions established in (1) above, the **director** will not issue an approval order") (emphasis added).

complete failure to require BACT for these emission units and air contaminants renders the permitting decision invalid.

69. Next, the limited BACT analysis present in the record is legally inadequate. Of note, the sum total of the BACT analysis for the entire 20,000 barrel per day oil refinery – the first new oil refinery in Utah permitted since 1976, and a refinery to be located only four miles from the town of Green River – performed by Emery and DAQ totals only four pages. Emery Refining LLC Notice of Intent, 10-11 (hereinafter NOI); DAQ Engineering Review, 4-5 (hereinafter Engineering Review). The record indicates no independent analysis by the Director of Emery's analysis. In its Engineering Review, DAQ states, "Emery Refining LLC has evaluated control options for all new, or modified equipment items in terms of practical feasibility, control efficiency, and weighed the amount of pollution controlled against the costs and energy impact of implementing a given technology or strategy." Engineering Review at 4. At no point does the record indicate that DAQ performed an independent analysis, or even conducted a critical assessment of the adequacy of Emery's BACT determination. Instead, DAQ simply listed its BACT recommendation; notably, none of DAQ's recommendations varied from Emery's chosen technology.

70. As discussed at length *supra*, the BACT reviews conducted by both Emery and DAQ do not result in an emissions limit. The record does not provide a supported finding of "technological or economic limits" that could justify the lack of emissions limits. For the few emissions limits established for Emery's refinery, the record does not indicate that either Emery or DAQ compared these limits to possible emissions limits for various alternative technologies. Indeed, the record does not indicate that either DAQ or Emery considered energy or environmental impacts or considered alternative technologies than the ones ultimately declared

BACT. This is contrary to the purpose of the Clean Air Act, the Utah Air Conservation Act, and the clear direction of R307-401-8, which establishes that BACT must flow from an analysis that takes into account energy impacts, environmental impacts, and costs.

71. Rather than a supported analysis, Emery's BACT analysis repeatedly states that the technologies chosen "are generally considered BACT." This is precisely the type of conclusory language that the *Kennon* court rejected as legally inadequate to support a BACT determination. Moreover, the BACT analysis appears to be based solely on cost considerations that are not transparent to the public. Therefore, DAQ's process cannot be considered an adequate decision-making process that accounts for energy and environmental impacts and costs as required under R307-401-8(1)(a).

72. An example serves to illustrate the severe inadequacy of the BACT review used to support the issuance of Emery's AO. On page 10 of its NOI, Emery provides a single paragraph BACT analysis for all products of combustion from all emission units contained within the distillation plant. As the BACT definition makes clear, BACT means "an emission limitation…for each air contaminant" and limitations should be instituted for each "emission unit." Emery's BACT analysis for "products of combustion" from the distillation plant, which include PM_{10} and $PM_{2.5}$, SO_x, NO_x, CO, VOC, and HAPs does not provide a separate discussion of each air pollutant, but rather resorts to general statements about "products of combustion." Compounding the problem, there are numerous emission units present in the distillation plant that qualify as combustion units. Specifically, the combustion units in the distillation plant include one heater, three boilers, and a furnace. The BACT analysis does not parse through each emissions unit, but rather provides a single paragraph for all products of combustion emitted from all emissions units in the distillation plant.

73. In addition to the inadequacy of the BACT analysis, Emery's lumped analysis of all products of combustion does not result in an emissions limitation for one or all of the pollutants purportedly being analyzed in the BACT review. There is no emission limitation established for PM_{10}, $PM_{2.5}$, SO_x, NO_x, VOCs, CO or HAPs. The lumped analysis for the distillation plant does not provide a description of current technology or a description of alternatives considered or rejected, and provides no basis in the record for the cost of limiting PM_{10}, $PM_{2.5}$, SO_x, NO_x, VOCs, CO or HAPs. This is in direct contravention of the BACT definition. Therefore, the analysis is not BACT. Emery repeats these errors for all products of combustion from all emission units in the wax plant (two heaters and three boilers). NOI at 10.

74. In its Engineering Review, DAQ seems to propose an emission limitation of .0098 lbs of NO_x/MMBTu. Engineering Review at 4. However, absent a condition in the AO that provides this emission limitation, the limitation is merely a suggestion; therefore it is meaningless as an enforcement device. Other than the one unenforceable suggestion of an emission limitation for NO_x for all fuel burning devices – which is entirely unsupported by a justification in the record – DAQ's BACT analysis does modify or alter Emery's BACT analysis. DAQ's analysis therefore does not ameliorate any of the legal inadequacies discussed above. Instead, DAQ's BACT analysis is an uncritical adoption of Emery's deeply flawed analysis, which does not meet the legal standards for BACT. Therefore neither the BACT analysis nor the issuance of the AO can be considered an adequate decision making process as required by the Clean Air Act, the Utah Air Conservation Act and the Utah Air Quality Rules.

75. The BACT analysis for VOCs from storage tanks is also legally inadequate. The single paragraph analysis does not result in an emissions limitation, fails to provide a description of current technology, fails to provide a description of alternatives considered and rejected, and

provides no basis for the cost of limiting VOC emissions. The BACT analysis appears to be based solely on cost considerations that are not transparent to the public. Therefore, DAQ's process cannot be considered an adequate decision-making process that accounts for energy and environmental impacts and costs as required under R307-401-8 (1)(a).

76. The BACT analysis for VOC emissions from loading racks is similarly flawed. The single paragraph analysis does not result in an emissions limitation, fails to provide a description of current technology, fails to provide a description of alternatives considered and rejected, and provides no basis for the cost of limiting VOC emissions. The BACT analysis appears to be based solely on cost considerations that are not transparent to the public. Therefore, DAQ's process cannot be considered an adequate decision-making process that accounts for energy and environmental impacts and costs as required under R307-401-8(1)(a).

77. DAQ's BACT analysis for VOC emissions from equipment leaks appears to be an unjustified adoption of NSPS standards, which is legally inadequate. NSPS standards function as a floor for BACT. Indeed, EPA has established, "[a]n NSPS simply defines the minimal level of control to be considered in the BACT analysis. The fact that a more stringent technology was not selected for a NSPS (or that a pollutant is not regulated by an NSPS) does not exclude that control alternative or technology as a BACT candidate. When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emissions level less stringent than the NSPS. If so, the option is unacceptable." NSR Manual at B-12. At no point is DAQ's adoption of NSPS standards as BACT supported by the record. For example, VOC emission leaks from valves and pump seals are controlled by inspection and maintenance in accordance with NSPS subpart GGGa. In its NOI, Emery declares "[t]hese VOC controls are generally considered BACT."

NOI at 10-11. Neither Emery nor DAQ provided any further evidence in the record of alternative technology considered, an economic analysis, or a consideration of environmental impacts. As each of these are required to support a decision that a given emissions limitation is BACT, DAQ's decision to utilize subpart GGGa as BACT must be overturned. This example holds true for each use of NSPS subparts as BACT.

78. Moreover, DAQ failed to consider technology that the Trust specifically demonstrated was "available." The Utah Supreme Court has found that if a control technology is operating or permitted for similar operations, the permitting authority should consider the technology available and consider it in its BACT analysis. *Utah Chapter of the Sierra Club v. Air Quality Board*, 2009 UT 76 ¶ 46.

79. Consideration of available technology must occur as part of a full BACT analysis as described in R307-401-2(1). Interpreting the identical federal BACT definition in the Clean Air Act, the United States Supreme Court has found that the use of the words "maximum" and "achievable" puts forth a requirement that "constrain[s] agency discretion in determining BACT." *Alaska Dep't of Envtl Conservation v. EPA*, 540 U.S. 461, 485-86 (2004). Pursuant to these requirements, "the most stringent technology is BACT" unless the applicant of Agency demonstrates that the technology is not feasible or should be rejected due to specific collateral impact concerns. *See, e.g., Alaska Dep't of Envtl. Conserv. V. EPA*, 298 F.3d 814, 822 (9th Cir. 2002). If an agency proposes or endorses permit limits that are less stringent than those for similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected. *In re Indeck-Elwood LLC*, PSD Appeal 03-04, 13 E.A.D.—slip op. at 77, 79-81 (E.A.B. Sept. 27, 2006).

80. In its comments, the Trust provided evidence showing that the Bay Area Air Quality

Management District ("BAAQMD") in California, where five large petroleum refineries are located, identifies use of an enclosed ground flare as BACT for flare emissions. The BAAQMD also assigns an assumed VOC destruction efficiency of 98.5% to an enclosed ground flare, higher than the assumed destruction efficiency of 98% assumed by the BAAQMD for all other flares. This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds. Thus, an enclosed ground flare is BACT for the Emery flare.

81. The Trust's technical expert, Dr. J. Phyllis Fox, provided comments showing that leakless components are applied as BACT for equipment leaks in other new oil refineries. Fox Comments at 5. Dr. Fox noted that the flange joining method chosen by Emery and DAQ did not satisfy BACT. Similarly, Dr. Fox noted that Emery and DAQ's decision to utilize conventional valves, pumps, and compressors rather than leakless or low-leak versions did not satisfy BACT. *Id*.

82. There is no evidence on the record indicating that DAQ considered welded systems as BACT to control fugitive emissions. Similarly, there is no evidence on the record that DAQ considered the use of an enclosed ground flare. In fact, the record is devoid of any BACT analysis at all for the flare. Because both leakless components and enclosed ground flares are available, the Trust provided evidence in its public comment of the availability of the technology, and the plain language of the BACT definition indicate available technologies must be considered, DAQ's BACT analysis conclusions must be vacated and remanded for consideration of these technologies. *See Utah Chapter of the Sierra Club v. Air Quality Board*, 2009 UT 76 ¶ 46 ("because IGCC was available and the plain language of the BACT definition indicates it should be considered in the BACT analysis, we vacate the Board's BACT analysis conclusions").

83. The Trust requests an order voiding the AO, declaring that the AO is not adequately supported by the record, enjoining Emery's refinery, and remanding the AO to DAQ with instructions that it undertake and apply defensible BACT analysis that includes full consideration of both enclosed ground flares and leakless components, that it otherwise fulfill its obligations under federal and state law, that this effort be documented in the record, and that any reissued AO reflect this analysis. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

G. DAQ Illegally Issued The AO Without Requiring PM_{10} Modeling

84. This cause of action did not arise until after the close of the comment period and therefore "was not reasonably ascertainable before or during the public comment period." Utah Code Ann. § 19-1-301.5(6)(c)(ii). As a result, the Trust had no obligation to raise this claim and, indeed, could not have fully raised this claim during the public comment period. However, the Trust did anticipate this issue due to ambiguity in the PM_{10} emissions estimates in the ITA. Accordingly, the Trust preserved this issue by raising it in comments submitted to DAQ. Trust Comments, 14.

85. Under R307-410-4, **"prior to receiving an approval order** under R307-401, a new source in an attainment area with a total controlled emission rate per pollutant greater than or equal to amounts specified in Table 1…**shall conduct air quality modeling**, as identified in R307-410-3, to estimate the impact of the new or modified source on air quality unless previously performed air quality modeling for the source indicates that the addition of the proposed emissions increase would not violate a National Ambient Air Quality Standard, as determined by the director." (emphasis added). The rule then displays values that trigger

monitoring requirements. Pertinent here, modeling must be conducted if a source's fugitive PM_{10} emissions exceed 5 tons per year.

86. In its recalculated PM_{10} calculations, Emery submitted documentation to DAQ that its fugitive PM_{10} emissions exceed 5 tpy. Therefore, pursuant to R307-410-4, Emery was required to conduct air quality modeling for its PM_{10} emissions. DAQ recognized this statutory requirement in an email exchange dated May 7, 2013 from Mr. Tim Andrus, DAQ's Minor New Source Review Manager, to Tim DeJulis, the project engineer. After Mr. DeJulis informed Mr. Andrus that Emery's fugitive dust emissions amounted to 5.38 tons per year, Mr. Andrus responded "Have you advised Mr. Kopta that modeling is required? If not, please point that out to him ASAP." Attached as Exhibit 4. The Trust subsequently requested all information pertaining to the recalculation of PM_{10} emissions. There is no information in the record indicating that Emery conducted air quality modeling for PM_{10} prior to receiving the AO.

87. On the basis of the information in the record, DAQ did not require Emery to conduct modeling of PM_{10} as required by R307-410-4. Emery's proposed refinery is located west of the town of Green River, a region where the prevailing winds blow from west to east. Thus, any haze generated from excess PM_{10} emissions will blow over Green River residents, impacting human health and bringing haze to the sweeping vistas of the western landscape. Moreover, DAQ should be hyper-vigilant about the impact of the refinery on visibility because Emery's refinery is located less than fifty miles from Arches National Park, a Class I visibility area. DAQ's decision to disregard R307-410-4 constitutes a failure to protect the health of Utah's population, and Utah's natural resources. DAQ's issuance of the AO without the requisite modeling renders the AO void.

88. The Trust requests an order voiding the AO, declaring that the AO is not adequately supported by the record, enjoining Emery's refinery, and remanding the AO to DAQ with instructions that DAQ require modeling for PM_{10} to estimate the impact of Emery's refinery on the NAAQS, that it otherwise fulfill its obligations under federal and state law, that this effort be documented in the record, and that any reissued AO reflect this analysis. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

H. DAQ Violated R307-4062 By Failing To Consider Visibility Impacts on Arches National Park

89. This cause of action did not arise until after the close of the comment period and therefore "was not reasonably ascertainable before or during the public comment period." Utah Code Ann. § 19-1-301.5(6)(c)(ii). As a result, the Trust had no obligation to raise this claim and, indeed, could not have fully raised this claim during the public comment period. Nonetheless, the Trust brought the issue of compromised visibility to DAQ's attention by commenting on the ITA's failure to protect the ozone NAAQS, and the lack of adequate monitoring for PM emissions. *See* Trust Comments 12, 14.

90. R307-406-2 provides:

> "[a]s a condition of any approval order issued to a source under R307-401, the director shall require the use of air pollution control equipment, technologies, methods or work practices deemed necessary to mitigate visibility impacts in Class I areas that would occur as a result of emissions from such source. The director shall take into consideration as a part of the review and control requirements: (a) the costs of compliance; (b) the time necessary for compliance; (c) the energy usage and conservation; (d) the non-air quality environmental impacts of compliance; (e) the useful life of the source; and (f) the degree of visibility improvement, which will be provided as a result of control."

91. Arches National Park is a Class I area, and is located 51 kilometers away and downwind from the proposed refinery. At no point in Emery's NOI, the Engineering Review, the ITA, or the AO did the Director consider visibility impacts to Arches National Park. As discussed

extensively *supra*, the recalculated PM_{10} emissions exceed modeling thresholds. It is nationally recognized that Uinta County, located less than fifty miles from the refinery regularly experiences exceedances of ozone NAAQS, particularly in winter months. The refinery will emit both VOCs and NO_x, the ozone precursors. Both PM and ozone are known to adversely impact visibility. DAQ's failure to consider visibility impacts to Arches National Park constitutes a failure to adhere to the mandates of R307-406-2, a disregard of DAQ's obligation to protect Utah's natural resources, and grounds for voiding the AO.

92. The Trust requests an order voiding the AO, declaring that the AO is not adequately supported by the record, enjoining Emery's refinery, and remanding the AO to the DAQ with instructions that DAQ fully evaluate the refinery's impacts on Arches National Park, that it require all technology and limitations necessary to protect visibility in Arches National Park, that it otherwise fulfill its obligations under federal and state law, that this effort be documented in the record, and that any reissued AO reflect this analysis. The Trust also requests any other or additional remedy that the Executive Director deems appropriate.

<u>VI. Notice</u>

In accordance with R305-7-203 and Utah Code Ann. § 19-1-301.5(3), on July 22, 2013, copies of this Request for Agency Action were **hand delivered** to:

Executive Director
Utah Department of Environmental Quality
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And served by certified mail and email to:

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Respectfully submitted this 22nd day of July, 2013.

Anne Mariah Tapp
Attorney for Grand Canyon Trust *et al.*

/s/

Charles R. Dubuc, Jr., USB # 12079
Serving as local counsel for
pro hac vice purposes.

Exhibit 1

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February 27, 2013

Re: Intent to Approve: Petroleum Processing Plant Project No: N146270001

Dear Mr. Bird, Mr. Andrus and Mr. DeJulis:

Thank you for the opportunity to comment on the February 1, 2013 Intent to Approve: Petroleum Processing Plant (Project Number: N146270001). We submit these comments on behalf of the Grand Canyon Trust, the Southern Utah Wilderness Alliance, Living Rivers, the Center for Biological Diversity, and the Sierra Club.

Before reaching our substantive comments, we would like to express our appreciation of your agency's readiness to provide us with documents relevant to the project as well as answer our questions concerning the planned facility and the intent to approve.

As these comments make clear, we are troubled by an insufficiently rigorous analysis of the factors relevant to the Green River Refinery Intent to Approve ("ITA"), a failure to implement adequate measures to control air pollution from the Green River Refining facility, and a failure to provide a sufficiently transparent public process. This comment takes three parts. First, the comment notes the context in which this ITA was issued, including the environmental impacts of oil shale and tar sand mining, the water shortage of the American Southwest, and the presence of endangered species in the Colorado River Basin. Second, the comment turns to the procedural shortcomings in the ITA and the lack of public transparency in the approval process. Finally, the comment addresses the legal shortcomings of the ITA.

Commenting Parties: Contact Information and Interests
This Protest is filed on behalf of the Grand Canyon Trust, Living Rivers, the Center for Biological Diversity, and the Sierra Club, as follows.

a. Grand Canyon Trust
Grand Canyon Trust is a non-profit corporation with offices in Flagstaff, Arizona, and Moab and Salt Lake City, Utah. The mission of the Grand Canyon Trust is to protect and restore the Colorado Plateau – its spectacular landscapes, flowing rivers, clean air, diversity of plants and

animals, and areas of beauty and solitude. The Colorado Plateau includes the town of Green River, Utah, the site of the Green River Refinery, and the larger area surrounding Green River that will be impacted by decreased air quality resulting from the operation of the Green River Refinery. One of the Trust's goals is to ensure that the Colorado Plateau is a region characterized by vast open spaces with restored, healthy ecosystems, and habitat for all native fish, animals, and plants. To accomplish this, the Trust works to curb climate change and advocates for sustainable energy policies across the Colorado Plateau. The Trust's board, staff, and members use the area whose air quality will be impacted by the proposed Green River Refinery for quiet recreation (including hiking, biking, fishing, rafting and camping), scientific research, aesthetic pursuits, and spiritual renewal. Many of the Trust board, staff, and members live in Utah, and thus air pollution in Utah adversely affects their health, quality of life, recreational pursuits, and aesthetic sense. The Grand Canyon Trust and its members have a protectable legal interest in ensuring that DAQ regulates the Green River Refinery to the maximum extent required by the Utah Air Conservation Act and that emissions from the facility are properly modeled, monitored, reported, quantified, characterized, and minimized as required by law.

b. Southern Utah Wilderness Alliance
The Southern Utah Wilderness Alliance is a non-profit environmental membership organization dedicated to the sensible management of all public lands within the state of Utah, to the preservation and protection of plant and animal species, the protection of air and water quality on public lands, and to the preservation of Utah's remaining wild lands. The Southern Utah Wilderness Alliance is headquartered in Salt Lake City, Utah and also has offices in Moab, Utah. The Southern Utah Wilderness Alliance has members in all fifty states and several foreign countries. The Southern Utah Wilderness Alliance's members use and enjoy public lands in and throughout Utah for a variety of purposes, including scientific study, recreation, wildlife viewing, hunting, aesthetic appreciation, and financial livelihood. Members of the Southern Utah Wilderness Alliance frequently visit and recreate (e.g., sightsee, view and appreciate pre-historic and historic cultural sites, bird watch, and enjoy solitude) throughout area that will be impacted by the Green River Refinery. Many of the Southern Utah Wilderness Alliance board, staff, and members live in Utah, and thus air pollution in Utah adversely affects their health, quality of life, recreational pursuits, and aesthetic sense. The Southern Utah Wilderness Alliance and its members have a protectable legal interest in ensuring that DAQ regulates the Green River Refinery to the maximum extent required by the Utah Air Conservation Act and that emissions from the facility are properly modeled, monitored, reported, quantified, characterized, and minimized as required by law.

c. Living Rivers
Living Rivers is a regional nonprofit organization that promotes river restoration through mobilization. By articulating conservation and alternative management strategies to the public, we seek to revive the natural habitat and spirit of rivers by undoing the extensive damage done by dams, diversions and pollution on the Colorado Plateau. Living Rivers' staff, board and members use the lands whose air quality will be impacted by the proposed Green River Refinery for quiet recreation (including hiking, biking, rafting and camping), scientific research, aesthetic pursuits, and spiritual renewal.

d. Center for Biological Diversity
The Center is a non-profit environmental organization with more than 450,000 members and online activists, including many members who live and recreate in the areas in and affected by actions taken within the planning area in Colorado, Utah and Wyoming. The Center uses science, policy and law to advocate for the conservation and recovery of species on the brink of extinction and the habitats they need to survive. The Center has and continues to actively advocate for increased protections for species and habitats in the area impacted by the Green River Refinery and its associated air emissions. The Center's board, staff, and members use the area potentially impacted by emissions from the Green River Refinery for quiet recreation (including hiking, biking and camping), scientific research, aesthetic pursuits, and spiritual renewal.

e. Sierra Club
The Sierra Club is a national nonprofit organization of approximately 2.4 million members and supporters dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club's Utah Chapter has approximately 3,600 members. The Sierra Club's staff and members use the lands and waters whose air quality will be impacted by the proposed Green River Refinery for quiet recreation (including hiking, biking and camping), scientific research, aesthetic pursuits, and spiritual renewal.

COMMENTS CONCERNING THE CONTEXT OF THE ITA

The Adverse Environmental Impacts of Tar Sand Development

The proposed Green River Refinery plans to accept oil shale and tar sands oil, and thus takes Utah, the United States, and the global community in the wrong direction in terms of emissions. Expanding the use of energy feedstocks that increase carbon pollution is inconsistent with actions to protect the climate – actions that are particularly essential for the Colorado Plateau, a region termed a "climate change hotspot." On average, over the full life-cycle, greenhouse gas (GHG) emissions from tar sands-derived fuel are about 20 percent greater than conventional petroleum fuels.[1] To curb global warming, we need dramatic cuts in carbon pollution across all sectors of the economy rather than decisions that condone the development of these energy intensive fuels.

Compounding the problem, the oil from Utah's tar sands and oil shale will be obtained through strip mining large swaths of the Uinta Basin, including the Book Cliffs. The Book Cliffs, which contains the P.R. Spring Special Tar Sand Area, is valuable habitat for numerous threatened and endangered species, and retains a wild character. This is in large part due to the topography of the area; the Book Cliffs are bound by a 250-mile long, 2,000 foot-high row of cliffs and there are no paved roads within the region. The Bureau of Land Management has described the Book Cliffs as "a place where a visitor can experience true solitude – where the forces of nature

[1] Simon Mui, Luke Tonachel, Bobby McEnaney, and Elizabeth Shope. *Greenhouse Gas Emissions of High Carbon Intensity Crude Oils*. Natural Resources Defense Council, 2010.

continue to shape the colorful, rugged landscape."[2] The Book Cliffs provide habitat for numerous species including mule deer, Rocky Mountain elk, antelope, mountain lion, black bear, waterfowl, shorebirds, blue and sage grouse, golden eagle, numerous hawks and owls, as well as many species of small mammals, birds, amphibians and reptiles. The Book Cliffs house one plant species listed as endangered under the Endangered Species Act ("ESA"), and five plant species listed as threatened.[3] The strip mining of this location for tar sand extraction operations will permanently damage this wild place.

The groups submitting these comments are very concerned that all the cumulative impacts associated with immature fuel development may push the Colorado River watershed and air shed over the brink. Not only will this development stress the perfected water rights of Utah, the loading of GHG emissions and fugitive dust will compound the magnitude of an already impaired hydrologic cycle. In addition, the water needs associated with tar sand development may contribute significantly to the reduction of the annual yield at the Compact Point, Lee's Ferry. Utah's participation in the development of immature fuels will create harm to six other states, ten sovereign Indian tribes, and the Republic of Mexico. The state of Utah is setting itself up to become the untenable neighbor in a watershed that is fully intended to be shared in an equitable manner. Additionally, diminished flows and the emissions of hazardous air pollutants on the banks of the Green River will compromise Utah's investment in the Upper Colorado River Basin Endangered Fish Recovery and Implementation Program.

By approving a refinery that processes oil shale and tar sands oil, Utah is making a short-sighted choice for its energy future and for the future of the American Southwest. Rather than aggravate a serious situation, we strongly urge that Utah become a leader in cooperation within the Colorado River basin by rejecting the development of immature fuels.

The Presence of Endangered Fish Species in the Green and Colorado River

The Endangered Species Act (ESA) provides several procedural and substantive protections for imperiled species and their habitat. Section 9(a)(1) of the ESA makes it unlawful for anyone to "take" a threatened or endangered species of fish or wildlife. 16 U.S.C. § 1538(a)(1)(B) & (G); 50 C.F.R. § 17.31(a). Congress broadly defined "take" to mean "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect." 16 U.S.C. § 1532(19). The term "harm" is further defined to include "significant habitat modification or degradation where it actually kills or injures wildlife by significantly impairing essential behavioral patterns, including breeding, feeding or sheltering." 50 C.F.R. § 17.3.

The humpback chub is a three-to-five million-year-old fish native only to the Colorado River Basin. Historically, the chub's habitat range extended throughout the Colorado River Basin from the Flaming Gorge on the Green River in Wyoming to below the Grand

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[2] Bureau of Land Management, Utah Wilderness Inventory, Northeast Region: Desolation Canyon , 127 (1999)
[3] See Bureau of Land Management, PROPOSED OIL SHALE AND TAR SAND RESOURCE MANAGEMENT PLAN
AMENDMENTS TO ADDRESS LAND USE ALLOCATIONS IN COLORADO, UTAH, AND WYOMING AND FINAL
PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT, at Appendix E.

Canyon on the Colorado River in Arizona. The chub's current range, however, represents a fraction of that and is limited to approximately six isolated populations, including one in the Green River and further downstream in the Colorado River. As a result, the chub is now protected as an endangered species under the ESA. 38 Fed. Reg. 106 (June 4, 1973).

The bonytail chub is a big-river minnow that was historically common throughout the Colorado River Basin. It was listed as endangered and given full protection under the Endangered Species Act in 1980. 45 FR 27710 (April 23, 1980). This is the rarest of the four endangered Colorado River fish species and wild populations no longer exist. The species is being reintroduced into the Green, and upper Colorado rivers, Lakes Mojave and Havasu, and the lower Colorado River to Yuma, Arizona.

The razorback sucker is a big-river fish found only in the Colorado River Basin. It was listed as endangered and given full protection under the Endangered Species Act in 1991. 56 FR 54957 (October 23, 1991). The species is being reintroduced into the Green, Gunnison, upper Colorado and San Juan rivers, Lakes Mojave and Havasu, and the lower Colorado and Verde rivers. The geomorphology of the Green River below the town of Green River is ideal breeding habitat for razorback sucker. During river trips to monitor the recruitment of endangered fish, field biologists have noted success in capturing juvenile razorback sucker near the mouth of the San Rafael River.[4]

Several cases demonstrate that state entities that issue permits or regulate conduct that results in harm to species listed as endangered can be indirectly liable for take under section 9 of the ESA. *See e.g*. *Strahan v. Coxe*, 127 F3d 155,163 (1st Cir 1997) ("[A] governmental third party pursuant to whose authority an actor directly exacts a taking of an endangered species may be deemed to have violated the provisions of the ESA."); *Palila v. Hawaii Department of Land and Natural Resources, 639 F2d 495* (9th Cir 1981) (state management of feral sheep and goats for hunting purposes violated ESA by destroying listed species habitat).

The commenting parties are concerned that the Green River Refinery's emissions of hazardous air pollutants (HAP) may cause a "take" of endangered fish species in violation of ESA Section 9. The US Fish and Wildlife Service has found correlation between hazardous air pollutants emissions and the presence of contaminants in endangered fish in the Southwest. *See* Letter from Wally Murphy, FWS New Mexico Ecological Services Field Office to Deborah Jordan, EPA Region 9 Air Division Director 4 (Feb. 26, 2009) ("atmospheric deposition of mercury with subsequent transfer is believed to be one of the most significant loading pathways to the mercury content of piscivorous fish"). The commenting parties urge DAQ to take a hard look at whether DAQ's ITA sufficiently monitors and limits HAP emissions to ensure that endangered fish species both in the Green River and in downstream populations on the Colorado River are not harmed.

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[4] Bestgen, K. R., K. A. Zelasko, and G. C. White. *Monitoring reproduction, recruitment, and population status of razorback suckers in the Upper Colorado River Basin*, Fort Collins: Department of Fish, Wildlife, and Conservation Biology (2012).

Water and Waste

There is no discussion of the source(s) of water to be used during construction and operations at the proposed refinery. Similarly, no evidence is presented on the means of waste water disposal or of the capacity and ability of Green River's water treatment facility to handle increased input or even if it can handle refinery waste water.

For the past two years (and likely into the 3rd year in 2013) the Green River has been running below its 10 year flow average. An assessment is needed of how the refinery construction and operations will impact water use. According to the Environmental Protection Agency ("EPA") "Refineries use about 1 to 2.5 gallons of water for every gallon of product...." "In addition, large amounts of energy are used to process and move water through the refinery."[5]

Emery LLC states the waste water will be trucked to an off-site landfill disposal site. Not specified is if this a site on the company property or one run by the town or county. The ability of a disposal site to handle waste-water with metal and chemical ingredients is never discussed. The environmental impact or mitigation of off-site disposal is not discussed, especially given that waste water and waste water sludge contain substantial concentrations of phenols, benzene, and ammonia. The company does not include evaporation ponds in its proposal and it is not explained if waste water will remain on the property for any period of time and if so in what types of containers. Nowhere does the company address the environmental impacts of waste water, on site or off-site. Selection of off-site disposal (at an unidentified qualified landfill) suggests that common components of waste water, namely phenol, ammonia, benzene and metals will be deposited in the landfill. Likewise, no analysis is provided for the disposal of waste solids and contaminants, which can include free hydrocarbons and sulphides and spent caustics.[6] An independent environment assessment of air quality and health impacts is needed of proposed waste water disposal. That assessment must take account of the Utah State Plan for Implementation of Emission Controls for Municipal Solid Waste Landfills (SECTION I).

Absence of Company History

As a newly formed company Emery LLC does not have a sufficient history for the DAQ or interested organizations to make an assessment of its ability to safely and appropriately construct, manage, and operate the proposed refinery and to remain in accordance with existing federal and state environmental laws and regulations while doing so. It is not sufficient to cite, as in Emery's Notice of Intent ("NOI"), specific regulations and say that the proposed refinery will function within those regulations and established industry parameters. The company does not offer an independent assessment of its abilities to construct and manage the proposed refinery. This is particularly notable in that the NOI does not include any reference to or information on the environmental impacts, abatement procedures, and mitigation activities it will follow during the construction phase of the proposed refinery. Thus, there is no basis upon which the state can make a reasonable and informed decision on the environmental feasibility of the proposed project.

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[5] http://www.epa.gov/region09/waterinfrastructure/oilrefineries.html
[6] http://dnn.cuwcc.org/Portals/0/FTP/CII-TF-Meeting/Jan-12-2012%20Public%20Workshop/IPIECA_Refining_Water%5B1%5D.pdf

Financial and Economic Appraisal

Emery Refinery does not offer its own or an independent appraisal of its financial ability to construct, run, and manage a complex oil refinery within industry, state and federal environmental and fiscal standards. There is no reference to the precedent of failure of a refinery in the town of Green River which filed for bankruptcy before it began operations. Emery's NOI fails to explain how the proposed refinery will become and remain profitable over at least a 30 year period of operations, thus avoiding being abandoned or periodically shut down to become an environmental hazard on the landscape.

An economic analysis and justification for the proposed refinery is needed in order to effectively assess the environmental implications of the proposed refinery. However, given the bankruptcy of the company that had constructed a refinery on the east side of Green River and the abandonment of the that plant, it is important for the state of Utah and Emery LLC to provide an economic analysis and justification for this proposed refinery. That analysis must include alternative scenarios over at least a 20 year period of time that account for potential changes in national energy policy, climate change impacts in the Colorado Plateau region, long-term environmental impacts within the immediate area and surrounding region (including downwind from the proposed refinery), and impacts on the region's tourism and recreation industries. Citizens of the county and state need to know that the refinery will not be closed or abandoned within a reasonable lifetime for the infrastructure of the refinery. Likewise, citizens and state officials have to know the expectations of their costs associated with the project, including monthly and annual use of water resources in an already arid region, city and county infrastructure improvements to accommodate increased truck traffic, any tax abatements or subsidies the company has requested or is likely to request, the amount of taxes the company will be paying to the city of Green River and/or Emery County and the state of Utah.

The company must provide an independent assessment of the wider environmental and economic costs to town of Green River, Emery County and the state for building new and maintaining existing infrastructure—new roads, road maintenance and repairs, sewage and garbage disposal and maintenance—within accepted environmental, sanitation, and safety standards. A part of that assessment must include upgrades of equipment, labor, training to Green River town's ability to respond to disruptions, spills, fires, and other emergencies at the refinery.

Construction Phase

A detailed description of the construction of the proposed refinery is not provided, both in terms of costs and available financing and environmental impacts. Construction of the proposed refinery will have significant environmental impacts, in terms of air quality, dust, visibility, increased truck and other commercial traffic. In turn, each of these environmental factors will impact the health and quality of life of residents. Abatement plans and procedures for these impacts need to be set out in detail.

Emery LLC has not conducted an assessment, at least for the public record, of the estimated cost of construction and the expected costs of refining a barrel of finished product. Both of these analyzes are critical for two reasons. First, will the proposed refinery be a viable business undertaking or be one of numerous examples of the "boom and bust" cycle of economic ventures in the region. Second, cost data on refining oil products is a basis for economic comparison with more environmental friendly energy technologies. This latter factor is essential for longer-term understanding of the cumulative environmental impacts in this region which has been identified as a "hot spot" as the climate of the southwest United States becomes warmer. A refinery is likely to contribute even further to increased heating, in the immediate area and surrounding region.

Diesel and Other Emissions

Emery LLC says that feedstock will be delivered to the refinery by highway tanker trucks. The NOI does not include any assessment of the environmental, air quality and health impacts of the increase in truck traffic through and/or close to residential and commercial areas of Green River. Such an assessment is needed. Even if truck deliveries were made round-the-clock to sustain the refinery's proposed 24/7 production schedule, this would result in at least two additional tanker trucks deliveries per hour, per 24 hour period. If deliveries are made during a ten hour daylight period, the number of hourly truck traffic would more than double to at least one every fifteen minutes. The company does not indicate how finished products will leave its facility (other than trucks delivering waste water to a landfill), but one can assume by tanker truck. It can be reasonably assumed that this has the potential to further double hourly truck traffic in, through and near Green River residential and commercial areas. In addition, a variety of additional heavy highway truck traffic will be entering and leaving the refinery, such as trucks delivering liquified natural gas. All of these will add substantially to emissions at and near the refinery.

Diesel emissions from hundreds of truck trips have profound health impacts. Two ground breaking studies on the toxicity of diesel emissions revealed that long-term exposure to even low levels of diesel exhaust raises the risk of dying from lung cancer about 50% for urban residents, and about 300% for occupationally exposed workers.[7] The environmental and health impacts of significant increases in diesel emissions from this truck traffic is reason for the DAQ to require an independent assessment of all aspects of the environmental impact of the proposed refinery.

COMMENTS CONCERNING TRANSPARENCY AND THE PUBLIC PROCESS

Federal Regulations Should be Directly Incorporated into the ITA

The DAQ references numerous federal regulations rather than expressly including the provisions in the text of the ITA. The commenting parties suggest that DAQ should include these provisions directly into the ITA rather than incorporate them by reference. As a matter of transparency, the public should not have to search the code of federal regulations in order to understand the decisions DAQ is making in its efforts to protect public health and Utah air quality.

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[7] Silverman DT, Samanic CM, Lubin JH, et al, *The diesel exhaust in Miners Study: A Nested Case-control study of Lung Cancer and Diesel Exhaust*. J Natl Cancer Inst. March 2, 2012; Attfield MD, Schlieff PL, Lubin JH, et al. *The Diesel Exhaust in Miners Study: A Cohort Mortality Study with Emphasis on Lung Cancer*. J Natl Cancer Inst. March 2, 2012.

The Public Must be Given the Opportunity to Comment on Additions to the Record

Throughout these comments, the commenting parties point out that the record does not support the permitting decisions made in the ITA. On the basis of information provided to the public, it appears that DAQ did not carefully consider the factors necessary to complete a legally adequate permitting decision. To remedy this deficiency, the DAQ should gather additional information, undertake a more thorough analysis, and provide better documentation to inform the public of its decision-making criteria. To the extent that DAQ decides to supplement the record with additional data and investigation, it should undertake a corresponding re-evaluation of the permitting decision that must be provided to the public for comment. To not do so would be to circumvent the requirement that new information and analysis be subject to public notice and comment.

COMMENTS SPECIFIC TO THE ITA

The ITA Does Not Impose Federally Enforceable Limits on Emery LLC's Potential to Emit VOCs

Emery LLC calculates that the Green River Refinery's uncontrolled emissions of volatile organic compounds (VOC) totals 338.38 tons per year. Without any operating restrictions, this level of emissions would render the Green River Refinery a major source based on emissions of VOCs in excess of 100 tons per year (tpy). However, Emery LLC then calculates that the Green River Refinery's controlled emissions of VOCs will total 36 typ, thus rendering it a synthetic minor source. The term synthetic minor is generally used to describe a source – such as the Green River Refinery – that limits its potential to emit to less than major source levels, but whose potential to emit in absence of any permit conditions would be above major source levels.

Whether the Green River Refinery is a major source and subject to new source review and Title V permit requirements, or whether it indeed qualifies as synthetic minor source depends on whether it has the potential to emit over 100 tpy of criteria pollutants, including VOCs. Therefore, the definition of "potential to emit" is extremely important. Potential to emit is defined at R307-401 as:

> "maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable."

As this definition indicates, enforceable permit limitations are significant in determining whether a source is subject to major new source review. In *United States v. Louisiana-Pacific Corporation*, 682 F. Supp. 1122 (D. Colo. Oct. 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988), a federal district court addressed the question of when limitations contained in permits qualify as enforceable. As a primary matter, the court found that all permits must contain a production or operations limitation in addition to the emission limitation in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. Next, the court found that restrictions on hours of operation and on the amount of materials combusted or produced are properly included; blanket restrictions on actual emissions are not.

Turning to the question of when an emissions limitation qualifies as "federally enforceable," the court emphasized that conditions contained in a permit must be enforceable as a practical matter. This is indicated when compliance with such conditions could easily be verified through testimony of officers, all manner of internal correspondence, and accounting, purchasing, and production records. In contrast, compliance with blanket restrictions on actual emissions would be virtually impossible to verify or enforce. EPA guidance reinforces the requirement that emissions limits contained in a permit must be practically enforceable. In a guidance document entitled "Limiting Potential to Emit in New Source Review Permitting," the EPA states, "[a] permit requirement may purport to be federally enforceable, but, in reality cannot be federally enforceable if it cannot be enforced as a practical matter."[8]

The particular circumstances of some individual sources make it difficult to state operating parameters for control equipment limits in a manner that is easily enforceable as a practical matter. Therefore there are two exceptions to the absolute prohibition on using blanket emissions levels to restrict potential to emit, one of which is applicable here. If the permitting agency determines that setting operating parameters is infeasible in a particular situation, a federally enforceable permit containing short term emissions limits would be sufficient to limit potential to emit, provided that such limits reflect the operation of the control equipment and the permit includes requirements to install, maintain, and operate a continuous emissions monitoring system ("CEMS"), to retain CEM data, and specifies that CEM data may be used to determine compliance with the emission limit.[9]

Applying this criteria to the ITA indicates that the emissions limitations on the Green River Refinery's VOC emissions are not federally enforceable. Neither the conditions contained in the ITA nor the NSPS regulations incorporated by reference impose federally enforceable short-term limits on the emissions for VOCs. There are numerous sections in the ITA that purport to impose limitations on VOC emissions, but none of these attempts meet the legal standard for federal enforceability.

First, Section II.B.1.c. imposes quantity limits on the amount of petroleum product – naptha, solvents, kerosene, diesel fuel, lube oils, wax products, asphalt, marine oil, and heavy fuel oil – processed by the plant. These limitations are imposed on a rolling 12 month period. A limitation of quantity of product evaluated on a rolling 12 month basis does not qualify as an emissions limit under the guidance offered by courts and the EPA. First, the quantity limitation on the liquid products does not justify a reduction of 302.38 tpy of VOC emissions, the difference between the uncontrolled emissions of 338.38 tpy and the controlled emissions of 36 tpy in the

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[8] Terrell Hunt, US EPA, Guidance on Limiting Potential to Emit in New Source Permitting (1989) available at http://www.epa.gov/region07/air/nsr/nsrmemos/lmitpotl.pdf
[9] *Id*.

ITA. There is no documentation of the amount of emissions associated with each type of liquid product. Moreover, there are no short-term emissions limits contained in a 12 month rolling limitation of volume of liquid processed. This does not protect NAAQS, as discussed below. Moreover, there is no CEMS requirement for VOC emissions, as required under *United States v. Louisiana-Pacific Corporation.*

Next, section II. B. of the ITA purports to limit VOC emissions by requiring that the operator shall develop a written leak-detection-and-repair (LDAR) plan that is consistent with certain federal regulations, namely 40 CFR 60.482-2a (g)(2), 60.482-7a (g)(2) & (3), 60.482-10a (j)(2) & (3), and 60.482-11a (e)(2). If a member of the public did not take time to read the referenced regulations, the citations to extensive federal regulations appears to impose substantive requirements on the facility. However, rather than impose federally enforceable limitations, each of the incorporated federal regulations is <u>an exception from monitoring and inspection requirements</u> that would otherwise be imposed by the other sections of 40 CFR 60.482. For example 40 CFR 60.482-2(a)(g)(2) provides:

> "Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:
> **(2)** The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

Similarly, 60.482-7a (g)(2) provides:

> **(g)** Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:
> **(2)** The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

40 CFR 60.482-10a (j)(2) & (3), and 60.482-11a (e)(2) are similar exceptions based on adherence to written plans that require monitoring of valves as frequently as practicable during safe-to-monitor times. These are not emissions limitations as required by applicable case law.

As discussed extensively below under the heading "**Monitoring and Regulation of Fugitive Emissions Is Inadequate,"** the language in these exceptions is not sufficiently precise to ensure adequate monitoring. The EPA has recognized problems with this type of language, and in its 2007 document entitled *Leak Detection and Repair: A Best Practices Guide* identifies "improperly identifying components as 'unsafe' or 'difficult' to monitor" <u>as a typical compliance problem in current LDAR programs</u>.[10] The commenting parties urge the DAQ to impose substantive monitoring requirements rather than further the trend of this type of language causing compliance problems. Appendix B is a paper showing two alternative VOC monitoring systems that have demonstrated ability to detect fugitive emissions, particularly from storage tanks. This is discussed in greater detail below.

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[10] US EPA, *Leak Detection And Repair: A Best Practices Guide* (2007) available at http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf

Finally, section II. B. 3. b of the ITA requires that Emery Refining install and operate a VOC monitoring device in accordance with 40 CFR 60.695 and 40 CFR 61.354. Regrettably, the ITA does not contain enough information for the public to ascertain which technology Emery plans to use to control VOC emissions and, therefore, the public cannot ascertain whether 60.695(a) (1), 60.695(a) (2), 60.695(a) (3), or 60.695(a) (4) applies. Regardless, none of the subsections of 60.695 contain enforceable emissions limitations on VOC; the provisions impose only monitoring and recording requirements. <u>The ITA should contain enforceable VOC emissions limitations expressed in tons monitored over the shortest time period economically feasible as justified by a complete BACT analysis.</u>

For all of these reasons, the commenting parties submit that Green River Refinery is not a synthetic minor source for VOCs emissions; instead it is a major source. Until effective monitoring and the imposition of federally enforceable limits occurs, a court – applying the reasoning in *United States v. Louisiana-Pacific Corporation* as well as the plain meaning of "potential to emit" as defined in the Utah regulations – would find that the Green River Refinery is in fact a major source subject to the legal requirements tied to this designation.

Therefore, Emery LLC is required to have a Title V permit under both federal law and state law. 40 C.F.R. part 70; Utah Admin. Code R307-415. After all, the Green River Refinery is a major source and thus bound by R307-415. Utah Admin. Code R307-415-4(1)(a); *see also* R307-415-4(2).

As a result, all of the requirements of Utah's Title V program apply to the permitting of the facility, including, but not limited to, a permit application that provides: 1) identification and description of all points of emission; 2) descriptions of fuels, fuel use, raw materials, production rates, and operating schedules; 3) citation and description of all applicable requirements; 4) a compliance plan; 5) a compliance schedule; 6) and, a schedule for submission of certified progress reports. Utah Code Ann. R307-415-5c. Yet, the NOI fails to meet these requirements.

In addition, a proper Title V permit must meet all the requirements listed in R307-415-6a, including; 1) emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance; and 2) monitoring and related recordkeeping and reporting requirements. The permit must also meet the requirements of R307-415-6b and 6c. Yet, the ITA fails to meet these standards.

The ITA Fails to Ensure that the Green River Refinery's Emissions Will Not Interfere with Attainment or Maintenance of the National Ambient Air Quality Standards

Pursuant to Utah regulation 307-410-1, all sources that require an approval order must have sufficient emissions limitations "to ensure that the source will not interfere with the attainment or maintenance of any National Ambient Air Quality Standards (NAAQS)." It is sensible for the public to assume that emissions limitations on sources will track the emissions goals contained in NAAQs. The EPA has promulgated primary standards for the NAAQS that have averaging times for the emissions of each criteria pollutant. In order to meet the goal that the Green River Refinery's emissions will not interfere with the attainment or maintenance of short term

NAAQS, the emissions limitations in the ITA must, at minimum, match the averaging time contained in the short term NAAQS.

The ITA does not come close to imposing requirements that track the averaging times in the NAAQS. For example, the Environmental Protection Agency ("EPA") has set NAAQS of 9 parts per million of carbon monoxide on an eight-hour average or 35 ppm on a one-hour averaging period. To meet Utah's stated goal that no source should interfere with the attainment or maintenance of NAAQS, the emissions limitations in the ITA should also be on a eight hour average. However, the ITA does not contain such hourly limitations either expressly in the permit or by reference to federal standards. The only direct emissions limits on CO in the entire ITA is found in the abstract, which states that the total tons per year of CO will not exceed 73.20 tons per year. <u>This is inadequate to ensure protection of NAAQS</u>.

Similarly, the EPA standards for ozone is .0075 ppm over an eight hour standard, yet the emissions limitations on VOCs are expressed by limiting the gallons of petroleum products processed over a rolling 12 month period. VOCs interact with NO_x to form ozone, and thereofore limitations on VOCs should be in the same form as the emission standards in the NAAQS. Limiting VOC emissions by simply limiting quantity of product processed over a rolling 12 month period is not sufficiently precise monitoring to meet the goal of ensuring short term ozone NAAQS are not violated. <u>Or to put it another way, without short term emission limits contained in the ITA, there is no way to ensure that short term NAAQS are attained and maintained</u>.

The ITA Must Incorporate Monitoring for Criteria Pollutants and Greenhouse Gases to Ensure that the Green River Refinery Emissions Remain Within the Permitted Limits

The commenting parties request that DAQ implement meaningful monitoring and reporting requirements to ensure that emissions from the Green River Refinery remain consistent with the emissions limits for each criteria pollutant and greenhouse gasses included in the ITA. The commenting parties are concerned that the current monitoring system is inadequate to report the emissions of criteria pollutants and GHG emissions. Unless there is a reliable monitoring and reporting of criteria pollutants and GHG, it is difficult to determine whether the Green River Refinery truly is a synthetic minor source or whether it is a major source subject to new source review and Title V permit requirements. Most importantly, a meaningful monitoring and reporting system is an essential component of protecting the health of Utah's citizen's and the environment. The commenting parties request an explanation of what elements in the ITA allow DAQ to determine if each criteria pollutant and greenhouse gas emissions exceed the permit limitations.

The commenting parties request the following monitoring systems be required. The flare system must have a monitoring requirement for NO_x, CO, and CO_2 in addition to the existing monitoring requirements for SO2 and H2S. The process boilers must have CEMS for NO_x and CO_2. The loading racks must have CEMS for VOC emissions at the exit of the combustion chambers. The combustion equipment accounts for the majority of CO_2 emissions projected in Emery LLC's NOI yet the ITA does not require CEMS for CO_2 for the combustion equipment. In fact, the record seems to show no federally enforceable limitations on CO_2 emissions because the federal regulations cited – 40 CFR 60.4200 to 60.4219 – do not impose emissions limitations; instead they impose standards of performance and only limit NO_x emissions. This must be remedied by DAQ requiring CEMS for all emissions sources of CO_2.

The commenting parties applaud DAQs imposition of specific enforceable short term emissions limitation on SO2 and H2S with regard to the flare system and the Process Boilers; <u>these are precisely the type of emissions limitations that should be required for each source and for each pollutant emitted</u>. However, although the emissions limitations contained in 60.102(a) (b)-(d) also place enforceable limitations on PM, NO_x, and CO that would further the goal of protecting NAAQS, DAQ did not adopt these provisions; instead it only incorporated section (g). The commenting parties request that DAQ provide an explanation for why it chose to only adopt limitations on SO2 and H2S, rather than the entirety of 60.102a.

An Emissions Impact Analysis Should Be Required Because the PM10 Limits May Exceed the Limits Set Forth in R307-410-4

Pursuant to R307- 410-4, a new source in an attainment area with a total controlled emission rate per pollutant greater than or equal to 5 tons per year of PM_{10} emissions attributable to fugitive emissions and fugitive dust shall conduct air quality modeling to estimate the impact of the new source on air quality.

Emery LLC admits that its PM_{10} emissions will 5.54 tons per year, and provides no explanation for the specific breakdown of the source of these PM_{10} emissions. Moreover, the ITA does not impose federally enforceable limitations on PM_{10} emissions nor does it impose a substantive monitoring system for fugitive emissions. For both of these reasons, the record suggests that the Green River Refinery may be emitting more than 5 tons per year of PM_{10} emissions attributable to fugitive emissions and fugitive dust; thus should be obligated to perform an emissions impact analysis. Emery LLC must either perform an emissions impact analysis or provide a supported justification for why the fact that that the Green River Refinery exceeds 5 tons per year in PM_{10} emissions does not render it subject to R307-410-4.

Moreover, R 307-410-4 improperly excludes VOC emissions from its list of threshold emission levels. VOC interacts with NO_x to form ozone; thus in order to protect ozone NAAQS, it would seem that VOC levels should also be considered in R307-410-4. The combined emissions of VOC and NO_x total 54 tons per year, which exceeds the 40 ton-per-year threshold contained in R307-410-5. To protect ozone NAAQS, the commenting parties suggest that DAQ re-examine the list of pollutants included in R307-410-4 and carefully consider whether the existing list is sufficient to protect Utah's public health and air quality.

The Record Does Not Support DAQ's BACT Determination

Emery LLC acknowledges that Rule 307-401-8(a) requires that in order to obtain an approval order, a new installation must show that the degree of pollution control for emissions is at least best available control technology (BACT). BACT is defined at 307-401-2 as:

> "an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed

> stationary source or modification which the executive secretary, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the executive secretary determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which to achieve equivalent results."

The Utah Supreme Court recognizes that BACT review is often conducted using the five-step "top down method," which requires the applicant to adopt the most stringent control technology, unless it can show that the technology is not achievable due to energy, environmental, or fiscal impacts. *Sierra Club v. Air Quality Board*, 2009 UT 76, 226 P.3d 719, 723 (2009). Under this standard, the company must make explicit its analysis on energy impacts, environmental impacts, economic impacts, other considerations, and cost calculations. It is not sufficient for the company to say, as it has, that a technology is "generally considered BACT." At no point in its NOI does Emery LLC provide explanation for its choices of technologies.

On the basis of the information provided to the public, Emery LLC's BACT analysis and DAQ's adoption of that analysis are legally inadequate for several reasons. First, in direct contradiction of the regulation's definition of BACT, the ITA lacks an enforceable emission limit for each subject emission unit at the source, and for each pollutant subject to review that is emitted from the source. For example the ITA does not impose emission limits on the combustion sources, namely the heaters and the boilers. None of the VOC emission units have associated enforceable emission limits in the ITA. There are no emissions units controlled for PM 2.5 or PM 10 emissions. The process boilers have no emission limits for NO_2. The flare system contains no emissions limitations on NO_x, CO, or CO_2.

During normal operations or abnormal events, the selective catalytic reduction (SCR) system proposed by Emery LLC are subject to contamination and plugging, thereby decreasing control over NO_x and increasing oxidation of ammonia which, in turn, results in more production of NO_x. The company has not included equipment to improve the effectiveness of SCR systems – such as sootblowers – thus it fails to demonstrate the technology is BACT. While low NO_x burners are used in the industry, they are only 40-70% efficient in removing NO_x.[11] Improvements on outcomes to 5 ppm of NO_x can be made with new technologies that are

[11] *see e.g.* Fuel Tek Inc., *Low NOx Burners*, available at http://www.ftek.com/en-US/products/apc/low-nox-burners.

available, such as Ultra Reduced NO_x Burners (URNB).[12] On the basis of the information in the record, Emery LLC appears to not have considered this enhanced equipment and thus seems to have not demonstrated that its chosen technology is indeed BACT.

Second, Emery LLC's BACT analysis and DAQ's adoption of that analysis in the ITA fails to compare the proposed emission limits at the Green River Refinery to possible emission limits for other potentially applicable technologies or to consider options other than the ones adopted. The Utah Supreme Court has held that "the purpose of BACT review is to ensure that the best available control technology is adopted. Implicit in this purpose is a goal to encourage the adoption of new technologies." *Sierra Club v. Air Quality Board*, 2009 UT 76, 226 P.3d 719, 723 (2009). On the basis of the information provided in the record, it appears that Emery LLC did not engage in any comparison of available technologies, rendering it impossible to adopt new technologies. For example, Emery LLC's BACT review of control alternatives for VOC fugitives fails to consider usage and work practices involving remote sensing and determination of refinery component leaks through infrared backscatter techniques and other methods of remote visualization; this is discussed further in subsequent headings below. Instead, Emery LLC's NOI repeatedly states that the chosen technology for the distillation plant, wax plant, and VOC controls "are generally considered BACT." These conclusions and DAQs adoption of those conclusions do not comport with BACT as defined in Utah regulations and by the Utah Supreme Court. The commenting parties request that DAQ provide an explanation for the technologies chosen with regard to the energy, environmental, and economic impacts taken into consideration as part of the BACT analysis.

Third, Emery LLC's BACT assessment does not include an economic impacts analysis, which eviscerates the public's ability to evaluate its justification of technology as BACT. Utah's BACT guidelines state: "In the economic impact analysis, primary consideration should be given to quantifying the cost of control (e.g., total cost, dollars per ton of pollutant removed, incremental costs per ton of pollutant removed) and not the economic situation of the individual source. It addresses all the costs of emission control. All data is to be reported on a "before taxes" basis." Emery LLC provides no evidence of the economic impacts of the control technologies it has chosen and the available alternatives. Emery LLC does not provide pollution-specific costs, additional product costs, or the percentage of total manufacturing costs that the cost of additional emission control represents. This information will determine if, and to what degree, the applicant will be at a competitive disadvantage in the market place because of the cost of an alternative control option. <u>Without this data, is not possible for DAQ, the EPA or the commenting parties to assess whether the selected technologies are cost effective</u>. This data-gap in the record compromises participation in the public process because the public cannot provide a comparative economic analysis between Emery LLC's chosen technology and any alternatives that the public proposes as BACT.

[12] US EPA, *Small Business Innovation Research Success Stories, Ultralow NOx Burner for Boilers and Process Heaters*, available at http://www.epa.gov/ncer/sbir/success/pdf/ultralow.pdf

Monitoring and Regulation of the Flare System Is Inadequate

The ITA's restrictions on flaring are inadequate to protect public health and ensure compliance with emissions limitations on CO_2, NO_x, and CO. As stated above, the monitoring imposed on the flare system must include enforceable emissions limitations for CO_2, CO, and NO_x. Next, Emery Refining should be required to implement flare minimization plans and Energy Star Guidelines for flaring. The EPA sponsored an "Energy Star" guide for refinery plant managers that included recommendations for a zero flaring strategy, which results in both reduced air pollutant emissions and in increased energy efficiency. This includes gas recovery systems, new ignitions systems, or the elimination of pilots altogether with the use of new ballistic ignition systems. This technology is commercially available and has been implemented in small refineries like the Lion Oil Co. in Arkansas. Yet, the record indicates that neither DAQ nor Emery LLC considered these technologies for the flare system as required by BACT as defined in Utah regulations and by the Utah Supreme Court. The Energy Star guide is attached as Appendix A.

Emery LLC's NOI did not appear to include any projections or estimates of emissions associated with an upset or unavoidable breakdown event. However, studies show that even one upset event can result in emission levels equivalent to a plant's annual output of certain criteria pollutants. In order to determine the actual emissions from the Green River Refinery, the company should provide estimated emissions associated with an upset event or, in the alternative, a well-supported justification of why an upset event should not be expected on an annual basis.

Monitoring and Regulation of Fugitive Emissions Is Inadequate

As stated above, the commenting parties are deeply concerned by the lack of substantive monitoring and reporting requirements in the ITA for fugitive emissions, particularly with regard to VOC emissions from the storage tanks and floating roof tanks. A proper BACT analysis for fugitive emissions is expressly required in 307-401-8(1)(a) (AO is appropriate only where "[t]he degree of pollution control for emissions, **to include fugitive emissions** and fugitive dust, is at least best available control technology." emphasis added).

A 1999 report to Congress found that (1) oil refineries vastly underreport leaks from valves to federal and state regulators and that (2) these unreported fugitive emissions from oil refineries add millions of pounds of harmful pollutants to the atmosphere each year, including volatile organic compounds and hazardous air pollutants. Data the EPA and from refinery reports reveals that over half of all reported VOC and toxic emissions from refineries are fugitive emissions.[13]

Similarly, the Houston Advanced Research Center found huge discrepancy between calculated fugitive emissions from refineries and actual measured emissions and issued a report –the Texas Air Quality Study 2000 – stating that actual measurements of refinery fugitive emissions were between 3 and 100 times greater than emissions estimates. Remote sensing and infrared

[13] Special Investigations Division, Committee on Government Reform for the US House of Representatives, *Oil Refineries Fail to Report Millions of Pounds of Harmful Emissions*, Prepared for Rep. Henry A. Waxman (November 10, 1999).

monitoring has proved to be an effective way to measure, and thus control fugitive emissions.[14]

Storage tanks and floating roof tanks account for the majority of potential uncontrolled VOC emissions from the Green River Refinery. As noted above, VOC emissions render the Green River Refinery a synthetic minor source based on the amount of potential uncontrolled emissions. The public, Emery LLC, DAQ, and the EPA have a strong interest in ensuring that these VOC emissions are monitored and controlled to the greatest extent possible. Despite this strong shared interest, the monitoring and reporting system currently required in the ITA for fugitive emissions is completely inadequate.

Appendix B is a technical paper presented to the EPA entitled "Why Emissions Factors Don't Work at Refineries and What to Do About It." This paper explains the use of infrared monitoring of leaks and details the success of two techniques – Differential Absorption Light Detection and Ranging (DIAL) and Solar Occultation Flux (SOF) that measure the VOC concentrations in a two dimensional vertical plane and calculate VOC flux in pounds per hour. DAQ's BACT analysis for fugitive emissions should include consideration of both DIAL and SOF technology.

Once again, we appreciate the opportunity to comment on this ITA. Please inform us directly of any further action you take with regard to the NOI, ITA, or approval order. We hope that you will carefully review our comments and reconsider your decision in light of what we say here.

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[14] Cowling, Ellis B., Furiness, Cari, Dimitriades, Basil and Parrish, David. "*Final Rapid Science Synthesis Report: Findings from the Second Texas Air Quality Study (TexAQS II)*", reported to the Texas Commission on Environmental Quality, by the TexAQS II Rapid Science Synthesis Team. August 31, 2007.

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Appendix A

LBNL-56183

ERNEST ORLANDO LAWRENCE
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Energy Efficiency Improvement and Cost Saving Opportunities For Petroleum Refineries

An ENERGY STAR® Guide for Energy and Plant Managers

Ernst Worrell and Christina Galitsky
Environmental Energy Technologies Division

February 2005

Sponsored by the U.S. Environmental Protection Agency

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This report was funded by the U.S. Environmental Protection Agency's Climate Protection Partnerships Division as part of ENERGY STAR. ENERGY STAR is a government-backed program that helps businesses protect the environment through superior energy efficiency. The work was supported by the U.S. Environmental Protection Agency through the U.S. Department of Energy Contract No.DE-AC02-05CH11231.

Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries

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ABSTRACT

The petroleum refining industry in the United States is the largest in the world, providing inputs to virtually any economic sector, including the transport sector and the chemical industry. The industry operates 146 refineries (as of January 2004) around the country, employing over 65,000 employees. The refining industry produces a mix of products with a total value exceeding $151 billion. Refineries spend typically 50% of cash operating costs (i.e.,, excluding capital costs and depreciation) on energy, making energy a major cost factor and also an important opportunity for cost reduction. Energy use is also a major source of emissions in the refinery industry making energy efficiency improvement an attractive opportunity to reduce emissions *and* operating costs.

Voluntary government programs aim to assist industry to improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency, stresses the need for strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. This Energy Guide describes research conducted to support ENERGY STAR and its work with the petroleum refining industry. This research provides information on potential energy efficiency opportunities for petroleum refineries.

This Energy Guide introduces energy efficiency opportunities available for petroleum refineries. It begins with descriptions of the trends, structure, and production of the refining industry and the energy used in the refining and conversion processes. Specific energy savings for each energy efficiency measure based on case studies of plants and references to technical literature are provided. If available, typical payback periods are also listed. The Energy Guide draws upon the experiences with energy efficiency measures of petroleum refineries worldwide. The findings suggest that given available resources and technology, there are opportunities to reduce energy consumption cost-effectively in the petroleum refining industry while maintaining the quality of the products manufactured. Further research on the economics of the measures, as well as the applicability of these to individual refineries, is needed to assess the feasibility of implementation of selected technologies at individual plants.

Contents

1. Introduction

As U.S. manufacturers face an increasingly competitive global business environment, they seek out opportunities to reduce production costs without negatively affecting product yield or quality. Uncertain energy prices in today's marketplace negatively affect predictable earnings, which are a concern, particularly for the publicly traded companies in the petroleum industry. Improving energy efficiency reduces the bottom line of any refinery. For public and private companies alike, increasing energy prices are driving up costs and decreasing their value added. Successful, cost-effective investment into energy efficiency technologies and practices meets the challenge of maintaining the output of a high quality product while reducing production costs. This is especially important, as energy efficient technologies often include "additional" benefits, such as increasing the productivity of the company.

Energy use is also a major source of emissions in the refinery industry, making energy efficiency improvement an attractive opportunity to reduce emissions *and* operating costs. Energy efficiency should be an important component of a company's environmental strategy. End-of-pipe solutions can be expensive and inefficient while energy efficiency can be an inexpensive opportunity to reduce criteria and other pollutant emissions. Energy efficiency can be an efficient and effective strategy to work towards the so-called "triple bottom line" that focuses on the social, economic, and environmental aspects of a business[1]. In short, energy efficiency investment is sound business strategy in today's manufacturing environment.

Voluntary government programs aim to assist industry to improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR®, a voluntary program managed by the U.S. Environmental Protection Agency (EPA), highlights the importance of strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. This Energy Guide describes research conducted to support ENERGY STAR and its work with the petroleum refining industry. This research provides information on potential energy efficiency opportunities for petroleum refineries. ENERGY STAR can be contacted through www.energystar.gov for additional energy management tools that facilitate stronger energy management practices in U.S. industry.

This Energy Guide assesses energy efficiency opportunities for the petroleum refining industry. Petroleum refining in the United States is the largest in the world, providing inputs to virtually all economic sectors, including the transport sector and the chemical industry. The industry operates 146 refineries (as of January 2004) around the country, employing over 65,000 employees, and produces a mix of products with a total value exceeding $151 billion (based on the 1997 Economic Census). Refineries spend typically 50% of cash

[1] The concept of the "triple bottom line" was introduced by the World Business Council on Sustainable Development (WBCSD). The three aspects of the "triple bottom line" are interconnected as society depends on the economy and the economy depends on the global ecosystem, whose health represents the ultimate bottom line.

operating costs (i.e., excluding capital costs and depreciation) on energy, making energy a major cost factor and also an important opportunity for cost reduction.

This Energy Guide first describes the trends, structure and production of the petroleum refining industry in the United States. It then describes the main production processes. Next, it summarizes energy use in refineries along with the main end uses of energy. Finally, it discusses energy efficiency opportunities for U.S. refineries. The Energy Guide focuses on measures and technologies that have successfully been demonstrated within individual plants in the United States or abroad. Because the petroleum refining industry is an extremely complex industry, this Energy Guide cannot include all opportunities for all refineries. Although new technologies are developed continuously (see e.g., Martin et al., 2000), the Energy Guide focuses on practices that are proven and currently commercially available.

This Energy Guide aims to serve as a guide for energy managers and decision-makers to help them develop efficient and effective corporate and plant energy management programs, by providing them with information on new or improved energy efficient technologies.

2. The U.S. Petroleum Refining Industry

The United States has the world's largest refining capacity, processing just less than a quarter of all crude oil in the world. Although the major products of the petroleum refining sector are transportation fuels, its products are also used in other energy applications and as feedstock for the chemical industries.

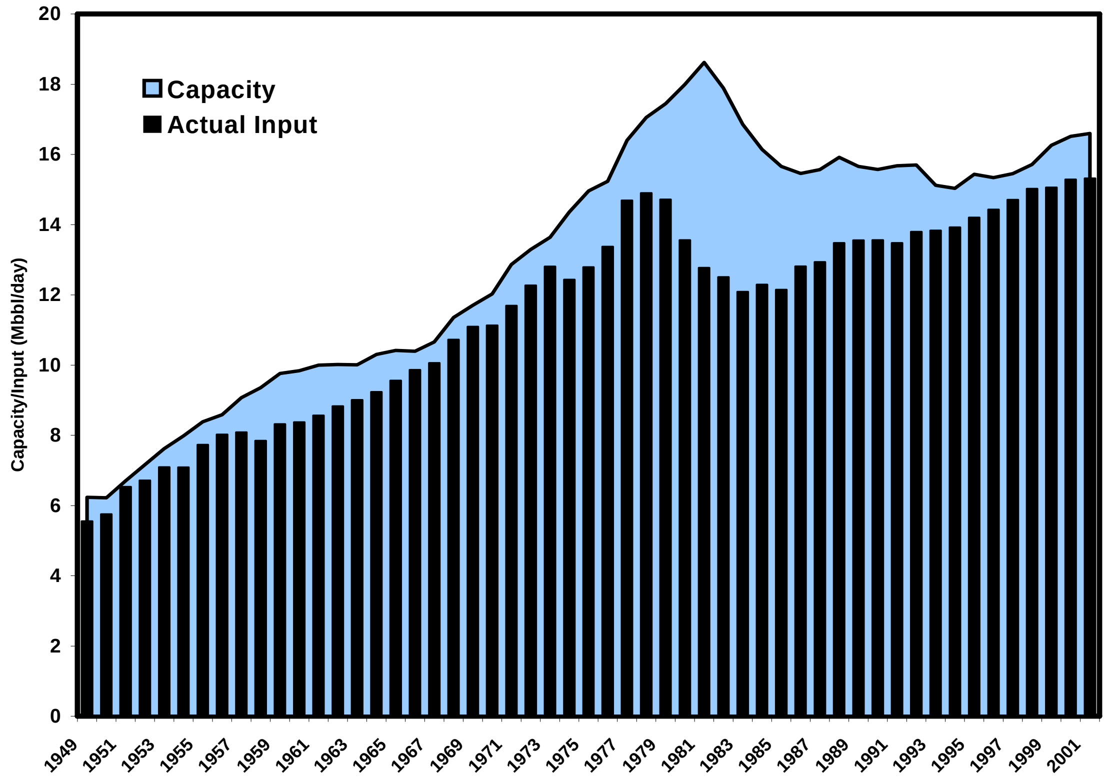

Figure 1. Capacity and actual crude intake of the U.S. petroleum refining industry between 1949 and 2001, expressed in million barrels/day of crude oil intake. Source: Energy Information Administration.

The U.S. petroleum refining sector has grown over the past 50 years by about 2%/year on average. Until the second oil price shock, refining capacity grew rapidly, but production already started to level off in the mid to late 1970s. This was a period where the industry started to reorganize. It was not until after the mid-1980s that refinery production started to grow again. Since 1985, the industry has been growing at a somewhat slower rate of 1.4%/year. Figure 1 shows the developments in installed capacity (expressed as crude intake capacity) and actual crude intake in the U.S. refining industry since 1949.

Figure 1 shows that capacity utilization has been pretty steady, with exception of the period between the two oil price shocks. Following the first oil price shock, federal legislation favoring domestic production and refining subsidized the construction and operation of many small refineries (U.S. DOE-OIT, 1998). As shown, this led to a reduced capacity utilization. Figure 2 shows the number of operating refineries in the United States since 1949.

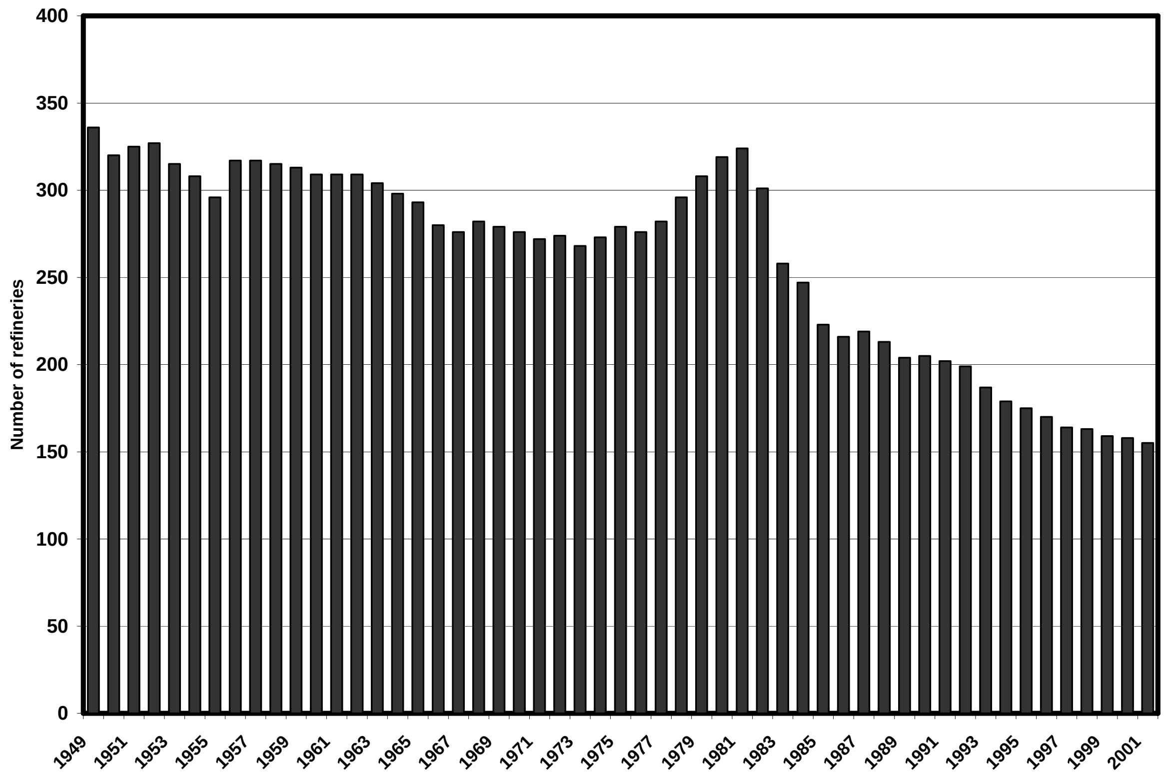

Figure 2. Number of operating refineries in the United States. Source: Energy Information Administration.

Figure 2 clearly demonstrates the increasing number of refineries after the first oil price shocks in the 1970s. The small refineries only distill products, and are most often inefficient and less flexible operations, producing only a small number of products. Increasing demand for lighter refinery products, and changes in federal energy policy, have led to a reduction in the number of refineries, while increasing capacity utilization (see Figure 1).

These market dynamics will also lead to a further concentration of the refinery industry into high capacity plants operating at higher efficiencies. The number of refineries has declined from 205 in 1990 to 147 in 2002. The current refineries have a higher capacity utilization and are generally more complex, with an emphasis on converting technology. This trend will continue to increase the ability to process a wider range of crudes and to produce an increasing share of lighter petroleum products. Also increasing is the need to produce cleaner burning fuels to meet environmental regulations (e.g., reduction of sulfur content). Appendix A provides a list of operating refineries in the United States as of January 2003.

Petroleum refineries can be found in 32 states, but the industry is heavily concentrated in a few states due to historic resource location and easy access to imported supplies (i.e., close to harbors). Hence, the largest number of refineries can be found on the Gulf Coast, followed by California, Illinois, New Jersey, Pennsylvania, and Washington. Some of the smallest producing states have only very small refineries operated by independent operators. These small refineries produce only a very small mix of products, and are ultimately not expected to be able to compete in the developing oil market. Figure 3 depicts refining capacity by state (expressed as share of total capacity crude intake) in 2002.

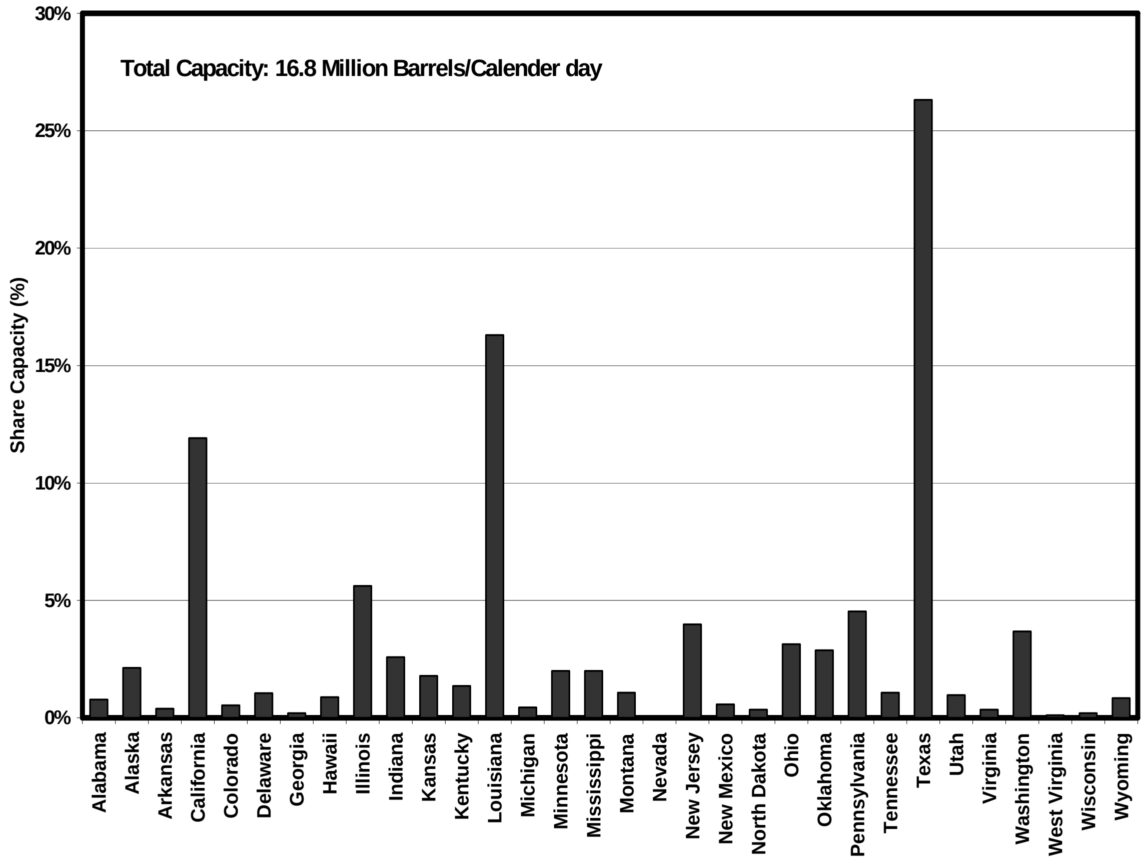

Figure 3. Refining capacity by state as share of total U.S. refining capacity in 2003. Capacity is expressed as capacity for crude intake. Source: Energy Information Administration.

The refineries are operated by 59 companies. Although there are a relatively large number of independent companies in the U.S. refining industry, the majority of the refining capacity is operated by a small number of multi-national or national oil processing companies. The largest companies (as of January 2003) are: ConocoPhilips (13% of crude capacity), ExxonMobil (11%), BP (9%), Valero (8%), ChevronTexaco (6%), Marathon Ashland (6%), and Shell (6%), which combined represent 59% of crude distillation (CDU) capacity. Each of these companies operates a number of refineries in different states. Figure 4 depicts companies operating over 0.5% of CDU capacity in the United States

The small refineries produce a relative simple mix of products. Small refineries may often use high cost feedstocks, which may result in a relatively low profitability. As a result, small companies' share of total industry economic value is smaller than their share of total industry production capacity.

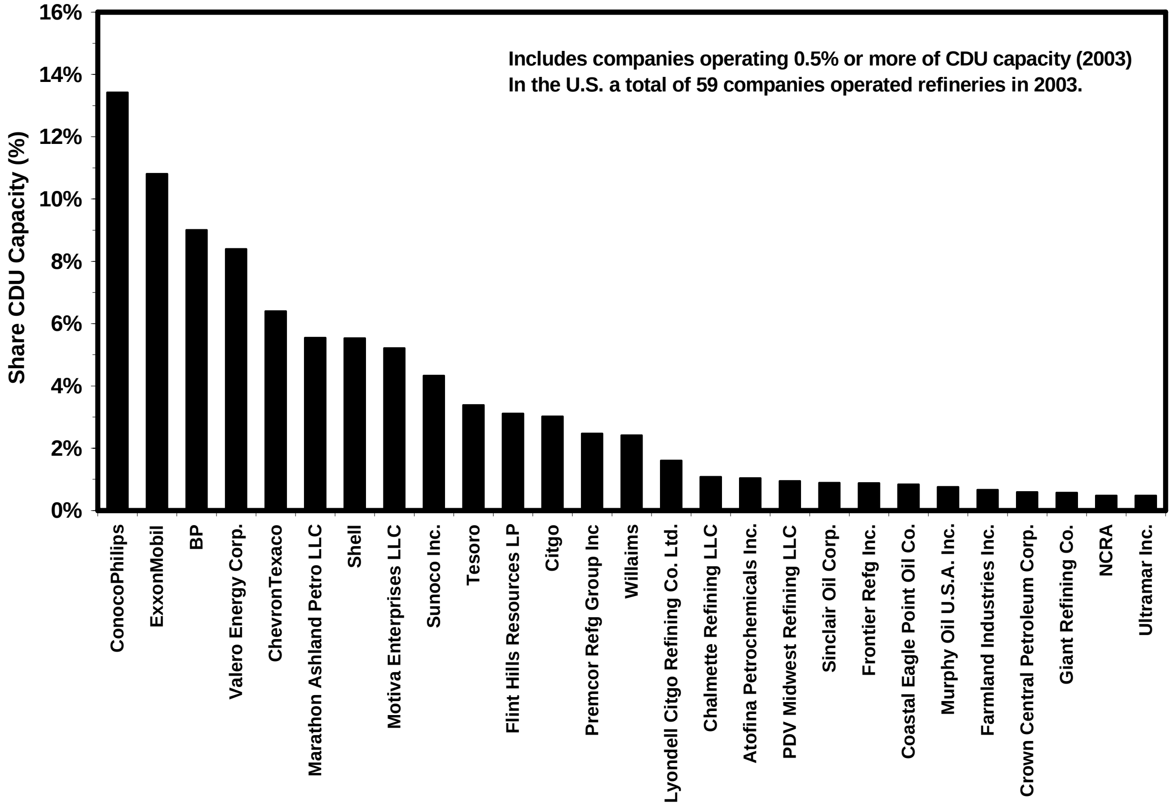

Figure 4. Refining capacity (expressed as percentage of CDU capacity) for companies operating over 0.5% of CDU capacity in 2003. The depicted companies operate 94% of total national capacity. Companies operating less than 0.5% of CDU capacity are not depicted. Source: Energy Information Administration.

The further concentration of refineries in the United States has contributed to a reduction in operating costs but has also impacted refining margins (Killen et al., 2001). The Western United States market is more or less isolated from the other primary oil markets in the United States. Although overall market dynamics in the United States and the Western United States market follow the same path, the operating margin from Western refineries is higher than that in other regions. Between 1995 and 2000, the operating margin of West Coast refineries has grown from $3 to a high of $8/bbl crude in 2000 (Killen et al., 2001), compared to 1 to 4$/bbl in other U.S. markets.

U.S. refineries process different kinds of crude oil types from different sources. Over the past years, overall there has been a trend towards more heavy crudes and higher sulfur content (Swain, 2002). These effects vary for the different regions in the United States, but overall this trend has been clear over the past 10 years. This trend is likely to continue, and will affect the product mix, processing needs, and energy use of refineries. This trend will also result in a further expansion of conversion capacity at U.S. refineries.

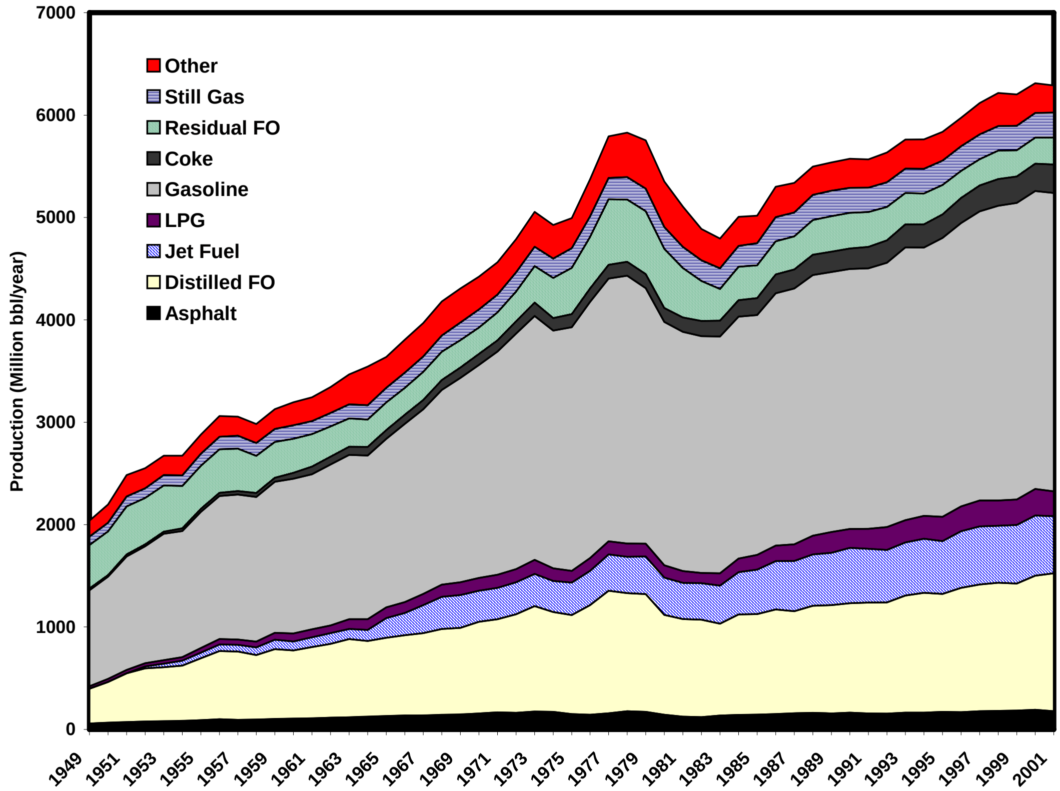

Figure 5. Petroleum refining production, by major product categories in the United States, 1949 – 2001. Source: Energy Information Administration.

While the type of processed crude oil is becoming increasingly heavier and higher in sulfur, the demand for oil products, and hence the product mix of the refineries, is changing towards an increased share of lighter products. Figure 5 depicts the past trend in production since 1949 by product category. Figure 5 shows an increase in the production and relative share of lighter products like gasoline, while the share of heavier fuels like residual fuel oil declined over the past 50 years.

Figure 5 does not show the changing quality demands of the product categories. Started in California, increased air quality demands in many parts of the United States will result in an increased demand for low-sulfur automotive fuels (gasoline, diesel). This will result in an increase of hydrotreating capacity at the petroleum refinery, as well as alternative desulfurization processes in the future. Small refineries will most likely not be able to invest in this type of expansion, and will further lose market share. With limited markets for the hydroskimming refineries, a further concentration of refineries is likely to take place over the next few years. Expansion of existing refineries will provide the increased demand, as no greenfield refineries will likely be built in the next few years within the United States

At the same time, the dynamic development of the petroleum industry faces other new challenges and directions. Increasing and more volatile energy prices will affect the bottom line of refineries. Commodity markets, like that of most oil products, show smaller and smaller margins. Both factors may negatively affect the profitability of petroleum refining.

Increased needs to reduce air pollutant emissions from refinery operations as well as increased safety demands will drive technology choice and investments for future process technology. However, environmental compliance alone has not been the major factor affecting profitability (EIA, 1997). Instead, a combination of the above factors is the driver for reduced profitability of refinery operations. This trend is expected to continue, and in the future the above challenges combined will affect the industry and technology choice profoundly.

The continued trend towards low-sulfur fuels and changes in the product mix of refineries will affect technology choice and needs. For example, the current desulfurization and conversion technologies use relatively large amounts of hydrogen. As hydrogen is an energy intensive product, increased hydrogen consumption will lead to increased energy use and operation expenses, unless more efficient technologies for hydrogen production and recovery are developed and applied. In the long-term, new desulfurization technologies may reduce the need for hydrogen. At the same time, refineries are faced with challenges to reduce air pollution and other energy related issues (e.g., regulatory changes of power supply). The petroleum refining industry will face many other challenges. Climate change, new developments in automotive technology, and biotechnology are posed to affect the future structure of refineries. Table 1 summarizes the challenges to the petroleum refining industry.

Table 1. Key drivers and challenges for the petroleum refining industry. The order in the table does not reflect an order of priorities.

Challenge	Key Issues
Safety	Safety incidents, refineries now mainly located in urbanized areas
Environment	Emissions of criteria air pollutants (NOx, VOC) and greenhouse gases
Profitability	Commodity market, further concentration of the industry
Fuel Quality	Sulfur, MTBE-replacement
Feedstock	Increasing demand for lighter products from decreasing quality crude
Energy	Costs of power and natural gas

Katzer et al. (2000) explored the forces of change and the impacts on the future of petroleum refining. They see important new development needs in catalysis, optimization and control, reaction engineering and reactor design, biotechnology for desulfurization, increased use of natural gas as feedstock, and power generation. In the view of Katzer et al., the refinery of the future will look more like an automated chemical plant that will maximize high-value products (e.g., engineered molecules for specific applications) and integrate into the total energy-infrastructure.

3. Process Description

A modern refinery is a highly complex and integrated system separating and transforming crude oil into a wide variety of products, including transportation fuels, residual fuel oils, lubricants, and many other products. The simplest refinery type is a facility in which the crude oil is separated into lighter and heavier fractions through the process of distillation. In the United States, about 25% of refinery facilities are small operations producing fewer than 50,000 barrels/day (U.S. DOE-OIT, 1998), representing about 5% of the total industry output. The existence of small, simple and relatively inefficient refineries is in part due to legislation subsidizing smaller operations following the first oil price shock. These small operations consist only of distillation capacity (i.e., no reforming or converting capacities) and make a limited number of products.

Modern refineries have developed much more complex and integrated systems in which hydrocarbon compounds are not only distilled but are also converted and blended into a wider array of products. The overall structure of the refinery industry has changed in recent years because of a growing demand for lighter products. This has led to more complex refineries with increased conversion capacities. Increased conversion will lead to an increase in the specific energy consumption but will also produce a product mix with a higher value. These dynamics will continue in the future, as demand for heating (fuel) oil is decreasing.

In all refineries, including small less complex refineries, the crude oil is first distilled, which is followed by conversion in more complex refineries. The most important distillation processes are crude or atmospheric distillation, and vacuum distillation. Different conversion processes are available using thermal or catalytic processes, e.g., using a catalytic reformer, where the heavy naphtha, produced in the crude distillation unit, is converted to gasoline, and the fluid catalytic cracker where the distillate of the vacuum distillation unit is converted. Newer processes, such as hydrocrackers, are used to produce more light products from the heavy bottom products. Finally, all products may be treated to upgrade the product quality (e.g., sulfur removal using a hydrotreater). Side processes that are used to condition inputs or produce hydrogen or by-products include crude conditioning (e.g., desalting), hydrogen production, power and steam production, and asphalt production. Lubricants and other specialized products may be produced at special locations.

The principal energy using processes in refineries (in order of overall energy consumption in the United States) are the crude (or atmospheric) distillation unit, hydrotreaters, reformer, vacuum distillation unit, alkylate production, catalytic crackers, and hydrocrackers.

The main production steps in refineries are discussed below, providing a brief process description and the most important operation parameters including energy use (see also Chapter 4). Figure 6 provides a simplified flow diagram of a refinery. The descriptions follow the flow diagram, starting with the intake of the crude through to the production of the final products. The flow of intermediates between the processes will vary by refinery, and depends on the structure of the refinery, type of crude processes, as well as product mix.

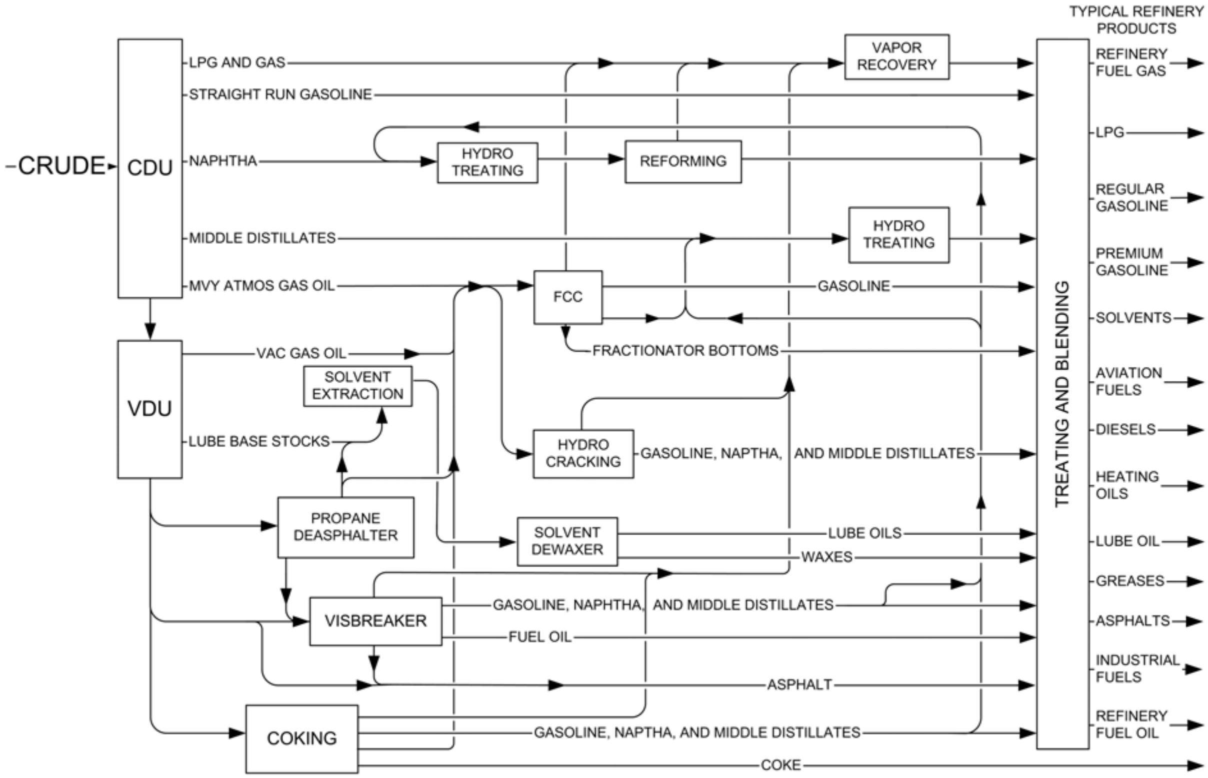

Figure 6. Simplified flowchart of refining processes and product flows. Adapted from Gary and Handwerk (1994).

Desalting. If the salt content of the crude oil is higher than 10 lb/1000 barrels of oil, the crude requires desalting (Gary and Handwerk, 1994). Desalting will reduce corrosion and minimize fouling of process units and heat exchangers. Heavier crudes generally contain more salts, making desalting more important in current and future refineries. The salt is washed from the crude with water (3-10% at temperatures of 200-300°F (90-150ºC). The salts are dissolved in the water, and an electric current is used to separate the water and the oil. This process also removes suspended solids. The different desalting processes vary in the amount of water used and the electric field used for separation of the oil and water. The efficiency of desalting is influenced by the pH, gravity, viscosity, and salt content of the crude oil, and the volume of water used in the process. Electricity consumption of desalting varies between 0.01 and 0.02 kWh/barrel of crude oil (IPPC, 2002).

Crude Distillation Unit (CDU). In all refineries, desalted and pretreated crude oil is split into three main fractions according to their boiling ranges by a fractional distillation process. The crude oil is heated in a furnace to approximately 750°F (390ºC), and subsequently fed into the fractionating or distillation tower. Most CDUs have a two-stage heating process. First, the hot gas streams of the reflux and product streams are used to heat the desalted crude to about 550°F (290ºC). Second, it is further heated in a gas-fired furnace to 400ºC (Gary and Handwerk, 1994). The feed is fed is to the distillation tower at a temperature between 650 and 750°F (340-390ºC). Energy efficiency of the heating process can be improved by using pump-around reflux to increase heat transfer (at higher temperatures at lower points in the column).

In the tower, the different products are separated based on their boiling points. The boiling point is a good measure for the molecule weight (or length of the carbon chain) of the different products. Gasoline, with relatively small molecules, boils between 70 and 140ºC, while naphtha, which has a larger molecule, has a boiling point between 140 and 180ºC. The distillation towers contains 30-50 fractionation trays. The number of trays depends on the desired number and purity of product streams produced at the particular CDU.

The lightest fraction includes fuel gas, LPG, and gasoline. The overhead, which is the top or lightest fraction of the CDU, is a gaseous stream and is used as a fuel or for blending.

The middle fraction includes kerosene, naphtha, and diesel oil. The middle fractions are used for the production of gasoline and kerosene. The naphtha is led to the catalytic reformer or used as feedstock for the petrochemical industry.

The heaviest fractions are fuel oil and a bottom fraction, which has the lowest value. Fuel oil can be further processed in the conversion unit to produce more valuable products. About 40% of the products of the CDU (on energy basis) cannot be used directly and are fed into the Vacuum Distillation Unit (VDU), where distillation is performed under low pressure.

Because the CDU processes all incoming crude oil, it is a large energy user, although the specific energy consumption compared to the conversion process is relatively low. Energy efficiency opportunities consist of improved heat recovery and heat exchange (process integration), improved separation efficiencies, and other smaller measures. Integration of heat from the CDU and other parts of the refinery may lead to additional energy savings.

Vacuum Distillation Unit (VDU) or High Vacuum Unit (HVU). The VDU/HVU further distills the heaviest fraction (i.e., heavy fuel oil) from the CDU under vacuum conditions. The reduced pressure decreases the boiling points making further separation of the heavier fractions possible, while reducing undesirable thermal cracking reactions (and associated fouling). The low pressure results in much larger process equipment. In the VDU, the incoming feedstream is heated in a furnace to 730-850°F (390-450ºC).

Vacuum conditions are maintained by the use of steam ejectors, vacuum pumps, and condensers. It is essential to obtain a very low pressure drop over the distillation column to reduce operating costs.

Of the VDU products, the lightest fraction becomes diesel oil. The middle fraction, which is light fuel oil, is sent to the hydrocracker (HCU) or fluid catalytic cracker (FCC), and the heavy fuel oil may be sent to the thermal cracker (if present at the refinery).

The distillation products are further processed, depending on the desired product mix. Refinery gas is used as fuel in the refinery operations to generate heat (furnaces), steam (boilers), or power (gas turbines), while some of the refinery gas may be flared. Parts of the refinery gas may also be used to blend with LPG or for hydrogen production. Hydrogen is used in different processes in the refinery to remove sulfur (e.g., hydrotreating) and to convert to lighter products (e.g., hydrocracking).

Hydrotreater. Naphtha is desulfurized in the hydrotreater and processed in a catalytic reformer. Contaminants such as sulfur and nitrogen are removed from gasoline and lighter fractions by hydrogen over a hot catalyst bed. Sulfur removal is necessary to avoid catalyst poisoning downstream, and to produce a clean product. The treated light gasoline is sent to the isomerization unit and the treated naphtha to the catalytic reformer or platformer to have its octane level increased. Hydrotreaters are also used to desulfurize other product streams in the refinery.

Although many different hydrotreater designs are marketed, they all work along the same principle. The feedstream is mixed with hydrogen and heated to a temperature between 500 and 800°F (260-430ºC). In some designs, the feedstream is heated and then mixed with the hydrogen. The reaction temperature should not exceed 800°F (430ºC) to minimize cracking. The gas mixture is led over a catalyst bed of metal oxides (most often cobalt or molybdenum oxides on different metal carriers). The catalysts help the hydrogen to react with sulfur and nitrogen to form hydrogen sulfides (H_2S) and ammonia. The reactor effluent is then cooled, and the oil feed and gas mixture is then separated in a stripper column. Part of the stripped gas may be recycled to the reactor.

In the hydrotreater, energy is used to heat the feedstream and to transport the flows. The hydrotreater also has a significant indirect energy use because of the consumption of hydrogen. In the refinery, most hydrogen is produced through reforming (see below). Some hydrogen is also produced as a by-product of cracking.

Catalytic Reformer. The reformer is used to increase the octane level in gasoline. The desulfurized naphtha and gasoline streams are sent to the catalytic reformer. The product, called reformate, is used in blending of different refinery products. The catalytic reformer produces around 30-40% of all the gasoline produced in the United States Because the catalytic reformer uses platinum as catalyst, the feed needs to be desulfurized to reduce the danger of catalyst poisoning.

Reforming is undertaken by passing the hot feed stream through a catalytic reactor. In the reactor, various reactions such as dehydrogenation, isomerization, and hydrocracking occur to reformulate the chemicals in the stream. Some of the reactions are endothermic and others exothermic. The types of reactions depend on the temperature, pressure, and velocity in the reactor. Undesirable side reactions may occur and need to be limited. The reformer is a net producer of hydrogen that is used elsewhere in the refinery.

Various suppliers and developers market a number of reforming processes. In principle all designs are continuous, cyclic, or semi-regenerative, depending on the frequency of catalyst regeneration (Gary and Handwerk, 1994). In the continuous process, the catalysts can be replaced during normal operation, and regenerated in a separate reactor. In the semi-regenerative reactor, the reactor needs to be stopped for regeneration of the catalysts. Depending on the severity and operating conditions, the period between regenerations is between 3 and 24 months (Gary and Handwerk, 1994). The cyclic process is an alternative in between these two processes. The advantage of the semi-regenerative process is the low capital cost. The marketed processes vary in reactor design.

Fluid Catalytic Cracker (FCC). The fuel oil from the CDU is converted into lighter products over a hot catalyst bed in the fluid catalytic cracker (FCC). The FCC is the most widely used conversion process in refineries. The FCC produces high octane gasoline, diesel, and fuel oil. The FCC is mostly used to convert heavy fuel oils into gasoline and lighter products. The FCC has virtually replaced all thermal crackers.

In a fluidized bed reactor filled with particles carrying the hot catalyst and a preheated feed (500-800°F, 260-425ºC), at a temperature of 900-1000°F (480-540ºC) the feed is 'cracked' to molecules with smaller chains. Different cracking products are generated, depending on the feed and conditions. During the process, coke is deposited on the catalysts. The used catalyst is continuously regenerated for reuse, by burning off the coke to either a mixture of carbon monoxide (CO) and carbon dioxide (CO_2) or completely to CO_2. If burned off to a CO/CO_2-mixture, the CO is combusted to CO_2 in a separate CO-burning waste heat recovery boiler to produce steam. The regeneration process is easier to control if the coke is burned directly to CO_2, but a waste heat recovery boiler should be installed to recover the excess heat in the regenerator. The cracking reactions are endothermic, while the regeneration is exothermic, providing an opportunity for thermal integration of the two process steps.

Older FCCs used metal catalysts, while new FCC designs use zeolite catalysts that are more active. This has led to a re-design of modern FCC units with a smaller reactor, and most of the reactions taking place in the so-called riser, which leads the hot feed and regenerated catalysts to the reaction vessel. The different FCC designs on the market vary in the way that the reactor and regeneration vessels are integrated. Varying the catalyst circulation rate controls the process.

Fluid catalytic crackers are net energy users, due to the energy needed to preheat the feed stream. However, modern FCC designs also produce steam and power (if power recovery turbines are installed) as by-products. The power recovery turbines can also be used to compress the air for the cracker. The recovery turbine is installed prior to the CO or waste heat boiler, if the FCC works at pressures higher than 15 psig (Gary and Handwerk, 1994).

Hydrocracker (HCU). The hydrocracker has become an important process in the modern refinery to allow for flexibility in product mix. The hydrocracker provides a better balance of gasoline and distillates, improves gasoline yield, octane quality, and can supplement the FCC to upgrade heavy feedstocks (Gary and Handwerk, 1994). In the hydrocracker, light fuel oil is converted into lighter products under a high hydrogen pressure and over a hot catalyst bed. The main products are naphtha, jet fuel, and diesel oil. It may also be used to convert other heavy fuel stocks to lighter products. The hydrocracker concept was developed before World War II to produce gasoline from lignite in Germany, and was further developed in the early 1960s. Today hydrocrackers can be found in many modern large refineries around the world.

In the hydrocracker, many reactions take place. The principal reactions are similar to that of an FCC, although *with* hydrogenation. The reactions are carried out at a temperature of 500-750°F (290-400ºC) and increased pressures of 8.3 to 13.8 Bar. The temperature and pressures used may differ with the licensed technology. The reactions are catalyzed by a combination of rare earth metals. Because the catalyst is susceptible to poisoning, the hydrocracker feed needs to be prepared by removing metallic salts, oxygen, nitrogenous compounds, and sulfur. This is done by first hydrogenating the feed, which also saturates the olefins. This is an exothermic reaction, but insufficient to provide all the heat for the hydrotreating units of the cracker. The nitrogen and sulfur-compounds are removed in a stripper column, while water is removed by a molecular sieve dryer or silica gel.

The prepared feed is mixed with recycled feed and hydrogen, and preheated before going to the reactor. The reactions are controlled by temperature, reactor pressure, and velocity. Typically the reactor is operated to have a conversion efficiency of 40-50%, meaning that 40-50% of the reactor product has a boiling point below 400F (205ºC). The product flow (effluent) is passed through heat exchangers and a separator, where hydrogen is recovered for recycling. The liquid products of the separator are distilled to separate the C_4 and lighter gases from the naphtha, jet fuel, and diesel. The bottom stream of the fractionator is mixed with hydrogen and sent to a second stage reactor to increase the conversion efficiency to 50-70% (Gary and Handwerk, 1994).

Various designs have been developed and are marketed by a number of licensors in the United States and Western Europe. The hydrocracker consumes energy in the form of fuel, steam, and electricity (for compressors and pumps). The hydrocracker also consumes energy indirectly in the form of hydrogen. The hydrogen consumption is between 150-300 scf/barrel of feed (27-54 Nm^3/bbl) for hydrotreating and 1000 and 3000 scf /barrel of feed (180-540 Nm^3/bbl) for the total plant (Gary and Handwerk, 1994). The hydrogen is produced as by-product of the catalytic reformer and in dedicated steam reforming plants (see below).

Coking. A new generation of coking processes has added additional flexibility to the refinery by converting the heavy bottom feed into lighter feedstocks and coke. Coking can be considered a severe thermal cracking process. Modern coking processes can also be used to prepare a feed for the hydrocracker (see above).

In the Flexi coking process, a heavy feed is preheated to 600-700°F (315-370ºC) and sprayed on a bed of hot fluidized coke (recycled internally). The coke bed has a reaction temperature between 950 and 1000°F (510-540ºC). At this temperature, cracking reactions take place. Cracked vapor products are separated in cyclones and are quenched. Some of the products are condensed, while the vapors are led to a fractionator column, which separates various product streams.

The coke is stripped from other products, and then processed in a second fluidized bed reactor where it is heated to 1100°F (590ºC). The hot coke is then gasified in a third reactor in the presence of steam and air to produce synthesis gas. Sulfur (in the form of H_2S) is removed, and the synthesis gas (mainly consisting of CO, H_2, CO_2 and N_2) can be used as fuel in (adapted) boilers or furnaces. The coking unit is a consumer of fuel (in preheating), steam, and power.

Visbreaker. Visbreaking is a relatively mild thermal cracking operation, used to reduce the viscosity of the bottom products to produce fuel oil. This reduces the production of heavy fuel oils, while the products can be used to increase FCC feedstock and increase gasoline yields. This is accomplished by cracking the side chains of paraffin and aromatics in the feed, and cracking of resins to light hydrocarbons. Depending on the severity (i.e., time and temperature in the cracker) of the reactions, different products may be produced.

There are two main processes: coil (or furnace) cracking and soak cracking. Coil cracking uses higher reactor temperatures and shorter residence times, while soak cracking has slightly lower temperatures and longer residence times (Gary and Handwerk, 1994). The reaction products are pretty similar, but the soaker cracker uses less energy due to the lower temperature, and has longer run times (due to reduced coke deposition on the furnace tubes). A soaker furnace consumes about 15% less energy than a coil furnace. The visbreaker consumes fuel (to heat the feed), steam, and electricity.

Alkylation and Polymerization. Alkylation (the reverse of cracking) is used to produce alkylates (used in higher octane motor fuels), as well as butane liquids, LPG, and a tar-like by-product. The reactions are catalyzed by either hydrofluoric acid or sulfuric acid. Several designs are used, using either of the catalysts. The most suitable alkylation process for a given refinery is determined by economics, especially with regard to the costs of acid purchase and disposal (Gary and Handwerk, 1994).

Alkylation processes use steam and power. There are no large differences in energy intensity between both processes (Gary and Handwerk, 1994).

Hydrogen Manufacturing Unit or Steam reforming (HMU). There are a number of supporting processes that do not produce the main refinery products directly, but produce intermediates used in the various refining processes. Hydrogen is generated from natural gas and steam over a hot catalyst bed, similar to the processes used to make hydrogen for ammonia.

Hydrogen is produced by reforming the natural gas feedstock with steam over a catalyst, producing synthesis gas. Synthesis gas contains a mixture of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam in the water-gas-shift reaction to produce CO_2 and hydrogen. The CO_2 is removed from the main gas stream using absorption, producing hydrogen.

Energy is used in the form of fuel (to heat the reformer), steam (in the steam reforming), and power (for compression). Many different licensors supply the technology. Modern variants use a physical adsorption process to remove CO_2, which uses less energy than chemical absorption processes.

Gas Processing Unit. Refinery gas processing units are used to recover C_3, C_4, C_5 and C_6 components from the different processes, and to produce a desulfurized gas which can be used as fuel or for hydrogen production in steam reforming (see above). The lighter products are used as fuel or for H_2 production, while the heavier fraction is recycled in the refinery.

The process consists of a number of distillation, absorption, and stripper columns to recover the ethane, propane, and butane. The process uses fuel (to heat the incoming gas) and power (for compressors and other uses).

Acid Gas Removal. Acid gases such as H_2S and CO_2 need to be removed to reduce air pollution (before 1970, they were just burned off) and are produced as a by-product of producing higher quality refinery products. These gases are removed by an (chemical) absorption process, and then further processed. H_2S can be processed into elemental sulfur through the Claus process. The process consumes fuel and electricity, but the Claus process produces low-pressure steam (1.7 bar).

Bitumen Blower (BBU). Heavy fuel oil of some heavy crude oil is blown with hot air to produce bitumen or asphalt.

Other processes may be used in refineries to produce lubricants (lube oil), petrochemical feedstocks, and other specialty products. These processes consist mainly of blending, stripping, and separation processes. These processes are not discussed in detail here, as they are not found in a large number of refineries.

Table 2 and Figure 7 provide an overview of the processing capacities of the different processes used in U.S. refineries, based on capacity as of January 1st, 2003. The distribution of the processes will vary by state depending on the type of crudes used and products produced. For example, California has a much higher capacity (relative to CDU-capacity) of hydrocracking and hydrotreating, when compared to the U.S. average. This is due to the types of crude processed in California, the relative higher desired output of lighter products (e.g., gasoline), and the regulatory demand for lower sulfur content from gasoline to reduce air pollution from transport.

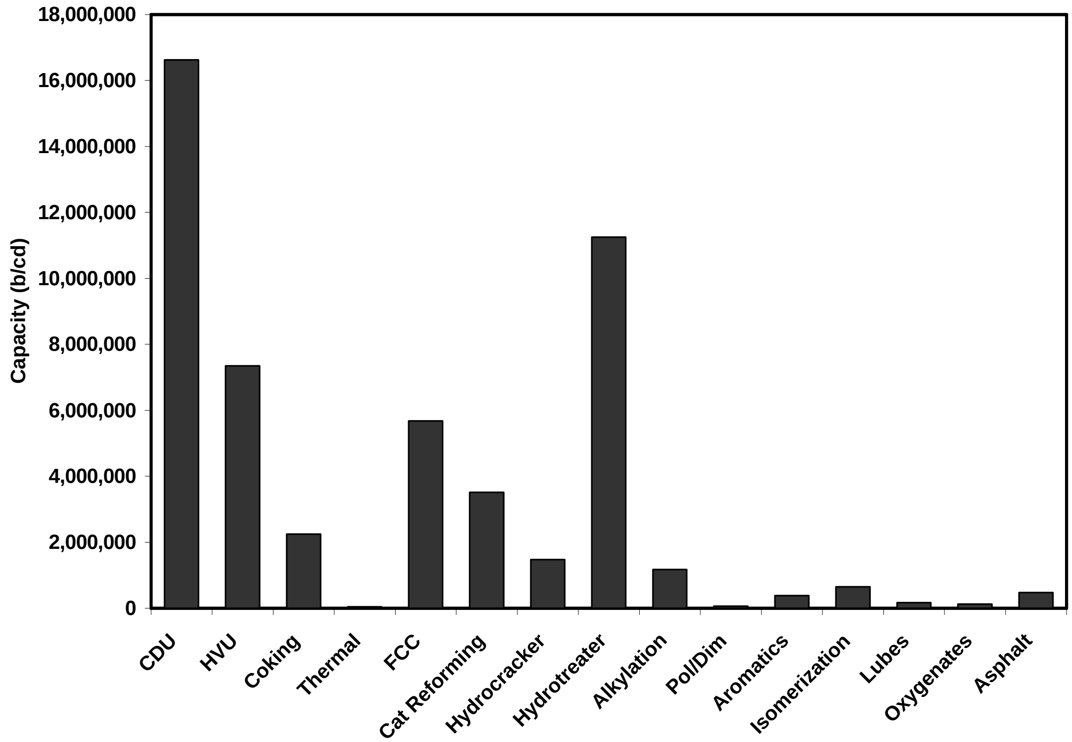

Figure 7. Capacity distribution of the major refining processes in U.S. petroleum refineries, as of January 1st, 2003. Source: Oil & Gas Journal (2002).

Table 2. Capacity distribution of the major refining processes in U.S. petroleum refineries, as of January 1st, 2003. The distribution is also given as share of CDU capacity. Source: Oil & Gas Journal (2002).

Process	Capacity (Barrel per calendar day)	Distribution (share of CDU capacity)
Crude Distillation	16,623,301	100.0%
Vacuum Distillation	7,347,704	44.2%
Coking	2,243,947	13.5%
Thermal Operations	43,500	0.3%
Catalytic Cracking	5,677,355	34.2%
Catalytic Reforming	3,512,237	21.1%
Hydrocracking	1,474,710	8.9%
Hydrotreating	11,247,745	67.7%
Alkylation	1,170,019	7.0%
Polymerization/Dim.	64,000	0.4%
Aromatics	383,255	2.3%
Isomerization	644,270	3.9%
Lubes	167,500	1.0%
Oxygenates	122,899	0.7%
Asphalt	471,850	2.8%
Hydrogen	3,631 MMcfd	-
Coke	114,387 tpd	-
Sulfur	27,051 tpd	-

4. Energy Consumption

The petroleum refining industry is one of the largest energy consuming industries in the United States. Energy use in a refinery varies over time due to changes in the type of crude processed, the product mix (and complexity of refinery), as well as the sulfur content of the final products. Furthermore, operational factors like capacity utilization, maintenance practices, as well as the age of the equipment affect energy use in a refinery from year to year.

The petroleum refining industry is an energy intensive industry spending over $7 billion on energy purchases in 2001. Figure 8 depicts the trend in energy expenditures of the U.S. petroleum refining industry. The graph shows a steady increase in total expenditures for purchased electricity and fuels, which is especially evident in the most recent years for which data is available. Value added as share of value of shipments dipped in the early 1990s and has increased since to about 20%. Figure 8 also shows a steady increase in fuel costs. Electricity costs are more or less stable, which seems to be only partially caused by increased cogeneration.

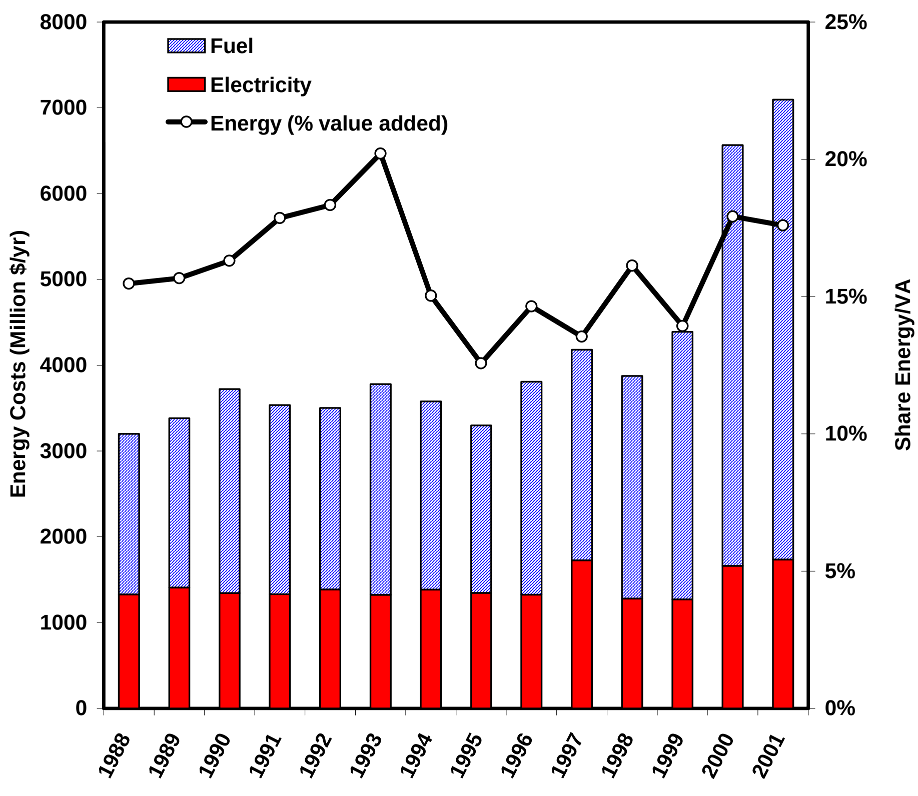

Figure 8. Annual energy costs of petroleum refineries in the United States 1988-2001 for purchased fuels. This excludes the value of fuels generated in the refinery (i.e., refinery gas and coke). Purchased fuels can be a relatively small part of the total energy costs of a refinery (see also Figure 9). The total purchased energy costs are given as share of the value added produced by petroleum refineries. Source: U.S. Census, Annual Survey of Manufacturers.

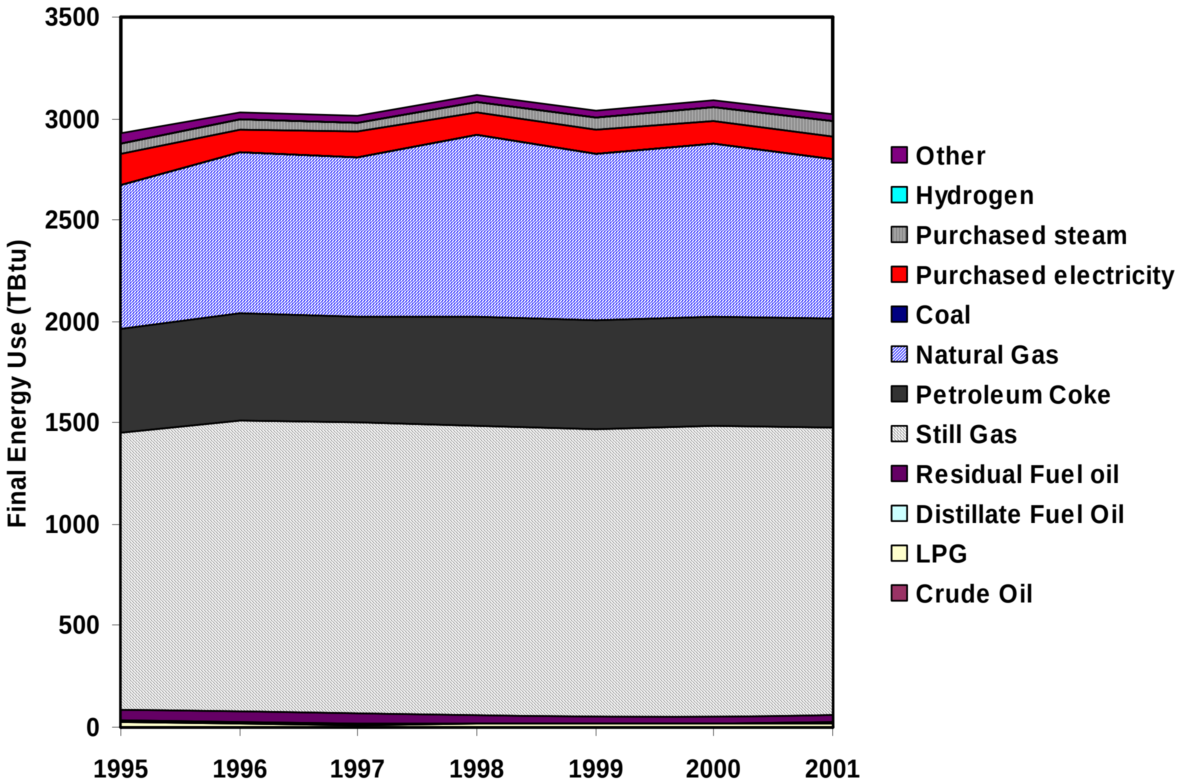

Figure 9. Annual final energy consumption of U.S. petroleum refineries for the period 1995 – 2001. Data for 1995 and 1997 contains estimated values for natural gas, coal, electricity, and steam purchases. The order in the legend corresponds with the order of fuels in the graph. Source: Petroleum Supply Annual, Energy Information Administration.

In recent years, energy consumption in refineries peaked in 1998, and has since then slightly declined. Based on data published by the Energy Information Administration, energy consumption trends are estimated by fuel since 1995.[2] In 2001, the latest year for which data were available, total final energy consumption is estimated at 3,025 TBtu. Primary energy consumption[3] is estimated at 3,369 TBtu. The difference between primary and final electricity consumption is relatively low due to the small share of electricity consumption in the refinery and relatively large amount of self-produced electricity. Figure 9 depicts the annual energy consumption of petroleum refineries between 1995 and 2001. Figure 9 shows

[2] Data before 1995 are also available. However, for some years (including 1995 and 1997) the data reported by EIA is not complete, and interpolations were made by the authors to estimate total energy consumption. For example, for 1995 EIA did not report on consumption of natural gas, coal, purchased electricity, and purchased steam, while for 1997 it did not report on coal, purchased steam, and other fuels. Furthermore, we use electricity purchase data as reported by the EIA, although the U.S. Census reports slightly different electricity purchases for most years. The differences are generally small and do not affect overall energy use data.

[3] Final energy assigns only the direct energy content to secondary energy carriers like purchased electricity and steam to calculate energy consumption. Primary energy consumption includes the losses of offsite electricity and steam production. We assume an average efficiency of power generation on the public grid of 32%. Steam generation efficiency is supposed to be similar to that of refinery boilers (assumed at 77%).

that energy use has basically remained flat, while production volumes and mix have changed, strongly suggesting an improvement of the energy efficiency of the industry over the same period.

Figure 9 shows that the main fuels used in the refinery are refinery gas, natural gas, and coke. The refinery gas and coke are by-products of the different processes. The coke is mainly produced in the crackers, while the refinery gas is the lightest fraction from the distillation and cracking processes. Natural gas and electricity represents the largest purchased fuels in the refineries. Natural gas is used for the production of hydrogen, fuel for co-generation of heat and power (CHP), and as supplementary fuel in furnaces.

Petroleum refineries are one of the largest cogenerators in the country, after the pulp and paper and chemical industries. In 1998, cogeneration within the refining industry represented almost 13% of all industrial cogenerated electricity (EIA, 2001). By 1999 cogeneration increased to almost 35% of total electricity use. In 2001, the petroleum refining industry generated about 13.2 TWh, which represented about 26% of all power consumed onsite (EIA, 2002). Figure 10 shows the historic development of electricity generation and purchases in oil refineries (generation data for 2000 were not reported by the U.S. Census).

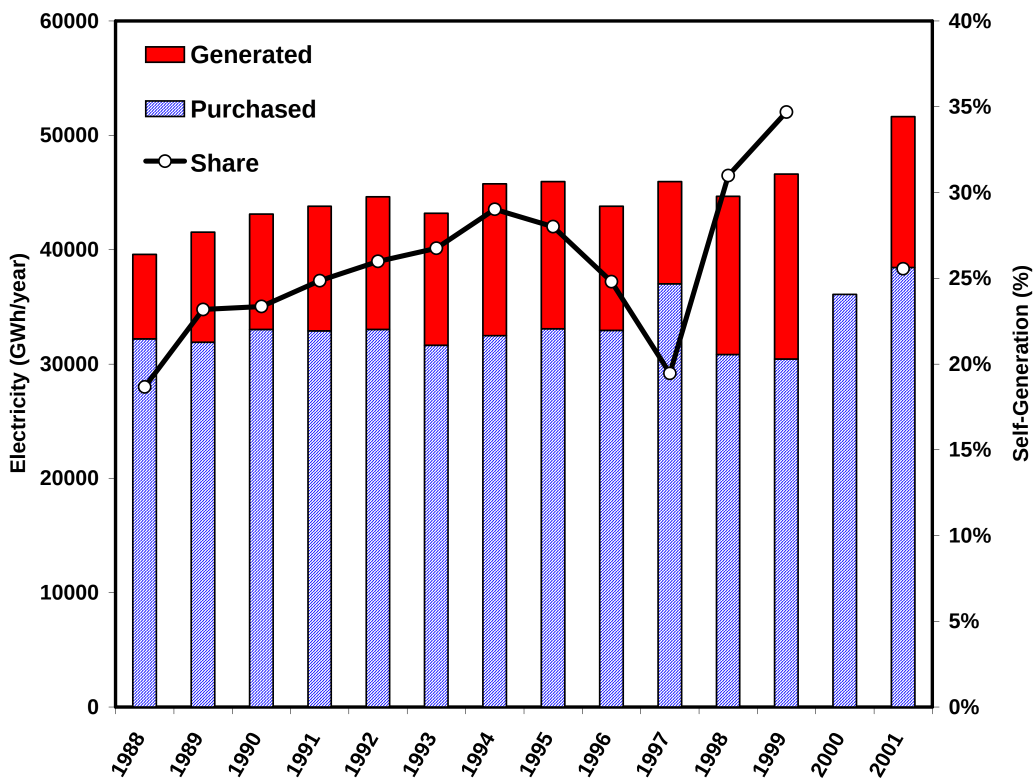

Figure 10. Electricity purchases and generation by petroleum refineries from 1988 to 2001. On the right-hand axis, the share of self-generation is expressed as a function of total power consumption. Source: U.S. Census, Annual Survey of Manufacturers.

Table 3. Estimated 2001 energy balance for the U.S. petroleum refining industry. Estimates are based on a combination of publicly available data sources. The energy balance for an individual refinery will be different due to different process configurations. Data sources are given in the text.

Process	Throughput	Fuel	Steam	Electricity	Final	Primary
	Million bbl/year [1]	TBtu	TBtu	GWh	TBtu [2]	TBtu [3]
Desalter	5313.3	0.2	0.0	265.7	1.1	3.0
CDU	5313.3	359.2	243.5	3613.0	687.8	714.0
VDU	2416.7	115.5	126.1	845.8	282.1	288.3
Thermal Cracking	723.4	84.1	-10.5	4485.3	85.8	118.3
FCC	1885.4	108.2	0.5	7013.8	132.8	183.7
Hydrocracker	507.2	68.5	36.9	5680.7	135.9	177.1
Reforming	1166.0	206.1	101.3	3416.3	349.4	374.1
Hydrotreater	3679.8	253.2	270.1	15455.4	656.6	768.7
Deasphalting	112.5	16.1	0.3	213.8	17.2	18.8
Alkylates	366.8	13.1	121.1	2640.7	179.3	198.5
Aromatics	97.2	11.7	4.1	291.5	18.0	20.1
Asphalt	284.9	59.6	0.0	740.7	62.1	67.5
Isomers	204.3	90.3	39.9	398.3	143.5	146.4
Lubes	67.8	87.5	2.5	1247.0	95.0	104.1
Hydrogen	5,959	268.2	0.0	893.9	271.2	277.7
Sulfur	9.0	0.0	-81.2	108.5	-105.1	-104.3
Other		*0.0*	*10.0*	*39.0*	*13.1*	13.4
	Total Process Site Use	**1741**	**865**	**47349**	**3026**	**3369**
Purchases			78.4	34187		
Site Generation			786.3			
Cogeneration [4]		140.3	61.8	13162		
Boiler generation [5]			724.5			
Boiler fuels		940.9				
	Total Energy Consumption	**2822**	**78**	**34187**	**3018**	**3289**

Notes:

1. Unit is million barrels/year, except for hydrogen (million lbs/year) and sulfur (million short tons/year).
2. Final fuel use is calculated by estimating the boiler fuel to generate steam used. Electricity is accounted as site electricity at 3,412 Btu/kWh.
3. Primary fuel use includes the boiler fuel use and primary fuels used to generate electricity. Including transmission and distribution losses the electric efficiency of the public grid is equal to 32%, accounting electricity as 10,660 Btu/kWh. Some refineries operate combined cycles with higher efficiencies. For comparison, Solomon accounts electricity at 9,090 Btu/kWh.
4. Cogeneration is assumed to be in large singe-cycle gas turbines with an electric efficiency of 32%.
5. Boiler efficiency is estimated at 77%.

A number of key processes are the major energy consumers in a typical refinery, i.e., crude distillation, hydrotreating, reforming, vacuum distillation, and catalytic cracking. Hydrocracking and hydrogen production are growing energy consumers in the refining industry. An energy balance for refineries for 2001 has been developed based on publicly available data on process throughput (EIA, 2002), specific energy consumption (Gary and Handwerk, 1994; U.S. DOE-OIT, 1998a, U.S. DOE-OIT, 2002), and energy consumption data (EIA, 2001; EIA, 2002; U.S. Census, 2003). Table 3 provides the estimated energy balance for 2001. The energy balance is an estimate based on publicly available data, and is based on many assumptions on process efficiencies and throughputs. The estimated energy balance matches with available energy consumption data for almost 100% on a final energy basis, and almost 98% on a primary energy basis. The process energy uses should be seen as approximate values to provide a view on important energy using processes in the refinery.

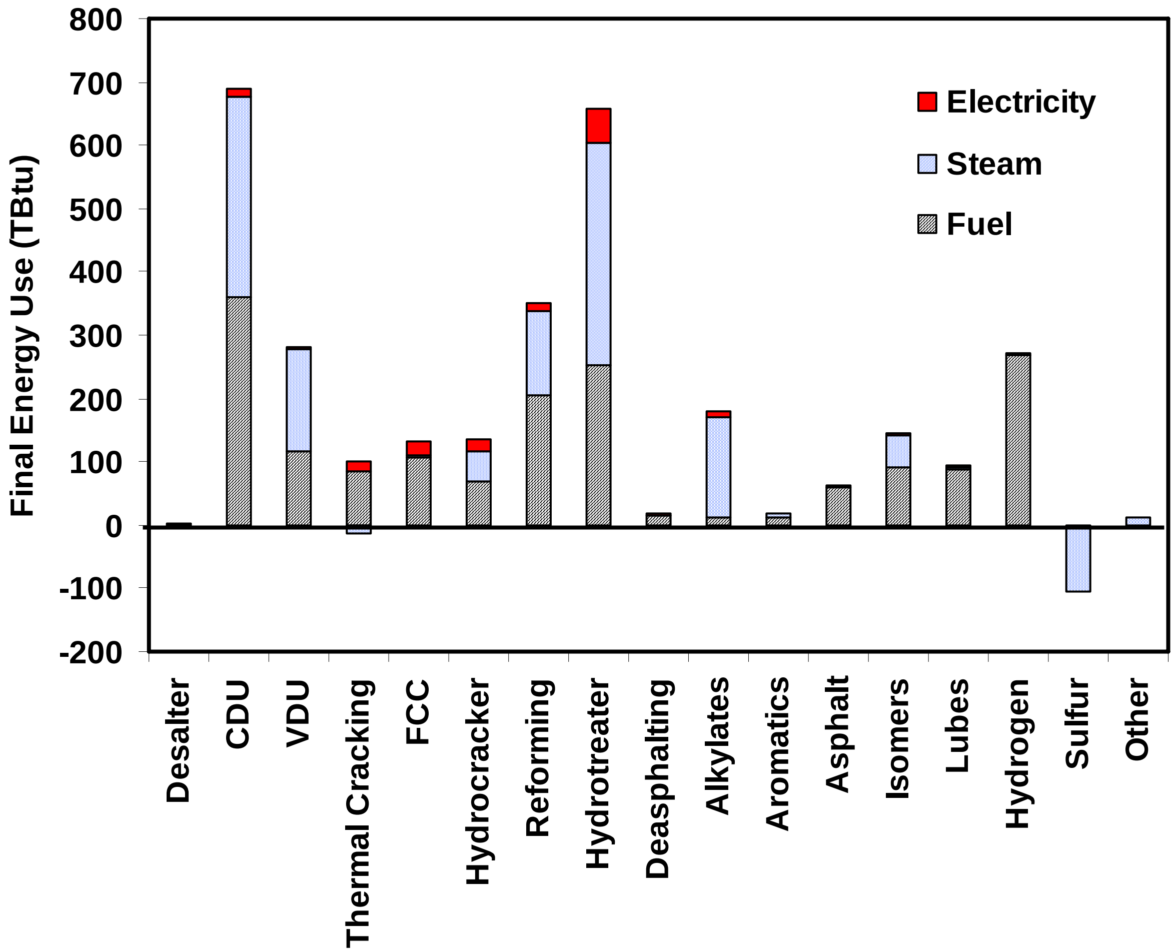

Figure 11. Estimated energy use by petroleum refining process. Energy use is expressed as primary energy consumption. Electricity is converted to fuel using 10,666 Btu/kWh (equivalent to an efficiency of 32% including transmission and distribution losses). All steam is generated in boilers with an efficiency of 77%.

The major energy consuming processes are crude distillation, followed by the hydrotreater, reforming, and vacuum distillation. This is followed by a number of processes consuming a somewhat similar amount of energy, i.e., thermal cracking, catalytic cracking, hydrocracking, alkylate and isomer production.

Note that the figures in Table 2 and Figure 11 are based on publicly available data. A similar capacity utilization is assumed for all installed processes, based on the average national capacity utilization. In reality, the load of the different processes may vary, which may lead to a somewhat different distribution. In cracking the severity and in hydrotreating the treated feed may affect energy use. An average severity is assumed for both factors. Furthermore, energy intensity assumptions are based on a variety of sources, and balanced on the basis of available data. The different literature sources provide varying assumptions for some processes, especially for electricity consumption.

Although the vast majority of greenhouse gas (GHG) emissions in the petroleum fuel cycle occur at the final consumer of the petroleum products, refineries are still a substantial source of GHG emissions. The high energy consumption in refineries also leads to substantial GHG emissions. This Energy Guide focuses on CO_2 emissions due to the combustion of fossil fuels, although process emissions of methane and other GHGs may occur at refineries. The estimate in this Energy Guide is based on the fuel consumption as reported in the Petroleum Supply Annual of the Energy Information Administration, and emission factors determined by the Energy Information Administration and U.S. Environmental Protection Agency. The Energy Information Administration provided emission factors for electricity consumption. The CO_2 emissions in 2001 are estimated at 222 million tonnes of CO_2 (equivalent to 60.5 MtCE). This is equivalent to 11.6% of industrial CO_2 emissions in the United States. Figure 12 provides estimates of CO_2 emissions (by fuel) for several recent years. Figure 12 shows that the main fuels contributing to the emissions are still gas, natural gas, and coke.

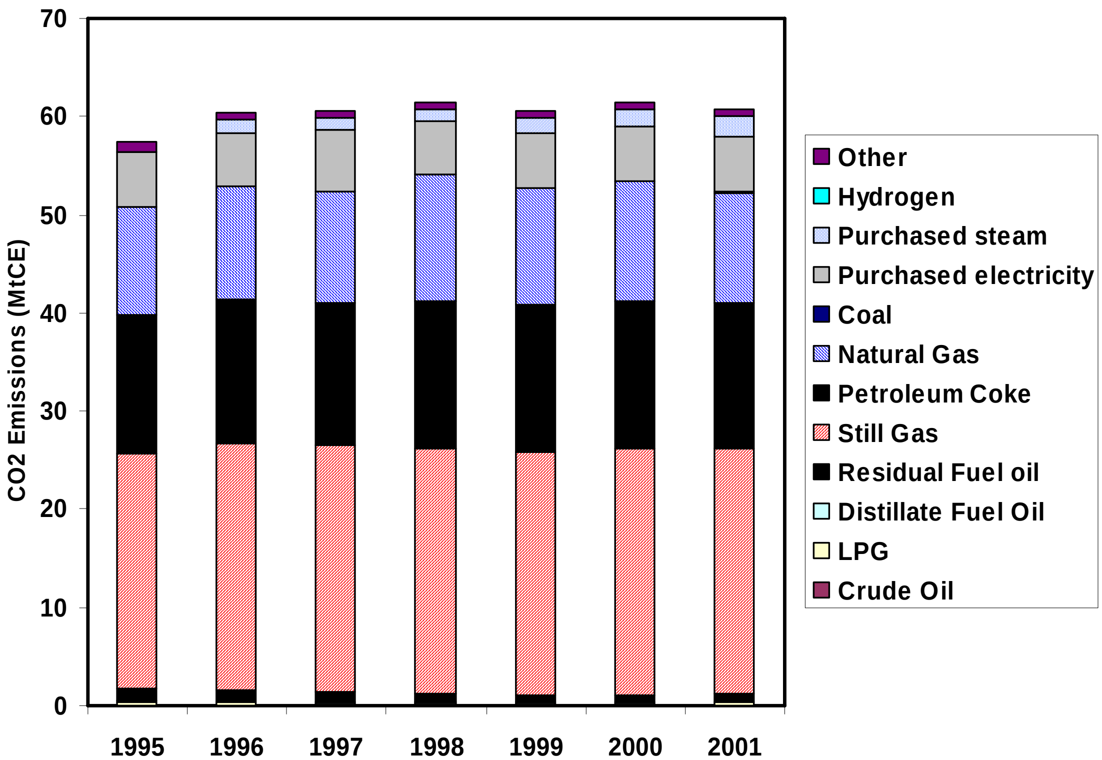

Figure 12. Estimated CO_2 emissions from fuel combustion and electricity consumption at U.S. petroleum refineries. Data for 1995 and 1997 includes estimates for different fuels (i.e., coal, purchased steam, and other fuels). Sources: Energy Information Administration, U.S. Environmental Protection Agency.

The Energy Information Administration estimated CO_2 emissions at 87.4 MtCE in 1998. This is substantially higher than the estimate above. The reason for the differences is unclear. Partially these may be due to different data sources and potentially due to emissions from flaring that are not included in the above estimate.

5. Energy Efficiency Opportunities

A large variety of opportunities exist within petroleum refineries to reduce energy consumption while maintaining or enhancing the productivity of the plant. Studies by several companies in the petroleum refining and petrochemical industries have demonstrated the existence of a substantial potential for energy efficiency improvement in almost all facilities. Competitive benchmarking data indicate that most petroleum refineries can economically improve energy efficiency by 10-20%. For example, a 2002 audit of energy use at the Equilon refinery (now Shell) at Martinez, California, found an overall efficiency improvement potential of 12% (US DOE-OIT, 2002b). This potential for savings amounts to annual costs savings of millions to tens of millions of dollars for a refinery, depending on current efficiency and size. Improved energy efficiency may result in co-benefits that far outweigh the energy cost savings, and may lead to an absolute reduction in emissions.

Major areas for energy efficiency improvement are utilities (30%), fired heaters (20%), process optimization (15%), heat exchangers (15%), motor and motor applications (10%), and other areas (10%). Of these areas, optimization of utilities, heat exchangers, and fired heaters offer the most low investment opportunities, while other opportunities may require higher investments. Experiences of various oil companies have shown that most investments are relatively modest. However, all projects require operating costs as well as engineering resources to develop and implement the project. Every refinery and plant will be different. The most favorable selection of energy efficiency opportunities should be made on a plant-specific basis.

In the following chapters energy efficiency opportunities are classified based on technology area. In each technology area, technology opportunities and specific applications by process are discussed. Table 4 summarizes the energy efficiency measures described in this Energy Guide, and provides access keys by process and utility system to the descriptions of the energy efficiency opportunities. This Energy Guide is far from exhaustive. For example, the Global Energy Management System (GEMS) of ExxonMobil has developed 12 manuals - containing some 1,200 pages, which describe in detail over 200 best practices and performance measures for key process units, major equipment, and utility systems. In addition to the strong focus on operation and maintenance of existing equipment, these practices also address energy efficiency in the design of new facilities. GEMS identified opportunities to improve energy efficiency by 15% at ExxonMobil refineries and chemical plants worldwide. This Energy Guide provides a general overview in am easily accessible format to help energy managers to select areas for energy efficiency improvement based on experiences around the world.

This Energy Guide includes case studies from U.S. refineries with specific energy and cost savings data when available. For other measures, the Energy Guide includes case study data from refineries around the world. For individual refineries, actual payback period and energy savings for the measures will vary, depending on plant configuration and size, plant location, and plant operating characteristics. Hence, the values presented in this Energy Guide are offered as guidelines. Wherever possible, the Energy Guide provides a range of savings and payback periods found under varying conditions.

Although technological changes in equipment conserve energy, changes in staff behavior and attitude can have a great impact. Staff should be trained in both skills and the company's general approach to energy efficiency in their day-to-day practices. Personnel at all levels should be aware of energy use and objectives for energy efficiency improvement. Often this information is acquired by lower level managers but not passed to upper management or down to staff (Caffal, 1995). Though changes in staff behavior, such as switching off lights or improving operating guidelines, often save only very small amounts of energy at one time, taken continuously over longer periods they can have a great effect. Further details for these programs can be found in Chapter 6.

Participation in voluntary programs like the ENERGY STAR program, or implementing an environmental management system such as ISO 14001, can help companies to track energy and implement energy efficiency measures. One ENERGY STAR partner noted that combining energy management programs with ISO 14001 has had the largest effect on saving energy at their plants.

Companies like BP have successfully implemented aggressive greenhouse gas (GHG) emission reduction programs at all their facilities worldwide (including exploration and refining). BP has reduced its global GHG emissions to 10% below 1990 levels within 5 years of the inception of its program; years ahead of its goal, while decreasing operation costs. These efforts demonstrate the potential success of a corporate strategy to reduce energy use and associated emissions. Yet, other companies used participation in voluntary programs to boost energy management programs. Petro-Canada participates in Canada's Climate Change Voluntary Challenge and Registry. Petro-Canada has developed a corporate-wide emission reduction and energy efficiency program, and reports the results annually. In Europe, various countries have voluntary agreements between industry sectors and governments to reduce energy or GHG emission intensity. For example, all refineries in the Netherlands participated in the Long-Term Agreements between 1989 and 2000. BP, ExxonMobil, Shell, and Texaco all operate refineries in the Netherlands. The refineries combined (processing about 61 million tons of crude annually) achieved a 17% improvement of energy efficiency. Today, the refineries participate in a new agreement in which the refineries will be among most energy efficient refineries worldwide by 2010, using the Solomon's index as a gauge.

Table 4 provides an access key to the Energy Guide. For each of the main processes used in a refinery, Table 4 provides the relevant sections describing energy efficiency measures that are applicable to that process and may be relevant when assessing energy efficiency opportunities for a particular process. Utility measures are summarized in the last row of Table 4. While boilers and lighting will be distributed around the refinery, they are only designated as utilities.

Table 4. Matrix of energy efficiency opportunities in petroleum refineries. For each major process in the refinery (in rows) the applicable categories of energy efficiency measures are given (in columns). The numbers refer to the chapter or section describing energy efficiency.

Process	Energy Management	Flare Gas Recovery	Power Recovery	Boilers	Steam Distribution	Heat Exchanger	Process Integration	Process Heaters	Distillation	Hydrogen Management	Motors	Pumps	Compressed Air	Fans	Lighting	Cogeneration	Power Generation	Other Opportunities
Desalting	6											14						
CDU	6	7.1			8.2	9.1	9.2	10	11		13	14		16				
VDU	6				8.2	9.1	9.2	10	11					16				
Hydrotreater	6				8.2	9.1	9.2	10	11	12				16				
Cat.Reformer	6	7.1			8.2	9.1	9.2	10	11	12				16				
FCC	6	7.1	7.2		8.2	9.1	9.2	10	11					16				
Hydrocracker	6	7.1	7.2		8.2	9.1	9.2	10	11	12				16				
Coker	6	7.1			8.2	9.1	9.2	10	11					16				
Visbreaker	6	7.1			8.2	9.1	9.2	10	11					16				
Alkylation	6				8.2	9.1	9.2	10	11					16				
Light End	6				8.2	9.1	9.2		11									
Aromatics	6				8.2	9.1	9.2	10	11									
Hydrogen	6				8.2	9.1	9.2	10		12				16				
Utilities	6	7.1	7.2	8.1	8.2	9.1	9.2			12			15	16	17	18	18	19

6. Energy Management and Control

Improving energy efficiency in refineries should be approached from several directions. A strong, corporate-wide energy management program is essential. Cross-cutting equipment and technologies, such as boilers, compressors, and pumps, common to most plants and manufacturing industries including petroleum refining, present well-documented opportunities for improvement. Equally important, the production process can be fine-tuned to produce additional savings.

6.1 Energy Management Systems (EMS) and Programs

Changing how energy is managed by implementing an organization-wide energy management program is one of the most successful and cost-effective ways to bring about energy efficiency improvements.

An energy management program creates a foundation for improvement and provides guidance for managing energy throughout an organization. In companies without a clear program in place, opportunities for improvement may be unknown or may not be promoted or implemented because of organizational barriers. These barriers may include a lack of communication among plants, a poor understanding of how to create support for an energy efficiency project, limited finances, poor accountability for measures, or perceived change from the status quo. Even when energy is a significant cost for an industry, many companies still lack a strong commitment to improve energy management.

The U.S. EPA, through ENERGY STAR, has worked with many of the leading industrial manufacturers to identify the basic aspects of an effective energy management program.[4] The major elements are depicted in Figure 13.

A successful program in energy management begins with a strong commitment to continuous improvement of energy efficiency. This typically involves assigning oversight and management duties to an energy director, establishing an energy policy, and creating a cross-functional energy team. Steps and procedures are then put in place to assess performance, through regular reviews of energy data, technical assessments, and benchmarking. From this assessment, an organization is then able to develop a baseline of performance and set goals for improvement.

Performance goals help to shape the development and implementation of an action plan. An important aspect for ensuring the successes of the action plan is involving personnel throughout the organization. Personnel at all levels should be aware of energy use and goals for efficiency. Staff should be trained in both skills and general approaches to energy efficiency in day-to-day practices. In addition, performance results should be regularly evaluated and communicated to all personnel, recognizing high performers. Some examples of simple employee tasks are outlined in Appendix B.

[4] See the U.S. EPA's Guidelines for Energy Management at www.energystar.gov.

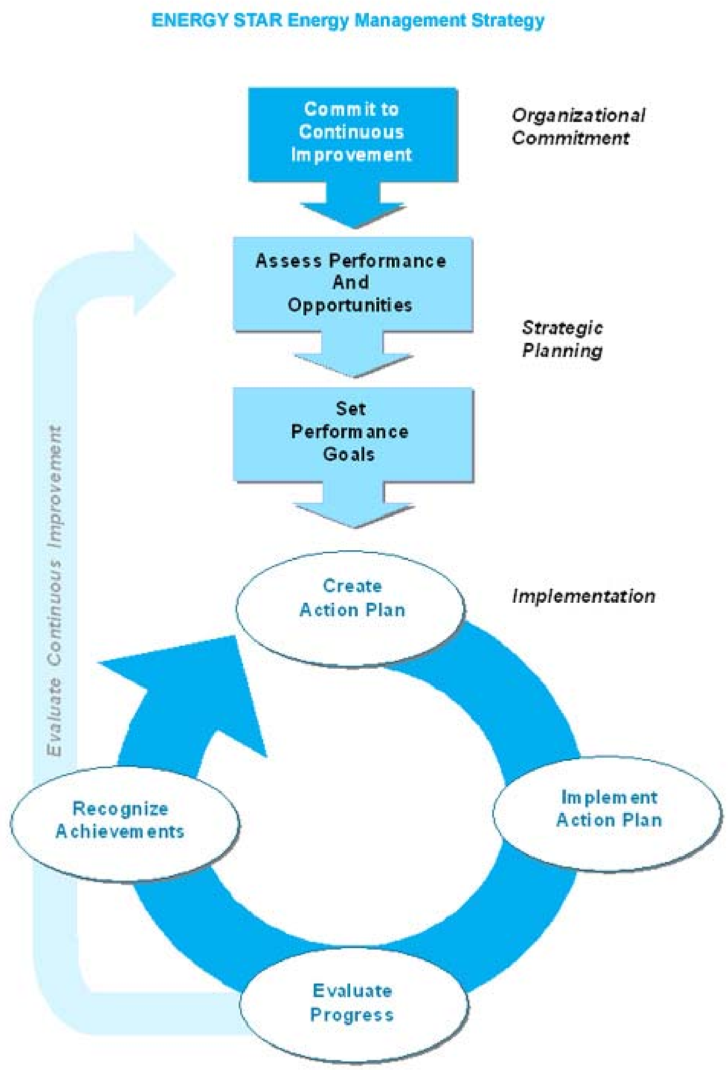

Figure 13. Main elements of a strategic energy management system.

Evaluating performance involves the regular review of both energy use data and the activities carried out as part of the action plan. Information gathered during the formal review process helps in setting new performance goals and action plans and in revealing best practices. Establishing a strong communications program and seeking recognition for accomplishments are also critical steps. Strong communication and recognition help to build support and momentum for future activities.

A quick assessment of an organization's efforts to manage energy can be made by comparing the current program against the table contained in Appendix C. Appendix D provides the ENERGY STAR energy management matrix to evaluate and score an energy management system.

6.2 Monitoring & Process Control Systems

The use of energy monitoring and process control systems can play an important role in energy management and in reducing energy use. These may include sub-metering, monitoring and control systems. They can reduce the time required to perform complex tasks, often improve product and data quality and consistency, and optimize process operations. Typically, energy and cost savings are around 5% or more for many industrial applications of process control systems. These savings apply to plants without updated process control systems; many refineries may already have modern process control systems in place to improve energy efficiency.

Although energy management systems are already widely disseminated in various industrial sectors, the performance of the systems can still be improved, reducing costs and increasing energy savings further. For example, total site energy monitoring and management systems can increase the exchange of energy streams between plants on one site. Traditionally, only one process or a limited number of energy streams were monitored and managed. Various suppliers provide site-utility control systems (HCP, 2001).

Specific energy savings and payback periods for overall adoption of an energy monitoring system vary greatly from plant to plant and company to company.

A variety of process control systems are available for virtually any industrial process. A wide body of literature is available assessing control systems in most industrial sectors such as chemicals and petroleum refining. Table 5 provides an overview of classes of process control systems.

Table 5. Classification of control systems and typical energy efficiency improvement potentials.

System	Characteristics	Typical energy savings (%)
Monitoring and Targeting	Dedicated systems for various industries, well established in various countries and sectors	Typical savings 4-17%, average 8% , based on experiences in the UK
Computer Integrated Manufacturing (CIM)	Improvement of overall economics of process, e.g., stocks, productivity and energy	> 2%
Process control	Moisture, oxygen and temperature control, air flow control “Knowledge based, fuzzy logic”	Typically 2-18% savings

Note: The estimated savings are valid for specific applications (e.g., lighting energy use). The energy savings cannot be added, due to overlap of the systems. Sources: (Caffal 1995, Martin et al., 2000).

Modern control systems are often not solely designed for energy efficiency, but rather for improving productivity, product quality, and the efficiency of a production line.

Applications of advanced control and energy management systems are in varying development stages and can be found in all industrial sectors. Control systems result in reduced downtime, reduced maintenance costs, reduced processing time, and increased resource and energy efficiency, as well as improved emissions control. Many modern energy efficient technologies depend heavily on precise control of process variables, and applications of process control systems are growing rapidly. Modern process control systems exist for virtually any industrial process. Still, large potentials exist to implement control systems and more modern systems enter the market continuously. *Hydrocarbon Processing* produces a semi-annual overview of new advanced process control technologies for the oil refining industry (see e.g., HCP, 2001).

Process control systems depend on information from many stages of the processes. A separate but related and important area is the development of sensors that are inexpensive to install, reliable, and analyze in real-time. Current development efforts are aimed at the use of optical, ultrasonic, acoustic, and microwave systems, that should be resistant to aggressive environments (e.g., oxidizing environments in furnace or chemicals in chemical processes) and withstand high temperatures. The information of the sensors is used in control systems to adapt the process conditions, based on mathematical ("rule"-based) or neural networks and "fuzzy logic" models of the industrial process.

Neural network based control systems have successfully been used in the cement (kilns), food (baking), non-ferrous metals (alumina, zinc), pulp and paper (paper stock, lime kiln), petroleum refineries (process, site), and steel industries (electric arc furnaces, rolling mills). New energy management systems that use artificial intelligence, fuzzy logic (neural network), or rule-based systems mimic the "best" controller, using monitoring data and learning from previous experiences.

Process knowledge based systems (KBS) have been used in design and diagnostics, but are hardly used in industrial processes. Knowledge bases systems incorporate scientific and process information applying a reasoning process and rules in the management strategy. A recent demonstration project in a sugar beet mill in the UK using model based predictive control system demonstrated a 1.2 percent reduction in energy costs, while increasing product yield by almost one percent and reducing off-spec product from 11 percent to four percent. This system had a simple payback period of 1.4 years (CADDET, 2000).

Although energy management systems are already widely disseminated in various industrial sectors, the performance of the systems can still be improved, reducing costs and increasing energy savings further. Research for advanced sensors and controls is ongoing in all sectors, both funded with public funds and private research. Several projects within U.S. DOE's Industries of the Future program try to develop more advanced control technologies (U.S. DOE-OIT, 2000). Sensors and control techniques are identified as key technologies in various development areas including energy efficiency, mild processing technology, environmental performance and inspection, and containment boundary integrity. Sensors and controls are also represented in a cross-cutting OIT-program. Outside the United States, Japan and Europe also give much attention to advanced controls. Future steps include further development of new sensors and control systems, demonstration in commercial scale, and dissemination of the benefits of control systems in a wide variety of industrial applications.

Process control systems are available for virtually all processes in the refinery, as well as for management of refinery fuel gas, hydrogen, and total site control. An overview of commercially offered products is produced by the journal *Hydrocarbon Processing*. The most recent overview was published in 2001. Below examples of processes and site-wide process control systems are discussed, selected on the basis of available case studies to demonstrate the specific applications and achieved energy savings

Refinery Wide Optimization. Total site energy monitoring and management systems (Kawano, 1996) can increase the exchange of energy streams between plants on one site. Traditionally, only one plant or a limited number of energy streams were monitored and managed. Various suppliers provide site-utility control systems (HCP, 2001). Valero and AspenTech have developed a plant-wide energy optimization model to optimize the flows of intermediates, hydrogen, steam, fuel and electricity use, integrated with an energy monitoring system. The optimization system includes the cogeneration unit, FCC power recovery, and optimum load allocation of boilers, as well as selection of steam turbines or electric motors to run compressors. The system was implemented at Valero's Houston refinery in 2003 and is expected to reduce overall site-wide energy use by 2-8%. Company wide, Valero expects to save $7-$27 million annually at 12 refineries (Valero, 2003).

CDU. A few companies supply control equipment for CDUs. Aspen technology has supplied over 70 control applications for CDUs and 10 optimization systems for CDUs. Typical cost savings are $0.05 - $0.12/bbl of feed, with paybacks less than 6 months. Key Control supplies an expert system advisor for CDUs. It has installed one system at a CDU, which resulted in reduced energy consumption and flaring and increased throughput with a payback of 1 year.

Installation of advanced control equipment at Petrogals Sines refinery (Portugal) on the CDU resulted in increased throughputs of 3-6% with a payback period of 3 months.

FCC. Several companies offer FCC control systems, including ABB Simcon, AspenTech, Honeywell, Invensys, and Yokogawa. Cost savings may vary between $0.02 to $0.40/bbl of feed with paybacks between 6 and 18 months.

Timmons et al. (2000) report on the advantages of combining an online optimizer with an existing control system to optimize the operation of a FCC unit at the CITGO refinery in Corpus Christi, Texas. The Citgo refinery installed a modern control system and an online optimizer on a 65,000 bpd FCC unit. The combination of the two systems was effective in improving the economic operation of the FCC. The installation of the optimizer led to additional cost savings of approximately $0.05/barrel of feed to the FCC, which resulted in an attractive payback (Timmons et al., 2000).

The ENI refinery in Sanassazzo (Italy) installed in 2001 an optimizer on a FCC unit from Aspen Technology. The system resulted in cost savings of $0.10/bbl with a payback of less than one year.

Hydrotreater. Installation of a multivariable predictive control (MPC) system was demonstrated on a hydrotreater at a SASOL refinery in South Africa. The MPC aimed to improve the product yield while minimizing the utility costs. The implementation of the system led to improved yield of gasoline and diesel, reduction of flaring, and a 12% reduction in hydrogen consumption and an 18% reduction in fuel consumption of the heater (Taylor et al., 2000). Fuel consumption for the reboiler increased to improve throughput of the unit. With a payback period of 2 months, the project resulted in improved yield and in direct and indirect (i.e., reduced hydrogen consumption) energy efficiency improvements.

Alkylation. Motiva's Convent (Louisiana) refinery implemented an advanced control system for their 100,000 bpd sulfuric acid alkylation plant. The system aims to increase product yield (by approximately 1%), reduce electricity consumption by 4.4%, reduce steam use by 2.2%, reduce cooling water use by 4.9%, and reduce chemicals consumption by 5-6% (caustic soda by 5.1%, sulfuric acid by 6.4%) (U.S. DOE-OIT, 2000). The software package integrates information from chemical reactor analysis, pinch analysis, information on flows, and information on energy use and emissions to optimize efficient operation of the plant. No economic performance data was provided, but the payback is expected to be rapid as only additional computer equipment and software had to be installed. The program is available through the Gulf Coast Hazardous Substance research Center and Louisiana State University. Other companies offering alkylation controls are ABB Simcon, Aspen technology, Emerson, Honeywell, Invensys, and Yokogawa. The controls typically result in cost savings of $0.10 to $0.20/bbl of feed with paybacks of 6 to 18 months.

7. Energy Recovery

7.1 Flare Gas Recovery

Flare gas recovery (or zero flaring) is a strategy evolving from the need to improve environmental performance. Conventional flaring practice has been to operate at some flow greater than the manufacturer's minimum flow rate to avoid damage to the flare (Miles, 2001). Typically, flared gas consists of background flaring (including planned intermittent and planned continuous flaring) and upset-blowdown flaring. In offshore flaring, background flaring can be as much as 50% of all flared gases (Miles, 2001). In refineries, background flaring will generally be less than 50%, depending on practices in the individual refinery. Recent discussions on emissions from flaring by refineries located in the San Francisco Bay Area have highlighted the issue from an environmental perspective (Ezerksy, 2002).[5] The report highlighted the higher emissions compared to previous assumptions of the Air Quality District, due to larger volumes of flared gases. The report also demonstrated the differences among various refineries, and plants within the refineries. Reduction of flaring will not only result in reduced air pollutant emissions, but also in increased energy efficiency replacing fuels, as well as less negative publicity around flaring.

Emissions can be further reduced by improved process control equipment and new flaring technology. Development of gas-recovery systems, development of new ignition systems with low-pilot-gas consumption, or elimination of pilots altogether with the use of new ballistic ignition systems can reduce the amount of flared gas considerably (see also section 19.3). Development and demonstration of new ignition systems without a pilot may result in increased energy efficiency and reduced emissions.

Reduction of flaring can be achieved by improved recovery systems, including installing recovery compressors and collection and storage tanks. This technology is commercially available. Various refineries in the United States have installed flare gas recovery systems, e.g., ChevronTexaco in Pascagoula (Mississippi) and even some small refineries like Lion Oil Co. (El Dorado, Arkansas). A plant-wide assessment of the Equilon refinery in Martinez (now fully owned by Shell) highlighted the potential for flare gas recovery. The refinery will install new recovery compressors and storage tanks to reduce flaring. No specific costs were available for the flare gas recovery project, as it is part of a large package of measures for the refinery. The overall project has projected annual savings of $52 million and a payback period of 2 years (U.S. DOE-OIT, 2002b).

Installation of two flare gas recovery systems at the 65,000 bpd Lion Oil Refinery in El Dorado (Arkansas) in 2001 has reduced flaring to near zero levels (Fisher and Brennan, 2002). The refinery will only use the flares in emergencies where the total amount of gas will exceed the capacity of the recovery unit. The recovered gas is compressed and used in the refineries fuel system. No information on energy savings and payback were given for this particular installation. John Zink Co., the installer of the recovery system, reports that

[5] ChevronTexaco commented on the report by the Bay Area Air Quality Management District on refinery flaring. The comments were mainly directed towards the VOC-calculations in the report and an explanation of the flaring practices at the ChevronTexaco refinery in Richmond, CA (Hartwig, 2003).

the payback period of recovery systems may be as short as one year. Furthermore, flare gas recovery systems offer increased flare tip life and emission reductions.

7.2 Power Recovery

Various processes run at elevated pressures, enabling the opportunity for power recovery from the pressure in the flue gas. The major application for power recovery in the petroleum refinery is the fluid catalytic cracker (FCC). However, power recovery can also be applied to hydrocrackers or other equipment operated at elevated pressures. Modern FCC designs use a power recovery turbine or turbo expander to recover energy from the pressure. The recovered energy can be used to drive the FCC compressor or to generate power. Power recovery applications for FCC are characterized by high volumes of high temperature gases at relatively low pressures, while operating continuously over long periods of time between maintenance stops (> 32,000 hours). There is wide and long-term experience with power recovery turbines for FCC applications. Various designs are marketed, and newer designs tend to be more efficient in power recovery. Recovery turbines are supplied by a small number of global suppliers, including GE Power Systems.

Many refineries in the United States and around the world have installed recovery turbines. Valero has recently upgraded the turbo expanders at its Houston and Corpus Christi (Texas) and Wilmington (California) refineries. Valero’s Houston Refinery replaced an older power recovery turbine to enable increased blower capacity to allow an expansion of the FCC. At the Houston refinery, the re-rating of the FCC power recovery train led to power savings of 22 MW (Valero, 2003), and will export additional power (up to 4 MW) to the grid. Petro Canada’s Edmonton refinery replaced an older turbo expander by a new more efficient unit in October 1998, saving around 18 TBtu annually.

Power recovery turbines can also be applied at hydrocrackers. Power can be recovered from the pressure difference between the reactor and fractionation stages of the process. In 1993, the Total refinery in Vlissingen, the Netherlands, installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker (get data on hydrocracker). The cracker operates at 160 bar. The power recovery turbine produces about 7.3 million kWh/year (assuming 8000 hours/year). The investment was equal to $1.2 million (1993$). This resulted in a payback period of approximately 2.5 years at the conditions in the Netherlands (Caddet, 2003).

8. Steam Generation and Distribution

Steam is used throughout the refinery. An estimated 30% of all onsite energy use in U.S. refineries is used in the form of steam. Steam can be generated through waste heat recovery from processes, cogeneration, and boilers. In most refineries, steam will be generated by all three sources, while some (smaller) refineries may not have cogeneration equipment installed. While the exact size and use of a modern steam systems varies greatly, there is an overall pattern that steam systems follow, as shown in Figure 14.

Figure 14 depicts a schematic presentation of a steam system. Treated cold feed water is fed to the boiler, where it is heated to form steam. Chemical treatment of the feed water is required to remove impurities. The impurities would otherwise collect on the boiler walls. Even though the feed water has been treated, some impurities still remain and can build up in the boiler water. As a result, water is periodically drained from the bottom of the boiler in a process known as blowdown. The generated steam travels along the pipes of the distribution system to get to the process where the heat will be used. Sometimes the steam is passed through a pressure reduction valve if the process requires lower pressure steam. As the steam is used to heat processes, and even as it travels through the distribution system to get there, the steam cools and some is condensed. This condensate is removed by a steam trap, which allows condensate to pass through, but blocks the passage of steam. The condensate can be recirculated to the boiler, thus recovering some heat and reducing the need for fresh treated feed water. The recovery of condensate and blowdown will also reduce the costs of boiler feed water treatment. For example, optimization of blowdown steam use at Valero's Houston refinery use led to cost savings of $213,500/year (Valero, 2003).

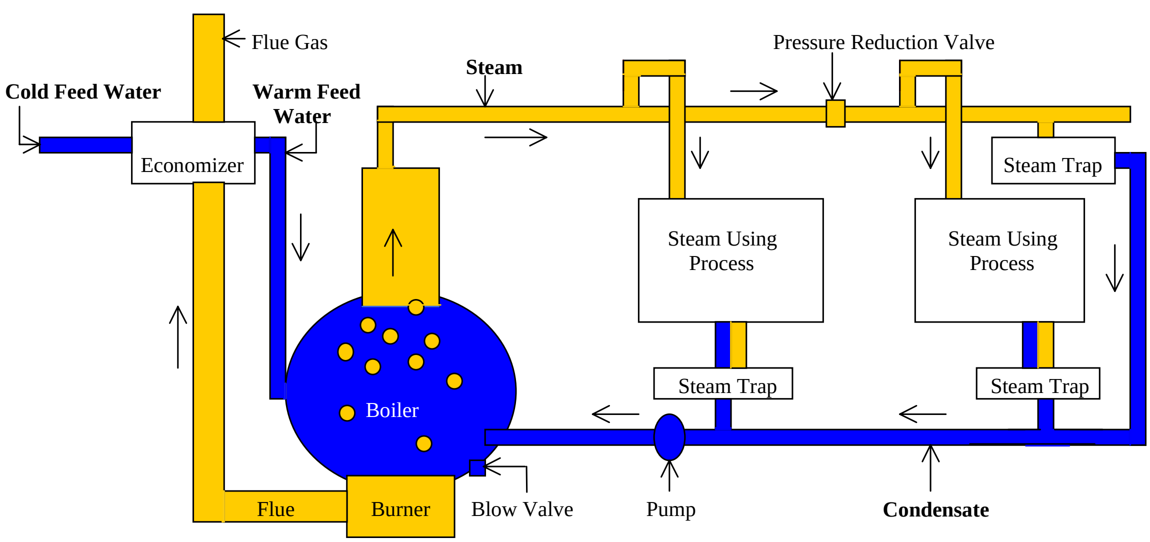

Figure 14. Schematic presentation of a steam production and distribution system.

The refining industry uses steam for a wide variety of purposes, the most important being process heating, drying or concentrating, steam cracking, and distillation. Whatever the use or the source of the steam, efficiency improvements in steam generation, distribution and end-use are possible. A recent study by the U.S. Department of Energy estimates the overall potential for energy savings in petroleum refineries at over 12% (U.S. DOE, 2002). It is estimated that steam generation, distribution, and cogeneration offer the most cost-effective energy efficiency opportunities on the short term. This section focuses on the steam generation in boilers (including waste heat boilers) and distribution. Table 6 summarizes the boiler efficiency measures, while Table 7 summarizes the steam distribution system measures.

Steam, like any other secondary energy carrier, is expensive to produce and supply. The use of steam should be carefully considered and evaluated. Often steam is generated at higher pressures than needed or in larger volumes than needed at a particular time. These inefficiencies may lead steam systems to let down steam to a lower pressure or to vent steam to the atmosphere. Hence, it is strongly recommended to evaluate the steam system on the use of appropriate pressure levels and production schedules. If it is not possible to reduce the steam generation pressure, it may still be possible to recover the energy through a turbo expander or steam expansion turbine (see section 18.3). Excess steam generation can be reduced through improved process integration (see section 9.2) and improved management of steam flows in the refinery (see section 6.2 on total site management systems). Many refineries operate multiple boilers. By dispatching boilers on the basis of efficiency, it is possible to save energy. An audit of the Equilon refinery (now owned by Shell) in Martinez, California, found that scheduling of steam boilers on the basis of efficiency (and minimizing losses in the steam turbines) can result in annual energy savings equaling $5.4 million (U.S. DOE-OIT, 2002b).

8.1 Boilers

Boiler Feed Water Preparation. Depending on the quality of incoming water, the boiler feed water (BFW) needs to be pre-treated to a varying degree. Various technologies may be used to clean the water. A new technology is based on the use of membranes. In reverse osmosis (RO), the pre-filtered water is pressed at increased pressure through a semi-permeable membrane. Reverse osmosis and other membrane technologies are used more and more in water treatment (Martin et al., 2000). Membrane processes are very reliable, but need semi-annual cleaning and periodic replacement to maintain performance.

The Flying J refinery in North Salt Lake (Utah) installed a RO-unit to remove hardness and reduce the alkalinity from boiler feedwater, replacing a hot lime water softener. The unit started operation in 1998, resulting in reduced boiler blowdown (from 13.3% to 1.5% of steam produced) and reduced chemical use, maintenance, and waste disposal costs (U.S. DOE-OIT, 2001). With an investment of $350,000 and annual benefits of approximately $200,000, the payback period amounted to less than 2 years.

Improved Process Control. Flue gas monitors are used to maintain optimum flame temperature, and to monitor CO, oxygen and smoke. The oxygen content of the exhaust gas is a combination of excess air (which is deliberately introduced to improve safety or reduce emissions) and air infiltration (air leaking into the boiler). By combining an oxygen monitor with an intake airflow monitor, it is possible to detect (small) leaks. Using a combination of

CO and oxygen readings, it is possible to optimize the fuel/air mixture for high flame temperature (and thus the best energy efficiency) and low emissions. The payback of improved process control is approximately 0.6 years (IAC, 1999). This measure may be too expensive for small boilers.

Reduce Flue Gas Quantities. Often, excessive flue gas results from leaks in the boiler and the flue, reducing the heat transferred to the steam, and increasing pumping requirements. These leaks are often easily repaired. Savings amount to 2-5% (OIT, 1998). This measure consists of a periodic repair based on visual inspection. The savings from this measure and from flue gas monitoring are not cumulative, as they both address the same losses.

Reduce Excess Air. The more air is used to burn the fuel, the more heat is wasted in heating air. Air slightly in excess of the ideal stoichometric fuel/air ratio is required for safety, and to reduce NO_x emissions, and is dependent on the type of fuel. For gas and oil-fired boilers, approximately 15% excess air is adequate (OIT, 1998; Ganapathy, 1994). Poorly maintained boilers can have up to 140% excess air. Reducing this back down to 15% even without continuous automatic monitoring would save 8%.

Improve Insulation. New materials insulate better, and have a lower heat capacity. Savings of 6-26% can be achieved if this improved insulation is combined with improved heater circuit controls. This improved control is required to maintain the output temperature range of the old firebrick system. As a result of the ceramic fiber's lower heat capacity, the output temperature is more vulnerable to temperature fluctuations in the heating elements (Caffal, 1995). The shell losses of a well-maintained boiler should be less than 1%.

Maintenance. A simple maintenance program to ensure that all components of the boiler are operating at peak performance can result in substantial savings. In the absence of a good maintenance system, the burners and condensate return systems can wear or get out of adjustment. These factors can end up costing a steam system up to 20-30% of initial efficiency over 2-3 years (DOE, 2001a). On average, the possible energy savings are estimated at 10% (DOE, 2001a). Improved maintenance may also reduce the emission of criteria air pollutants.

Fouling of the fireside of the boiler tubes or scaling on the waterside of the boiler should also be controlled. Fouling and scaling are more of a problem with coal-fed boilers than with natural gas or oil-fed ones (i.e., boilers that burn solid fuels like coal should be checked more often as they have a higher fouling tendency than liquid fuel boilers do). Tests show that a soot layer of 0.03 inches (0.8 mm) reduces heat transfer by 9.5%, while a 0.18 inch (4.5 mm) soot layer reduces heat transfer by 69% (CIPEC, 2001). For scaling, 0.04 inches (1 mm) of buildup can increase fuel consumption by 2% (CIPEC, 2001). Moreover, scaling may result in tube failures.

Recover Heat From Flue Gas. Heat from flue gasses can be used to preheat boiler feed water in an economizer. While this measure is fairly common in large boilers, there is often still potential for more heat recovery. The limiting factor for flue gas heat recovery is the economizer wall temperature that should not drop below the dew point of acids in the flue gas. Traditionally this is done by keeping the flue gases at a temperature significantly above the acid dew point. However, the economizer wall temperature is more dependent on the feed water temperature than flue gas temperature because of the high heat transfer coefficient of water. As a result, it makes more sense to preheat the feed water to close to the acid dew point before it enters the economizer. This allows the economizer to be designed so that the flue gas exiting the economizer is just barely above the acid dew point. One percent of fuel use is saved for every 25°C reduction in exhaust gas temperature. (Ganapathy, 1994). Since exhaust gas temperatures are already quite low, limiting savings to 1% across all boilers, with a payback of 2 years (IAC, 1999).

Recover Steam From Blowdown. When the water is blown from the high-pressure boiler tank, the pressure reduction often produces substantial amounts of steam. This steam is low grade, but can be used for space heating and feed water preheating. For larger high-pressure boilers, the losses may be less than 0.5%. It is estimated that this measure can save 1.3% of boiler fuel use for all boilers below 100 MMBtu/hr (approximately 5% of all boiler capacity in refineries). The payback period of blowdown steam recovery will vary between 1 and 2.7 years (IAC, 1999).

Table 6. Summary of energy efficiency measures in boilers.

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Improved Process Control	3%	0.6	Reduced Emissions
Reduced Flue Gas Quantity	2-5%	-	Cheaper emission controls
Reduced Excess Air	1% improvement for each 15% less excess air	-	
Improved Insulation	6-26%	?	Faster warm-up
Boiler Maintenance	10%	0	Reduced emissions
Flue Gas Heat Recovery	1%	2	
Blowdown Steam Heat Recovery	1.3%	1 - 2.7	Reduced damage to structures (less moist air is less corrosive).
Alternative Fuels	Variable	-	Reduces solid waste stream at the cost of increased air emissions

Reduce Standby Losses. In refineries often one or more boilers are kept on standby in case of failure of the operating boiler. The steam production at standby can be reduced to virtually zero by modifying the burner, combustion air supply and boiler feedwater supply. By installing an automatic control system the boiler can reach full capacity within 12 minutes. Installing the control system and modifying the boiler can result in energy savings up to 85% of the standby boiler, depending on the use pattern of the boiler.

The Kemira Oy ammonia plant at Rozenburg (the Netherlands) applied this system to a small 40 t/hr steam boiler, reducing the standby steam consumption from the boiler from 6 t/hr to 1 t/hr. This resulted in energy savings of 54 TBtu/year. Investments were approximately $270,000 (1991$), resulting in a payback period of 1.5 years at this particular plant (Caddet, 1997b).

8.2 Steam Distribution

When designing new steam distribution systems, it is very important to take into account the velocity and pressure drop (Van de Ruit, 2000). This reduces the risk of oversizing a steam pipe, which is not only a cost issue but would also lead to higher heat losses. A pipe too small may lead to erosion and increased pressure drop. Installations and steam demands change over time, which may lead to under-utilization of steam distribution capacity utilization, and extra heat losses. However, it may be too expensive to optimize the system for changed steam demands. Still, checking for excess distribution lines and shutting off those lines is a cost-effective way to reduce steam distribution losses. Other maintenance measures for steam distribution systems are described below.

Improve Insulation. This measure can be to use more insulating material, or to make a careful analysis of the proper insulation material. Crucial factors in choosing insulating material include: low thermal conductivity, dimensional stability under temperature change, resistance to water absorption, and resistance to combustion. Other characteristics of insulating material may also be important depending on the application, e.g., tolerance of large temperature variations and system vibration, and compressive strength where insulation is load bearing (Baen and Barth, 1994). Improving the insulation on the existing stock of heat distribution systems would save an average of 3-13% in all systems (OIT, 1998) with an average payback period of 1.1 years[6] (IAC, 1999). The U.S. Department of Energy has developed the software tool 3E-Plus to evaluate the optimal insulation for steam systems (see Appendix E).

Maintain Insulation. It is often found that after repairs, the insulation is not replaced. In addition, some types of insulation can become brittle, or rot. As a result, energy can be saved by a regular inspection and maintenance system (CIBO, 1998). Exact energy savings and payback periods vary with the specific situation in the plant.

Improve Steam Traps. Using modern thermostatic elements, steam traps can reduce energy use while improving reliability. The main advantages offered by these traps are that they open when the temperature is very close to that of the saturated steam (within 2°C), purge non-condensable gases after each opening, and are open on startup to allow a fast steam system warm-up. These traps are also very reliable, and useable for a wide variety of steam pressures (Alesson, 1995). Energy savings will vary depending on the steam traps installed and state of maintenance.

Maintain Steam Traps. A simple program of checking steam traps to ensure that they operate properly can save significant amounts of energy. If the steam traps are not regularly monitored, 15-20% of the traps can be malfunctioning. In some plants, as many as 40% of the steam traps were malfunctioning. Energy savings for a regular system of steam trap

[6] The IAC database shows a series of case studies where a particular technology was used. It gives a wide variety of information, including the payback period for each case. We calculated an overall payback for a technology by averaging all the individual cases.

checks and follow-up maintenance is estimated at up to 10% (OIT, 1998; Jones 1997; Bloss, 1997) with a payback period of 0.5 years (IAC, 1999). This measure offers a quick payback but is often not implemented because maintenance and energy costs are separately budgeted. Some systems already use this practice.

An audit of the Flying J Refinery in North Salt Lake (Utah) identified annual savings of $147,000 by repairing leaking steam traps (Brueske et al., 2002).

Monitor Steam Traps Automatically. Attaching automated monitors to steam traps in conjunction with a maintenance program can save even more energy, without significant added cost. This system is an improvement over steam trap maintenance alone, because it gives quicker notice of steam trap malfunctioning or failure. Using automatic monitoring is estimated to save an additional 5% over steam trap maintenance, with a payback of 1 year[7] (Johnston, 1995; Jones, 1997). Systems that are able to implement steam trap maintenance are also likely to be able to implement automatic monitoring. On average, 50% of systems can still implement automatic monitoring of steam traps.

Repair Leaks. As with steam traps, the distribution pipes themselves often have leaks that go unnoticed without a program of regular inspection and maintenance. In addition to saving up to 3% of energy costs for steam production, having such a program can reduce the likelihood of having to repair major leaks (OIT, 1998). On average, leak repair has a payback period of 0.4 years (IAC, 1999).

Recover Flash Steam. When a steam trap purges condensate from a pressurized steam distribution system to ambient pressure, flash steam is produced. This steam can be used for space heating or feed water preheating (Johnston, 1995). The potential for this measure is extremely site dependent, as it is unlikely that a producer will want to build an entirely new system of pipes to transport this low-grade steam to places where it can be used, unless it can be used close to the steam traps. Hence, the savings are strongly site dependent. Many sites will use multi-pressure steam systems. In this case, flash steam formed from high-pressure condensate can be routed to reduced pressure systems.

Vulcan Chemicals in Geismar (Louisiana) implemented a flash steam recovery project at one of the processes at their chemical plant. The project recovers 100% of the flash steam and resulted in net energy savings of 2.8% (Bronhold, 2000).

[7] Calculated based on a UK payback of 0.75 years. The U.S. payback is longer because energy prices in the U.S. are lower, while capital costs are similar.

Table 7. Summary of energy efficiency measures in steam distribution systems.

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Improved Insulation	3-13%	1.1	
Improved Steam Traps	Unknown	Unknown	Greater reliability
Steam Trap Maintenance	10-15%	0.5	
Automatic Steam Trap Monitoring[8]	5%	1	
Leak Repair	3-5%	0.4	Reduced requirement for major repairs
Flash Steam Recovery/ Condensate Return	83%[9]	Unknown	Reduced water treatment costs
Condensate Return Alone	10%	1.1	Reduced water treatment costs

Return Condensate. Reusing the hot condensate in the boiler saves energy and reduces the need for treated boiler feed water. The substantial savings in energy costs and purchased chemicals costs makes building a return piping system attractive. This measure has already been implemented in most places where it is easy to accomplish. Care has to be taken to design the recovery system to reduce efficiency losses (van de Ruit, 2000). Maximum energy savings are estimated at 10% (OIT, 1998) with a payback of 1.1 years (IAC, 1999) for those sites without or with insufficient condensate return. An additional benefit of condensate recovery is the reduction of the blowdown flow rate because boiler feedwater quality has been increased.

[8] In addition to a regular maintenance program

[9] Includes flash steam recovery from the boiler. Although this represents actual savings achieved in a case study, it seems much to high to be a generally applicable savings number. As a result, it is not included in our total savings estimate.

9. Heat Exchangers and Process Integration

Heating and cooling are operations found throughout the refinery. Within a single process, multiple streams are heated and cooled multiple times. Optimal use and design of heat exchangers is a key area for energy efficiency improvement.

9.1 Heat Transfer– Fouling

Heat exchangers are used throughout the refinery to recover heat from processes and transfer heat to the process flows. Next to efficient integration of heat flows throughout the refinery (see process integration below), the efficient operation of heat exchangers is a major area of interest. In a complex refinery, most processes occur under high temperature and pressure conditions; the management and optimization of heat transfer among processes is therefore key to increasing overall energy efficiency. Fouling, a deposit buildup in units and piping that impedes heat transfer, requires the combustion of additional fuel. For example, the processing of many heavy crude oils in the United States increases the likelihood of localized coke deposits in the heating furnaces, thereby reducing furnace efficiency and creating potential equipment failure. An estimate by the Office of Industrial Technology at the U.S. Department of Energy noted that the cost penalty for fouling could be as much as $2 billion annually in material and energy costs. The problem of fouling is expected to increase with the trend towards processing heavier crudes.

Fouling is the effect of several process variables and heat exchanger design. Fouling may follow the combination of different mechanisms (Bott, 2001). Several methods of investigation have been underway to attempt to reduce fouling including the use of sensors to detect early fouling, physical and chemical methods to create high temperature coatings (without equipment modification), the use of ultrasound, as well as the improved long term design and operation of facilities. The U.S. Department of Energy initially funded preliminary research into this area, but funding has been discontinued (Huangfu, 2000; Bott, 2000). Worldwide, research in fouling reduction and mitigation is continuing (Polley and Pugh, 2002; Polley et al. 2002) by focusing on understanding the principles of fouling and redesign of heat exchangers and reactors. Currently, various methods to reduce fouling focus on process control, temperature control, regular maintenance and cleaning of the heat exchangers (either mechanically or chemically) and retrofit of reactor tubes (Barletta, 1998).

A study of European refineries identified overall energy savings of 0.7% by cleaning the heat exchanger tubes of the CDU and other furnaces with an estimated payback period of 0.7 years.

Fouling was identified as a major energy loss in an audit of the Equilon refinery in Martinez, California (now owned by Shell). Regular cleaning of heat exchangers and maintenance of insulation would result in estimated annual savings of over $14 million at a total expenditure of $9.85 million (U.S. DOE-OIT, 2002b). Hence, the simple payback period is around 8 months.

CDU. Fouling is an important factor for efficiency losses in the CDU, and within the CDU, the crude preheater is especially susceptible to fouling (Barletta, 1998). Initial analysis on fouling effects of a 100,000 bbl/day crude distillation unit found an additional heating load of 12.3 kBtu/barrel (13.0 MJ/barrel) processes (Panchal and Huangfu, 2000). Reducing this additional heating load could results in significant energy savings.

9.2 Process Integration

Process integration or pinch technology refers to the exploitation of potential synergies that are inherent in any system that consists of multiple components working together. In plants that have multiple heating and cooling demands, the use of process integration techniques may significantly improve efficiencies.

Developed in the early 1970s, it is now an established methodology for continuous processes (Linnhoff, 1992; Caddet, 1993). The methodology involves the linking of hot and cold streams in a process in a thermodynamic optimal way (i.e., not over the so-called 'pinch'). Process integration is the art of ensuring that the components are well suited and matched in terms of size, function and capability. Pinch analysis takes a systematic approach to identifying and correcting the performance limiting constraint (or pinch) in any manufacturing process (Kumana, 2000a). It was developed originally in the late 1970s at the University of Manchester in England and other places (Linnhoff, 1993) in response to the "energy crisis" of the 1970s and the need to reduce steam and fuel consumption in oil refineries and chemical plants by optimizing the design of heat exchanger networks. Since then, the pinch approach has been extended to resource conservation in general, whether the resource is capital, time, labor, electrical power, water or a specific chemical species such as hydrogen.

The critical innovation in applying pinch analysis was the development of "composite curves" for heating and cooling, which represent the overall thermal energy demand and availability profiles for the process as a whole. When these two curves are drawn on a temperature-enthalpy graph, they reveal the location of the process pinch (the point of closest temperature approach), and the minimum thermodynamic heating and cooling requirements. These are called the energy targets. The methodology involves first identifying the targets and then following a systematic procedure for designing heat exchanger networks to achieve these targets. The optimum approach temperature at the pinch is determined by balancing the capital-energy tradeoffs to achieve the desired payback. The procedure applies equally well to new designs as well as to retrofits of existing plants.

The analytical approach to this analysis has been well documented in the literature (Kumana, 2000b; Smith, 1995; Shenoy, 1994). Energy savings potential using pinch analysis far exceeds that from well-known conventional techniques such as heat recovery from boiler flue gas, insulation and steam trap management.

Pinch analysis, and competing process integration tools, have been developed further in the past several years. The most important developments in the energy area are the inclusion of alternative heat recovery processes such as heat pumps and heat transformers, as well as the development of pinch analysis for batch processes (or in other words bringing in time as a factor in the analysis of heat integration). Furthermore, pinch analysis should be used in the design of new processes and plants, as process integration goes beyond optimization of heat exchanger networks (Hallale, 2001). Even in new designs additional opportunities for energy efficiency improvement can be identified. Pinch analysis has also been extended to the areas of water recovery and efficiency, and hydrogen recovery (hydrogen pinch, see also below). Water used to be seen as a low-cost resource to the refinery, and was used inefficiently. However, as the standards and costs for waste water treatment increase and the costs for feedwater makeup increase, the industry has become more aware of water costs. In addition, large amounts of energy are used to process and move water through the refinery. Hence, water savings will lead to additional energy savings. Water pinch can be used to develop targets for minimal water use by reusing water in an efficient manner. Optimization software has been developed to optimize investment and operation costs for water systems in a plant (Hallale, 2001). New tools have been developed to optimize water and energy use in an integrated manner (Wu, 2000). Water pinch has until now mainly been used in the food industry, reporting reductions in water intake of up to 50% (Polley and Polley, 2000). Dunn and Bush (2001) report the use of water pinch for optimization of water use in chemical plants operated by Solutia, resulting in sufficient water use reductions to allow expansion of production and of the site with no net increase in water use. No water pinch analysis studies specific for the petroleum refining industry were found. Major oil companies, e.g., BP and Exxon, have applied hydrogen pinch analysis for selected refineries.

Total Site Pinch Analysis has been applied by over 40 refineries around the world to find optimum site-wide utility levels by integrating heating and cooling demands of various processes, and by allowing the integration of CHP into the analysis. Process integration analysis of existing refineries and processes should be performed regularly, as continuous changes in product mix, mass flows, and applied processes can provide new or improved opportunities for energy and resource efficiency.

Major refineries that have applied total site pinch analysis are: Amoco, Agip (Italy), BP, Chevron, Exxon (in the Netherlands and UK), and Shell (several European plants). Typical savings identified in these site-wide analyses are around 20-30%, although the economic potential was found to be limited to 10-15% (Linnhoff-March, 2000). A total-site analysis was performed of a European oil refinery in the late 1990s. The Solomon's EII of the refinery was within the top quartile. The refinery operates 16 processes including a CDU, VDU, FCC, reformer, coker and hydrotreaters. A study of the opportunities offered by individual process optimization of the CDU, VDU, FCC, coker, and two hydrotreaters found a reduction in site EII of 7.5%. A total-site analysis including the cogeneration unit identified a potential reduction of 16% (Linnhoff-March, 2000). Identified opportunities including the conversion of a back-pressure turbine to a condensing turbine, and improved integration of the medium-pressure and low-pressure steam networks. The economically attractive projects would result in savings of approximately 12-13%.

Site analyses by chemical producer Solutia identified annual savings of $3.9 million (of which 2.7 with a low payback) at their Decatur plant, 0.9M$/year at the Anniston site and 3.6 M$/year at the Pensacola site (Dunn and Bush, 2001).

Process Integration - Hot Rundown – Typically process integration studies focus on the integration of steam flows within processes and between processes. Sometimes it is possible to improve the efficiency by retaining the heat in intermediate process flows from one unit to another unit. This reduces the need for cooling or quenching in one unit and reheating in the other unit. Such an integration of two processes can be achieved through automated process controls linking the process flows between both processes. An audit of the Equilon refinery in Martinez, California, identified annual savings of $4.3 million (U.S. DOE-OIT, 2002b). However, the audit results did not include an assessment of investments and payback.

Crude Distillation Unit (CDU). The CDU process all the incoming crude and, hence, is a major energy user in all refinery layouts (except for those refineries that receive intermediates by pipeline from other refineries). In fact, in Chapter 4 it is estimated that the CDU is the largest energy consuming process of all refinery processes. Energy use and products of the CDU depend on the type of crude processed. New CDUs are supplied by a number of global companies such as ABB Lummus, Kellog Brown & Root, Shell Global Solutions, Stone & Webster, Technip/Elf, and UOP. An overview of available process designs is published as Hydrocarbon Processing's Refining Processes (HCP, 2000).

Process integration is especially important in the CDU, as it is a large energy consumer processing all incoming crude oil. Older process integration studies show reductions in fuel use between 10 and 19% for the CDU (Clayton, 1986; Sunden, 1988; Lee, 1989) with payback periods less than 2 years. An interesting opportunity is the integration of the CDU and VDU, which can lead to fuel savings from 10-20% (Clayton, 1986; Petrick and Pellegrino, 1999) compared to non-integrated units, at relatively short paybacks. The actual payback period will depend heavily on the layout of the refinery, needed changes in the heat exchanger network and the fuel prices.

The CDU at BP's Kwinana (Australia) refinery was already performing well with limited opportunities for further economic process integration. An analysis of the CDU identified a significant potential for reduction but with a payback of around 6 years. However, integration with the residue cracking unit offered significant opportunities to reduce the combined heating demand by 35-40% with a simple payback period of 1.6 years (Querzoli, 2002).

Fluid Catalytic Cracker (FCC). The FCC is a considerable energy consumer in a modern refiner. In this Energy Guide, the FCC energy use is estimated at 6% of total energy use. Depending on the design and product mix of a particular refinery, FCC energy use can be higher than 6%. There are a large number of FCC designs in use, and many were originally built in the 1970s. Today, more energy efficient designs are being marketed by a number of suppliers. The designs vary in reactor design, type of catalyst used and degree of heat integration. An overview of available process designs is published as Hydrocarbon Processing's Refining Processes (HCP, 2000). The major suppliers are ABB Lummus, Kellog Brown & Root, Shell Global Solutions, Stone & Webster, and UOP. The optimal design will be based on the type of feed processed and desired product mix and quality.

When selecting a new FCC, process energy efficiency should be an integral part of the selection process.

In existing FCC units, energy efficiency can be improved by increasing heat integration and recovery, process flow scheme changes, and power recovery. A FCC has a multitude of flows that need to be heated (sink) and cooled (source). The better the integration of the heat sinks and sources, the lower the energy consumption of an FCC will be. Older FCC designs often do not have an optimized heat exchange setup, which may especially lead to wasted low-temperature heat, which could be used to preheat boiler feed water or cold feed. However, by better integrating the sources and sinks, following the principles of pinch technology (see above), through improved combinations of temperature levels and heating/cooling loads energy use is lowered. Various authors have reported on the application of pinch analysis and process optimization of FCCs (Hall et al., 1995; Golden and Fulton, 2000). The appropriate combination will depend on the feed processed and output produced. Furthermore, economics for the installation of heat exchangers may determine the need for less efficient combinations.

Al-Riyami et al. (2001) studied the opportunities for process integration of a FCC unit in a refinery in Romania. The FCC unit was originally built by UOP and is used to convert vacuum gas oil and atmospheric gas oil. Several design options were identified to reduce utility consumption. The study of the FCC identified a reduction in utilities of 27% at a payback of 19 months. However, the calculation for the payback period only includes the heat exchangers, and, depending on the design of the FCC and layout of the plant, the payback period may be longer for other plant designs.

At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The audit identified additional opportunities for heat recovery in the FCC by installing a waste heat boiler before the electrostatic precipitator, resulting in savings of $210,000/year at a payback of 2 years (Venkatesan and Iordanova, 2003).

FCC-Process Flow Changes. The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or changing the number of pumparounds can improve energy efficiency of the FCC, as it allows increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions to enhance product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC-unit with appropriate modifications of equipment and operating conditions can increase the yield of high octane gasoline and alkylate from 3% to 7% per barrel of crude oil. This would result in energy savings.

Reformer. At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The audit identified opportunities to improve the performance of the economizer in the waste heat boilers of two reformer furnaces. The changes would result in annual savings of $140,000 in each reformer at a payback period of 2 years (Venkatesan and Iordanova, 2003).

Coker. A simulation and optimization of a coker of Jinling Petrochemical Corp.'s Nanjing refinery (China) in 1999 identified a more efficient way to integrate the heat flows in the process. By changing the diesel pumparound, they achieved an energy cost reduction of $100,000/year (Zhang, 2001). Unfortunately, there is insufficient data to estimate the savings for U.S. refineries or to evaluate the economics of the project under U.S. conditions.

10. Process Heaters

Over 60% of all fuel used in the refinery is used in furnaces and boilers. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations, the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that on average a 10% improvement in energy efficiency can be achieved in furnace and burner design.

The efficiency of heaters can be improved by improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air-preheaters, and improved controls. New burner designs aim at improved mixing of fuel and air and more efficient heat transfer. Many different concepts are developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002e). At the same time, furnace and burner design has to address safety and environmental concerns. The most notable is the reduction of NOx emissions. Improved NOx control will be necessary in almost all refineries to meet air quality standards, especially as many refineries are located in non-attainment areas.

10.1 Maintenance

Regular maintenance of burners, draft control and heat exchangers is essential to maintain safe and energy efficient operation of a process heater.

Draft Control. Badly maintained process heaters may use excess air. This reduces the efficiency of the burners. Excess air should be limited to 2-3% oxygen to ensure complete combustion.

Valero’s Houston refinery has installed new control systems to reduce excess combustion air at the three furnaces of the CDU. The control system allows running the furnace with 1% excess oxygen instead of the regular 3-4%. The system has not only reduced energy use by 3 to 6% but also reduced NOx emissions by 10-25%, and enhanced the safety of the heater (Valero, 2003). The energy savings result in an estimated cost savings of $340,000. Similar systems will be introduced in 94 process heaters at the 12 Valero refineries, and is expected to result in savings of $8.8 million/year.

An audit of the Paramount Petroleum Corp.’s asphalt refinery in Paramount (California) identified excess draft air in six process heaters. Regular maintenance (twice per year) can reduce the excess draft air and would result in annual savings of over $290,000 (or nearly 100,000 MBtu/year). The measure has a simple payback period of 2 months (U.S. DOE-OIT, 2003b).

An audit co-funded by U.S. Department of Energy, of the Equilon refinery (now owned by Shell) in Martinez (California) found that reduction of excess combustion and draft air would result in annual savings of almost $12 million (U.S. DOE-OIT, 2002b). A similar audit of the Flying J Refinery at North Salt Lake (Utah) found savings of $100,000/year through oxygen control of the flue gases to control the air intake of the furnaces (Brueske et al., 2002).

10.2 Air Preheating

Air preheating is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 35°F drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and is typically economically attractive if the flue gas temperature is higher than 650°F and the heater size is 50 MMBtu/hr or more (Garg, 1998). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater, the burner needs to be rerated for optimum efficiency. The typical payback period for combustion air preheating in a refinery is estimated at 2.5 years. However, the costs may vary strongly depending on the layout of the refinery and furnace construction.

VDU. At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The refinery operated 3 VDUs of which one still used natural draught and had no heat recovery installed. By installing a combustion air preheater, using the hot flue gas, and an additional FD fan, the temperature of the flue gas was reduced to 470°F. This led to energy cost savings of $109,000/year with a payback period of 2.2 years (Venkatesan and Iordanova, 2003).

10.3 New Burners

In many areas, new air quality regulation will demand refineries to reduce NOx and VOC emissions from furnaces and boilers. Instead of installing expensive selective catalytic reduction (SCR) flue gas treatment plants, new burner technology reduces emissions dramatically. This will result in cost savings as well as help to decrease electricity costs for the SCR.

ChevronTexaco, in collaboration with John Zink Co., developed new low-NOx burners for refinery applications based on the lean premix concept. The burners help to reduce NOx emissions from 180 ppm to below 20 ppm. The burners have been installed in a CDU, VDU, and a reformer at ChevronTexaco’s Richmond, (California) refinery, without taking the furnace out of production. The burner was also applied to retrofit a steam boiler. The installation of the burners in a reforming furnace reduced emissions by over 90%, while eliminating the need for an SCR. This saved the refinery $10 million in capital costs and $1.5 million in annual operating costs of the SCR (Seebold et al., 2001). The operating costs include the saved electricity costs for operating compressors and fans for the SCR. The operators had to be retrained to operate the new burners as some of the operation characteristics had changed.

11. Distillation

Distillation is one of the most energy intensive operations in the petroleum refinery. Distillation is used throughout the refinery to separate process products, either from the CDU/VDU or from conversion processes. The incoming flow is heated, after which the products are separated on the basis of boiling points. Heat is provided by process heaters (see Chapter 10) and/or by steam (see Chapter 9). Energy efficiency opportunities exist in the heating side and by optimizing the distillation column.

Operation Procedures. The optimization of the reflux ratio of the distillation column can produce significant energy savings. The efficiency of a distillation column is determined by the characteristics of the feed. If the characteristics of the feed have changed over time or compared to the design conditions, operational efficiency can be improved. If operational conditions have changed, calculations to derive new optimal operational procedures should be done. The design reflux should be compared with the actual ratios controlled by each shift operator. Steam and/or fuel intensity can be compared to the reflux ratio, product purity, etc. and compared with calculated and design performance on a daily basis to improve the efficiency.

Check Product Purity. Many companies tend to excessively purify products and sometimes with good reason. However, purifying to 98% when 95% is acceptable is not necessary. In this case, the reflux rate should be decreased in small increments until the desired purity is obtained. This will decrease the reboiler duties. This change will require no or very low investments (Saxena, 1997).

Seasonal Operating Pressure Adjustments. For plants that are in locations that experience winter climates, the operating pressure can be reduced according to a decrease in cooling water temperatures (Saxena, 1997). However, this may not apply to the VDU or other separation processes operating under vacuum. These operational changes will generally not require any investment.

Reducing Reboiler Duty. Reboilers consume a large part of total refinery energy use as part of the distillation process. By using chilled water, the reboiler duty can in principal be lowered by reducing the overhead condenser temperature. A study of using chilled water in a 100,000 bbl/day CDU has led to an estimated fuel saving of 12.2 MBtu/hr for a 5% increase in cooling duty (2.5 MBtu/hr) (Petrick and Pellegrino, 1999), assuming the use of chilled water with a temperature of 50°F. The payback period was estimated at 1 to 2 years, however, excluding the investments to change the tray design in the distillation tower. This technology is not yet proven in a commercial application. This technology can also be applied in other distillation processes.

Upgrading Column Internals. Damaged or worn internals can result in increased operation costs. As the internals become damaged, efficiency decreases and pressure drops rise. This causes the column to run at a higher reflux rate over time. With an increased reflux rate, energy costs will increase accordingly. Replacing the trays with new ones or adding a high performance packing can have the column operating like the day it was brought online. If operating conditions have seriously deviated from designed operating conditions, the investment may have a relative short payback.

New tray designs are marketed and developed for many different applications. When replacing the trays, it will often be worthwhile to consider new efficient tray designs. New tray designs can result in enhanced separation efficiency and decrease pressure drop. This will result in reduced energy consumption. When considering new tray designs, the number of trays should be optimized

Stripper Optimization. Steam is injected into the process stream in strippers. Steam strippers are used in various processes, and especially the CDU is a large user. The strip steam temperature can be too high, and the strip steam use may be too high. Optimization of these parameters can reduce energy use considerably. This optimization can be part of a process integration (or pinch) analysis for the particular unit (see section 9.2).

Progressive Crude Distillation. Technip and Elf (France) developed an energy efficient design for a crude distillation unit, by redesigning the crude preheater and the distillation column. The crude preheat train was separated in several steps to recover fractions at different temperatures. The distillation tower was re-designed to work at low pressure and the outputs were changed to link to the other processes in the refinery and product mix of the refinery. The design resulted in reduced fuel consumption and better heat integration (reducing the net steam production of the CDU). Technip claims up to a 35% reduction in fuel use when compared to a conventional CDU (Technip, 2000). This technology has been applied in the new refinery constructed at Leuna (Germany) in 1997 and is being used for another new refinery under construction in Europe. Because of the changes in CDU-output and needed changes in intermediate flows, progressive crude distillation is especially suited for new construction or large crude distillation expansion projects.

12. Hydrogen Management and Recovery

Hydrogen is used in the refinery in processes such as hydrocrackers and desulfurization using hydrotreaters. The production of hydrogen is an energy intensive process using naphtha reformers and natural gas-fueled reformers. These processes and other processes also generate gas streams that may contain a certain amount of hydrogen not used in the processes, or generated as by-product of distillation of conversion processes. In addition, different processes have varying quality (purity) demands for the hydrogen feed. Reducing the need for hydrogen make-up will reduce energy use in the reformer and reduce the need for purchased natural gas. Natural gas is an expensive energy input in the refinery process, and lately associated with large fluctuations in prices (especially in California). The major technology developments in hydrogen management within the refinery are hydrogen process integration (or hydrogen cascading) and hydrogen recovery technology (Zagoria and Huycke, 2003). Revamping and retrofitting existing hydrogen networks can increase hydrogen capacity between 3% and 30% (Ratan and Vales, 2002).

12.1 Hydrogen Integration

Hydrogen network integration and optimization at refineries is a new and important application of pinch analysis (see above). Most hydrogen systems in refineries feature limited integration and pure hydrogen flows are sent from the reformers to the different processes in the refinery. But as the use of hydrogen is increasing, especially in California refineries, the value hydrogen is more and more appreciated. Using the approach of composition curves used in pinch analysis, the production and uses of hydrogen of a refinery can be made visible. This allows identification of the best matches between different hydrogen sources and uses based on quality of the hydrogen streams. It allows the user to select the appropriate and most cost-effective technology for hydrogen purification. A recent improvement of the analysis technology also accounts for gas pressure, to reduce compression energy needs (Hallale, 2001). The analysis method accounts also for costs of piping, besides the costs for generation, fuel use, and compression power needs. It can be used for new and retrofit studies.

The BP refinery at Carson (California), in a project with the California Energy Commission, has executed a hydrogen pinch analysis of the large refinery. Total potential savings of $4.5 million on operating costs were identified, but the refinery decided to realize a more cost-effective package saving $3.9 million per year. As part of the plant-wide assessment of the Equilon (Shell) refinery at Martinez, an analysis of the hydrogen network has been included (U.S. DOE-OIT, 2002b). This has resulted in the identification of large energy savings. Further development and application of the analysis method at California refineries, especially as the need for hydrogen is increasing due to reduced future sulfur-content of diesel and other fuels, may result in reduced energy needs at all refineries with hydrogen needs (Khorram and Swaty, 2002). One refinery identified savings of $6 million/year in hydrogen savings without capital projects (Zagoria and Huycke, 2003).

12.2 Hydrogen Recovery

Hydrogen recovery is an important technology development area to improve the efficiency of hydrogen recovery, reduce the costs of hydrogen recovery, and increase the purity of the resulting hydrogen flow. Hydrogen can be recovered indirectly by routing low-purity hydrogen streams to the hydrogen plant (Zagoria and Huycke, 2003). Hydrogen can also be recovered from offgases by routing it to the existing purifier of the hydrogen plant, or by installing additional purifiers to treat the offgases and ventgases. Suitable gas streams for hydrogen recovery are the offgases from the hydrocracker, hydrotreater, coker, or FCC. Not only the hydrogen content determines the suitability, but also the pressure, contaminants (i.e., low on sulfur, chlorine and olefins) and tail end components (C_5+) (Ratan and Vales, 2002). The characteristics of the source stream will also impact the choice of recovery technology. The cost savings of recovered hydrogen are around 50% of the costs of hydrogen production (Zagoria and Huycke, 2003).

Hydrogen can be recovered using various technologies, of which the most common are pressure swing and thermal swing absorption, cryogenic distillation, and membranes. The choice of separation technology is driven by desired purity, degree of recovery, pressure, and temperature. Various manufacturers supply different types of hydrogen recovery technologies, including Air Products, Air Liquide, and UOP. Membrane technology generally represents the lowest cost option for low product rates, but not necessarily for high flow rates (Zagoria and Hucyke, 2003). For high-flow rates, PSA technology is often the conventional technology of choice. PSA is the common technology to separate hydrogen from the reformer product gas. Hundreds of PSA units are used around the world to recover hydrogen from various gas streams. Cryogenic units are favored if other gases, such as LPG, can be recovered from the gas stream as well. Cryogenic units produce a medium purity hydrogen gas steam (up to 96%).

Membranes are an attractive technology for hydrogen recovery in the refinery. If the content of recoverable products is higher than 2-5% (or preferably 10%), recovery may make economic sense (Baker et al., 2000). New membrane applications for the refinery and chemical industries are under development. Membranes for hydrogen recovery from ammonia plants have first been demonstrated about 20 years ago (Baker et al., 2000), and are used in various state-of-the-art plant designs. Refinery offgas flows have a different composition, making different membranes necessary for optimal recovery. Membrane plants have been demonstrated for recovery of hydrogen from hydrocracker offgases. Various suppliers offer membrane technologies for hydrogen recovery in the refining industry, including Air Liquide, Air Products and UOP. Air Liquide and UOP have sold over 100 membrane hydrogen recovery units around the world. Development of low-cost and efficient membranes is an area of research interest to improve cost-effectiveness of hydrogen recovery, and enable the recovery of hydrogen from gas streams with lower concentrations.

At the refinery at Ponca City (Oklahoma, currently owned by ConocoPhilips), a membrane system was installed to recover hydrogen from the waste stream of the hydrotreater, although the energy savings were not quantified (Shaver et al., 1991). Another early study quotes a 6% reduction in hydrogen makeup after installing a membrane hydrogen recovery unit at a hydrocracker (Glazer et al., 1988).

12.3 Hydrogen Production

Reformer – Adiabatic Pre-Reformer. If there is excess steam available at a plant, a pre-reformer can be installed at the reformer. Adiabatic steam reforming uses a highly active nickel catalyst to reform a hydrocarbon feed, using waste heat (900°F) from the convection section of the reformer. This may result in a production increase of as much as 10% (Abrardo and Khurana, 1995). The Kemira Oy ammonia plant in Rozenburg, the Netherlands, implemented an adiabatic pre-reformer. Energy savings equaled about 4% of the energy consumption at a payback period between 1 and 3 years (Worrell and Blok, 1994). ChevronTexaco included a pre-reformer in the design of the new hydrogen plant for the El Segundo refinery (California). The technology can also be used to increase the production capacity at no additional energy cost, or to increase the feed flexibility of the reformer. This is especially attractive if a refinery faces increased hydrogen demand to achieve increased desulfurization needs or switches to heavier crudes. Various suppliers provide pre-reformers including Haldor-Topsoe, Süd-Chemie, and Technip-KTI.

13. Motors

Electric motors are used throughout the refinery, and represent over 80% of all electricity use in the refinery. The major applications are pumps (60% of all motor use), air compressors (15% of all motor use), fans (9%), and other applications (16%). The following sections discuss opportunities for motors in general (section 13.1), pumps (Chapter 14), compressors (Chapter 15), and fans (Chapter 16). When available, specific examples are listed detailing the refining process to which the measure has been applied and to what success.

Using a "systems approach" that looks at the entire motor system (pumps, compressors, motors, and fans) to optimize supply and demand of energy services often yields the most savings. For example, in pumping, a systems approach analyzes both the supply and demand sides and how they interact, shifting the focus of the analysis from individual components to total system performance. The measures identified below reflect aspects of this system approach including matching speed and load (adjustable speed drives), sizing the system correctly, as well as upgrading system components. However, for optimal savings and performance, the systems approach is recommended. Pumps and compressors are both discussed in more detail in Chapters 14 and 15.

13.1 Motor Optimization

Sizing of Motors. Motors and pumps that are sized inappropriately result in unnecessary energy losses. Where peak loads can be reduced, motor size can also be reduced. Correcting for motor oversizing saves 1.2% of their electricity consumption (on average for the U.S. industry), and even larger percentages for smaller motors (Xenergy, 1998).

Higher Efficiency Motors. High efficiency motors reduce energy losses through improved design, better materials, tighter tolerances, and improved manufacturing techniques. With proper installation, energy efficient motors run cooler and consequently have higher service factors, longer bearing and insulation life and less vibration. Yet, despite these advantages, less than 8% of U.S. industrial facilities address motor efficiency in specifications when purchasing a motor (Tutterow, 1999).

Typically, high efficiency motors are economically justified when exchanging a motor that needs replacement, but are not economically feasible when replacing a motor that is still working (CADDET, 1994). Typically, motors have an annual failure rate varying between 3 and 12% (House et al., 2002). Sometimes though, according to a case study by the Copper Development Association (CDA, 2000), even working motor replacements may be beneficial. The payback for individual motors varies based on size, load factor, and running time. The best savings are achieved on motors running for long hours at high loads. When replacing retiring motors, paybacks are typically less than one year from energy savings alone (LBNL et al., 1998).

To be considered energy efficient in the United States, a motor must meet performance criteria published by the National Electrical Manufacturers Association (NEMA). However, most manufacturers offer lines of motors that significantly exceed the NEMA-defined criteria (U.S. DOE-OIT, 2001d). NEMA and other organizations have created the “Motor Decisions Matter” campaign to market NEMA approved premium efficient motors to industry (NEMA, 2001). Even these premium efficiency motors may have low a payback period. According to data from the CDA, the upgrade to high efficiency motors, as compared to motors that achieve the minimum efficiency as specified by the Energy Policy Act, have paybacks of less than 15 months for 50 hp motors (CDA, 2001). Because of the fast payback, it usually makes sense not only to buy an energy efficient motor but also to buy the most efficient motor available (LBNL, 1998).

Replacing a motor with a high efficiency motor is often a better choice than rewinding a motor. The practice of rewinding motors currently has no quality or efficiency standards. To avoid uncertainties in performance of the motor, a new high efficiency motor can be purchased instead of rewinding one.

Power Factor. Inductive loads like transformers, electric motors and HID lighting may cause a low power factor. A low power factor may result in increased power consumption, and hence increased electricity costs. The power factor can be corrected by minimizing idling of electric motors, avoiding operation of equipment over its rated voltage, replacing motors by energy efficient motors (see above) and installing capacitors in the AC circuit to reduce the magnitude of reactive power in the system.

Voltage Unbalance. Voltage unbalance degrades the performance and shortens the life of three-phase motors. A voltage unbalance causes a current unbalance, which will result torque pulsations, increased vibration and mechanical stress, increased losses, motor overheating reducing the life of a motor. Voltage unbalances may be caused by faulty operation of power correction equipment, unbalanced transformer bank or open circuit. It is recommended that voltage unbalance at the motor terminals does not exceed 1%. Even a 1% unbalance will reduce motor efficiency at part load operation. If the unbalance would increase to 2.5%, motor efficiency will also decrease at full load operation. For a 100 hp motor operating 8000 hours per year, a correction of the voltage unbalance from 2.5% to 1% will result in electricity savings of 9,500 kWh or almost $500 at an electricity rate of 5 cts/kWh (U.S. DOE-OIT, 2000b). By regularly monitoring the voltages at the motor terminal and using annual thermographic inspections of motors, voltage unbalances may be identified. Furthermore, make sure that single-phase loads are evenly distributed and install ground fault indicators. Another indicator for a voltage unbalance is a 120 Hz vibration (U.S. DOE-OIT, 2000b).

Adjustable Speed Drives (ASDS)/ Variable Speed Drives (VSDs). ASDs better match speed to load requirements for motor operations. Energy use on many centrifugal systems like pumps, fans and compressors is approximately proportional to the cube of the flow rate. Hence, small reductions in flow that are proportional to motor speed can sometimes yield large energy savings. Although they are unlikely to be retrofitted economically, paybacks for installing new ASD motors in new systems or plants can be as low as 1.1 years (Martin et al., 2000). The installation of ASDs improves overall productivity, control and product quality, and reduces wear on equipment, thereby reducing future maintenance costs.

Variable Voltage Controls (VVCs). In contrast to ASDs, which have variable flow requirements, VVCs are applicable to variable loads requiring constant speed. The principle of matching supply with demand, however, is the same as for ASDs.

14. Pumps

In the petroleum refining industry, about 59% of all electricity use in motors is for pumps (Xenergy, 1998). This equals 48% of the total electrical energy in refineries, making pumps the single largest electricity user in a refinery. Pumps are used throughout the entire plant to generate a pressure and move liquids. Studies have shown that over 20% of the energy consumed by these systems could be saved through equipment or control system changes (Xenergy, 1998).

It is important to note that initial costs are only a fraction of the life cycle costs of a pump system. Energy costs, and sometimes operations and maintenance costs, are much more important in the lifetime costs of a pump system. In general, for a pump system with a lifetime of 20 years, the initial capital costs of the pump and motor make up merely 2.5% of the total costs (Best Practice Programme, 1998). Depending on the pump application, energy costs may make up about 95% of the lifetime costs of the pump. Hence, the initial choice of a pump system should be highly dependent on energy cost considerations rather than on initial costs. Optimization of the design of a new pumping system should focus on optimizing the lifecycle costs. Hodgson and Walters (2002) discuss software developed for this purpose (OPSOP) and discuss several case studies in which they show large reductions in energy use and lifetime costs of a complete pumping system. Typically, such an approach will lead to energy savings of 10-17%.

Pumping systems consist of a pump, a driver, pipe installation, and controls (such as adjustable speed drives or throttles) and are a part of the overall motor system, discussed in Section 13.1. Using a “systems approach” on the entire motor system (pumps, compressors, motors and fans) was also discussed in section 13.1. In this section, the pumping systems are addressed; for optimal savings and performance, it is recommended that the systems approach incorporating pumps, compressors, motors and fans be used.

There are two main ways to increase pump system efficiency, aside from reducing use. These are reducing the friction in dynamic pump systems (not applicable to static or "lifting" systems) or adjusting the system so that it draws closer to the best efficiency point (BEP) on the pump curve (Hovstadius, 2002). Correct sizing of pipes, surface coating or polishing and adjustable speed drives, for example, may reduce the friction loss, increasing energy efficiency. Correctly sizing the pump and choosing the most efficient pump for the applicable system will push the system closer to the best efficiency point on the pump curve.

Operations and Maintenance. Inadequate maintenance at times lowers pump system efficiency, causes pumps to wear out more quickly and increases costs. Better maintenance will reduce these problems and save energy. Proper maintenance includes the following (Hydraulic Institute, 1994; LBNL et al., 1999):

- Replacement of worn impellers, especially in caustic or semi-solid applications.
- Bearing inspection and repair.
- Bearing lubrication replacement, once annually or semiannually.
- Inspection and replacement of packing seals. Allowable leakage from packing seals is usually between two and sixty drops per minute.

- Inspection and replacement of mechanical seals. Allowable leakage is typically one to four drops per minute.
- Wear ring and impeller replacement. Pump efficiency degrades from 1 to 6 points for impellers less than the maximum diameter and with increased wear ring clearances (Hydraulic Institute, 1994).
- Pump/motor alignment check.

Typical energy savings for operations and maintenance are estimated to be between 2 and 7% of pumping electricity use for the U.S. industry. The payback is usually immediate to one year (Xenergy, 1998; U.S. DOE-OIT, 2002c).

Monitoring. Monitoring in conjunction with operations and maintenance can be used to detect problems and determine solutions to create a more efficient system. Monitoring can determine clearances that need be adjusted, indicate blockage, impeller damage, inadequate suction, operation outside preferences, clogged or gas-filled pumps or pipes, or worn out pumps. Monitoring should include:

- Wear monitoring
- Vibration analyses
- Pressure and flow monitoring
- Current or power monitoring
- Differential head and temperature rise across the pump (also known as thermodynamic monitoring)
- Distribution system inspection for scaling or contaminant build-up

Reduce Need. Holding tanks can be used to equalize the flow over the production cycle, enhancing energy efficiency and potentially reducing the need to add pump capacity. In addition, bypass loops and other unnecessary flows should be eliminated. Energy savings may be as high as 5-10% for each of these steps (Easton Consultants, 1995). Total head requirements can also be reduced by lowering process static pressure, minimizing elevation rise from suction tank to discharge tank, reducing static elevation change by use of siphons, and lowering spray nozzle velocities.

More Efficient Pumps. According to inventory data, 16% of pumps are more than 20 years old. Pump efficiency may degrade 10 to 25% in its lifetime (Easton Consultants, 1995). Newer pumps are 2 to 5% more efficient. However, industry experts claim the problem is not necessarily the age of the pump but that the process has changed and the pump does not match the operation. Replacing a pump with a new efficient one saves between 2 to 10% of its energy consumption (Elliott, 1994). Higher efficiency motors have also been shown to increase the efficiency of the pump system 2 to 5% (Tutterow, 1999).

A number of pumps are available for specific pressure head and flow rate capacity requirements. Choosing the right pump often saves both in operating costs and in capital costs (of purchasing another pump). For a given duty, selecting a pump that runs at the highest speed suitable for the application will generally result in a more efficient selection as well as the lowest initial cost (Hydraulic Institute and Europump, 2001). Exceptions to this include slurry handling pumps, high specific speed pumps, or where the pump would need a very low minimum net positive suction head at the pump inlet.

Correct Sizing Of Pump(s) (Matching Pump To Intended Duty). Pumps that are sized inappropriately result in unnecessary losses. Where peak loads can be reduced, pump size can also be reduced. Correcting for pump oversizing can save 15 to 25% of electricity consumption for pumping (on average for the U.S. industry) (Easton Consultants, 1995). In addition, pump load may be reduced with alternative pump configurations and improved O&M practices.

Where pumps are dramatically oversized, speed can be reduced with gear or belt drives or a slower speed motor. This practice, however, is not common. Paybacks for implementing these solutions are less than one year (OIT, 2002a).

The Chevron Refinery in Richmond, California, identified two large horsepower secondary pumps at the blending and shipping plant that were inappropriately sized for the intended use and needed throttling when in use. The 400 hp and 700 hp pump were replaced by two 200 hp pumps, and also equipped with adjustable speed drives. The energy consumption was reduced by 4.3 million kWh per year, and resulted in annual savings of $215,000 (CEC, 2001). With investments of $300,000 the payback period was 1.4 years.

The Welches Point Pump Station, a medium sized waste water treatment plant located in Milford (CT), as a participant in the Department of Energy's Motor Challenge Program, decided to replace one of their system's three identical pumps with one smaller model (Flygt, 2002). They found that the smaller pump could more efficiently handle typical system flows and the remaining two larger pumps could be reserved for peak flows. While the smaller pump needed to run longer to handle the same total volume, its slower pace and reduced pressure resulted in less friction-related losses and less wear and tear. Substituting the smaller pump has a projected savings of 36,096 kW, more than 20% of the pump system's annual electrical energy consumption. Using this system at each of the city's 36 stations would result in energy savings of over $100,000. In addition to the energy savings projected, less wear on the system results in less maintenance, less downtime and longer life of the equipment. The station noise is significantly reduced with the smaller pump.

Use Multiple Pumps. Often using multiple pumps is the most cost-effective and most energy efficient solution for varying loads, particularly in a static head-dominated system. Installing parallel systems for highly variable loads saves 10 to 50% of the electricity consumption for pumping (on average for the U.S. industry) (Easton Consultants, 1995). Variable speed controls should also be considered for dynamic systems (see below). Parallel pumps also offer redundancy and increased reliability. One case study of a Finnish pulp and paper plant indicated that installing an additional small pump (a "pony pump"), running in parallel to the existing pump used to circulate water from the paper machine into two tanks, reduced the load in the larger pump in all cases except for startup. The energy savings were estimated at $36,500 (or 486 MWh, 58%) per year giving a payback of 0.5 years (Hydraulic Institute and Europump, 2001).

Trimming Impeller (or Shaving Sheaves). If a large differential pressure exists at the operating rate of flow (indicating excessive flow), the impeller (diameter) can be trimmed so that the pump does not develop as much head. In the food processing, paper and petrochemical industries, trimming impellers or lowering gear ratios is estimated to save as much as 75% of the electricity consumption for specific pump applications (Xenergy, 1998).

In one case study in the chemical processing industry, the impeller was reduced from 320 mm to 280 mm, which reduced the power demand by more than 25% (Hydraulic Institute and Europump, 2001). Annual energy demand was reduced by 83 MWh (26%). With an investment cost of $390 (US), the payback on energy savings alone was 23 days. In addition to energy savings, maintenance costs were reduced, system stability was improved, cavitation was reduced, and excessive vibration and noise were eliminated.

In another case study, Salt Union Ltd., the largest salt producer in the UK, trimmed the diameter of a pump impeller at its plant from 320 mm to 280 mm (13 to 11 inches) (Best Practice Programme, 1996b). After trimming the impeller, they found significant power reductions of 30%, or 197,000 kWh per year (710 GJ/year), totaling 8,900 GBP ($14,000 1994 US). With an investment cost of 260 GBP ($400 1993 US), and maintenance savings of an additional 3,000 GBP ($4,600 1994 US), this resulted in a payback of 8 days (11 days from energy savings alone). In addition to energy and maintenance savings, like the chemical processing plant, cavitation was reduced and excessive vibration and noise were eliminated. With the large decrease in power consumption, the 110 kW motor could be replaced with a 75kW motor, with additional energy savings of about 16,000 kWh per year.

Controls. The objective of any control strategy is to shut off unneeded pumps or reduce the load of individual pumps until needed. Remote controls enable pumping systems to be started and stopped more quickly and accurately when needed, and reduce the required labor. In 2000, Cisco Systems (CA) upgraded the controls on its fountain pumps to turn off the pumps during peak hours (CEC and OIT, 2002). The wireless control system was able to control all pumps simultaneously from one location. The project saved $32,000 and 400,000 kWh annually, representing a savings of 61.5% of the fountain pumps' total energy consumption. With a total cost of $29,000, the simple payback was 11 months. In addition to energy savings, the project reduced maintenance costs and increased the pumping system's equipment life.

Adjustable Speed Drives (ASDs). ASDs better match speed to load requirements for pumps where, as for motors, energy use is approximately proportional to the cube of the flow rate[10]. Hence, small reductions in flow that are proportional to pump speed may yield large energy savings. New installations may result in short payback periods. In addition, the installation of ASDs improves overall productivity, control, and product quality, and reduces wear on equipment, thereby reducing future maintenance costs.

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[10] This equation applies to dynamic systems only. Systems that solely consist of lifting (static head systems) will accrue no benefits from (but will often actually become more inefficient) ASDs because they are independent of flow rate. Similarly, systems with more static head will accrue fewer benefits than systems that are largely dynamic (friction) systems. More careful calculations must be performed to determine actual benefits, if any, for these systems.

According to inventory data collected by Xenergy (1998), 82% of pumps in U.S. industry have no load modulation feature (or ASD). Similar to being able to adjust load in motor systems, including modulation features with pumps is estimated to save between 20 and 50% of pump energy consumption, at relatively short payback periods, depending on application, pump size, load and load variation (Xenergy, 1998; Best Practice Programme, 1996a). As a general rule of thumb, unless the pump curves are exceptionally flat, a 10% regulation in flow should produce pump savings of 20% and 20% regulation should produce savings of 40% (Best Practice Programme, 1996a).

The ChevronTexaco refinery in Richmond (California) upgraded the feed pumps of the diesel hydrotreater by installing an ASD on a 2,250 hp primary feed pump, as well as changing the operation procedures for a backup pump system. The cost savings amount to $700,000/year reducing electricity consumption by 12 GWh/year. The pump system retrofit was implemented as part of a demand side management program by the local utility. The refinery did not have to put up any investment capital as it participated in this program (U.S. DOE-OIT, 1999).

Hodgson and Walters (2002) discuss the application of an ASD to replace a throttle of a new to build pumping system. Optimization of the design using a dedicated software package led to the recommendation to install an ASD. This would result in 71% lower energy costs over the lifetime of the system, a 54% reduction in total lifetime costs of the system.

Avoid Throttling Valves. Throttling valves should always be avoided. Extensive use of throttling valves or bypass loops may be an indication of an oversized pump (Tutterow et al., 2000). Variable speed drives or on off regulated systems always save energy compared to throttling valves (Hovstadius, 2002).

An audit of the 25,000 bpd Flying J Refinery in Salt Lake City (Utah) identified throttle losses at two 200 hp charge pumps. Minimizing the throttle losses would result in potential energy cost savings of $39,000 (Brueske et al., 2002). The shutdown of a 250 hp pump when not needed and the minimization of throttle losses would result in additional savings of $28,000 per year.

Correct Sizing Of Pipes. Similar to pumps, undersized pipes also result in unnecessary losses. The pipe work diameter is selected based on the economy of the whole installation, the required lowest flow velocity, and the minimum internal diameter for the application, the maximum flow velocity to minimize erosion in piping and fittings, and plant standard pipe diameters. Increasing the pipe diameter may save energy but must be balanced with costs for pump system components. Easton Consultants (1995) and others in the pulp and paper industry (Xenergy, 1998) estimate retrofitting pipe diameters saves 5 to 20% of their energy consumption, on average for the U.S. industry. Correct sizing of pipes should be done at the design or system retrofit stages where costs may not be restrictive.

Replace Belt Drives. Inventory data suggests 4% of pumps have V-belt drives, many of which can be replaced with direct couplings to save energy (Xenergy, 1998). Savings are estimated at 1% (on average for the U.S. industry) (Xenergy, 1998).

Precision Castings, Surface Coatings, Or Polishing. The use of castings, coatings, or polishing reduces surface roughness that in turn, increases energy efficiency. It may also help maintain efficiency over time. This measure is more effective on smaller pumps. One case study in the steel industry analyzed the investment in surface coating on the mill supply pumps (350 kW pumps). They determined that the additional cost of coating, $1,200, would be paid back in 5 months by energy savings of $2,700 (or 36 MWh, 2%) per year (Hydraulic Institute and Europump, 2001). Energy savings for coating pump surfaces are estimated to be 2 to 3% over uncoated pumps (Best Practice Programme, 1998).

Sealings. Seal failure accounts for up to 70% of pump failures in many applications (Hydraulic Institute and Europump, 2001). The sealing arrangements on pumps will contribute to the power absorbed. Often the use of gas barrier seals, balanced seals, and no-contacting labyrinth seals optimize pump efficiency.

Curtailing Leakage Through Clearance Reduction. Internal leakage losses are a result of differential pressure across the clearance between the impeller and the pump casing. The larger the clearance, the greater is the internal leakage causing inefficiencies. The normal clearance in new pumps ranges from 0.35 to 1.0 mm (0.014 to 0.04 in.) (Hydraulic Institute and Europump, 2001). With wider clearances, the leakage increases almost linearly with the clearance. For example, a clearance of 5 mm (0.2 in.) decreases the efficiency by 7 to 15% in closed impellers and by 10 to 22% in semi-open impellers. Abrasive liquids and slurries, even rainwater, can affect the pump efficiency. Using very hard construction materials (such as stainless steel) can reduce the wear rate.

Dry Vacuum Pumps. Dry vacuum pumps were introduced in the semiconductor industry in Japan in the mid-1980s, and were introduced in the U.S. chemical industry in the late 1980s. The advantages of a dry vacuum pump are high energy efficiency, increased reliability, and reduced air and water pollution. It is expected that dry vacuum pumps will displace oil-sealed pumps (Ryans and Bays, 2001). Dry pumps have major advantages in applications where contamination is a concern. Due to the higher investment costs of a dry pump, it is not expected to make inroads in the petroleum refining industry in a significant way, except for special applications where contamination and pollution control are an important driver.

15. Compressors and Compressed Air

Compressors consume about 12% of total electricity use in refineries, or an estimated 5,800 GWh. The major energy users are compressors for furnace combustion air and gas streams in the refinery. Large compressors can be driven by electric motors, steam turbines, or gas turbines. A relatively small part of energy consumption of compressors in refineries is used to generate compressed air. Compressed air is probably the most expensive form of energy available in an industrial plant because of its poor efficiency. Typically, efficiency from start to end-use is around 10% for compressed air systems (LBNL et al., 1998). In addition, the annual energy cost required to operate compressed air systems is greater than their initial cost. Because of this inefficiency and the sizeable operating costs, if compressed air is used, it should be of minimum quantity for the shortest possible time, constantly monitored and reweighed against alternatives. Because of its limited use in a refinery (but still an inefficient source of energy), the main compressed air measures found in other industries are highlighted. Many opportunities to reduce energy in compressed air systems are not prohibitively expensive; payback periods for some options are extremely short – less than one year.

Compressed Air - Maintenance. Inadequate maintenance can lower compression efficiency, increase air leakage or pressure variability and lead to increased operating temperatures, poor moisture control and excessive contamination. Better maintenance will reduce these problems and save energy. Proper maintenance includes the following (LBNL et al., 1998, unless otherwise noted):

- Blocked pipeline filters increase pressure drop. Keep the compressor and intercooling surfaces clean and foul-free by inspecting and periodically cleaning filters. Seek filters with just a 1 psi pressure drop. Payback for filter cleaning is usually under 2 years (Ingersoll-Rand, 2001). Fixing improperly operating filters will also prevent contaminants from entering into equipment and causing them to wear out prematurely. Generally, when pressure drop exceeds 2 to 3 psig replace the particulate and lubricant removal elements. Inspect all elements at least annually. Also, consider adding filters in parallel to decrease air velocity and, therefore, decrease pressure drop. A 2% reduction of annual energy consumption in compressed air systems is projected for more frequent filter changing (Radgen and Blaustein, 2001). However, one must be careful when using coalescing filters; efficiency drops below 30% of design flow (Scales, 2002).
- Poor motor cooling can increase motor temperature and winding resistance, shortening motor life, in addition to increasing energy consumption. Keep motors and compressors properly lubricated and cleaned. Compressor lubricant should be sampled and analyzed every 1000 hours and checked to make sure it is at the proper level. In addition to energy savings, this can help avoid corrosion and degradation of the system.
- Inspect fans and water pumps for peak performance.
- Inspect drain traps periodically to ensure they are not stuck in either the open or closed position and are clean. Some users leave automatic condensate traps partially open at all times to allow for constant draining. This practice wastes substantial

amounts of energy and should never be undertaken. Instead, install simple pressure driven valves. Malfunctioning traps should be cleaned and repaired instead of left open. Some automatic drains do not waste air, such as those that open when condensate is present. According to vendors, inspecting and maintaining drains typically has a payback of less than 2 years (Ingersoll-Rand, 2001).
- Maintain the coolers on the compressor to ensure that the dryer gets the lowest possible inlet temperature (Ingersoll-Rand, 2001).
- Check belts for wear and adjust them. A good rule of thumb is to adjust them every 400 hours of operation.
- Check water-cooling systems for water quality (pH and total dissolved solids), flow and temperature. Clean and replace filters and heat exchangers per manufacturer's specifications.
- Minimize leaks (see also Reduce leaks section, below).
- Specify regulators that close when failed.
- Applications requiring compressed air should be checked for excessive pressure, duration or volume. They should be regulated, either by production line sectioning or by pressure regulators on the equipment itself. Equipment not required to operate at maximum system pressure should use a quality pressure regulator. Poor quality regulators tend to drift and lose more air. Otherwise, the unregulated equipment operates at maximum system pressure at all times and wastes the excess energy. System pressures operating too high also result in shorter equipment life and higher maintenance costs.

Monitoring. Proper monitoring (and maintenance) can save a lot of energy and money in compressed air systems. Proper monitoring includes the following (CADDET, 1997):
- Pressure gauges on each receiver or main branch line and differential gauges across dryers, filters, etc.
- Temperature gauges across the compressor and its cooling system to detect fouling and blockages
- Flow meters to measure the quantity of air used
- Dew point temperature gauges to monitor the effectiveness of air dryers
- kWh meters and hours run meters on the compressor drive
- Compressed air distribution systems should be checked when equipment has been reconfigured to be sure no air is flowing to unused equipment or obsolete parts of the compressed air distribution system.
- Check for flow restrictions of any type in a system, such as an obstruction or roughness. These require higher operating pressures than are needed. Pressure rise resulting from resistance to flow increases the drive energy on the compressor by 1% of connected power for every 2 psi of differential (LBNL et al., 1998; Ingersoll-Rand, 2001). Highest pressure drops are usually found at the points of use, including undersized or leaking hoses, tubes, disconnects, filters, regulators, valves, nozzles and lubricators (demand side), as well as air/lubricant separators, aftercoolers, moisture separators, dryers and filters.

Reduce leaks (in pipes and equipment). Leaks can be a significant source of wasted energy. A typical plant that has not been well maintained could have a leak rate between 20 to 50% of total compressed air production capacity (Ingersoll Rand, 2001). Leak repair and maintenance can sometimes reduce this number to less than 10%. Overall, a 20% reduction of annual energy consumption in compressed air systems is projected for fixing leaks (Radgen and Blaustein, 2001).

The magnitude of a leak varies with the size of the hole in the pipes or equipment. A compressor operating 2,500 hours per year at 6 bar (87 psi) with a leak diameter of 0.02 inches (½ mm) is estimated to lose 250 kWh/year; 0.04 in. (1 mm) to lose 1,100 kWh/year; 0.08 in. (2 mm) to lose 4,500 kWh/year; and 0.16 in. (4 mm) to lose 11,250 kWh/year (CADDET, 1997).

In addition to increased energy consumption, leaks can make pneumatic systems/equipment less efficient and adversely affect production, shorten the life of equipment, and lead to additional maintenance requirements and increased unscheduled downtime. Leaks cause an increase in compressor energy and maintenance costs. The most common areas for leaks are couplings, hoses, tubes, fittings, pressure regulators, open condensate traps and shut-off valves, pipe joints, disconnects, and thread sealants. Quick connect fittings always leak and should be avoided. A simple way to detect large leaks is to apply soapy water to suspect areas. The best way to detect leaks is to use an ultrasonic acoustic detector, which can recognize the high frequency hissing sounds associated with air leaks. After identification, leaks should be tracked, repaired, and verified. Leak detection and correction programs should be ongoing efforts.

A retrofit of the compressed air system of a Mobil distribution facility in Vernon (CA) led to the replacement of a compressor by a new 50 hp compressor and the repair of air leaks in the system. The annual energy savings amounted to $20,700, and investments were equal to $23,000, leading to a payback period of just over 1 year (U.S. DOE-OIT, 2003b).

Reducing the Inlet Air Temperature. Reducing the inlet air temperature reduces energy used by the compressor. In many plants, it is possible to reduce inlet air temperature to the compressor by taking suction from outside the building. Importing fresh air has paybacks of up to 5 years, depending on the location of the compressor air inlet (CADDET, 1997). As a rule of thumb, each 5°F (3°C) will save 1% compressor energy use (CADDET, 1997; Parekh, 2000).

Maximize Allowable Pressure Dew Point at Air Intake. Choose the dryer that has the maximum allowable pressure dew point, and best efficiency. A rule of thumb is that desiccant dryers consume 7 to 14% of the total energy of the compressor, whereas refrigerated dryers consume 1 to 2% as much energy as the compressor (Ingersoll Rand, 2001). Consider using a dryer with a floating dew point. Note that where pneumatic lines are exposed to freezing conditions, refrigerated dryers are not an option.

Controls. Remembering that the total air requirement is the sum of the average air consumption for pneumatic equipment, not the maximum for each, the objective of any control strategy is to shut off unneeded compressors or delay bringing on additional compressors until needed. All compressors that are on should be running at full load, except for one, which should handle trim duty. Positioning of the control loop is also important; reducing and controlling the system pressure downstream of the primary receiver results in reduced energy consumption of up to 10% or more (LBNL et al., 1998). Radgen and Blaustein (2001) report energy savings for sophisticated controls to be 12% annually. Start/stop, load/unload, throttling, multi-step, variable speed, and network controls are options for compressor controls and described below.

Start/stop (on/off) is the simplest control available and can be applied to small reciprocating or rotary screw compressors. For start/stop controls, the motor driving the compressor is turned on or off in response to the discharge pressure of the machine. They are used for applications with very low duty cycles. Applications with frequent cycling will cause the motor to overheat. Typical payback for start/stop controls is 1 to 2 years (CADDET, 1997).

Load/unload control, or constant speed control, allows the motor to run continuously but unloads the compressor when the discharge pressure is adequate. In most cases, unloaded rotary screw compressors still consume 15 to 35% of full-load power when fully unloaded, while delivering no useful work (LBNL et al., 1998). Hence, load/unload controls may be inefficient and require ample receiver volume.

Modulating or throttling controls allows the output of a compressor to be varied to meet flow requirements by closing down the inlet valve and restricting inlet air to the compressor. Throttling controls are applied to centrifugal and rotary screw compressors. Changing the compressor control to a variable speed control has saved up to 8% per year (CADDET, 1997). Multi-step or part-load controls can operate in two or more partially loaded conditions. Output pressures can be closely controlled without requiring the compressor to start/stop or load/unload.

Properly Sized Regulators. Regulators sometimes contribute to the biggest savings in compressed air systems. By properly sizing regulators, compressed air will be saved that is otherwise wasted as excess air. Also, it is advisable to specify pressure regulators that close when failing.

Sizing Pipe Diameter Correctly. Inadequate pipe sizing can cause pressure losses, increase leaks, and increase generating costs. Pipes must be sized correctly for optimal performance or resized to fit the current compressor system. Increasing pipe diameter typically reduces annual energy consumption by 3% (Radgen and Blaustein, 2001).

Heat Recovery For Water Preheating. As much as 80 to 93% of the electrical energy used by an industrial air compressor is converted into heat. In many cases, a heat recovery unit can recover 50 to 90% of the available thermal energy for space heating, industrial process heating, water heating, makeup air heating, boiler makeup water preheating, industrial drying, industrial cleaning processes, heat pumps, laundries or preheating aspirated air for oil burners (Parekh, 2000). Paybacks are typically less than one year. With large water-cooled compressors, recovery efficiencies of 50 to 60% are typical (LBNL et al., 1998). Implementing this measure recovers up to 20% of the energy used in compressed air systems annually for space heating (Radgen and Blaustein, 2001).

Adjustable Speed Drives (ASDs). Implementing adjustable speed drives in rotary compressor systems has saved 15% of the annual compressed air energy consumption (Radgen and Blaustein, 2001). The profitability of installing an ASD on a compressor depends strongly on the load variation of the particular compressor. When there are strong variations in load and/or ambient temperatures there will be large swings in compressor load and efficiency. In those cases, or where electricity prices are relatively high (> 4 cts/kWh) installing an ASD may result in attractive payback periods (Heijkers et al., 2000).

High Efficiency Motors. Installing high efficiency motors in compressor systems reduces annual energy consumption by 2%, and has a payback of less than 3 years (Radgen and Blaustein, 2001). For compressor systems, the largest savings in motor performance are typically found in small machines operating less than 10kW (Radgen and Blaustein, 2001).

16. Fans

Fans are used in boilers, furnaces, cooling towers, and many other applications. As in other motor applications, considerable opportunities exist to upgrade the performance and improve the energy efficiency of fan systems. Efficiencies of fan systems vary considerably across impeller types (Xenergy, 1998). However, the cost-effectiveness of energy efficiency opportunities depends strongly on the characteristics of the individual system.

Fan Oversizing. Most of the fans are oversized for the particular application, which can result in efficiency losses of 1-5% (Xenergy, 1998). However, it may often be more cost-effective to control the speed (see below with adjustable speed drives) than to replace the fan system.

Adjustable Speed Drive (ASD). Significant energy savings can be achieved by installing adjustable speed drives on fans. Savings may vary between 14 and 49% when retrofitting fans with ASDs (Xnergy, 1998).

An audit of the Paramount Petroleum Corp.'s asphalt refinery in Paramount (California) identified the opportunity to install ASDs on six motors in the cooling tower (ranging from 40 hp to 125 hp). The motors are currently operated manually, and are oversized for operation in the winter. If ASDs were installed at all six motors to maintain the cold-water temperature set point electricity savings of 1.2 million kWh/year could be achieved (U.S. DOE-OIT, 2003b). The payback would vary be relatively high due to the size of the motors and was to be around 5.8 years, resulting in annual savings of $46,000.

High Efficiency Belts (Cog Belts). Belts make up a variable, but significant portion of the fan system in many plants. It is estimated that about half of the fan systems use standard V-belts, and about two-thirds of these could be replaced by more efficient cog belts (Xenergy, 1998). Standard V-belts tend to stretch, slip, bend and compress, which lead to a loss of efficiency. Replacing standard V-belts with cog belts can save energy and money, even as a retrofit. Cog belts run cooler, last longer, require less maintenance and have an efficiency that is about 2% higher than standard V-belts. Typical payback periods will vary from less than one year to three years.

17. Lighting

Lighting and other utilities represent less than 3% of electricity use in refineries. Still, potential energy efficiency improvement measures exist, and may contribute to an overall energy management strategy. Because of the relative minor importance of lighting and other utilities, this Energy Guide focuses on the most important measures that can be undertaken. Additional information on lighting guidelines and efficient practices is available from the Illuminating Engineering Society of North America (www.iesna.org) and the California Energy Commission (CEC, 2003).

Lighting Controls. Lights can be shut off during non-working hours by automatic controls, such as occupancy sensors, which turn off lights when a space becomes unoccupied. Manual controls can also be used in addition to automatic controls to save additional energy in small areas.

Replace T-12 Tubes by T-8 Tubes or Metal Halides. T-12 refers to the diameter in 1/8 inch increments (T-12 means 12/8 inch or 3.8 cm diameter tubes). The initial output for T-12 lights is high, but energy consumption is also high. T-12 tubes have poor efficacy, lamp life, lumen depreciation and color rendering index. Because of this, maintenance and energy costs are high. Replacing T-12 lamps with T-8 lamps approximately doubles the efficacy of the former. It is important to remember, however, to work both with the suppliers and manufacturers on the system through each step of the retrofit process. There are a number of T-8 lights and ballasts on the market and the correct combination should be chosen for each system.

Ford North America paint shops retrofitted eleven of their twenty-one paint shops and saw lighting costs reduced by more than 50% (DEQ, 2001). Initial light levels were lower, but because depreciation is less, the maintained light level is equal and the new lamps last two to three times longer. Energy savings totaled 17.5 million kWh annually; operation savings were $500,000 per year. The Gillette Company manufacturing facility in Santa Monica, California replaced 4300 T-12 lamps with 496 metal halide lamps in addition to replacing 10 manual switches with 10 daylight switches (EPA, 2001). They reduced electricity use by 58% and saved $128,608 annually. The total project cost was $176,534, producing a payback of less than 1.5 years.

Replace Mercury Lights by Metal Halide or High-Pressure Sodium Lights. In industries where color rendition is critical, metal halide lamps save 50% compared to mercury or fluorescent lamps (Price and Ross, 1989). Where color rendition is not critical, high-pressure sodium lamps offer energy savings of 50 to 60% compared to mercury lamps (Price and Ross, 1989). High-pressure sodium and metal halide lamps also produce less heat, reducing HVAC loads. In addition to energy reductions, the metal halide lights provide better lighting, provide better distribution of light across work surfaces, improve color rendition, and reduce operating costs (GM, 2001).

Replace Standard Metal Halide HID With High-Intensity Fluorescent Lights. Traditional HID lighting can be replaced with high-intensity fluorescent lighting. These new systems incorporate high efficiency fluorescent lamps, electronic ballasts, and high-efficacy fixtures that maximize output to the workspace. Advantages of the new system are many: lower energy consumption, lower lumen depreciation over the lifetime of the lamp, better dimming options, faster start-up and restrike capability, better color rendition, higher pupil lumens ratings, and less glare (Martin et al., 2000). High-intensity fluorescent systems yield 50% electricity savings over standard metal halide HID. Dimming controls that are impractical in the metal halide HIDs save significant energy in the new system. Retrofitted systems cost about $185 per fixture, including installation costs (Martin et al., 2000). In addition to energy savings and better lighting qualities, high-intensity fluorescents may help improve productivity and have reduced maintenance costs.

Replace Magnetic Ballasts With Electronic Ballasts. A ballast is a mechanism that regulates the amount of electricity required to start a lighting fixture and maintain a steady output of light. Electronic ballasts save 12 to 25% power over their magnetic predecessors (EPA, 2001). Electronic ballasts have dimming capabilities as well (Eley et al., 1993). If automatic daylight sensing, occupancy sensing and manual dimming are included with the ballasts, savings can be greater than 65% (Turiel et al., 1995).

Reflectors. A reflector is a highly polished "mirror-like" component that directs light downward, reducing light loss within a fixture. Reflectors can minimize required wattage effectively.

Light Emitting Diodes (LEDs) or Radium Lights. One way to reduce energy costs is simply switching from incandescent lamps to LEDs or radium strips in exit sign lighting. LEDs use about 90% less energy than conventional exit signs (Anaheim Public Utilities, 2001). A 1998 Lighting Research Center survey found that about 80 percent of exit signs being sold use LEDs (LRC, 2001). In addition to exit signs, LEDs are increasingly being used for path marking and emergency way finding systems. Their long life and cool operation allows them to be embedded in plastic materials, which makes them perfect for these applications. Radium strips use no energy at all and can be used similarly.

The Flying J Refinery in North Salt Lake (Utah) replaced exit signs by new LED signs saving about $1,200/year.

System Improvements. By combining several of the lighting measures above, light system improvements can be the most effective and comprehensive way to reduce lighting energy. High frequency ballasts and specular reflectors can be combined with 50% fewer efficient high-frequency fluorescent tubes and produce 90% as much light while saving 50 to 60% of the energy formerly used (Price and Ross, 1989). An office building in Michigan reworked their lighting system using high-efficiency fluorescent ballasts and reduced lighting load by 50% and total building electrical load by nearly 10% (Price and Ross, 1989). Similar results were obtained in a manufacturing facility when replacing fluorescent fixtures with metal halide lamps. Often these system improvements improve lighting as well as decrease energy consumption.

Reducing system voltage may also save energy. One U.S. automobile manufacturer put in reduced voltage HID lights and found a 30% reduction in lighting. Electric City is one of the suppliers of EnergySaver, a unit that attaches to a central panel switch (controllable by computer) and constricts the flow of electricity to fixtures, thereby reducing voltage and saving energy, with an imperceptible loss of light. Bristol Park Industries has patented another lighting voltage controller called the Wattman© Lighting Voltage Controller that works with high intensity discharge (HID) and fluorescent lighting systems with similar energy saving results (Bristol Park Industries, 2002).

18. Power Generation

Most refineries have some form of onsite power generation. In fact, refineries offer an excellent opportunity for energy efficient power generation in the form of combined heat and power production (CHP). CHP provides the opportunity to use internally generated fuels for power production, allowing greater independence of grip operation and even export to the grid. This increases reliability of supply as well as the cost-effectiveness. The cost benefits of power export to the grid will depend on the regulation in the state where the refinery is located. Not all states allow wheeling of power (i.e., sales of power directly to another customer using the grid for transport) while the regulation may also differ with respect to the tariff structure for power sales to the grid operator.

18.1 Combined Heat and Power Generation (CHP)

The petroleum refining industry is one of the largest users of cogeneration or CHP in the country. Current installed capacity is estimated to be over 6,000 MWe, making it the largest CHP user after the chemical and pulp & paper industries. Still, only about 10% of all steam used in refineries is generated in cogeneration units. Hence, the petroleum refining industry is also identified as one of the industries with the largest potential for increased application of CHP. In fact, an efficient refinery can be a net exporter of electricity. The potential for exporting electricity is even enlarged with new innovative technologies currently used commercially at selected petroleum refineries (discussed below). The potential for conventional cogeneration (CHP) installations is estimated at an additional 6,700 MWe (Onsite, 2000), of which most in medium to large-scale gas turbine based installations.

Where process heat, steam, or cooling and electricity are used, cogeneration plants are significantly more efficient than standard power plants because they take advantage of what are losses in conventional power plants by utilizing waste heat. In addition, transportation losses are minimized when CHP systems are located at or near the refinery. Third parties have developed CHP for use by refineries. In this scenario, the third party company owns and operates the system for the refinery, which avoids the capital expenditures associated with CHP projects, but gains (part of) the benefits of a more energy efficient system of heat and electricity supply. In fact, about 60% of the cogeneration facilities operated within the refinery industry are operated by third party companies (Onsite, 2000). For example, in 2001 BP’s Whiting refinery (Indiana) installed a new 525 MW cogeneration unit with a total investment of $250 million carried by Primary Energy Inc. Many new cogeneration projects can be financed in this way. Other opportunities consist of joint-ventures between the refinery and an energy generation or operator to construct a cogeneration facility.

Optimization of the operation strategy of CHP units and boilers is an area in which additional savings can be achieved. The development of a dispatch optimization program at the Hellenic Aspropyrgos Refinery (Greece) to meet steam and electricity demand demonstrates the potential energy and cost-savings (Frangopoluos et al., 1996).

For systems requiring cooling, absorption cooling can be combined with CHP to use waste heat to produce cooling power. In refineries, refrigeration and cooling consumes about 5-6% of all electricity. Cogeneration in combination with absorption cooling has been demonstrated for building sites and sites with refrigeration leads. The authors do not know of applications in the petroleum refinery industry.

Innovative gas turbine technologies can make CHP more attractive for sites with large variations in heat demand. **Steam injected gas turbines** (STIG or Cheng cycle) can absorb excess steam, e.g., due to seasonal reduced heating needs, to boost power production by injecting the steam in the turbine. The size of typical STIGs starts around 5 MW_e, and is currently scaled up to sizes of 125 MW. STIGs have been installed at over 50 sites worldwide, and are found in various industries and applications, especially in Japan and Europe, as well as in the United States. Energy savings and payback period will depend on the local circumstances (e.g., energy patterns, power sales, conditions). In the United States, the Cheng Cycle is marketed by International Power Systems (San Jose, California). The Austrian oil company OMV has considered the use of a STIG to upgrade an existing cogeneration system. The authors do not know of any current commercial applications of STIG in an oil refinery.

Steam turbines are often used as part of the CHP system in a refinery or as stand-alone systems for power generation. The efficiency of the steam turbine is determined by the inlet steam pressure and temperature as well as the outlet pressure. Each turbine is designed for a certain steam inlet pressure and temperature, and operators should make sure that the steam inlet temperature and pressure are optimal. An 18°F decrease in steam inlet temperature will reduce the efficiency of the steam turbine by 1.1% (Patel and Nath, 2000). Similarly, maintaining exhaust vacuum of a condensing turbine or the outlet pressure of a backpressure turbine too high will result in efficiency losses.

Valero's Houston refinery constructed a 34 MW cogeneration unit in 1990, using two gas turbines and two heat recovery steam generators (boilers). The system supplies all electricity for the refinery and occasionally allows export to the grid. The CHP system has resulted in savings of about $55,000/day (Valero, 2003).

Even for small refineries, CHP is an attractive option. An audit of the Paramount Petroleum Corp.'s asphalt refinery in Paramount (CA) identified the opportunity to install CHP at this refinery. The audit identified a CHP unit as the largest energy saving measure in this small refinery. A 6.5 MWe gas turbine CHP unit would result in annual energy savings of $3.8 million and has a payback period 2.5 years (U.S. DOE-OIT, 2003b). In addition, the CHP unit would reduce the risk of power outages for the refinery. The investment costs assume best available control technology for emission reduction. The installation was installed in 2002.

18.2 Gas Expansion Turbines

Natural gas is often delivered to a refinery at very high pressures. Gas is transmitted at high pressures, from 200 to 1500 psi. Expansion turbines use the pressure drop when natural gas from high-pressure pipelines is decompressed to generate power or to use in a process heater. An expansion turbine includes both an expansion mechanism and a generator. In an expansion turbine, high-pressure gas is expanded to produce work. Energy is extracted from pressurized gas, which lowers gas pressure and temperature. These turbines have been used for air liquefaction in the chemical industry for several decades. The application of expansion turbines as energy recovery devices started in the early 1980s (SDI, 1982b). The technology has much improved since the 1980s and is highly reliable today. A simple expansion turbine consists of an impeller (expander wheel) and a shaft and rotor assembly attached to a generator. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. If flow is too low for efficient generation, or the expansion turbine fails, pressure is reduced in the traditional manner. The drop in pressure in the expansion cycle causes a drop in temperature. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below –15°C. In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. This necessitates heating the gas just before or after expansion. The heating is generally performed with either a combined heat and power (CHP) unit, or a nearby source of waste heat. Petroleum refineries often have excess low-temperature waste heat, making a refinery an ideal location for a power recovery turbine. Industrial companies and utilities in Europe and Japan have installed expansion turbine projects. However, it is unknown if any petroleum refineries have installed this technology.

In 1994, the Corus integrated steel mill at IJmuiden (the Netherlands) installed a 2 MW power recovery turbine. The mill receives gas at 930 psi, preheats the gas, and expands with the turbine to 120 psi. The maximum turbine flow is 1.4 million ft^3/hr (40,000 m^3/hr) while the average capacity is 65%, resulting in an average flow of 0.9 million ft^3/hr. The turbine uses cooling water from the hot strip mill of approximately 160°F (70 °C), to preheat the gas (Lehman and Worrell, 2001). The 2 MW turbine generated roughly 11,000 MWh of electricity in 1994, while the strip mill delivered a maximum of 12,500 MWh of waste heat to the gas flow. Thus, roughly 88% of the maximum heat input to the high-pressure gas emerged as electricity. The cost of the installation was $2.6 million, and the operation and maintenance costs total $110,000 per year. With total costs of $110,000 per year and income of $710,000 per year from electricity generation (at the 1994 Dutch electricity cost of 6.5 cents per kWh), the payback period for the project is 4.4 years.

18.3 Steam Expansion Turbines.

Steam is generated at high pressures, but often the pressure is reduced to allow the steam to be used by different processes. For example, steam is generated at 120 to 150 psig. This steam then flows through the distribution system within the plant. The pressure is reduced to as low as 10-15 psig for use in different process. Once the heat has been extracted, the condensate is often returned to the steam generating plant. Typically, the pressure reduction is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop. This energy could be recovered by using a micro scale backpressure steam turbine. Several manufactures produce these turbine sets, such as Turbosteam (previously owned by Trigen) and Dresser-Rand.

The potential for application will depend on the particular refinery and steam system used. Applications of this technology have been commercially demonstrated for campus facilities, pulp and paper, food, and lumber industries, but not yet in the petroleum industry. The investments of a typical expansion turbine are estimated at 600 $/kWe, and operation and maintenance costs at 0.011 $/kWh.

18.4 High-temperature CHP

Turbines can be pre-coupled to a crude distillation unit (or other continuously operated processes with an applicable temperature range). The offgases of the gas turbine can be used to supply the heat for the distillation furnace, if the outlet temperature of the turbine is high enough. One option is the so-called `repowering' option. In this option, the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen, and can thus be used as combustion air for the furnaces. The gas turbine can deliver up to 20% of the furnace heat. Two of these installations are installed in the Netherlands, with a total capacity of 35 MW_e at refineries (Worrell et al., 1997). A refinery on the West Coast has installed a 16 MW_e gas turbine at a reformer (Terrible et al., 1999). The flue gases of the turbine feed to the convection section of the reformer increasing steam generation. The steam is used to power a 20 MW_e steam turbine.

Another option, with a larger CHP potential and associated energy savings, is "high-temperature CHP". In this case, the flue gases of a CHP plant are used to heat the input of a furnace or to preheat the combustion air. The potential at U.S. refineries is estimated at 34 GW (Zollar, 2002). This option requires replacing the existing furnaces. This is due to the fact that the radiative heat transfer from gas turbine exhaust gases is much smaller than from combustion gases, due to their lower temperature (Worrell et al., 1997). A distinction is made between two different types. In the first type, the exhaust heat of a gas turbine is led to a waste heat recovery furnace, in which the process feed is heated. In the second type, the exhaust heat is led to a "waste heat oil heater" in which thermal oil is heated. By means of a heat exchanger, the heat content is transferred to the process feed. In both systems, the remaining heat in the exhaust gases after heating the process feed should be used for lower temperature purposes to achieve a high overall efficiency. The second type is more reliable, due to the fact that a thermal oil buffer can be included. The main difference is that in the first type the process feed is directly heated by exhaust gases, where the second uses thermal oil as an intermediate, leading to larger flexibility. An installation of the first type is installed in Fredericia, Denmark at a Shell refinery. The low temperature remaining heat is used for district heating. R&D has to be aimed at making detailed design studies for specific refineries and the optimization of furnace design, and more demonstration projects have to be carried out.

18.5 Gasification

Gasification provides the opportunity for cogeneration using the heavy bottom fraction and refinery residues (Marano, 2003)**.** Because of the increased demand for lighter products and increased use of conversion processes, refineries will have to manage an increasing stream of heavy bottoms and residues. Gasification of the heavy fractions and coke to produce synthesis gas can help to efficiently remove these by-products. The state-of-the-art gasification processes combine the heavy by-products with oxygen at high temperature in an entrained bed gasifier. Due to the limited oxygen supply, the heavy fractions are gasified to a mixture of carbon monoxide and hydrogen. Sulfur can easily be removed in the form of H_2S to produce elemental sulfur. The synthesis gas can be used as feedstock for chemical processes. However, the most attractive application seems to be generation of power in an Integrated Gasifier Combined Cycle (IGCC). In this installation the synthesis gas is combusted in a gas turbine (with an adapted combustion chamber to handle the low to medium-BTU gas) generating electricity. The hot fluegases are used to generate steam. The steam can be used onsite or used in a steam turbine to produce additional electricity (i.e., the combined cycle). Cogeneration efficiencies can be up to 75% (LHV) and for power production alone the efficiency is estimated at 38-39% (Marano, 2003).

Entrained bed IGCC technology is originally developed for refinery applications, but is also used for the gasification of coal. Hence, the major gasification technology developers were oil companies like Shell and Texaco. IGCC provides a low-cost opportunity to reduce emissions (SOx, NOx) when compared to combustion of the residue, and to process the heavy bottoms and residues while producing power and/or feedstocks for the refinery. Potentially about 40 refineries in the United States have a sufficiently large capacity to make the technology attractive (Marano, 2003).

IGCC is used by the Shell refinery in Pernis (the Netherlands) to treat residues from the hydrocracker and other residues to generate 110 MWe of power and 285 tonnes of hydrogen for the refinery. The IPA Falconara refinery (Italy) uses IGCC to treat visbreaker residue to produce 241 MWe of power (Cabooter, 2001). New installations have been announced or are under construction for the refineries at Baytown (ExxonMobil, Texas), Deer Park (Shell, Texas), Sannazzaro (Agip, Italy), Lake Charles, (Citgo, Louisiana) and Bulwer Island (BP, Australia).

The investment costs will vary by capacity and products of the installation. The capital costs of a gasification unit consuming 2,000 tons per day of heavy residue would cost about $229 million of the production of hydrogen and $347 million for an IGCC unit. The operating cost savings will depend on the costs of power, natural gas, and the costs of heavy residue disposal or processing.

19. Other Opportunities

19.1 Process Changes and Design

Desalter. Alternative designs for desalting include multi-stage desalters and combination of AC and DC fields. These alternative designs may lead to increased efficiency and lower energy consumption (IPPC, 2002).

Catalytic Reformer - Increased Product Recovery. Product recovery from a reformer may be limited by the temperature of the distillation to separate the various products. An analysis of a reformer at the Colorado Refinery in Commerce City, Colorado (now operated by Valero) showed increased LPG losses at increased summer temperatures. The LPG would either be flared or used as fuel gas. By installing a waste heat driven ammonia absorption refrigeration plant, the recovery temperature was lowered, debottlenecking the compressors and the unsaturated light-cycle oil streams (Petrick and Pellegrino, 1999). The heat pump uses a 290°F waste heat stream of the reformer to drive the compressor. The system was installed in 1997 and was supported by the U.S. Department of Energy as a demonstration project. The project resulted in annual savings of 65,000 barrels of LPG. The recovery rate varies with ambient temperature. The liquid product fraction contained a higher percentage of heavier carbon chain (C_5, C_6+) products. The payback period is estimated at 1.5 years (Brant et al., 1998).

Hydrotreater. Desulfurization is becoming more and more important as probable future regulations will demand a lower sulfur content of fuels. Desulfurization is currently mainly done by hydrotreaters. Hydrotreaters use a considerable amount of energy directly (fuel, steam, electricity) and indirectly (hydrogen). Various alternatives are being developed, but of which many are not yet commercially available (Babich and Moulijn, 2003). New catalysts increase the efficiency of sulfur removal, while new reactor designs are proposed to integrate some of the process steps (e.g., catalytic distillation as used in the CDTech process implemented at Motiva's Port Arthur (TX) refinery. In the future, designs building on process intensification that integrate chemical reactions and separation are proposed. Use of any alternative desulfurization technology to produce low sulfur should be evaluated on the basis of the sulfur content of the naphtha and diesel streams, and on the applicability of the process to the specific conditions of the refinery.

Various alternatives are demonstrated at refineries around the world, including the oxidative desulfurization process (Valero's Krotz Springs, Louisiana) and the S Zorb process at Philip's Borger (TX). The S Zorb process is a sorbent operated in a fluidized bed reactor. Philips Petroleum Co. claims a significant reduction in hydrogen consumption to produce low-sulfur gasoline and diesel (Gislason, 2001). A cursory comparison of the characteristics of the S Zorb process and that of selected hydrotreaters suggests a lower fuel and electricity consumption, but increased water consumption.

19.2 Alternative Production Flows

FCC - Process Flow Changes. The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or changing the number of pumparounds can improve energy efficiency of the FCC, as it allows increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions to enhance product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC unit with appropriate modifications of equipment and operating conditions can increase the yield of high octane gasoline and alkylate from 3% to 7% per barrel of crude oil. This would result in energy savings.

19.3 Other Opportunities

Flare Optimization. Flares are used to safely dispose of combustible gases and to avoid release to the environment of these gases through combustion/oxidation. All refineries operate flares. Which, in the majority of refineries are used to burn gases in the case of a system upset. Older flare systems have a pilot flame that is burning continuously. This results in losses of natural gas. Also, this may lead to methane (a powerful greenhouse gas) losses to the environment if the pilot flame is extinguished.

Modern flare pilot designs are more efficient using electronic ignition when the flare is needed, have sensors for flame detection and shut off the fuel gas, reducing methane emissions. These systems can reduce average natural gas use to below 45 scf/hour. The spark ignition systems use low electrical power, which can be supplied by photovoltaic (solar cell) system, making the whole system independent of an external power supply. Various systems are marketed by a number of suppliers, e.g., John Zink.

Chevron replaced a continuous burning flare by an electronic ignition system at a refinery, which resulted in savings of 1.68 million scf/year (or 168 MBtu/year), with a payback off less than 3 years.

Heated Storage Tanks. Some storage tanks at the refinery are kept at elevated temperatures to control viscosity of the product stored. Insulation of the tank can reduce the energy losses.

An audit of the Fling J Refinery at North Salt Lake (Utah) found that insulating the top of a 80,000 bbl storage tank that is heated to a temperature of 225°F would result in annual savings of $148,000 (Brueske et al., 2002).

20. Summary and Conclusions

Petroleum refining in the United States is the largest refining industry in the world, providing inputs to virtually any economic sector, including the transport sector and the chemical industry. The industry operates 146 refineries (as of 2004) around the country, employing over 65,000 employees. The refining industry produces a mix of products with a total value exceeding $151 billion. Energy costs represents one the largest production cost factors in the petroleum refining industry, making energy efficiency improvement an important way to reduce costs and increase predictable earnings, especially in times of high energy-price volatility.

Voluntary government programs aim to assist industry to improve competitiveness through increased energy efficiency and reduced environmental impact. ENERGY STAR, a voluntary program managed by the U.S. Environmental Protection Agency, stresses the need for strong and strategic corporate energy management programs. ENERGY STAR provides energy management tools and strategies for successful corporate energy management programs. This Energy Guide describes research conducted to support ENERGY STAR and its work with the petroleum refining industry. This research provides information on potential energy efficiency opportunities for petroleum refineries.

Competitive benchmarking data indicates that most petroleum refineries can economically improve energy efficiency by 10-20%. This potential for savings amounts to annual costs savings of millions to tens of millions of dollars for a refinery, depending on current efficiency and size. Improved energy efficiency may result in co-benefits that far outweigh the energy cost savings, and may lead to an absolute reduction in emissions.

This Energy Guide introduced energy efficiency opportunities available for petroleum refineries. It started with descriptions of the production trends, structure and production of the refining industry and the energy used in the refining and conversion processes. Specific energy savings for each energy efficiency measure based on case studies of plants and references to technical literature were provided. The Energy Guide draws upon the experiences with energy efficiency measures of petroleum refineries worldwide. If available, typical payback periods were also listed.

The findings suggest that given available resources and technology, there are opportunities to reduce energy consumption cost-effectively in the petroleum refining industry while maintaining the quality of the products manufactured, underling the results of benchmarking studies. Further research on the economics of the measures, as well as the applicability of these to different refineries, is needed to assess the feasibility of implementation of selected technologies at individual plants. Table 8 summarizes the energy efficiency opportunities.

Table 8. Summary of energy efficiency opportunities for utilities and cross-cutting energy uses.

Management & Control Energy monitoring Site energy control systems	**Process Integration** Total site pinch analysis Water pinch analysis
Power Generation CHP (cogeneration) Gas expansion turbines High-Temperature CHP Gasification (Combined Cycle)	**Energy Recovery** Flare gas recovery Power recovery Hydrogen recovery Hydrogen pinch analysis
Boilers Boiler feedwater preparation Improved boiler controls Reduced flue gas volume Reduced excess air Improve insulation Maintenance Flue gas heat recovery Blowdown heat recovery Reduced standby losses	**Steam Distribution** Improved insulation Maintain insulation Improved steam traps Maintain steam traps Automatic monitoring steam traps Leak repair Recover flash steam Return condensate
Heaters and Furnaces Maintenance Draft control Air preheating Fouling control New burner designs	**Distillation** Optimized operation procedures Optimized product purity Seasonal pressure adjustments Reduced reboiler duty Upgraded column internals
Compressed Air Maintenance Monitoring Reduce leaks Reduce inlet air temperature Maximize allowable pressure dewpoint Controls Properly sized regulators Size pipes correctly Adjustable speed drives Heat recovery for water preheating	**Pumps** Operations & maintenance Monitoring More efficient pump designs Correct sizing of pumps Multiple pump use Trimming impeller Controls Adjustable speed drives Avoid throttling valves Correct sizing of pipes Reduce leaks Sealings Dry vacuum pumps
Motors Proper sizing of motors High efficiency motors Power factor control Voltage unbalance Adjustable speed drives Variable voltage controls Replace belt drives	**Fans** Properly sizing Adjustable speed drives High-efficiency belts
Lighting Lighting controls T8 Tubes Metal halides/High-pressure sodium	**High-intensity fluorescent (T5)** Electronic ballasts Reflectors LED exit signs

Table 9. Summary of process-specific energy efficiency opportunities.

Desalter Multi-stage desalters Combined AC/DC fields	**Hydrocracker** Power recovery Process integration (pinch) Furnace controls Air preheating Optimization distillation
CDU Process controls High-temperature CHP Process integration (pinch) Furnace controls Air preheating Progressive crude distillation Optimization distillation	**Coking** Process integration (pinch) Furnace controls Air preheating
VDU Process controls Process integration (pinch) Furnace controls Air preheating Optimization distillation	**Visbreaker** Process integration (pinch) Optimization distillation
Hydrotreater Process controls Process integration (pinch) Optimization distillation New hydrotreater designs	**Alkylation** Process controls Process integration (pinch) Optimization distillation
Catalytic Reformer Process integration (pinch) Furnace controls Air preheating Optimization distillation	**Hydrogen Production** Process integration (pinch) Furnace controls Air preheating Adiabatic pre-reformer
FCC Process controls Power recovery Process integration (pinch) Furnace controls Air preheating Optimization distillation Process flow changes	**Other** Optimize heating storage tanks Optimize flares

Acknowledgements

This work was supported by the Climate Protection Partnerships Division of the U.S. Environmental Protection Agency as part of its ENERGY STAR program through the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Many people inside and outside the industry provided helpful insights in the preparation of this Energy Guide. We would like to thank Brian Eidt and staff at ExxonMobil, F.L. Oaks (Marathon Ashland), and Marc Taylor (Shell) for the review of the draft report. We would like to thank Susan Gustofson (Valero) and Chaz Lemmon (ConocoPhillips) for providing insights into the petroleum refining industry in California. We also like to thank Gunnar Hovstadius (ITT Fluid Technology) for his review and help, as well as Elizabeth Dutrow (U.S. Environmental Protection Agency), Don Hertkorn and Fred Schoeneborn for their review of earlier drafts of the report. Despite all their efforts, any remaining errors are the responsibility of the authors. The views expressed in this paper do not necessarily reflect those of the U.S. Environmental Protection Agency, the U.S. Department of Energy or the U.S. Government.

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Appendix A: Active refineries in the United States as of January 2003

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Age Refining & Marketing	Big Spring	Texas	58,500	0.3%	67,500	0.4%
	San Antonio	Texas	9,000	0.1%		
American International Rfy Inc	Lake Charles	Louisiana	30,000	0.2%	30,000	0.2%
American Refining Group Inc.	Bradford	Pennsylvania	10,000	0.1%	10,000	0.1%
Atofina Petrochemicals Inc.	Port Arthur	Texas	175,068	1.0%	175,068	1.0%
BP	Ferndale (Cherry Point)	Washington	225,000	1.3%	1,519,200	9.0%
	Kuparuk	Alaska	16,000	0.1%		
	Prudhoe Bay	Alaska	14,200	0.1%		
	Toledo	Ohio	157,000	0.9%		
	Whiting	Indiana	410,000	2.4%		
	Texas City	Texas	437,000	2.6%		
	Los Angeles	California	260,000	1.5%		
Calcasieu Refining Co.	Lake Charles	Louisiana	29,400	0.2%	29,400	0.2%
Calumet Lubricants Co. LP	Cotton Valley	Louisiana	13,020	0.1%	67,520	0.4%
	Princeton	Louisiana	8,300	0.0%		
	Shreveport	Louisiana	46,200	0.3%		
Cenex Harvest States Coop	Laurel	Montana	55,000	0.3%	55,000	0.3%
Chalmette Refining LLC	Chalmette	Louisiana	182,500	1.1%	182,500	1.1%
ChevronTexaco	El Paso	Texas	90,000	0.5%	1,079,000	6.4%
	El Segundo	California	260,000	1.5%		
	Honolulu	Hawaii	54,000	0.3%		
	Pascagoula	Mississippi	325,000	1.9%		
	Perth Amboy	New Jersey	80,000	0.5%		
	Richmond	California	225,000	1.3%		
	Salt Lake City	Utah	45,000	0.3%		
Citgo	Corpus Christi	Texas	156,000	0.9%	510,000	3.0%
	Lake Charles	Louisiana	326,000	1.9%		
	Savannah	Georgia	28,000	0.2%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Coastal Eagle Point Oil Co.	Westville	New Jersey	142,287	0.8%	142,287	0.8%
ConocoPhilips	Arroyo Grande	California	41,800	0.2%	2,263,200	13.4%
	Belle Chasse	Louisiana	253,500	1.5%		
	Billings	Montana	60,000	0.4%		
	Borger	Texas	143,800	0.9%		
	Commerce City	Colorado	60,000	0.4%		
	Ferndale (Cherry Point)	Washington	92,000	0.5%		
	Linden	New Jersey	250,000	1.5%		
	Ponca City	Oklahoma	194,000	1.2%		
	Rodeo	California	73,200	0.4%		
	Sweeny	Texas	213,000	1.3%		
	Trainer	Pennsylvania	180,000	1.1%		
	Westlake	Louisiana	252,000	1.5%		
	Wilmington	California	136,600	0.8%		
	Wood River	Illinois	288,300	1.7%		
	Woods Cross	Utah	25,000	0.1%		
Countrymark Cooperative Inc.	Mount Vernon	Indiana	23,000	0.1%	23,000	0.1%
Cross Oil Refining and Mktg, Inc.	Smackover	Arkansas	6,800	0.0%	6,800	0.0%
Crown Central Petroleum Corp.	Pasadena	Texas	100,000	0.6%	100,000	0.6%
Edgington Oil Co.	Long Beach	California	14,000	0.1%	14,000	0.1%
Ergon Refining Inc.	Vicksburg	Mississippi	23,000	0.1%	42,400	0.3%
	Newell (Congo)	West Virginia	19,400	0.1%		
ExxonMobil	Baton Rouge	Louisiana	491,000	2.9%	1,823,000	10.8%
	Baytown	Texas	516,500	3.1%		
	Beaumont	Texas	348,500	2.1%		
	Billings	Montana	58,000	0.3%		
	Joliet	Illinois	238,000	1.4%		
	Mobile Bay	Alabama	22,000	0.1%		
	Torrance	California	149,000	0.9%		
Farmland Industries Inc.	Coffeyville	Kansas	112,000	0.7%	112,000	0.7%
Flint Hills Resources LP	Corpus Christi	Texas	259,980	1.5%	524,980	3.1%
	Saint Paul	Minnesota	265,000	1.6%		
Flying J Inc.	North Salt Lake	Utah	25,000	0.1%	25,000	0.1%
Foreland Refining Corp.	Eagle Springs	Nevada	5,000	0.0%	5,000	0.0%
Frontier Refg Inc.	Cheyenne	Wyoming	46,000	0.3%	149,000	0.9%
	El Dorado	Kansas	103,000	0.6%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Giant Refining Co.	Bloomfield	New Mexico	16,800	0.1%	96,200	0.6%
	Gallup	New Mexico	20,800	0.1%		
	Yorktown	Virginia	58,600	0.3%		
Haltermann Products	Channelview	Texas	880	0.0%	880	0.0%
Hunt Refining Co.	Tuscaloosa	Alabama	35,000	0.2%	35,000	0.2%
Kern Oil & Refining Co.	Bakersfield	California	25,000	0.1%	25,000	0.1%
La Gloria Oil & Gas Co.	Tyler	Texas	55,000	0.3%	55,000	0.3%
Lion Oil Co.	El Dorado	Arkansas	63,000	0.4%	63,000	0.4%
Lunday Thagard	South Gate	California	8,500	0.1%	8,500	0.1%
Lyondell Citgo Refining Co. Ltd.	Houston	Texas	270,200	1.6%	270,200	1.6%
Marathon Ashland Petro LLC	Canton	Ohio	73,000	0.4%	935,000	5.5%
	Catlettsburg	Kentucky	222,000	1.3%		
	Detroit	Michigan	74,000	0.4%		
	Garyville	Louisiana	232,000	1.4%		
	Robinson	Illinois	192,000	1.1%		
	Saint Paul Park	Minnesota	70,000	0.4%		
	Texas City	Texas	72,000	0.4%		
Montana Refining Co.	Great Falls	Montana	7,000	0.0%	7,000	0.0%
Motiva Enterprises LLC	Convent	Louisiana	235,000	1.4%	879,700	5.2%
	Delaware City	Delaware	175,000	1.0%		
	Norco	Louisiana	219,700	1.3%		
	Port Arthur	Texas	250,000	1.5%		
Murphy Oil U.S.A. Inc.	Meraux	Louisiana	95,000	0.6%	128,000	0.8%
	Superior	Wisconsin	33,000	0.2%		
Navajo Refining Co.	Artesia	New Mexico	58,000	0.3%	58,000	0.3%
NCRA	McPherson	Kansas	81,200	0.5%	81,200	0.5%
Paramount Petroleum Corp.	Paramount	California	50,000	0.3%	50,000	0.3%
PDV Midwest Refining LLC	Lemont (Chicago)	Illinois	160,000	0.9%	160,000	0.9%
Petro Star Inc.	North Pole	Alaska	18,000	0.1%	68,000	0.4%
	Valdez	Alaska	50,000	0.3%		
Placid Refining Co.	Port Allen	Louisiana	48,500	0.3%	48,500	0.3%
Premcor Refg Group Inc	Lima	Ohio	161,500	1.0%	416,500	2.5%
	Port Arthur	Texas	255,000	1.5%		

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
San Joaquin Refining Co Inc.	Bakersfield	California	24,300	0.1%	24,300	0.1%
Shell	Anacortes	Washington	140,800	0.8%	932,800	5.5%
	Bakersfield	California	65,000	0.4%		
	Deer Park	Texas	333,700	2.0%		
	Martinez	California	154,800	0.9%		
	Saint Rose	Louisiana	55,000	0.3%		
	Saraland (Mobile)	Alabama	85,000	0.5%		
	Wilmington	California	98,500	0.6%		
Silver Eagle Refining	Evanston	Wyoming	3,000	0.0%	19,000	0.1%
	Woods Cross	Utah	11,000	0.1%		
Sinclair Oil Corp.	Evansville (Casper)	Wyoming	22,500	0.1%	150,195	0.9%
	Sinclair	Wyoming	62,000	0.4%		
	Tulsa	Oklahoma	65,695	0.4%		
Somerset Refinery Inc.	Somerset	Kentucky	5,500	0.0%	5,500	0.0%
Southland Oil Co.	Lumberton	Mississippi	5,800	0.0%	16,800	0.1%
	Sandersville	Mississippi	11,000	0.1%		
Sunoco Inc.	Marcus Hook	Pennsylvania	175,000	1.0%	730,000	4.3%
	Toledo	Ohio	140,000	0.8%		
	Tulsa	Oklahoma	85,000	0.5%		
	Philadelphia	Pennsylvania	330,000	2.0%		
Tenby Inc.	Oxnard	California	2,800	0.0%	2,800	0.0%
Tesoro	Anacortes	Washington	115,000	0.7%	570,500	3.4%
	Ewa Beach	Hawaii	93,500	0.6%		
	Mandan	North Dakota	58,000	0.3%		
	Martinez	California	166,000	1.0%		
	Salt Lake City	Utah	58,000	0.3%		
	Kenai	Alaska	80,000	0.5%		
U.S. Oil & Refining Co.	Tacoma	Washington	35,150	0.2%	35,150	0.2%
Ultramar Inc.	Wilmington	California	80,887	0.5%	80,887	0.5%
United Refining Co.	Warren	Pennsylvania	65,000	0.4%	65,000	0.4%

Company	Site	State	Capacity (b/cd)	Share	Company - Total (b/cd)	Share company
Valero Energy Corp.	Ardmore	Oklahoma	85,000	0.5%	1,416,000	8.4%
	Benicia	California	144,000	0.9%		
	Corpus Christi	Texas	134,000	0.8%		
	Denver	Colorado	28,000	0.2%		
	Houston	Texas	83,000	0.5%		
	Krotz Springs	Louisiana	83,000	0.5%		
	Paulsboro	New Jersey	167,000	1.0%		
	St. Charles	Louisiana	155,000	0.9%		
	Sunray (McKee)	Texas	155,000	0.9%		
	Texas City	Texas	215,000	1.3%		
	Three Rivers	Texas	90,000	0.5%		
	Wilmington	California	77,000	0.5%		
Williams	North Pole	Alaska	227,513	1.3%	407,513	2.4%
	Memphis	Tennessee	180,000	1.1%		
Wynnewood Refining Co.	Wynnewood	Oklahoma	52,500	0.3%	52,500	0.3%
Wyoming Refining Co.	Newcastle	Wyoming	12,500	0.1%	12,500	0.1%
Young Refining Corp.	Douglasville	Georgia	5,400	0.0%	5,400	0.0%

Appendix B: Employee Tasks for Energy Efficiency

One of the key steps to a successful energy management program is the involvement of all personnel. Staff may be trained in both skills and the general approach to energy efficiency in day-to-day practices. Personnel at all levels should be aware of energy use and objectives for efficiency. By passing information to everyone, each employee may be able to save energy every day. In addition, performance results should be regularly evaluated and communicated to all personnel, recognizing high performers. Examples of some simple tasks employees can do include the following (Caffal, 1995):

- Report leaks of water (both process water and dripping taps), steam and compressed air and ensure they are repaired quickly.
- Check to make sure the pressure and temperature of equipment is not set too high.
- Carry out regular maintenance of energy consuming equipment.
- Ensure that the insulation on process heating equipment is effective.
- Switch off motors, fans and machines when they are not being used and it does not affect production, quality or safety.
- Switch off unnecessary lights and relying on day lighting whenever possible.
- Use weekend and night setbacks on HVAC in any unused offices or conditioned buildings.
- Look for unoccupied, heated or cooled areas and switch off heating or cooling.
- Check that heating controls are not set too high or cooling controls set too low. In this situation, windows and doors are often left open to lower temperatures instead of lowering the heating.
- Prevent drafts from badly fitting seals, windows and doors, and hence, leakage of cool or warm air.

Appendix C: Energy Management System Assessment for Best Practices in Energy Efficiency

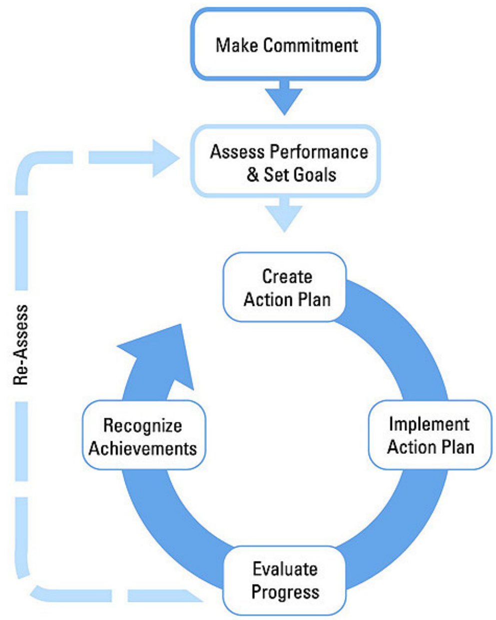
	ORGANIZATION		SYSTEMS MONITORING		TECHNOLOGY		O & M
	Accountability	**Organization**	**Monitoring & Targeting**	**Utilities Management**	**Reviews**	**Plans**	**Operation & Maintenance**
0	No awareness of responsibility for energy usage. Energy not specifically discussed in meetings.	No energy manager or "energy champion."	Energy efficiency of processes on site not determined. Few process parameters monitored regularly.	No utilities consumption monitoring.	No specific reviews held.	No energy improvement plans published.	No written procedures for practices affecting energy efficiency.
1	Operations staff aware of the energy efficiency performance objective of the site.	Energy manager is combined with other tasks and roles such that less than 10% of one person’s time is given to specific energy activities.	Energy efficiency of site determined monthly or yearly. Site annual energy efficiency target set. Some significant process parameters are monitored.	Utilities (like power and fuel consumption) monitored on overall site basis.	Energy only reviewed as part of other type reviews	Energy improvement plans published but based on an arbitrary assessment of opportunities.	No procedures available to operating staff.
2	Energy efficiency performance indicators are produced and available to operations staff. Periodic energy campaigns. Intermittent energy review meetings.	Energy manager appointed giving greater than 10% of time to task. Occasional training in energy related issues.	Weekly trend monitoring of energy efficiency of processes and of site, monitored against targets. Process parameters monitored against target.	Weekly monitoring of steam/power balance.	Infrequent energy review.	Energy performance plan published based on estimate of opportunities.	Procedures available to operators but not recently reviewed.

	ORGANIZATION		SYSTEMS MONITORING		TECHNOLOGY		O & M
	Accountability	**Organization**	**Monitoring & Targeting**	**Utilities Management**	**Reviews**	**Plans**	**Operation & Maintenance**
3	Energy efficiency performance parameter determined for all energy consuming areas. Operations staff advised of performance. All employees aware of energy policy. Performance review meetings held once/month.	Energy manager in place greater than 30% of time given to task. Ad-hoc training arranged. Energy performance reported to management.	Daily trend monitoring of energy efficiency of processes and of site, monitored against target. Process parameters monitored against targets.	Daily monitoring of steam/power. Steam & fuel balances adjusted daily.	Regular plant/site energy reviews carried out.	A five-year energy improvement plan is published based on identified opportunities from energy review.	Procedures available to operators and reviewed in the last three years.
4	Energy efficiency performance parameter included in personal performance appraisals. All staff involved in site energy targets and improvement plans. Regular weekly meeting to review performance.	An energy manager is in place giving greater than 50% time to task. Energy training to take place regularly. Energy performance reported to management and actions followed up.	Same as 3, with additional participation in energy efficiency target setting. Process parameters trended.	Real time monitoring of fuel, steam and steam/power balance. Optimum balances maintained.	Site wide energy studies carried out at least every five years with follow up actions progressed to completion	A ten year energy improvement plan based on review is published and integrated into the Business Plan.	Procedures are reviewed regularly and updated to incorporate the best practices. Used regularly by operators and supervisors.

Appendix D: Energy Management Assessment Matrix

ENERGY STAR Guidelines For Energy Management Assessment Matrix
The U.S. EPA has developed guidelines for establishing and running an effective energy management program based on the successful practices of ENERGY STAR partners.

These guidelines, illustrated in the graphic, are structured on seven fundamental management elements that encompass specific activities.



This Assessment Matrix is designed to help organizations and energy managers compare their energy management practices to those outlined in the Guidelines. The full Guidelines can be viewed on the ENERGY STAR web site - www.energystar.gov

How To Use The Assessment Matrix
The matrix outlines the key activities identified in the ENERGY STAR Guidelines for Energy Management and three levels of implementation:

● No evidence
● Most elements
● Fully Implemented

Compare your program to the Guidelines by choosing the degree of implementation that most closely matches your organization's program. You can assign yourself a score in order to help identify areas to focus on for improvement.

Interpreting Your Results
Comparing your program to the level of implementation identified in the Matrix should help you identify the strengths and weaknesses of your program.

The total "score" achieved in the matrix is less important than the process of evaluating your program's practices, identifying gaps, and determining areas for improvement.

The U.S. EPA has observed that organizations fully implementing the practices outlined in the Guidelines achieve the greatest results. Organizations are encouraged to implement the Guidelines as fully as possible.

Resources and Help
ENERGY STAR offers a variety tools and resources to help organizations strengthen their energy management programs. Here are some next steps you can take with ENERGY STAR:

1. Read the Guidelines sections for the areas where you scored lower.

2. Become an ENERGY STAR Partner, if you are not already.

3. Review ENERGY STAR Tools and Resources.

4. Find more sector-specific energy management information at www.energystar.gov.

5. Contact ENERGY for additional resources.

ENERGY STAR Guidelines For Energy Management Assessment				
	0 - Little or no evidence	**1 - Some elements/degree**	**2 - Fully implemented**	**Score**
Make Commitment to Continuous Improvement				
Energy Director	No central corporate resource Decentralized management	Corporate resource not empowered	Empowered corporate leader with senior management support	
Energy Team	No company energy network	Informal organization	Active cross-functional team guiding energy program	
Energy Policy	No formal policy	Referenced in environmental or other policies	Formal stand-alone EE policy endorsed by senior mgmt.	
Assess Performance and Opportunities				
Gather and Track Data	Little metering/no tracking	Local or partial metering/tracking/reporting	All facilities report for central consolidation/analysis	
Normalize	Not addressed	Some unit measures or weather adjustments	All meaningful adjustments for corporate analysis	
Establish baselines	No baselines	Various facility-established	Standardized corporate base year and metric established	
Benchmark	Not addressed or only same site historical comparisons	Some internal comparisons among company sites	Regular internal & external comparisons & analyses	
Analyze	Not addressed	Some attempt to identify and correct spikes	Profiles identifying trends, peaks, valleys & causes	
Technical assessments and audits	Not addressed	Internal facility reviews	Reviews by multi-functional team of professionals	
Set Performance Goals				
Determine scope	No quantifiable goals	Short term facility goals or nominal corporate goals	Short & long term facility and corporate goals	
Estimate potential for improvement	No process in place	Specific projects based on limited vendor projections	Facility & corporate defined based on experience	
Establish goals	Not addressed	Loosely defined or sporadically applied	Specific & quantifiable at various organizational levels	

Create Action Plan				
Define technical steps and targets	Not addressed	Facility-level consideration as opportunities occur	Detailed multi-level targets with timelines to close gaps	
Determine roles and resources	Not addressed	Informal interested person competes for funding	Internal/external roles defined & funding identified	
Implement Action Plan				
Create a communication plan	Not addressed	Tools targeted for some groups used occasionally	All stakeholders are addressed on regular basis	
Raise awareness	No overt effort made	Periodic references to energy initiatives	All levels of organization support energy goals	
Build capacity	Indirect training only	Some training for key individuals	Broad training/certification in technology & best practices	
Motivate	Occasional mention	Threats for non-performance or periodic reminders	Recognition, financial & performance incentives	
Track and monitor	No system for monitoring progress	Annual reviews by facilities	Regular reviews & updates of centralized system	
Evaluate Progress				
Measure results	No reviews	Historical comparisons	Compare usage & costs vs. goals, plans, competitors	
Review action plan	No reviews	Informal check on progress	Revise plan based on results, feedback & business factors	
Recognize Achievements				
Provide internal recognition	Not addressed	Identify successful projects	Acknowledge contributions of individuals, teams, facilities	
Get external recognition	Not sought	Incidental or vendor acknowledgement	Government/third party highlighting achievements	
			Total Score	

Appendix E: Support Programs for Industrial Energy Efficiency Improvement

This appendix provides a list of energy efficiency supports available to industry. A brief description of the program or tool is given, as well as information on its target audience and the URL for the program. Included are federal and state programs. Use the URL to obtain more information from each of these sources. An attempt was made to provide as complete a list as possible; however, information in this listing may change with the passage of time.

Tools for Self-Assessment

Steam System Assessment Tool

Description:	Software package to evaluate energy efficiency improvement projects for steam systems. It includes an economic analysis capability.
Target Group:	Any industry operating a steam system
Format:	Downloadable software package (13.6 MB)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/steam/ssat.html

Steam System Scoping Tool

Description:	Spreadsheet tool for plant managers to identify energy efficiency opportunities in industrial steam systems.
Target Group:	Any industrial steam system operator
Format:	Downloadable software (Excel)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/software_tools.shtml#steamtool

MotorMaster+

Description:	Energy efficient motor selection and management tool, including a catalog of over 20,000 AC motors. It contains motor inventory management tools, maintenance log tracking, efficiency analysis, savings evaluation, energy accounting and environmental reporting capabilities.
Target Group:	Any industry
Format:	Downloadable Software (can also be ordered on CD)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/software_tools.shtml

ASDMaster: Adjustable Speed Drive Evaluation Methodology and Application

Description:	Software program helps to determine the economic feasibility of an adjustable speed drive application, predict how much electrical energy may be saved by using an ASD, and search a database of standard drives.
Target Group:	Any industry
Format:	Software package (not free)
Contact:	EPRI, (800) 832-7322
URL:	http://www.epri-peac.com/products/asdmaster/asdmaster.html

AirMaster:+ Compressed Air System Assessment and Analysis Software

Description:	Modeling tool that maximizes the efficiency and performance of compressed air systems through improved operations and maintenance practices
Target Group:	Any industry operating a compressed air system
Format:	Downloadable software
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/software_tools.shtml

Fan System Assessment Tool (FSAT)

Description:	The Fan System Assessment Tool (FSAT) helps to quantify the potential benefits of optimizing fan system. FSAT calculates the amount of energy used by a fan system; determines system efficiency; and quantifies the savings potential of an upgraded system.
Target Group:	Any user of fans
Format:	Downloadable software
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/software_tools.shtml

Pump System Assessment Tool (PSAT)

Description:	The tool helps industrial users assess the efficiency of pumping system operations. PSAT uses achievable pump performance data from Hydraulic Institute standards and motor performance data from the MotorMaster+ database to calculate potential energy and associated cost savings.
Target Group:	Any industrial pump user
Format:	Downloadable software
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/steam/psat.html

ENERGY STAR Portfolio Manager

Description:	Online software tool helps to assess the energy performance of buildings by providing a 1-100 ranking of a building's energy performance relative to the national building market. Measured energy consumption forms the basis of the ranking of performance.
Target Group:	Any building user or owner
Format:	Online software tool
Contact:	U.S. Environmental Protection Agency,
URL:	http://www.energystar.gov/index.cfm?c=business.bus_index

Optimization of the Insulation of Boiler Steam Lines – 3E Plus

Description:	Downloadable software to determine whether boiler systems can be optimized through the insulation of boiler steam lines. The program calculates the most economical thickness of industrial insulation for a variety of operating conditions. It makes calculations using thermal performance relationships of generic insulation materials included in the software.
Target Group:	Energy and plant managers
Format:	Downloadable software
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/software_tools.shtml

Assessment and Technical Assistance

Industrial Assessment Centers

Description:	Small- to medium-sized manufacturing facilities can obtain a free energy and waste assessment. The audit is performed by a team of engineering faculty and students from 30 participating universities in the United States and assesses the plant's performance and recommends ways to improve efficiency.
Target Group:	Small- to medium-sized manufacturing facilities with gross annual sales below $75 million and fewer than 500 employees at the plant site.
Format:	A team of engineering faculty and students visits the plant and prepares a written report with energy efficiency, waste reduction and productivity recommendations.
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/iac/

Plant-Wide Audits

Description:	An industry-defined team conducts an on-site analysis of total energy use and identifies opportunities to save energy in operations and in motor, steam, compressed air and process heating systems. The program covers 50% of the audit costs.
Target Group:	Large plants
Format:	Solicitation (put out regularly by DOE)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/plant_wide_assessments.shtml

Manufacturing Extension Partnership (MEP)

Description:	MEP is a nationwide network of not-for-profit centers in over 400 locations providing small- and medium-sized manufacturers with technical assistance. A center provides expertise and services tailored to the plant, including a focus on clean production and energy efficient technology.
Target Group:	Small- and medium-sized plants
Format:	Direct contact with local MEP Office
Contact:	National Institute of Standards and Technology, (301) 975-5020
URL:	http://www.mep.nist.gov/

Small Business Development Center (SBDC)

Description:	The U.S Small Business Administration (SBA) administers the Small Business Development Center Program to provide management assistance to small businesses through 58 local centers. The SBDC Program provides counseling, training and technical assistance in the areas of financial, marketing, production, organization, engineering and technical problems and feasibility studies, if a small business cannot afford consultants.
Target Group:	Small businesses
Format:	Direct contact with local SBDC
Contact:	Small Business Administration, (800) 8-ASK-SBA
URL:	http://www.sba.gov/sbdc/

ENERGY STAR – Selection and Procurement of Energy Efficient Products for Business

Description:	ENERGY STAR identifies and labels energy efficient office equipment. Look for products that have earned the ENERGY STAR. They meet strict energy efficiency guidelines set by the EPA. Office equipment included such items as computers, copiers, faxes, monitors, multifunction devices, printers, scanners, transformers and water coolers.
Target Group:	Any user of labeled equipment.
Format:	Website
Contact:	U.S. Environmental Protection Agency
URL:	http://www.energystar.gov/index.cfm?c=business.bus_index

Training

Best Practices Program

Description:	The Best Practices Program of the Office for Industrial Technologies of U.S. DOE provides training and training materials to support the efforts of the program in efficiency improvement of utilities (compressed air, steam) and motor systems (including pumps). Training is provided regularly in different regions. One-day or multi-day trainings are provided for specific elements of the above systems. The Best Practices program also provides training on other industrial energy equipment, often in coordination with conferences. A clearinghouse provides answers to technical questions and on available opportunities: 202-586-2090 or http://www.oit.doe.gov/clearinghouse/
Target Group:	Technical support staff, energy and plant managers
Format:	Various training workshops (one day and multi-day workshops)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.oit.doe.gov/bestpractices/training/

ENERGY STAR

Description:	As part of ENERGY STAR's work to promote superior energy management systems, energy managers for the companies that participate in ENERGY STAR are offered the opportunity to network with other energy managers in the partnership. The networking meetings are held monthly and focus on a specific strategic energy management topic to train and strengthen energy managers in the development and implementation of corporate energy management programs.
Target Group:	Corporate and plant energy managers
Format:	Web-based teleconference
Contact:	Climate Protection Partnerships Division, U.S. Environmental Protection Agency
URL:	http://www.energystar.gov/

Financial Assistance

Below the major federal programs are summarized that provide assistance for energy efficiency investments. Many states also offer funds or tax benefits to assist with energy efficiency projects.

Industries of the Future - U.S. Department of Energy

Description:	Collaborative R&D partnerships in nine vital industries. The partnership consists of the development of a technology roadmap for the specific sector and key technologies, and cost-shared funding of research and development projects in these sectors.
Target Group:	Nine selected industries: agriculture, aluminum, chemicals, forest products, glass, metal casting, mining, petroleum and steel.
Format:	Solicitations (by sector or technology)
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.eere.energy.gov/industry/technologies/industries.html

Inventions & Innovations (I&I)

Description:	The program provides financial assistance through cost-sharing of 1) early development and establishing technical performance of innovative energy-saving ideas and inventions (up to $75,000) and 2) prototype development or commercialization of a technology (up to $250,000). Projects are performed by collaborative partnerships and must address industry-specified priorities.
Target Group:	Any industry (with a focus on energy intensive industries)
Format:	Solicitation
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.eere.energy.gov/inventions/

National Industrial Competitiveness through Energy, Environment and Economics (NICE^3)

Description:	Cost-sharing program to promote energy efficiency, clean production and economic competitiveness in industry through state and industry partnerships (large and small business) for projects that develop and demonstrate advances in energy efficiency and clean production technologies. Applicants must submit project proposals through a state energy, pollution prevention or business development office. Non-federal cost share must be at least 50% of the total cost of the project.
Target Group:	Any industry
Format:	Solicitation
Contact:	U.S. Department of Energy, Industry Technologies Program
URL:	http://www.eere.energy.gov/wip/program/nice3.html

Small Business Administration (SBA)

Description:	The Small Business Administration provides several loan and loan guarantee programs for investments (including energy efficient process technology) for small businesses.
Target Group:	Small businesses
Format:	Direct contact with SBA
Contact:	Small Business Administration
URL:	http://www.sba.gov/

State and Local Programs

Many state and local governments have general industry and business development programs that can be used to assist businesses in assessing or financing energy efficient process technology or buildings. Please contact your state and local government to determine what tax benefits, funding grants, or other assistance they may be able to provide your organization. This list should not be considered comprehensive but instead merely a short list of places to start in the search for project funding. Below we summarize selected programs earmarked specifically for support of energy efficiency activities.

California – Public Interest Energy Research (PIER)

Description:	PIER provides funding for energy efficiency, environmental, and renewable energy projects in the state of California. Although there is a focus on electricity, fossil fuel projects are also eligible.
Target Group:	Targeted industries (e.g., food industries) located in California
Format:	Solicitation
Contact:	California Energy Commission, (916) 654-4637
URL:	http://www.energy.ca.gov/pier/funding.html

California – Energy Innovations Small Grant Program (EISG)

Description:	EISG provides small grants for development of innovative energy technologies in California. Grants are limited to $75,000.
Target Group:	All businesses in California
Format:	Solicitation
Contact:	California Energy Commission, (619) 594-1049
URL:	http://www.energy.ca.gov/research/innovations/index.html

Indiana – Industrial Programs

Description:	The Energy Policy Division of the Indiana Department of Commerce operates two industrial programs. The Industrial Energy Efficiency Fund (IEEF) is a zero-interest loan program (up to $250,000) to help Indiana manufacturers increase the energy efficiency of manufacturing processes. The fund is used to replace or convert existing equipment, or to purchase new equipment as part of a process/plant expansion that will lower energy use. The Distributed Generation Grant Program (DGGP) offers grants of up to $30,000 or up to 30% of eligible costs for distributed generation with an efficiency over 50% to install and study distributed generation technologies such as fuel cells, micro turbines, cogeneration, combined heat & power and renewable energy sources. Other programs support can support companies in the use of biomass for energy, research or building efficiency.
Target Group:	Any industry located in Indiana
Format:	Application year-round for IEEF and in direct contact for DGGP
Contact:	Energy Policy Division, (317) 232-8970.
URL:	http://www.in.gov/doc/businesses/EP_industrial.html

Iowa – Alternate Energy Revolving Loan Program

Description:	The Alternate Energy Revolving Loan Program (AERLP) was created to promote the development of renewable energy production facilities in the state.
Target Group:	Any potential user of renewable energy
Format:	Proposals under $50,000 are accepted year-round. Larger proposals are accepted on a quarterly basis.
Contact:	Iowa Energy Center, (515) 294-3832
URL:	http://www.energy.iastate.edu/funding/aerlp-index.html

New York – Industry Research and Development Programs

Description:	The New York State Energy Research & Development Agency (NYSERDA) operates various financial assistance programs for New York businesses. Different programs focus on specific topics, including process technology, combined heat and power, peak load reduction and control systems.
Target Group:	Industries located in New York
Format:	Solicitation
Contact:	NYSERDA, (866) NYSERDA
URL:	http://www.nyserda.org/programs/Commercial_Industrial/default.asp?i=2

Wisconsin – Focus on Energy

Description:	Energy advisors offer free services to identify and evaluate energy-saving opportunities, recommend energy efficiency actions, develop an energy management plan for business; and integrate elements from national and state programs. It can also provide training.
Target Group:	Industries in Wisconsin
Format:	Open year round
Contact:	Wisconsin Department of Administration, (800) 762-7077
URL:	http://focusonenergy.com/page.jsp?pageId=4

Appendix B

Why Emission Factors Don't Work at Refineries and What to do about it

By Alex Cuclis

Presentation/Paper for: Environmental Protection Agency

At the Emissions Inventory Conference in Tampa, Florida on August 13-16, 2012

"Emission Inventories – Meeting the Challenges Posed by Emerging Global, National, Regional and Local Air Quality Issues"

Abstract

A number of studies in the U.S., Canada and Europe have found that reported emissions of volatile organic compounds (VOCs) at refineries and chemical plants are substantially lower than the measured emissions. In several cases the reported emissions were an order of magnitude or more lower than the measured emissions. One of the main flaws of emissions reporting is that emission factors and other emissions estimating techniques assume equipment is "well-maintained". However, process equipment can have failures due to operator error, faulty design or maintenance that was performed incorrectly or not at all. In order to capture these errors, measurements are required; however, total vapor analyzers (TVAs) or "sniffers" typically used in Leak Detection and Repair (LDAR) programs only measure one point in space. Techniques such as Differential Absorption Light Detection and Ranging (DIAL) and Solar Occultation Flux (SOF) measure the VOC concentrations in a two dimensional vertical plane and calculate VOC flux in pounds per hour. The results determine the total VOC mass released. The National Institute of Science and Technology (NIST) has chosen to develop a DIAL system to measure and verify reductions in greenhouse gases that may be used in off-sets, carbon trading, a carbon tax or other exchange since there are concerns that the emission estimating techniques for greenhouse gases have similar problems. This paper provides a list of studies where measured VOC emissions were found to be substantially higher than reported values and how Sweden is using DIAL and SOF in place of emission factors and emission estimates. Additional information is provided on which parts of the petrochemical facilities are most responsible for low emission estimates and how the U.S. could benefit from the Swedish model as well as some of the obstacles.

Introduction

Several studies performed in the U.S. indicate that the reported values of VOCs from petrochemical facilities are substantially lower than measured values. In 1985, Keith Bauges of the U.S. EPA found that emissions near the Houston petrochemical complex were 5.9 times higher than expected based on reported values.[1] In 2000 at the Texas Air Quality Study (TexAQS) near Houston, the University of Texas (UT) found that emissions were underestimated by a factor of 3-15,[2, 3] whereas a team from the National Oceanic and Atmospheric Administration (NOAA) estimated the error was between one to two orders of magnitude.[4,5] A follow-up study in 2006 (TexAQS 2006 or TexAQS II) found that emissions had dropped by 40% since 2000, but they were still one to two orders of magnitude higher than reported based on the last available inventory.[6]

Similar results have been found in Europe where they have consistently found measured emissions that are several times higher than expected based on EPA/AP-42 estimating techniques. Because of these discrepancies, Sweden has been using either DIAL or SOF surveys as the basis for calculating annual emissions estimates that are entered into their emissions inventories for over two decades despite objections raised by various industry groups.

The concern of underestimated emissions was expressed by EPA employee Brenda Shine in a technical memorandum dated July 27, 2007, with the subject "Potential Low Bias of Reported VOC Emissions from the Petroleum Refining Industry." The memo describes the Swedish approach for determining emissions from refineries as well as the DIAL results indicating measured emissions have been found to be 10 times or more than reported emissions. Shine cited this information, stating that these techniques must be investigated since reported emissions are the basis of U.S. ozone control strategies and abatement of air toxics.[7]

A critical feature of DIAL and SOF measuring techniques is their ability to systematically identify the general location as well as the magnitude of the leaks so that corrective actions can be taken in an efficient manner. The early applications of DIAL at refineries in Sweden has been published by Lennart Frisch, who worked for the local regulatory agency at the time and was the main driving force for getting DIAL as the established method for measuring refinery emissions.[8] Frisch also presented Sweden's experiences with DIAL at a Remote Sensing Workshop in Research Triangle Park hosted by EPA in 2006.[9]

The graphic below by Spectrasyne, one of the DIAL vendors, displays the differences observed between calculated or estimated emissions and measured emissions.

Comparison of Reported Emissions to Emissions Measured by DIAL

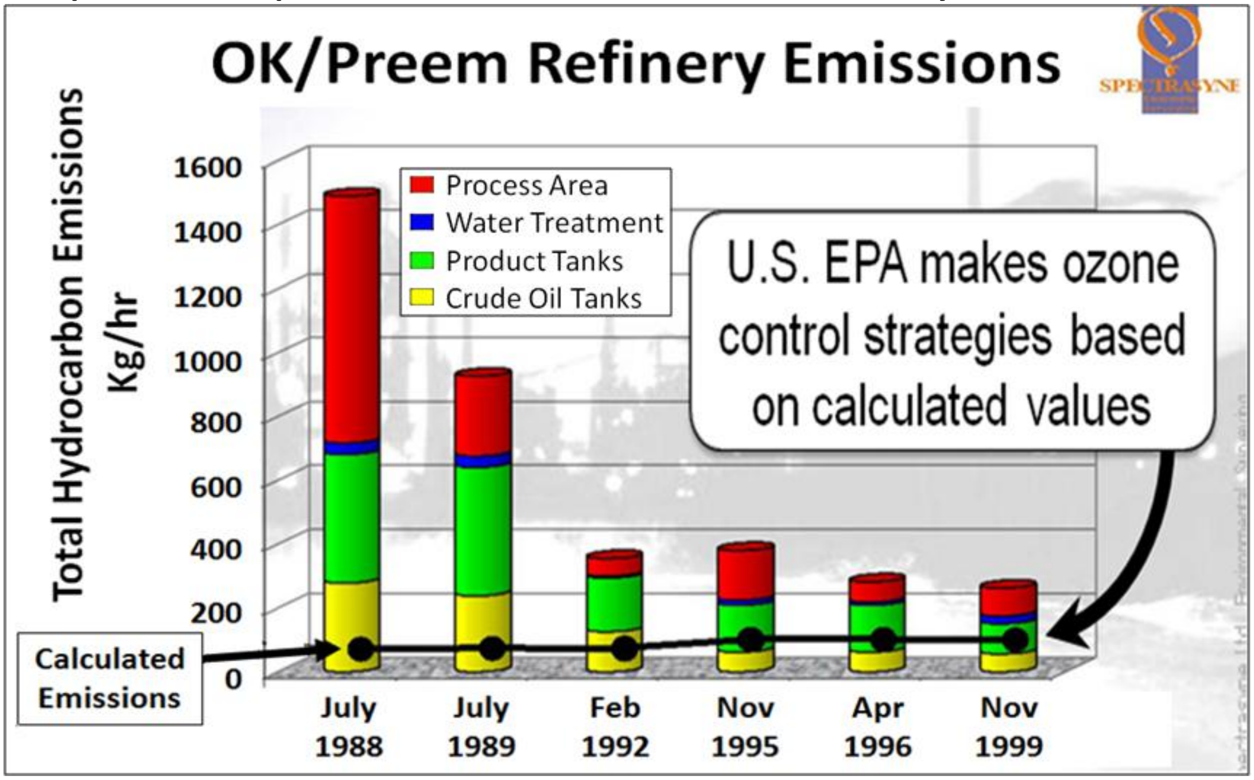


Figure 1. DIAL results at a refinery in Sweden over several years. (used with permission from Jan Moncrieff, Technical Director, Spectrasyne).[10]

Figure 1 illustrates several important issues:

1. At this refinery, measured emissions were initially 20 times higher than reported, but emissions dropped by about 80% over a ten year period.

2. Calculated values, which are based on EPA/AP-42 estimating techniques, did not change much, and actually increased to adjust for increasing capacity, but did not decrease to reflect changes implemented to reduce emissions at the facility.

3. After significant problems have been resolved, the measured emissions change very little, even with changing temperatures. This is an indication that annualization, or taking results from a 2 - 3 week DIAL survey, provides a reasonable estimate of annual emissions. If there were problems accounting for seasonal swings in temperature or extrapolating based on temporal emissions, then there should be much more variation observed in the data.

4. Even after many years of measuring with DIAL, measured emissions are higher than the emissions calculated with AP-42 or other similar methods. This result is consistent with many other studies.

In the late 1980's and early 1990's the Swedish EPA based their hydrocarbon emissions on the calculated results. In 1992 they required all 5 refineries to measure emissions instead of calculating them, without specifying any measuring principle. However, many of the methods selected by Swedish refiners (Open path Fourier Transform Infrared Spectroscopy (FTIR), Differential Optical Absorbance Spectroscopy (DOAS), and others) were incapable of translating concentration or path length measurements to mass flux. As a result in 1995, Swedish authorities required all refiners to report emissions based on DIAL studies performed at least once every 3 years. (Note: Vertical Radial Plume Mapping or VRPM, developed after DIAL and SOF, can be used to measure the mass flux of chemicals on a small scale).

The first DIAL study of hydrocarbons at a refinery was in July 1988. The hydrocarbon emissions measured at the Swedish BP refinery exceeded 1400 kg/h, whereas the expected emission rate based on reported values was less than 100 kg/h. The DIAL measurements led to the discovery of a large and previously unknown leak from a distillation column. After the column was repaired, another DIAL survey was performed in the following year, finding 25% fewer emissions. National Physical Laboratories (NPL) DIAL operator, Rod Robinson, has noted that DIAL studies "often identify emissions not known to the operators. These are usually outside and LDAR programme, and so would likely remain 'unknown.'"[11] This sentiment is also relayed in the DIAL brochure developed by Shell Global Solutions while trying to market their DIAL system. The brochure provides several pages describing why measurement with DIAL is superior to standard estimating methods which can give a "false sense of security" about emissions. It goes on to say, "If you're not measuring, you are guessing."[12]

Canada performed a DIAL study at a refinery in 2005 and found emissions to be 15 times higher than reported, and has not performed another DIAL study since. [13, 14] The Texas Commission on Environmental Quality (TCEQ) with some EPA funding, performed partial studies using DIAL at a U.S. refinery in 2007 and found high emissions at storage tanks and at flares, although not as high as were found in previous DIAL studies.[15] The City of Houston, with EPA funding, performed a DIAL study of a large refinery in 2010, and found very high emissions during a tank-cleaning operation as well as at a wastewater facility.[16]

SOF studies have been performed in the U.S. in 2006,[17] 2009[18] and 2011.[19] "The results from the campaign that was carried out during September 2006 in the Houston area show that the emissions of ethene and propene, obtained by SOF, are on average an order of magnitude larger than what is reported in the 2006 daily emissions inventory (EI)."[20] The 2006 and 2009 studies were focused around the Houston Ship Channel and the Texas City Industrial Complex. A follow-up study in 2011 repeated the measurements in Houston and Texas City, and added measurements at the petrochemical facilities in Port Arthur/Beaumont and Longview, Texas. Figure 2 shows some of the results that were obtained in the Houston Ship Channel.

SOF Measurements of VOCs in the Houston Ship Channel

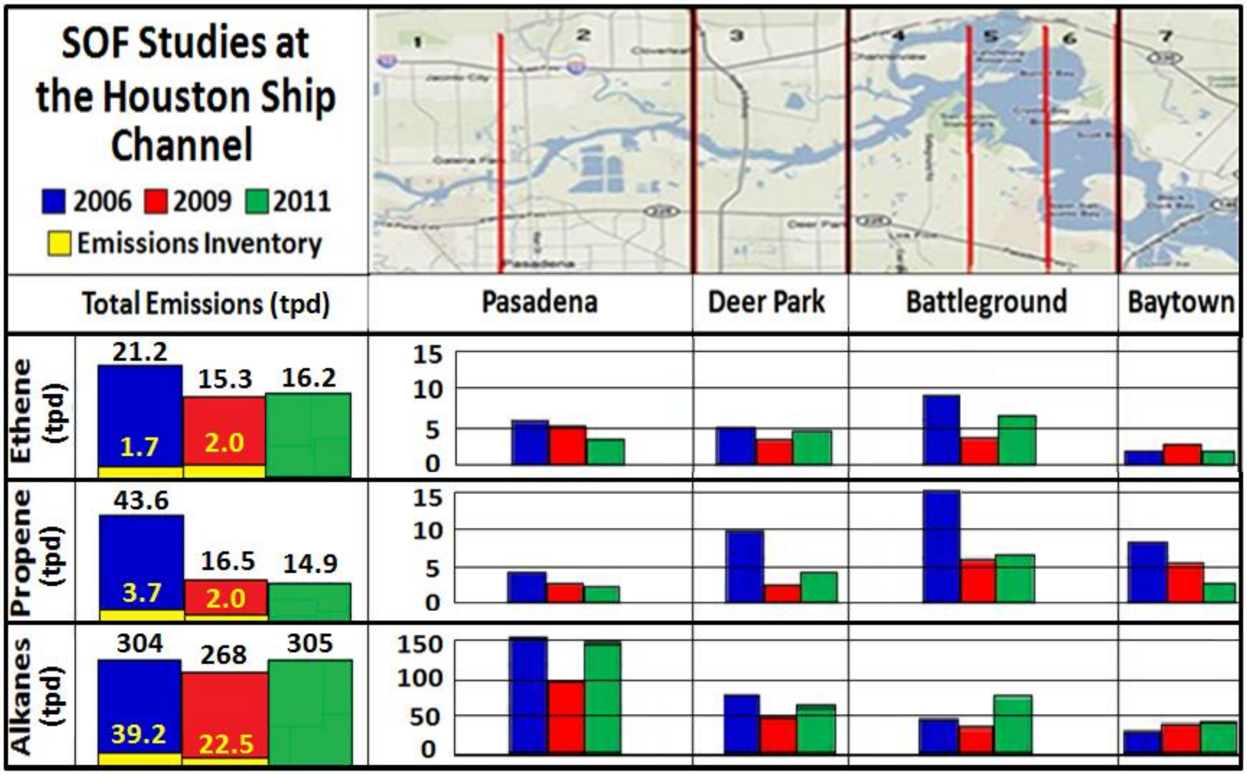


Figure 2. The total ethene, propene and alkanes measured by SOF in 2006, 2009 and 2011 were several times higher than the emissions inventory (in yellow on the left). The emissions were separated into sectors indicated above; however, different wind directions during some measurements likely moved some emissions from one sector to another.[19]

Comparisons between the measured emissions and reported/estimated emissions in the inventory were consistent, leading to the following statement made in the executive summary of the 2011 SOF report:

"A comparison of the 2011 measurements with the 2009 TCEQ inventory… …shows good overall agreement for NOx ((-20)–50)% and SO2 (18–44)%, with the exception for Texas city (260%). However, for the VOCs there are larger discrepancies with (400–1500)% for alkanes, (300–1500)% for ethene and (170–800)% for propene. For the two new areas observed here, Port Arthur/Beaumont and Longview the discrepancies are (300–700)% for ethene, (200–800)% for propene and (900–1500)% for alkanes. Hence, for VOCs it appears to be a persistent difference between inventories and measurements, independent of industrial area or region."[19]

How Sweden Uses DIAL and SOF in Place of Emission Factors and Emission Estimates

When local Swedish environmental authorities saw the results of DIAL measurements at refineries in the late 1980's and early 1990's, they became skeptical of emissions estimating techniques based on EPA's AP-42 results. In 1992 they required all refineries to submit "measured" emissions. By 1995 they required the measured emissions to be obtained using DIAL, citing flaws with other analytical techniques. The DIAL measurements were required every 3 years. In the early 2000's testing began with SOF, a technique developed at Chalmers University in Sweden. By 2005 the Swedish authorities allowed either DIAL or SOF to be used, but also required the measurements to be taken annually. Currently all refiners in Sweden use SOF, because it is much cheaper than DIAL. There are advantages and disadvantages in both DIAL and SOF techniques which will be discussed later.

The DIAL and SOF results are generally gathered during two or three week surveys, however, these measurements frequently get extrapolated to calculate annual emissions. Some have claimed that these extrapolations may not be accurate for the following reasons:

1. DIAL and SOF are "snapshots" of an emissions story that is changing significantly due to the temporal nature of petrochemical emissions and changing winds.
2. Upwind and downwind are not measured simultaneously, so interfering emissions from other sources are possible.
3. The process and emissions are constantly changing, yielding a constantly changing emissions pattern.
4. Petrochemical emissions include emission events which occur during start-ups, shutdowns, or during upset conditions.

These errors cited from taking a snapshot of a variable process and winds would imply that sometimes the snapshots would measure numbers higher than reported and other times the snapshots would measure numbers lower than reported. However, this is not the case. In over 35 studies performed between 1988 and 2008 (as shown in Figure 3), the measured emissions were consistently considerably higher than reported emissions. Never has a comprehensive DIAL or SOF survey of an entire refinery found that emissions are less than expected based on annual estimates.

Refinery VOC Emissions Expressed as a Fraction of Total Throughput

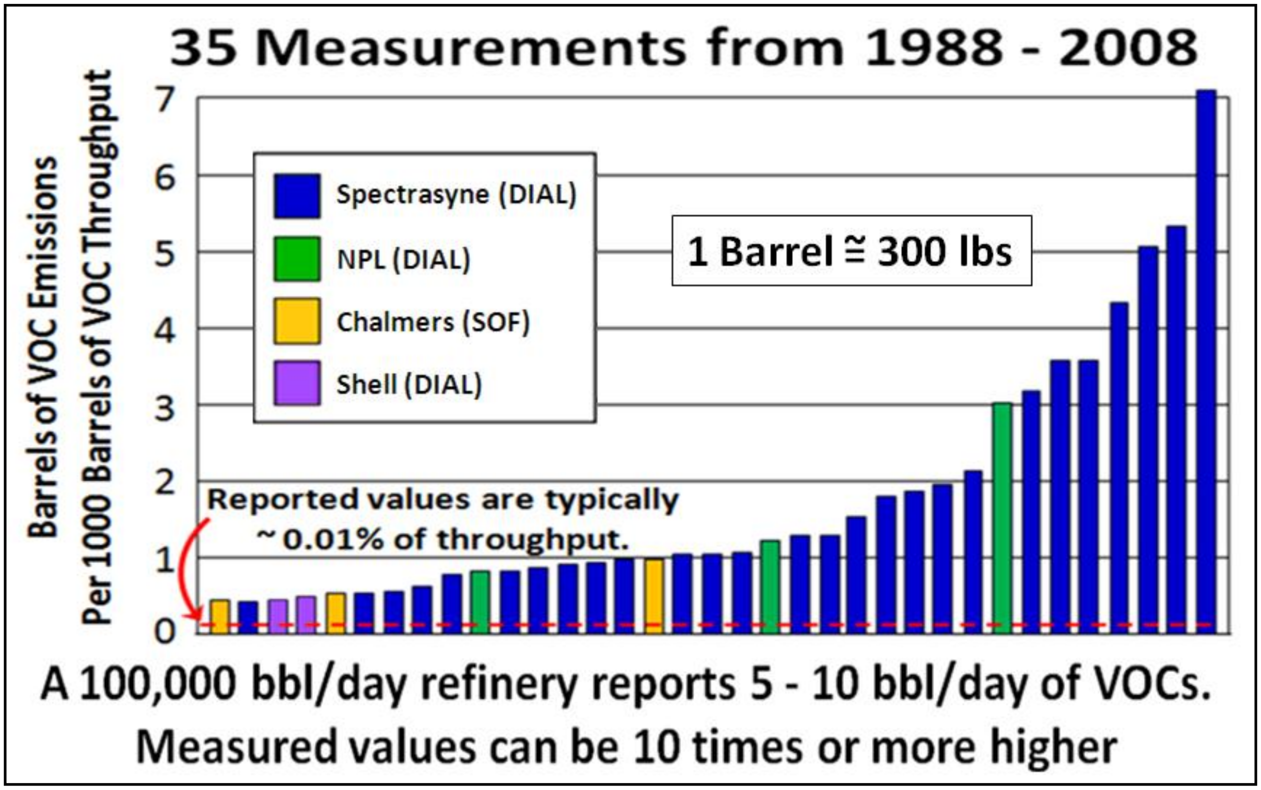


Figure 3. Emissions of volatile organic compounds (VOCs) as a fraction of throughput. Based on data from Jan Moncrieff of Spectrasyne,[10] Rod Robinson of NPL,[11] Johan Mellqvist of Chalmers University[17], Lennart Frisch (formerly with the local environmental regulatory agency in Gotenburg, Sweden)[8] and Allan Chambers, Alberta Research Council.[13, 14] compiled by Alex Cuclis.

There are other arguments that the annual emissions estimates from DIAL and SOF may have a high bias based on the time of day or time of year that most of the samples are taken. For example, some operational activities such as filling and draining a tank may create more emissions, and are likely to occur during the daytime. Also, DIAL and SOF measurements are most often taken in warmer seasons which can lead to a higher bias. Those who have taken these measurements note that measurements taken in February in Sweden, for example, are high and comparable to measurements taken in warmer months. Also, the daytime to nighttime swing in temperatures of a liquid in a tank is very small compared to the swing in ambient temperatures. When the Texas Commission on Environmental Quality (TCEQ) performed a DIAL study in Texas they could not find any significant difference in tank emissions between daytime and nighttime.[15]

Typically when refineries report emissions using standard EPA/AP-42 techniques, the totals come to roughly 0.01-0.02% of throughput (based on an analysis of reported emissions of refineries near Houston in 2004). The reported emissions are the values that the U.S. EPA and many state agencies use to enter into complex air quality models for predicting ozone.

Measured emissions, based on the surveys performed in Figure 3, are more likely to be around 0.1% of throughput, though there is a considerable range. In a 2009 presentation, Robinson on NPL has stated that the average refinery emission rate is closer to 0.2%.[11] The lowest measured numbers are higher than the highest reported numbers. Measured values that are 10 times or more than the reported values are not uncommon and many of those surveys which indicate that emissions are "low" or less than 0.1% of throughput have had the benefit of previous DIAL or SOF surveys which were useful for making corrections about previously unrecognized emissions problems.

All of the above surveys were performed in Europe, with one exception, which was performed in Canada in 2005. Bo Jansson with the Swedish EPA also documented the use of DIAL in "A Swedish background Report for the IPPC Information exchange on Best Available Techniques for the Refining Industry."[21] Jansson continues to advocate measuring techniques over AP-42 approaches to regulatory agencies in other countries.[22]

The Shell Global Solutions DIAL team (which operated from about 1994 – 2002) also found higher than reported emissions from refineries in Europe. In one report focused on tanks, it was noted that "The mean DIAL emission rate for all sites (including the bad tanks) was 4.6 times higher than the corresponding mean API estimate," and "The difference, which is due principally to the few bad tanks, suggests the need to revise the calculations if they are to represent emissions from the average in-service population rather than ideal new installations."[23] P.T. Woods at NPL also reported higher measured emissions from tanks using DIAL, but found the measurements were only a factor of 2.7 times higher than reported emissions.[24]

Annualization of hydrocarbon emission results from DIAL studies at European refineries has been in practice for over two decades. In a report published in 2000 by The European Union Network for the Implementation and Enforcement of Environmental Law (an informal network of the environmental authorities of EU Member States), it is stated that "Remote sensing techniques are applied increasingly and DIAL has become common practise in some of the countries for estimation of the annual VOC emission."[25]

The Shell Sweden annual environmental report for 2008 notes that they have used SOF for several years as the basis for their annual emissions and it includes the chart shown in Figure 4:

VOC Emissions at the Former Shell Refinery in Sweden

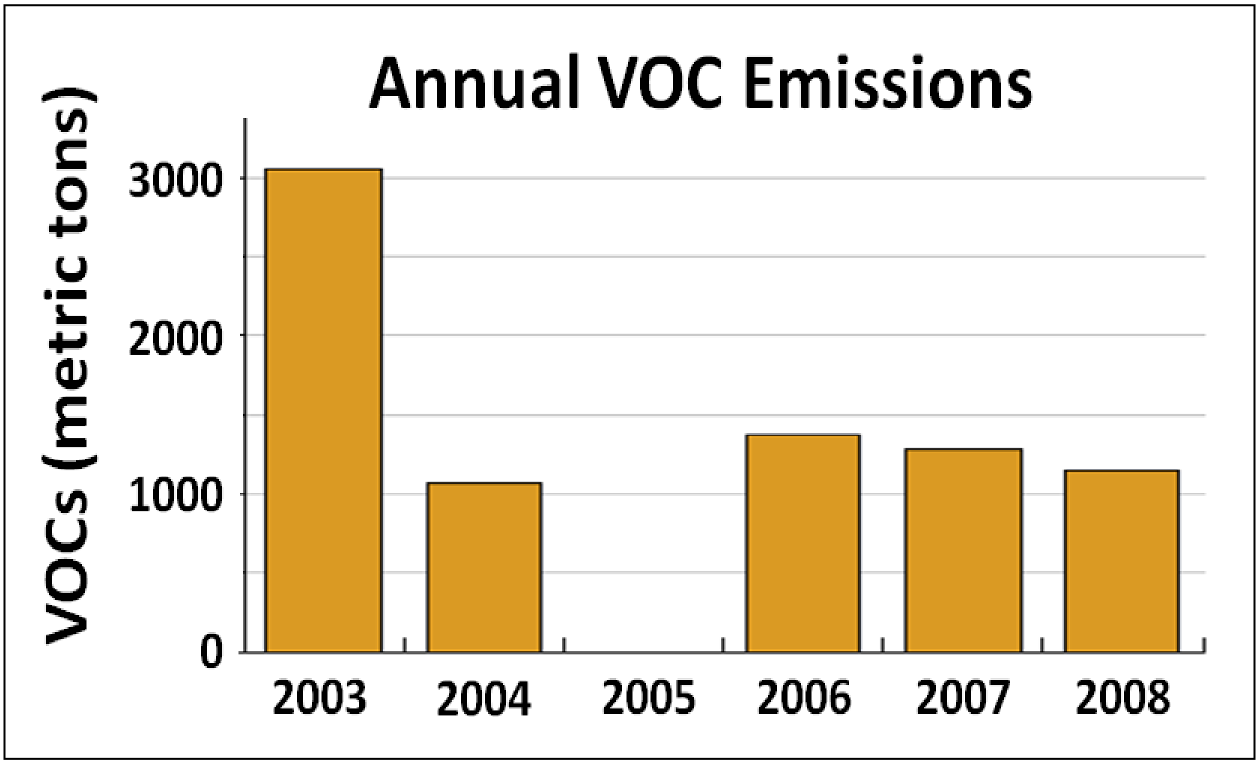


Figure 4. Shell's Swedish Refinery, which has since been sold, has a throughput of about 4 million metric tons. The annual emissions as measured by SOF are 1071 tons per year, or about 0.029% of the annual throughput. This chart was taken from a Shell report to the Swedish environmental agency.[26]

The emission rate of 0.029% of throughput was the lowest reported rate for any refinery that uses SOF or DIAL for measurements at the time. The vendors will be quick to note that this is a very small refinery, about 70,000 barrels/day (larger, more complex refineries routinely have larger leak rates) and it has had the benefit of many DIAL and SOF studies over many years to repair problem areas. This refinery and 4 others in Sweden have been reporting annualized DIAL or SOF emissions to the regulatory authorities since 1995 and, in some cases, as far back as 1988.

In an email exchange with Bo Jansson of the Swedish EPA, notes are referenced to the data shown in Figure 1 of this paper:

"If I understand right the oil industry accept(s) the monitoring techniques (DIAL and SOF) as such but does not accept to extrapolate the two week data to an annual emission. We had that discussion also in Sweden with the refineries. By having the monitoring campaigns at different periods of the year (as you see from the PREEM Gothenburg data) we discovered that summer or winter did not make any important difference in emissions. Also finding that (as you see for the Shell Gothenburg refinery) that emission levels (after having done most improvements at the refinery) are almost on the same level from year to year indicates that Annualization of short term data works quite well."[27]

In 2 review drafts of the EPA's Emission Estimation Protocol for Petroleum Refineries submitted by RTI International in 2009 and 2010, DIAL is mentioned. It must be emphasized that both versions are drafts and are marked specifically, "Do not cite or quote" and should not be considered EPA's position until finalized. These documents have been presented for public comment and a section is quoted here in order to put the comments in context:

"There are other direct measurement methods that have been used to measure emissions from storage tanks even when the emissions from the tank are not vented (i.e., DIAL [Differential Absorption Light Detection and Ranging (LIDAR)] techniques); however, these methods do not provide continuous monitoring and have additional limitations (requiring consistent wind direction, etc.). Therefore, at the present time they are not recommended as primary techniques for emissions estimation. However, they can be used to verify and assess the accuracy and uncertainties associated with tank-specific modeling."[28, 29]

In response, members of the American Petroleum Institute and the National Petrochemical Refiners Association had stronger opposition to DIAL, stating in their written response:

"Because DIAL measurements are typically not long term and have other limitations, there are significant issues with extrapolation of DIAL measurements to estimates of emissions. In addition, since this section of the Protocol acknowledges that 'these methods do not provide continuous monitoring and have additional limitations,' it would not be appropriate to use them to verify and assess other estimating techniques as is suggested. The paragraph in the Protocol is contradictory and needs to be corrected."[30]

Environmental Integrity Project (EIP) also commented on the Emissions Protocol, stating that DIAL should be used more often in the U.S. since it has been successfully used in Europe and Canada. It also cites several incidents where DIAL emissions found that emission rates were several times higher than reported numbers based on annualized calculations.[31]

However, a different section of EPA seems to think annualization on the basis of DIAL results is possible, at least at the Tonawanda Coke facility in New York. In September 2010 they wrote:

"EPA has reviewed the data in this report and has determined that it can be used to estimate TCC's facility-wide annual benzene emission rate for regulatory compliance purposes, notwithstanding CRA's statements in the Executive Summary."[32]

Measured vs. Reported Emissions at Refineries

The U.S. EPA uses reported emissions to build emissions inventories which are used in complex air quality models and become the basis for ozone reduction strategies. Emissions inventories are frequently cited as one of the weakest links in the air quality program design. The U.S. EPA Office of Inspector General has documented the problems with the use of EPA emission factors for developing emission inventories.[33]

The estimates of VOC emissions using these equations have substantial deficiencies due to the limitations of the applicability of the emissions factors. This problem has been noted by several sources. Shell Global Solutions, in a brochure that described the advantages of measuring emissions with DIAL, stated:

"Our experience has shown that the use of emission factors alone can lull you into a false sense of security. Calculations such as those based on component counts and tank roof fittings are fundamentally flawed as they have to assume the typical conditions of the component or fitting… …What calculations do not tell you, is the condition of the components, the effectiveness of maintenance, or about operations that result in emissions… …An important element of ensuring compliance and continuous improvement is verification and 'if you are not measuring you are guessing.'"[12]

There have been several studies in Texas where measured emissions at petrochemical facilities have been several times higher than expected based on reported emissions. Examples are as follows:

1. In an analysis of non methane organic compounds (NMOC) and nitrogen oxides (NOx) data gathered in 1985, Keith Baugues found that, "In Houston, the predicted NMOC levels are always lower than the observed NMOC levels. On average predicted NMOC concentrations in Houston are 5.9 times lower than observed values." However when Baugues included reported emissions from a nearby point source, the value dropped from 5.9 to 4.3. Baugues also suggests that analyses including other point sources that were further away may lower the factor further, and recommended additional studies.[1]

2. Texas Air Quality Study 2000 (TexAQS 2000) – More than 200 scientists participated in this study of the air quality issues in Houston using over $20 million research dollars.[34, 35] One of the primary scientists, David Allen from the University of Texas, reported that when examining measured emissions of ethene and propene near petrochemical facilities, they were 3-10 or 3-15 times higher than expected based on reported values. Researchers from the National Oceanic and Atmospheric Organization (NOAA) claimed that the measured emissions were 10-100 times reported. The final report does not quantify the differences between the inventory and measured values, but notes that while the reported values of nitrogen oxide appear to be in line with the measurements, the reported values of non-methane organic compounds (NMOC) appear to be underestimated.[2]

The Texas Commission on Environmental Quality (TCEQ) noted that "Corroborating field studies (aircraft, monitoring) indicated that reported VOC EIs may be underestimated by 10-100x."[34] In 2002, when TCEQ was developing the State Implementation Plan (SIP) for ozone, they added an additional 200 tons per day of olefins to the inventory, which substantially improved the model results.[35] The changes were justified by TCEQ, "Because of the greater certainty associated with the NOx emissions estimates, TCEQ concluded that industrial emissions of terminal olefins were likely understated in earlier emissions inventories. This conclusion has been reviewed and documented in numerous scientific journals."[36]

3. Texas Air Quality Study 2006 (TexAQS 2006) – A follow-up study to TexAQS 2000 which also involved over $20 million in research funds and over 100 scientists took another look at Houston's air quality. In the final report assembled by contributions from numerous scientists, they claimed that correcting for differences in whether the concentrations of ethene and propene had dropped by 40% since 2000; however, they were still 10-40 times higher than expected based on what was reported in the inventory.[6]

4. The Texas Environmental Research Consortium (TERC) has performed extensive air quality research in Texas. George Beatty, TERC's executive director, asked TERC's Science Advisory Committee, a group of nationally recognized air quality scientists, to develop a strategic plan for 2007-2009. The plan states that "TexAQS (2006) aircraft measurements of pollutant ratios and direct flux measurements using the Solar Occultation Flux (SOF) technique both point to the conclusion that, while VOC emissions in Houston do seem to have decreased between 2000 and 2006, they may still be underestimated by at least an order of magnitude." The report also states that an essential part of improving air quality in the Houston area rests on improving the emissions inventories.[36]

5. Thomas Ryerson, et. al. at NOAA examined the ratio of measured alkene to nitrogen oxide ratios during the TexAQS 2000 campaign, compared them with reported values and found that the alkene emissions were off by a factor between 10 and 100.[4]

6. B.P. Wert, et. al. followed a similar procedure to Ryerson with similar results, finding that VOC emissions roughly 20 times higher than reported.[5]

7. Johan Mellqvist performed a SOF study in the Houston area in 2006 and found VOC emissions roughly an order of magnitude higher than expected when compared to the reported values in the emissions inventory (EI).[37, 38] SOF studies were repeated in the Houston area occurred in 2009 and 2011 with similar results.[18, 19] Note that Mellqvist examined alkanes as well as alkenes. His reports show that, although there is variability in the data, the emissions are consistently several times higher than the inventory levels would indicate.

8. Joost de Gouw, et. al. looked at aircraft measurements of ethene in the Mont Belvieu area near Houston and compared them to the results from the SOF measurements. Although the difference between the measurements was up to 50%, both showed emissions to be multiple times higher than values expected based on the inventory.[39]

9. Additional details regarding the underestimation of emissions from petrochemical facilities can be found in the paper submitted at the National Spring 2009 AIChE Conference in Tampa titled, "Underestimated Emission Inventories."[40]

It is worth noting that shortly after TexAQS 2000, when the environmental regulating agency of Texas was told that the emission inventories may be off by an order of magnitude or more, they hired a consultant to study the problem. One of their conclusions was, "On-site observations reveal that existing EPA emission inventory methods do not reflect local conditions and are not likely to produce accurate emission estimates." The facilities were following the proscribed estimating procedures, but there were problems with those procedures.[41]

SOF Measurements in Texas City

The industrial complex located in Texas City, Texas provides a unique setting for measuring air quality downwind from petrochemical facilities. As can be seen by the map provided in Figure 5, the Texas City Industrial Complex is filled with petrochemical plants and tank storage facilities in an area that is approximately 1 ½ miles by 3 ½ miles. These facilities include 3 refineries and several chemical plants. They are bounded on the west side by Highway 146 and on the east side by Galveston Bay. When wind is flowing from east to west, it passes over the Gulf of Mexico, Galveston Bay and on to the Texas City facilities. When SOF samples are taken along Highway 146, they are rich from the petrochemical facilities' emissions and have relatively small background emissions due to the geography of the bay and the gulf.

Texas City Industrial Complex

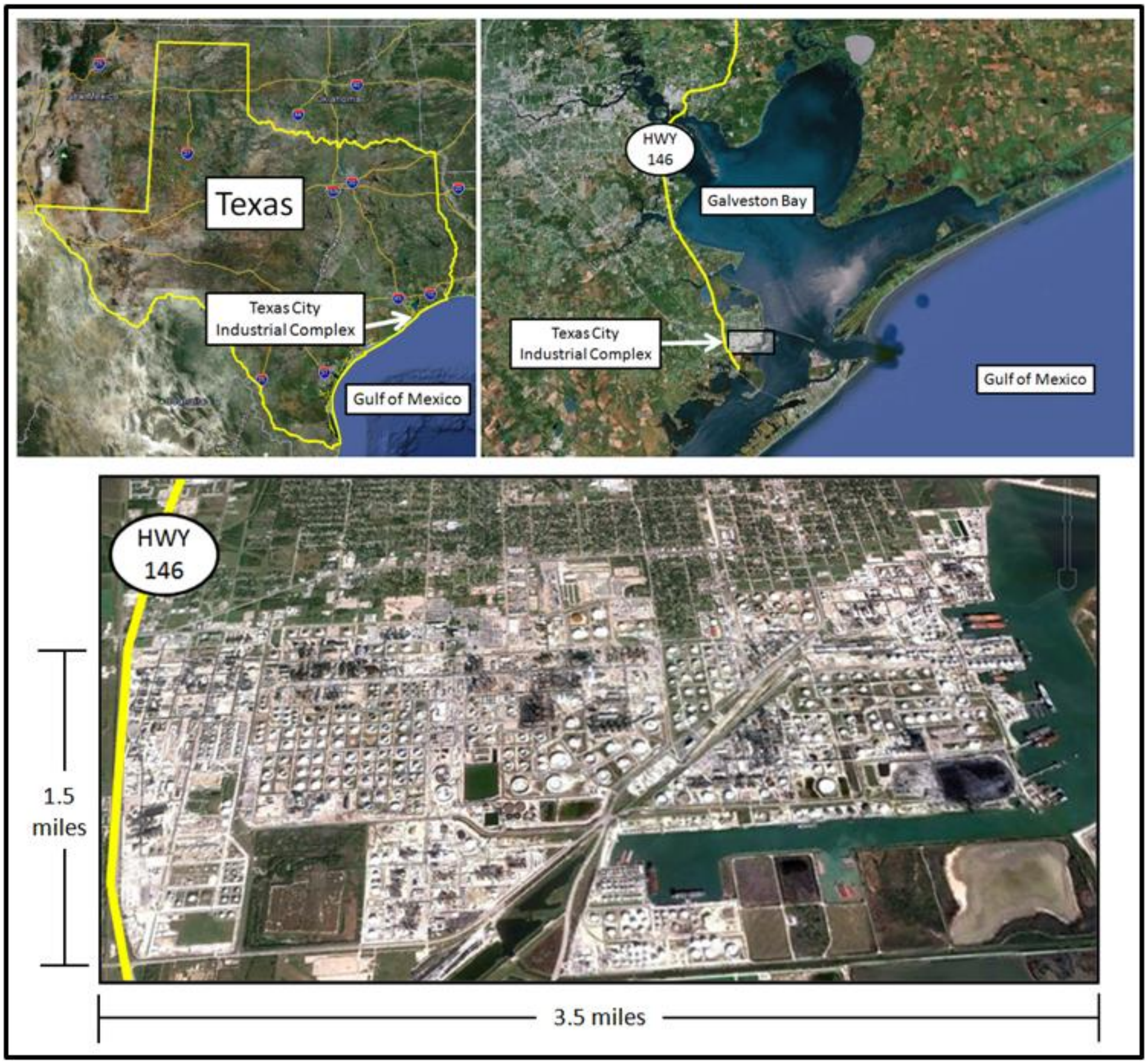


Figure 5. The Texas City Industrial Complex is located south of Houston between Highway 146 and Galveston Bay in Texas City, Texas. Maps taken from Google Earth.

Several SOF measurements were taken in Texas City, Texas in 2006, 2009 and 2011. When the winds were blowing from the east to the west, the SOF van drove multiple times down Highway 146 . A baseline is taken before and after approaching the industrial complex and is subtracted from the total to remove contributions from other sources. Figure 6 has a plot of what the measured alkanes were compared to what is expected on the basis of the 2006 annual inventory.

Emissions Measurements Using SOF at Texas City's Industrial Complex

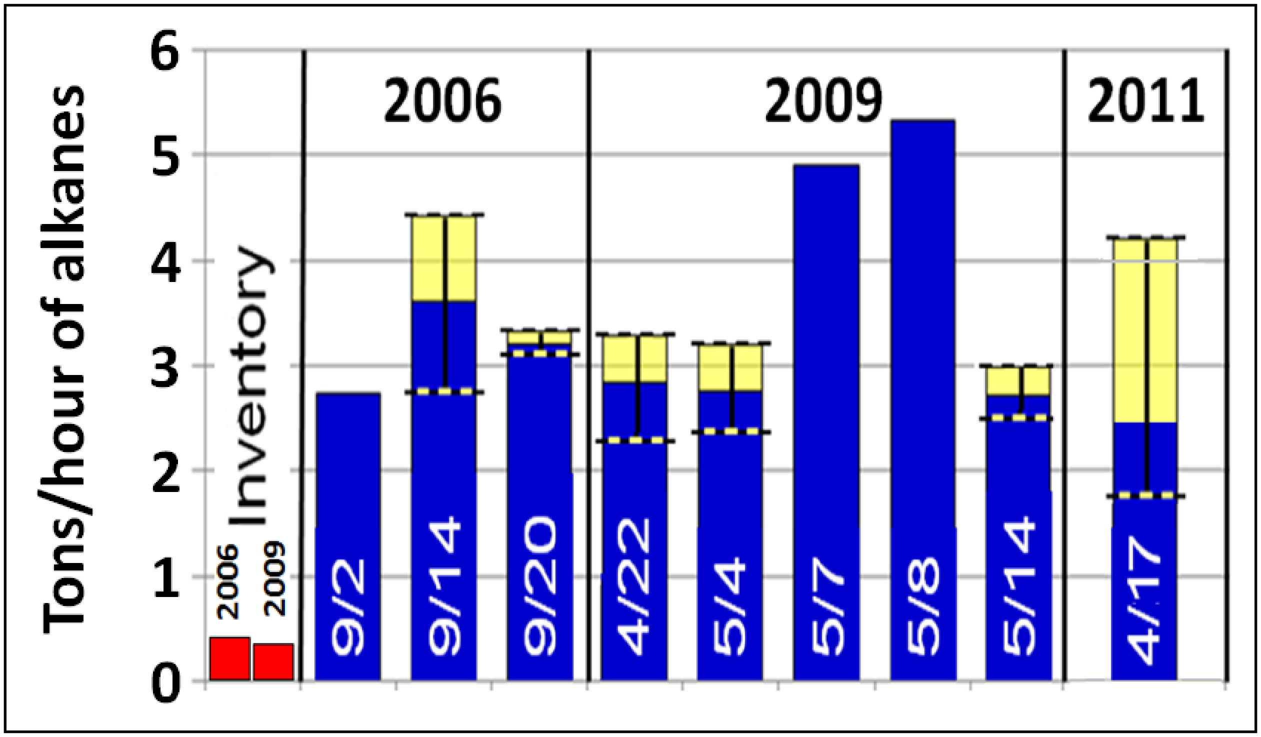


Figure 6. SOF measurements taken in Texas City, Texas in 2006, 2009 and 2011 by Chalmers University, Sweden.[17, 18, 19]

The results show that every time the SOF measurements are taken the alkane emissions are close to 5000 lbs/hr or more, or at least 6 times higher than expected based on the conversion of annually reported emissions to hourly values. Some of the highest values, e.g. May 7 and 8, 2009, were higher than normal due to a flaring event at a refinery; however, repeated passes down Highway 146 provide the same results. The variation in measurement never shows that emissions are lower than the 2006 or the 2009 inventory. These measurements are taken during the day time, in months from March through September, when operations may have more on-going activities which can generate a high bias; however, this does not account for underestimations of a factor of at least 6 or more. This pattern observed with SOF is consistent with other SOF and DIAL results.

DIAL and SOF Technologies

The two technologies that Sweden has used in place of emissions estimates are DIAL and SOF.

DIAL technology was developed in the 1960's and first applied to measure pollutants at petrochemical facilities by National Physical Laboratories in the U.K. DIAL makes use of pulsed lasers which reflect off particles in the air to provide information about pollutant concentration. Typically these lasers are scanned across a vertical plane perpendicular to the wind direction. A two dimensional concentration map is constructed and used in conjunction with the perpendicular wind speed to measure the mass flux of emissions. A depiction of this is provided in the graphic from Spectrasyne, a DIAL vendor, in Figure 7.

How Differential Absorption LIDAR Works

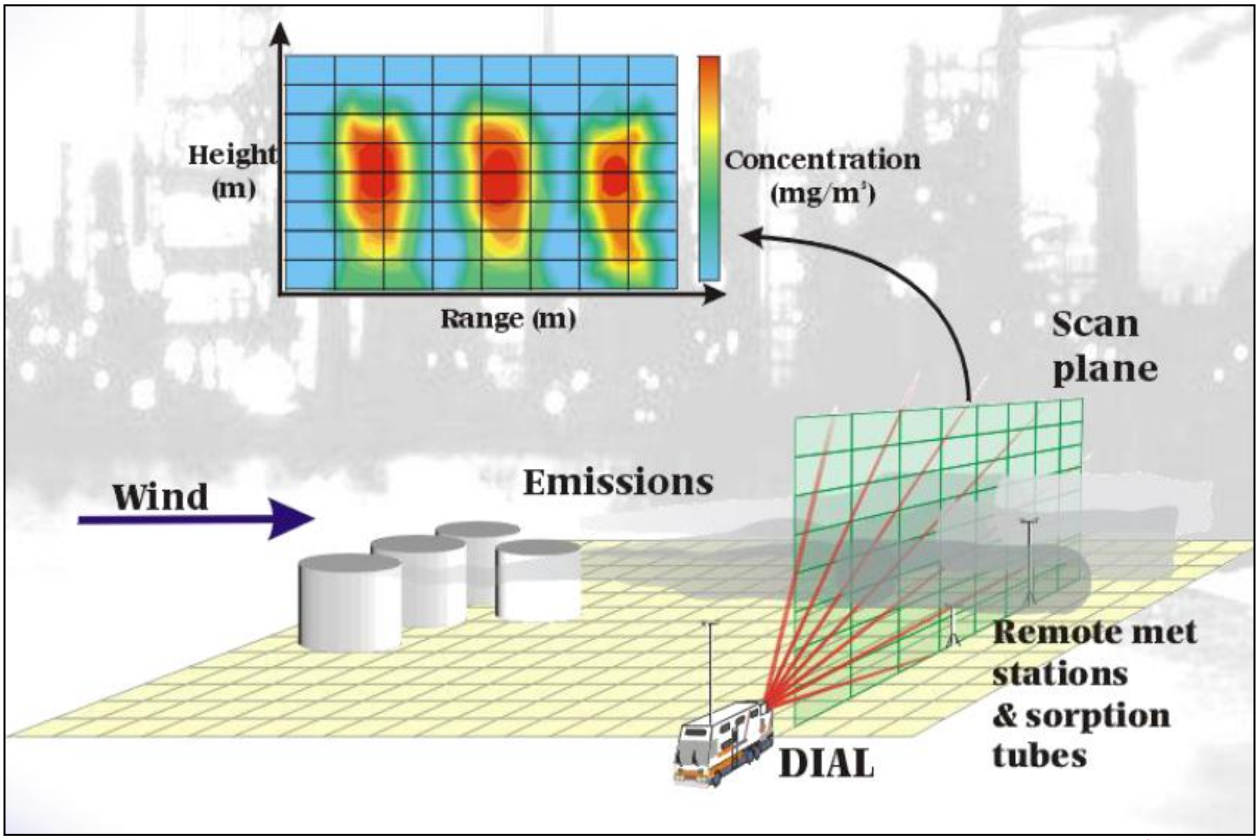


Figure 7. A diagram of a DIAL unit measuring tank emissions, provided by Spectrasyne.[10]

Since all DIAL vendors who take measurements at petrochemical facilities currently are based in the U.K., the cost of the measurement techniques can easily exceed $500,000 for a one-month study. Estimates for the construction of a new DIAL system are typically at least $2-3 million.

SOF technology was developed by Johan Mellqvist at Chalmers University of Technology in Sweden. SOF uses a Fourier Transform Infrared (FTIR) spectrometer mounted in a passenger van. The van has a hole cut in the roof where a solar tracker is mounted designed to always point towards the sun and draw light to the spectrometer. As the van drives past a petrochemical complex on a sunny day, it gathers information about the concentration of chemical species. Readings are also taken before and after approaching the petrochemical facilities to subtract out background signals. When this information is combined with wind direction and speed, it can also be used to calculate the mass flux of pollutants. The cartoon/picture in Figure 8 was provided by Johan Mellqvist.

Illustration of Solar Occultation Flux

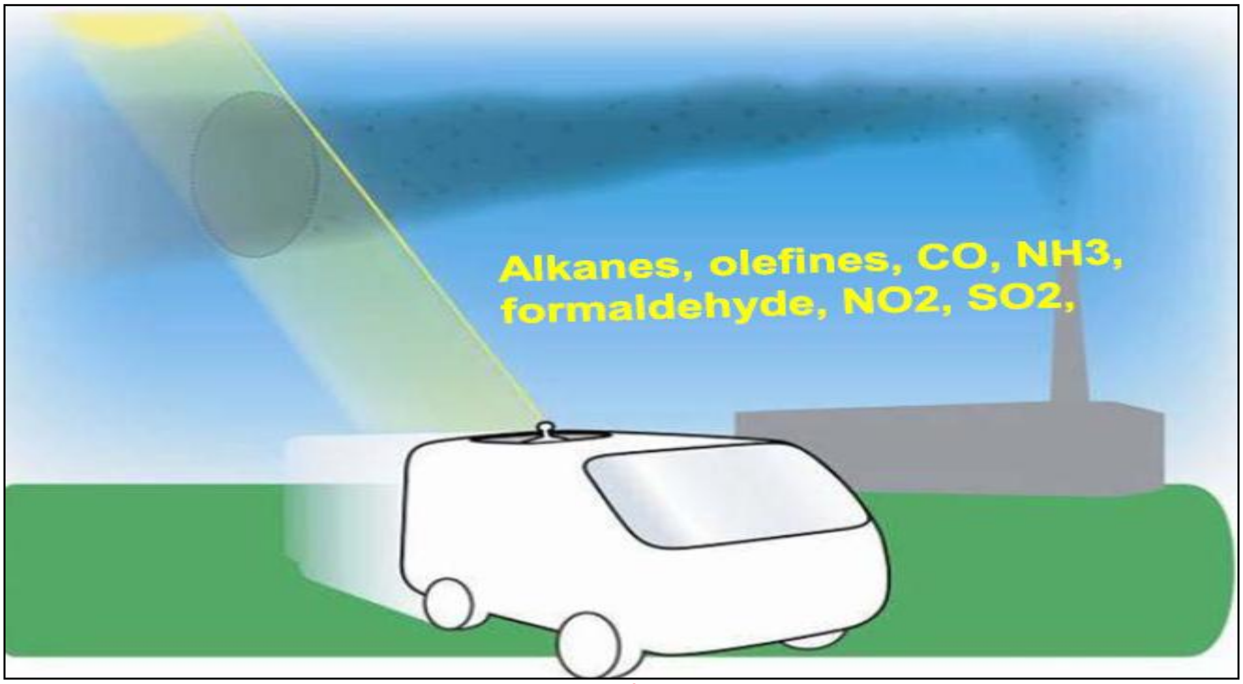


Figure 8. A depiction of the SOF measurement.[42]

The SOF technique requires direct sunlight and cannot measure some compounds like benzene directly. However, the developers use other measurement techniques to address these issues. In this case, the method is currently only available from the developers who are in Sweden. The cost for a one-month study can be less than \$200,000. A new SOF unit may be built for \$400,000 -\$500,000; however, issues relating to purchasing or licensing the SOF technology must be resolved with the developer.

More details regarding the DIAL and SOF technologies and applications can be found in documents by David Picard[43] and Steve Ramsey and Jennifer Keane.[44]

Locating Emissions Inside Refineries

DIAL and SOF were developed not merely to quantify emissions, but also to locate where the emissions problems are inside a refinery. When DIAL and SOF studies are performed, they are set up in specific locations of the refinery. Typically the DIAL studies look at each of the following areas separately: process units, storage tanks, waste water treatment systems, delayed cokers, and flares. SOF is less expensive and easier to set up than DIAL, but it is not possible to take SOF in all the locations that DIAL can go. Both DIAL and SOF studies indicate that about 50% of all VOC emissions come from storage tanks. In fact DIAL vendors have used the ability to detect emissions at tanks to sell their services. They find that a large portion of the emissions come from relatively few tanks. As a result, in order to fix the problem, DIAL will focus on maintenance and repair of a few tanks rather than a large, indiscriminate maintenance program for all tanks. Figure 9 shows where emissions have typically been found inside refineries.

Typical Distribution of a Refinery VOC Emissions Based on DIAL Measurements

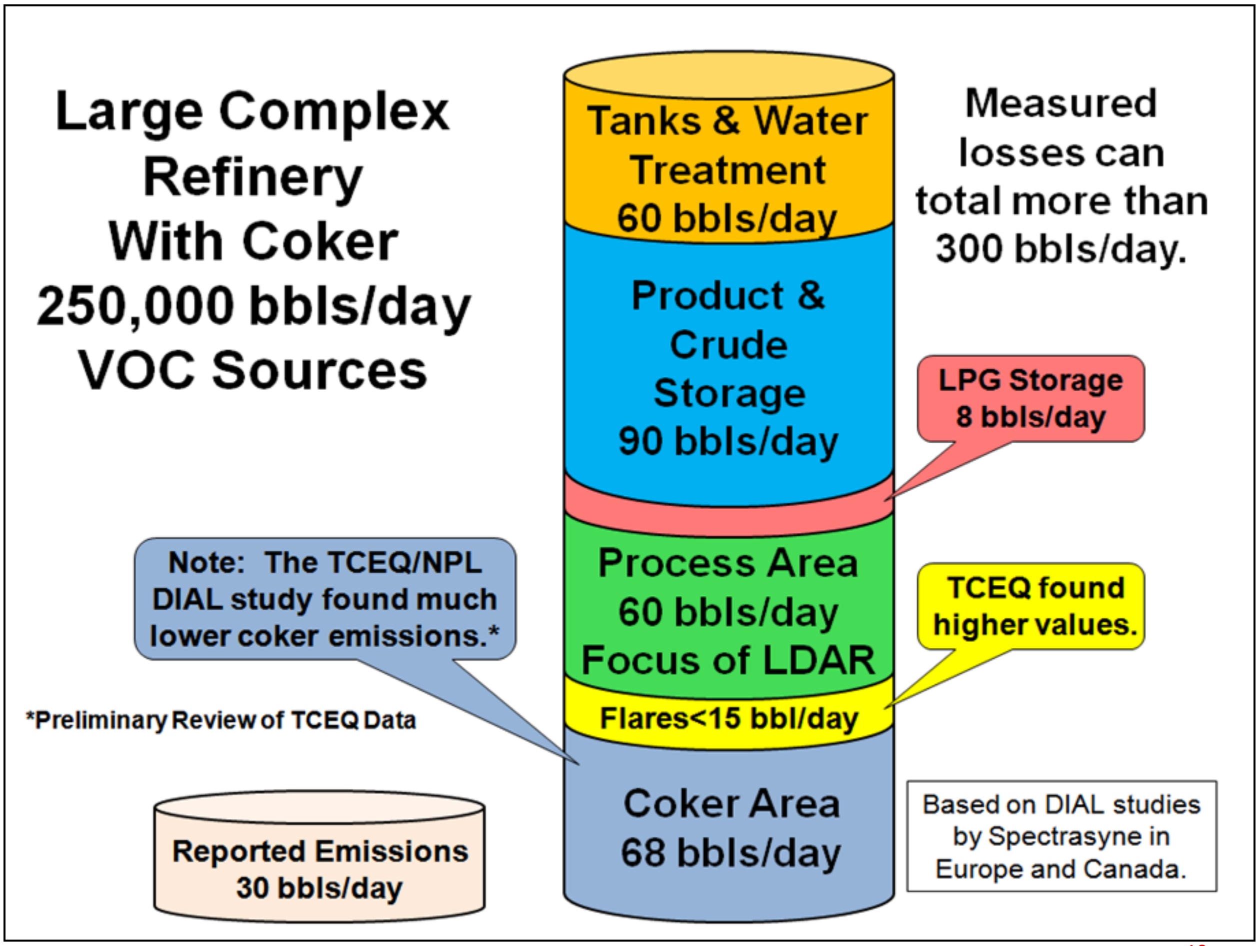


Figure 9. Typical location of emissions from a refinery based on a report from Spectrasyne[10] who has completed over 30 refinery studies and results from a TCEQ/NPL study.[15] Results will vary significantly depending on refinery design. Information compiled and organized in this drawing by Alex Cuclis.[40]

It has become common practice in DIAL and SOF studies to have an IR Camera available, as well, to help locate the exact emission source location. This has been helpful in some cases; however, DIAL and SOF each have detection limits that are 2-3 orders of magnitude more sensitive than the IR Camera. As a result, there are times that the IR Camera does not see emissions identified by DIAL and SOF.

TCEQ is currently working on improving tank emission estimates based on measurements from DIAL taken near tanks in Texas City, Texas. These calculations will be more accurate according to TCEQ because they will eliminate the use of default values for tank parameters among other concerns.[45] However, this process does not address the major concern identified by DIAL and

SOF vendors- the assumption that the tanks are "well-maintained". Emissions can be substantially higher in poorly maintained or damaged tanks.

Verification of DIAL and SOF Results

DIAL is self-calibrating by nature in that it looks at two different wavelengths and subtracts off the wavelength which is not absorbing, providing a continuous zeroing function. This is a major advantage of DIAL. In addition, DIAL vendors typically take a fraction of the light beam while sampling in the field and send it through a cylinder filled with a known concentration of gas so they can automatically correct for other issues such as changes in laser beam intensity. More detail is provided by National Physical Laboratories (NPL) in their report to the Texas Commission on Environmental Quality (TCEQ) for work performed in Texas City, Texas in 2007.[15]

Industry typically does not argue the accuracy of DIAL measurements, but are concerned about extrapolating the results to annual emissions. When Brenda Shine at the EPA performed a review of literature on DIAL in 2007, she wrote the following:

"The general experience reported in the literature from the application of DIAL technology to quantify atmospheric emissions at petroleum refineries has been that, despite some limitations, DIAL is able to accurately quantify the amount of VOC emissions occurring at the time of measurement." [7]

"As noted above, the American Petroleum Institute (API) prepared a letter taking issue with the comparison of the DIAL Canada study and the API estimation methods (AP-42 equations).[46] Additionally, Rob Ferry, API Consultant prepared a critique of the use of the DIAL method for quantifying VOC emissions. Generally, API's objection to the Canadian reports is not that the DIAL measurements are incorrect, but that they were taken over an inadequate time period to allow them to be used for calculating a yearly emission number. Secondly, they note that higher than expected emissions generally occur when there are extraordinary conditions or when emission sources are not properly operated or maintained."[7]

Typically, when a DIAL study is performed in the U.S., comparisons are made between the DIAL results and open path FTIR and/or Differential Optical Absorbance Spectroscopy (DOAS). However, due to concerns about proprietary data and liabilities, access to the instruments while they are inside the facilities has been very limited. In addition, the largest error associated with both DIAL and SOF is generally ascribed to the mass flux values which cannot be obtained with traditional open path techniques. The largest error in mass flux is the wind speeds which can vary in time and altitude; hence, selecting the proper values to calculate flux can be difficult, so measuring the wind speed in or near the measurement plane is important. Finally, collecting data upwind and downwind simultaneously is generally not possible. In order to account for process and other changes, attempts are made to take samples on different days at different times and take an average value. It is also crucial that all the relevant process data is collected during the measurement period.

Open, double-blind cross-comparisons of DIAL and SOF instruments that include released gases as tracers are needed. These kinds of comparisons should occur several times to ensure the measurements maintain their accuracy and to identify improvements over time. However, these kinds of tests are costly and difficult because of concerns about fines, penalties and potential litigation.

There are a number of ways in which the DIAL and SOF techniques have been validated over time in Europe and Canada. One that has already been alluded to in Figure 1 is that DIAL has been used to identify large leaks. When those leaks have been addressed and DIAL is brought back, the measurements indicate that significant problems have been resolved. The same is true for SOF.

A listing of the known studies which have been done in the past to verify DIAL and SOF results is provided below.

1. The Shell DIAL team, led by Harold Walmsley, published a number of studies in the literature regarding their DIAL work. In 1997 Walmsley and Simon O'Connor published a report identifying the factors influencing the sensitivity and accuracy of DIAL.[47] Walmsley and O'Connor's paper published in 1998 "describes the procedures used for measurement, emission rate calculation and data display, and then discusses the factors that affect the accuracy and detection limits of column content and emission rate measurements under practical operating conditions."[48] Walmsley published several other articles about DIAL in scientific journals and at conferences.

2. In November 1993 the European counterpart to the American Petroleum Institute (API), CONCAWE, compared Spectrasyne's DIAL measurements during a barge loading to the measurements obtained by measuring the flow rate of the gasoline being loaded which was equivalent to the volumetric flow rate of the vapors coming out of the barge vent. Samples were also taken of the vent emissions and analyzed for hydrocarbons. DIAL estimated emissions of 390 kg, which was about 12% less than the 435 kg calculated from the vent and gas analysis.[49] CONCAWE mentions DIAL in a 1999 report on best available technologies for refineries. DIAL is recognized as a valid technique, although expensive, and concerns are raised about attempts to extrapolate results for annual averages.[50] In a 2003 report CONCAWE states, "Any attempt by a permitting authority to impose DIAL as BAT would be inappropriate. The record of the TWG meetings will confirm that the debate on this led to the consensus that DIAL is one of the options (not **the** Best Available Technology option) of monitoring VOC."[51]

   In another report published in 2008, CONCAWE describes the details of the DIAL and SOF techniques including discussions about accuracy. Although the report is favorable to both techniques in many regards, CONCAWE states that there is a potential problem with overestimating emissions using DIAL and the accuracy of SOF is +/- 30% - 50%.[52] The DIAL and SOF vendors would disagree, saying they have evidence from verification studies (including the one from CONCAWE in 1993) demonstrating accuracies better than 15-30%. However, the vendors and many air quality modelers, note that even a +/- 50% accuracy is useful when there is evidence that the reported emissions may have a low bias that is off by a factor of 10 (1000%) or more.

3. DIAL was part of the Remote Optical Sensor Evaluation (ROSE) in Europe from August 2001 – July 2004. The purpose of ROSE was described as follows:
   "The primary objectives of ROSE are the determination of "Best Practice" and performance standards, along with a firm theoretical foundation on which to support such statements… …It addresses the problems associated with system and certification approval by inter-comparing five diverse commercially available (remote optical measurement techniques) under both field and laboratory conditions. The measurement techniques included differential optical absorption spectroscopy (DOAS), tunable diode laser spectroscopy (TDLAS), Fourier transform infrared and ultraviolet spectroscopy (FTIR and FTUV), as well as differential optical absorption light detection and ranging spectroscopy (DIAL-LIDAR)."[53]

   The report, "Recommendations for best practise for open path instrumentation," was developed from the review of the results of ROSE. It provides a description of several validations of the Spectrasyne DIAL, indicating that all methods of comparison showed agreement within 15% as well as results from the ROSE comparisons.[54]

4. In Alberta, Canada Allan Chambers has verified DIAL measurements using emissions from a sulfur stack and from a turbine exhaust. Concentrations were measured with in-situ analytical instruments and combined with flow rate to determine the mass flux. Measurements were made of SO2 from the incinerator and of NO from the gas turbine. The observed differences were 11% and 1% respectively.[55]

5. A comparison was obtained of the SOF instrument during the TexAQS II campaign in the Houston area with NOAA aircraft. Both SOF and the NOAA aircraft took ethene samples in Mont Belvieu near the Houston Ship Channel, and both independently found that emissions were roughly an order of magnitude higher than the reported values. However, there were differences of up to a factor of two between the SOF and NOAA readings. This was first described in the Final Rapid Science Synthesis report for TexAQS II[6] and later included as part of a peer reviewed scientific journal.[39]

6. The SOF technique has been tested in Europe using sulfur hexafluoride (SF6) as a tracer gas. Two studies in 2005 showed the SOF measurements were within 10-30% of known amounts of SF6 tracer released.[56, 57] In another study which used a different measurement technique combining flow rate and VOC concentrations, found the SOF measurement differed only 1% (SOF overestimated) in one trial involving bitumen cisterns and by 26% (SOF underestimated) in a separate trial involving storage tanks.[58]

7. NPL performed several tests during the DIAL study in Texas City in 2007. Comparisons were made with an open path Differential Optical Absorbance Spectrometer (DOAS) on

benzene emissions. TCEQ reports that the DIAL measurements were 0.3 - 26 parts per billion (ppb) which matched well with DOAS which obtained a range of 4.9 - 12.7 ppb. In a blind test, standard concentrations of propane, pentane and benzene were placed in gas cells and measured by the NPL DIAL system. The DIAL measurement generally fell within the expected ranges of what the standard values were.[15]

8. In the DIAL study performed at the Tonawanda Coke facility in Tonawanda, ENVIRON found that their open path FTIR measurements of benzene were "generally consistent"[59] with both the EPA DOAS measurements[60] and NPL's DIAL findings.[61]

Although verifications of DIAL have not been published by the National Institute of Science and Technology (NIST), they are currently developing a DIAL system. The NIST DIAL system will focus on improving the measurements of greenhouse gases. [62]

Key Events Related to Underestimated Emissions at Refineries

1978

- NPL and BP begin an IR DIAL development project with the intent of measuring the mass flux rate of hydrocarbon leaks at petrochemical facilities.

1982

- NPL and BP use UV DIAL to measure sulfur dioxide emissions at refineries.

1987

- NPL and BP deploy a jointly funded mobile IR DIAL system.

- BP builds a commercial UV-vis-IR DIAL system.

1985

- EPA Study by Keith Bauges, "On average predicted NMOC concentrations in Houston are 5.9 times lower than observed values."[1]

1988

- BP and NPL begin joint DIAL tests at refineries and chemical plants in Europe.

- A refinery in Sweden finds that emissions are 20 times higher than reported values based on DIAL results. The largest leak was on a distillation column – which had not been previously identified.

1989

- When DIAL returned to the Swedish refinery, after the leak on the distillation column was repaired, emissions were still 15 times higher than the reported values.

1990

- BP starts operating a commercial DIAL system in-house.

1992

- Sweden compels 5 refineries to measure VOCs without specifying a measurement technique.

- NPL and Siemens build an IR DIAL for Shell and British Gas.

- Spectrasyne, consisting of the former BP employees that developed the DIAL system, purchased UV-vis-IR DIAL from BP management.

1993

- NPL finds that tank emissions are on average 2.7 times higher than predicted by AP-42 estimates. Measurements at individual tanks differ from AP-42 estimates by factors ranging from 0.8 to 4.0.[25]

1994

- Shell and British Gas begin using their IR DIAL system in house.

1995

- Sweden requires that DIAL be used at 5 different refineries. The previous requirement to "measure" VOCs led refiners to try using FTIR, DOAS and other methods, none of which provided information that indicated it was an accurate measurement of mass emissions of VOCs that the Swedish regulators desired.

- CONCAWE reports that DIAL measures accurately by taking measurements from a barge. The actual mass flux of VOCs is determined by calculating the known volume being displaced according to the loading flow rate and analyzing the composition of vent samples. DIAL results agree within 12%.[49]

- CONCAWE reports that DIAL can verify emissions estimates from tanks from AP-42. This seems to imply that DIAL is the standard – the tool that can be used to find actual emissions. Concerns have been raised that the tanks used in this study were in near perfect condition, and not indicative of the tanks in the field.[49]

1997

- Chalmers University of Technology in Sweden builds a mobile SOF unit.[63]

2000

- Texas Air Quality Study (TexAQS 2000) results indicate measured emissions of ethene and propene are either 3-10 times or 10-100 times reported.[2, 3, 6]

- Shell DIAL team reports that tank emissions are 4.6 times higher on average than what would be predicted by AP-42. A few tanks are responsible for most of the emissions.[24]

2001

- A Shell brochure, "Industry and Atmosphere: A Ten-Point Guide for Managers", advocates using DIAL over standard techniques (similar to AP-42) for determining VOC emissions. The brochure states that "If you're not measuring, you're just guessing."[12]

2002

- SOF begins testing at Swedish refineries. SOF and DIAL have never been compared side-by-side; however the SOF results obtained were similar to the results found by previous DIAL studies at the same refineries.[63]

- Shell ceases DIAL operation.

2003

- Spectrasyne performs first DIAL study in North America measuring sulfur dioxide, VOCs, methane, benzene and oxides of nitrogen fluxes.[64]

- DIAL presentation at EPA NARSTO conference in Austin. The underestimate emissions identified in TexAQS of an order of magnitude, was very similar to the findings by Europeans using DIAL in petrochemical facilities. Cuclis described how DIAL could be used to systematically identify emission sources from different portions of petrochemical plants, something that was not capable with the aircraft flights or other methods used in Texas at the time.[65]

2005

- Shell sells IR DIAL system to NPL. Shell could not find enough customers to continue their DIAL service.

- Canadian DIAL study at a refinery finds VOCs to be about 15 times higher than reported. This draws attention from U.S. regulators and refiners.[13, 14]

- Sweden to refiners: Pick either DIAL or SOF annually. SOF has been verified as a technique in Sweden. Local regulators require that measurements be taken annually, but the refiners can choose to use either SOF or DIAL. All refiners choose SOF because it is much cheaper. Norway has had a similar policy since the 1990s, but all operators choose DIAL as it gives more detailed information. In Norway, VOCs, methane and benzene measurements are also required.

2006

- EPA Inspector General says that EPA can improve emission factors development and management.[34]

- Texas Air Quality Study II (TexAQS II), as indicated previously, found that emissions of ethene and propene dropped by 40% since 2000, however the measured amounts were still 10 - 40 times higher than expected on the basis of the inventory. Reported NOx from facilities with CEMS appears to be reasonably accurate.[6]

- NPL upgrades the Shell DIAL system. The Shell system had only an IR laser. NPL installed a new IR laser and the capability of swapping out a UV laser into the system.

- API tells EPA the limits of DIAL for VOC estimates. Karin Ritter and Paula Watkins of API states, "The DIAL technology can be a useful tool for measuring short term emissions, but it is inappropriate to extrapolate from such short term emissions to an estimate of annual emissions." The letter discusses API's analysis of the results and conclusions from the DIAL study performed in Canada.[46]

- First U.S. SOF study in Houston. Johan Mellqvist finds that emissions are about an order of magnitude higher for alkanes as well as alkenes.[37, 38]

- EPA holds international workshop featuring the IR Camera, DIAL and SOF.[66]

- Shell Canada uses **"**Spectrasyne, a world leader in environmental surveying, to measure our air emissions. Their laser technology, housed in a mobile unit, allows very accurate measurement of concentrations and emissions rates" – finding measured methane emissions matched reported emissions in tar sands applications.[67]

2007

- EPA writes low bias memo based, in part, on DIAL results.[7]

- TCEQ tests DIAL in Texas City. Finds some high emissions from flares, and some, but not all tanks. Coker emissions at BP in Texas City were not as high as those found at the Canadian refinery coker.[15]

- DIAL finds emissions from a U.S. coker. No report is available. Several DIAL studies of delayed cokers have occurred in Europe since the 1990s.

- Environmental Integrity Project (EIP) tells EPA that the Maximum Achievable Control Technology (MACT) is flawed, citing DIAL findings.[68]

2008

- EPA holds second international conference on remote sensing.[69]

- CONCAWE gives a detailed description of DIAL and SOF in a report.[52]

- Mayor of Houston sends EPA a request for correction under the data quality act, based on numerous reports citing underestimated emissions from petrochemical facilities, including DIAL studies.[70]

2009

- EPA responds to the Mayor of Houston, citing the following items:
  a. EPA plans to fund a DIAL study in the Houston area.
  b. EPA had already begun development of a protocol book to include DIAL and other remote sensing techniques.
  c. EPA plans to evaluate the DIAL study in Texas City and other remote sensing studies.
  d. EPA began development of a comprehensive protocol for estimating VOC and air toxic emissions from petrochemical facilities.
  e. EPA is developing an Electronic Reporting Tool (ERT) to improve data quality. [71]

- A bill (House Bill 4581) was proposed by Scott Hochberg, Texas State Representative, District 137, to the Texas House to build a DIAL, but the bill did not get out of committee. Testimony was given by Alex Cuclis of the Houston Advanced Research Center, Russell Nettles of the Texas Commission on Environmental Quality and Matthew Tejada from Galveston-Houston Association for Smog Prevention (GHASP).[72]

- A presentation on DIAL and SOF was given at the NPRA Environmental Conference in Denver, Colorado by ENVIRON and Baker Botts.[42]

- A detailed QAPP was developed for the DIAL study performed at the Shell Deer Park complex.[16]

- The Texas State Implementation Plan (SIP) submitted to EPA includes a discussion about the value and limits of SOF and DIAL. For example they allow for the monitoring of components at elevated sources such as flares, vents and storage tanks. However, "These technologies normally measure a path length average concentration or number of molecules and as such do not provide a specific concentration at any given point. Therefore, results can be difficult to compare with standards or guideline concentrations."[73]

- Second SOF study in the Houston area. Emissions are generally lower than found in the 2006 SOF study, but still 5 - 10 times higher than expected based on the emission inventories.[38]

- Canadian Petroleum Products Institute (CPPI) advises companies not to use DIAL until after results from studies by TCEQ in Texas City and the City of Houston at Shell Deer Park.[74] Canada had already performed the first three DIAL studies in North America on a well test flare in 2003,[64] and oil and gas facility in 2004[55,75] and at an oil refinery in 2005.[13, 14]

2010

- EIP comments on EPA's protocol for estimating refinery emissions, citing DIAL.[32]

- DIAL study at Shell Deer Park. [76]

- BP Consent decree with EPA requires a DIAL study be performed on the environmental biodegradation unit (EBU) by April 1, 2010. No significant emissions were found.[77]

- Tonawanda Coke DIAL study. EPA found high benzene emissions near the Tonawanda facility and required Tonawanda to conduct a DIAL study. The results confirmed that the facility was a significant source of benzene emissions and ordered corrective actions. Details of the exchanges with EPA, Tonawanda, the test results and communications with the surrounding community can be found at this link: http://www.epa.gov/region02/capp/TCC/april2011update.pdf

- EPA performs a critical review of the TCEQ DIAL study.[78]

- Johan Mellqvist, et. al. publish results finding that emissions of ethene and propene are more than 10 times reported values in the Journal of Geophysical Research. [79]

2011

- SOF study is repeated in the Houston area. Emissions are similar to those seen in 2009. High emissions are also observed in test performed in Port Arthur and Longview for the first time.[19]

- EPA completes "EPA Handbook: Optical Remote Sensing for Measurement and Monitoring of Emissions Flux."[80]

- TCEQ uses SOF to measure VOCs in the Houston Ship Channel, Texas City, Beaumont/Port Arthur and Longview. Measured emissions are consistently high, ranging from 3 – 15 times reported values.[20]

- TCEQ uses SOF to quantify emissions from Barnett Shale oil and gas operations in Barnett Shale.[20]

2012

- Alberta, Canada has contracted with the University of Utah to construct a DIAL to measure greenhouse gases.[81]

Finding a Forward Plan in the United States

In the early 1990's in Sweden, when it became clear to local regulators that the VOC emissions from refineries were far greater than they were reporting, they stopped believing in the estimating methods that are based on EPA AP-42 approaches. As mentioned previously, they required that emissions be reported based on measurements in 1992, and in 1995 they required the measurements be taken with DIAL. By the early 2000's the Swedish regulators determined that either DIAL or SOF were acceptable.

The refiners in Sweden were amenable to these changes in large part because the Swedish regulators did not enforce any VOC limits. Instead each time the measurements were performed the regulators reviewed the results with the refiners and discussed what action plan should be put in place to ensure that emissions would be lower during the next scheduled measurement.

There are several barriers to attempting the Swedish approach at refineries in the United States.

1. The permitting system is much more rigorous in the U.S. Even if a new, more accurate means of measuring emissions was universally accepted to be better than the current estimating techniques, the process of revising State Implementation Plan (SIP) permitting and compliance testing would take years.
2. The U.S. regulatory agencies do not have the option of providing an unspecified VOC limit at refineries due to regulatory requirements and the pressures to achieve attainment for ozone in many locations across the U.S.
3. Even if the U.S. regulatory agencies did find a way to give allowances for more VOC emissions during a transitional phase from EPA AP-42 methods to measurements with DIAL and/or SOF, environmental and community groups would potentially sue the agencies, the refiners or both.
4. The refiners are likely to argue that when they obtained their permits and when they have reported their emissions they followed EPA approve estimating techniques. By requiring them to use measurements like DIAL and/or SOF, they are being asked to use a different measuring system from the one that was agreed to when they first estimated their costs to build and operate the refinery. They will argue that higher VOC allowanced must be made in order for this change to measurements to be fair. (Environmental groups will likely provide counter arguments, saying refiners have not kept their facilities "well-maintained", they should always be using the best technologies to perform measurements, and make corrections accordingly, etc.).

For these reasons a different approach may be necessary in the U.S. One proposed scenario, designed with the intent of substantially reducing emissions and improving the accuracy of emissions inventories without creating any fines or penalties for industry, goes like this:

Over 25% of U.S. refining capacity and literally hundreds of chemical plants and storage tank facilities exist on the upper Texas Gulf Coast between Port Arthur and Corpus Christi, Texas (Figure 10). If an independent company operating out of Houston built and operated a licensed SOF van it could be used to quantify mass VOC emissions from more than 200 petrochemical plants and storage tank facilities in a few months. Additionally it could compare those mass VOC emissions with the expected emissions based on reported values and metrological conditions. A deviation report could be developed based on where the largest differences are observed between reported and measured emissions.

Texas Gulf Coast

Figure 10. More than 25% of U.S. refining capacity lies on the Texas Gulf Coast between Port Arthur and Corpus Christi. Map taken from Google Earth.

A regulatory agency could contract the SOF company to produce deviation reports each quarter. After analyzing and verifying the reports, the agency could then contact facilities upwind of the highest emissions and ask them to examine their operations for problems. In those areas in which the deviations persist, the regulatory agency may ask the facilities to consider a contract with the SOF or DIAL company to take measurements inside their property lines. Other monitoring techniques such as UV-DOAS, FTIR, the IR Camera and hand-held toxic vapor analyzers may be used to help isolate the problem.

By taking measurements in an on-going fashion, it will help to alleviate the concerns industry frequently raises regarding the extrapolation of short term measurements for annual emissions estimates. These measurements would also help identify the best performers, who could be recognized by the environmental agency. Finally, over time these measurements may also be used to identify patterns in either type of facilities, process units or even specific equipment that has higher emission rates than are expected based on existing estimating techniques.

This process of measuring emissions will help to identify and reduce the biggest problems and will help establish the actual emission rates that modelers need for input to the complex air quality models. The end result will be lower emissions and better ozone reduction policies, since the accuracy of the models will be improved.

Conclusions

The main points cited in this paper are as follows:

1. Models need to be verified with measurements, and the AP-42 VOC emission estimates perform very poorly compared to measurements at petrochemical facilities.
2. Underestimating VOC emissions impairs the ability of regulatory authorities to identify effective strategies for reducing emissions of air toxic compounds and ozone precursors.
3. Tweaking or otherwise adjusting the calculations or emission factors will only improve the estimates for equipment that is "well-maintained", but will not solve the problem.
4. The problem of poorly maintained or unmaintained equipment needs to be addressed, as well as other issues such as an operator who accidentally leaves a valve open. Measurements are the only want to identify, locate and resolve these issues.
5. Total vapor analyzers or "sniffers" used as part of leak detection and repair programs help, but they are not used universally around the plant, have limited ability to identify all the potential leaks inside a facility and only measure one point in space. LDAR sniffers lead to the reduction of many emissions, but they do not eliminate them.
6. The IR Camera helps, but does not solve all problems. The response is different for different compounds and the sensitivity is 2-3 orders of magnitude less than techniques such as DIAL and SOF.
7. If you are not measuring you are just guessing. This is a direct quote from a Shell brochure which describes the problems of using techniques like AP-42 for estimating emissions and standard LDAR programs.
8. Fixing VOC emission inventories should not be delayed on the hope of some newer technology. There will always be new technologies. SOF and DIAL have a demonstrated track record of improving the understanding of actual emissions. SOF can be applied economically, and DIAL, although more expensive, can be used for some targeted applications or close in work as needed.
9. Industry will always be concerned about a new monitoring technique because it could lead to more lawsuits, more regulations, more maintenance and in some cases major equipment redesign. These concerns need to be addressed in a thoughtful way.
10. A workgroup made up of various stakeholders from industry, regulatory agencies, the environmental community and scientists to identify the benefits and disincentives for using DIAL and SOF for VOCs and greenhouse gases (GHGs). Consideration should be given to the impacts on permits, ozone reduction models, VOC taxes, the price of carbon, competitive disadvantages, etc.
11. We need to find ways to make refineries greener and more profitable. If the greenest refineries go bankrupt, everyone loses.

Industry representatives rarely comment openly about DIAL and SOF technologies, the findings regarding emissions inventory errors or proposals to fix these problems. Some way must be found for all of these issued to be discussed and argued by industry, regulatory agencies and environmentalists openly.

DIAL was developed and applied for use at refineries during the 1980's when Ronald Reagan was president and MS DOS was the dominate software operating system. DIAL is not new technology. For more than 2 decades it has been applied at facilities in different parts of the world, identifying substantial leaks that the owner operators were not aware of. This technique can identify problem areas in a facility (storage tanks, waste water treatment, flares, process units and others) and help to isolate the location of the leaks. It can help identify whether or not adequate maintenance has been performed and provides an auditing function of emission inventories that is not possible with "sniffers", IR Cameras or other analytical techniques.

SOF was developed in the late 1990's, but has been proven many times in several different countries. In Sweden it has been used annually since 2005 at each of 5 refineries to determine the emission inventories. It is generally much cheaper and easier to employ than DIAL; however, there are measurement trade-offs that must be taken into consideration.

There are substantial challenges to employing DIAL and SOF as the basis for emissions inventories in the U.S., but there are ways to create information about the location of measured emissions and providing opportunities to address them through cooperative efforts with the agencies, industry and community groups.

Ultimately we need to find a way to create a system where the greenest refineries are also the most profitable refineries.

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Exhibit 2

ENVIRONMENTAL MANAGEMENT
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March 7, 2013

Re: Intent to Approve: Petroleum Processing Plant Project No: N146270001

I have reviewed the Emery Refining, LLC, 20,000 bb/day Oil Refinery Green River, Utah Air Quality Notice of Intent, November, 2012 (NOI) and the Utah Department of Environmental Quality Intent to Approve, February 1, 2013 (ITA). I support the comments previously filed by Grand Canyon Trust, the Southern Utah Wilderness Alliance, the Center for Biological Diversity, and Living Rivers and submit additional comments as set out below. My qualifications to evaluate the NOI and ITA are documented in my resume submitted as Appendix A.

I. Greenhouse Gas Emissions Were Underestimated

The NOI estimated the project would increase GHGe by 80,307 ton/yr, concluding the project is minor for GHG emissions. However, the GHG emission calculations in Appendix C of the NOI are based only on emissions from combustion sources. The GHGe emissions from fugitive sources are excluded.

Fugitive emission sources – pumps, valves, compressors, and connectors – and certain other non-combustion sources including tanks, the loading rack, and the oil-water separator emit significant amounts of methane that were excluded from the GHGe emission estimates. All of the fired sources, for example, burn natural gas which is predominantly methane. The fugitive components in the gas supply lines will leak significant amounts of methane unless leakless components are used. These are not proposed

Methane is a potent greenhouse gas that is about 21 times more powerful at warming the atmosphere than carbon dioxide (CO2). The NOI estimated VOCs from these sources, but VOCs exclude methane. Thus, the GHGe emissions are significantly underestimated.

The NOI does not contain sufficient information for me to make an independent estimate of these emissions, e.g., stream composition data that includes methane is absent from the NOI. In my opinion, the methane emissions could be large enough to classify the subject source as major for GHGe emissions. The emission inventory in Appendix C of the NOI should be revised to include these emissions and recirculated for public review. Further, the proposed ITC should be revised to include enforceable limits on GHGe.

II. VOC Emissions Were Underestimated

The VOC emissions from fugitive sources were estimated using emission factors published in 1995 with very aggressive control efficiencies. NOI, Appx. C, p. 33. This approach and these factors have been widely discredited in numerous field studies in which VOC emissions were measured. These field studies show that the approach used in the Emery NOI significantly underestimate actual VOC emissions from fugitive sources.

In general, it has been estimated that VOC emissions from equipment leaks are underestimated by factors of 3 to 20 when estimated using conventional U.S. EPA emission factors.[1] The U.K.'s National Physical

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[1] Allan K. Chambers, et al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, *J. Air & Waste Mgmt. Ass'n*, 58:1047-1056 (2008), at 1054 and Table 7; Clearstone Engineering Ltd., September 6, 2006,; M. Kihlman, et al., *Monitoring of VOC Emissions from Refineries in Sweden Using the SOF Method*, http://www.fluxsense.se/reports/paper%202%20final%20lic.pdf; IMPEL, Diffuse VOC Emissions, December 2000, at p. 38; U.S. Environmental Protection Agency, Office of Inspector General, EPA Can Improve Emissions Factors Development and Management, Evaluation Report, Report No. 2006-P-00017 (March 22, 2006), pp. 11-12 (summarizing the Texas 2000 Air Quality Study… "This primarily involved under reporting of emissions from flares, process vents, and cooling towers, as well as from fugitive emissions (leaks). The under-reporting was caused largely due to the use of poor quality emissions factors.") ; U.S. Environmental Protection Agency, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, 2006 International Workshop (October 25-27, 2006), ("VOC Fugitive Losses") p. vii and p. 1 ("emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors."); *Id.*, p. 3 ("Typically, measurements did show some 10 to 20 times higher emissions than calculated at initial measurement activities…Today, after long term experience with the measurements and also after successful

Laboratory (equivalent to the U.S. National Institute of Standards and Technology) has compared direct measurements of fugitive VOCs with those estimated by emission factors for over a decade and found the direct measurements were about three times higher than the emission factor estimates on a plant-wide basis.[2] Finally, U.S. EPA auditors have found far more leaks than reported by the facility's program, indicating higher routine emissions than belied by the data.[3]

Recent studies confirm the approach used by Emery to estimate fugitive VOC emissions result in significant underestimates in VOC emissions (and methane, a GHG). Monitoring and modeling studies in Texas have demonstrated "severe inconsistencies" between reported and measured emissions. One study concluded: "We believe that our results show that the inventory of industrial VOC emissions [prepared using the fugitive emission factor calculation method] is inaccurate in its location, composition, and emission rates of major sources… Most of the emissions are so-called fugitive emissions from leaking valves, pipes, or connectors, of which there are tens of thousands in a large facility."[4]

This conclusion has been confirmed in numerous studies in the past decade, *viz*., "The analysis presented here for 2000, 2002, and 2006 measurements in the Houston-Galveston-Brazoria area indicates that emission inventory inaccuracies persist."[5] "We conclude that consistently large discrepancies between measurement-derived and tabulated (alkene/NOx) ratios are due to

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improvements of plant operations regarding emissions, emission levels of some 3 to 10 times higher than what is theoretically calculated are typically seen.")

2 VOC Fugitive Losses at. 23. *See* also results of Swedish studies in this same report at p. 213.

3 *See* U.S. EPA's recent refinery settlements at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.

4 Ronald C. Henry and others, Reported Emissions of Organic Gases are not Consistent with Observation, Proc. Natl. Acad. Sci., v. 94, June 1997, pp. 6596-6599; available at: http://www.pnas.org/content/94/13/6596.full.pdf.

5 R.A. Washenfelder and others, Characterization of NOx, SO_2, Ethene, and Propene from Industrial Emission Sources in Houston, Texas, J. Geophys. Res., v. 115, D16311, 2010; J.A. de Gouw and others, Airborne Measurements of Ethene from Industrial Sources using Laser Photo-Acoustic Spectroscopy, Environ. Sci. Technol., v. 43, no. 7, 2009, pp. 2437-2442; B.T. Jobson and others, Hydrocarbon Source Signatures in Houston, Texas: Influence of the Petrochemical Industry, J. Geophys. Res., v. 109, 2004; T. Karl and others, Use of Proton-transfer-reaction Mass Spectrometry to Characterize Volatile Organic Compound Sources at the La Porte Super Site during the Texas Air Quality Study 2000, J. Geophys. Res., v. 108(D16), 2003; L.I. Kleinman and others, Ozone Production Rate and Hydrocarbon Reactivity in 5 Urban Areas: A Cause of High Ozone Concentration in Houston, Geophys. Res. Lett., v. 29, no. 10, 2002; J. Mellqvist and others, Measurements of Industrial Emissions of Alkenes in Texas using the Solar Occultation Flux Method, J. Geophys. Res., v. 115, 2010; T.B. Ryerson and others, Effect of Petrochemical Industrial Emissions of Reactive Alkenes and NOx on Tropospheric Ozone Formation in Houston, Texas, J. Geophys. Res., v. 108(D8), 2003; B.P. Wert, Signatures of Terminal Alkene Oxidation in Airborne Formaldehyde Measurements during TexAQS 2000, J. Geophys. Res., v. 108(D3), 2003.

consistently and substantially underestimated VOC emissions from the petrochemical facilities."[6] "The results… show that the emissions of ethene and propene, obtained by SOF [solar occultation flux], are on average an order of magnitude larger than what is reported in the 2006 daily EI [Emission Inventory]."[7]

A 2006 study reported: "… we do not find good agreement between the measured plume composition and the VOC speciation in the emissions inventory. These observations are not surprising, as previous research has shown that emission fluxes of individual VOCs may be underestimated by as much as 1-2 orders of magnitude in inventories for the Houston area… The frequent lack of correlation between large VOC enhancements and enhancements in SO_2, NOx and CO suggests large, non-combustion sources of VOCs"[8] [*e.g.*, fugitive sources]. One study, for example, reported that measurements of ethene from petrochemical facilities were one to two orders of magnitude higher than reported in the emission inventory.[9] Monitoring data collected during the 2006 Texas Air Quality Study demonstrated that "[i]ndustrial ethylene and propylene emissions in the NEI05-REF are greatly underestimated relative to the estimates using SOF measurements in the Houston Ship Channel during the study period."[10]

These and other studies have consistently shown based on actual monitoring that emissions estimated using the emission factors used in the NOI to estimate Emery VOC emission has underestimate VOC emissions by significant amounts. This is particularly critical here as the proposed ITC does not require any monitoring to confirm the underlying emission factors and control efficiencies.

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[6] T.B. Ryerson and others.

[7] J. Mellqvist and others.

[8] Daniel Bon and others, Evaluation of the Industrial Point Source Emission Inventory for the Houston Ship Channel Area Using Ship-Based, High Time Resolution Measurements of Volatile Organic Compounds, CIRES; available at: http://cires.colorado.edu/events/rendezvous/posters/detail.php?id=3866.

[9] E.B. Cowling and others, A Report to the Texas Commission on Environmental Quality by the TexAQSII Rapid Science Synthesis Team, Prepared by the Southern oxidants Study Office of the Director at North Carolina State University, August 31, 2007, available at: http://aqrp.ceer.utexas.edu/docs/RSSTFinalReportAug31.pdf.

[10] S.-W. Kim and others, Evaluations of NOx and Highly Reactive VOC Emission Inventories in Texas and the Implications for Ozone Plume Simulations during the Texas Air Quality Study 2006, Atmos. Chem. Phys. Discuss, v. 11, 2011, pp. 21,201 - 21,265, available at: http://www.atmos-chem-phys-discuss.net/11/21201/2011/acpd-11-21201-2011.pdf..

III. BACT Was Not Required for All Emission Units

A. Equipment Leaks

Equipment leaks are emissions from piping components and associated equipment including valves, connectors, pumps, compressors, process drains, and open-ended lines, as opposed to large point sources of emissions coming from stacks. These components leak small amounts of the gases and liquids they handle through seals and screw fittings. Thus, they are commonly called fugitive emissions or fugitive leaks. The emissions include compounds found in the streams that pass through the components – CO, VOM, H_2S, total reduced sulfur ("TRS"), methane ("CH_4"), carbon dioxide ("CO_2"), and numerous individual hazardous air pollutants ("HAPs"), such as methanol and carbonyl sulfide ("COS"). As discussed above for GHG emissions, the collective leaks from these fugitive components can add up to a large amount of emissions in the aggregate because there are thousands of them.

Emissions from equipment leaks can be controlled by eliminating them at the source with leakless or low-leak components, such as welded connectors. These components are BACT for a new facility such as Emery.

Pipes, valves, pumps and other equipment are commonly connected using flanges that are welded or screwed. Flanged joints are made by bolting together two flanges with a gasket between them to provide a seal, such as socket weld flanges and threaded flanges. These joining methods leak, no matter how carefully executed. Further, flanged pipe system need much more space, *e.g.*, pipe racks. Insulation of flanged pipe systems is more expensive due to the need for special flange caps.

In a newly built facility, it is customary to minimize flanged connections, because only one weld is needed to connect two pieces of pipe. This saves on the capital costs of two flanges, the gasket, the stud bolts, the second weld, the cost of non-destructive tests for the second weld, etc. Welded connections, which eliminate 100% of the emissions, generally cost less than other joining methods that do have emissions.[11] However, here, the NOI has assumed the old, non-BACT flange joining method, which does not satisfy BACT. Similarly, the ITC has assumed conventional valves, pumps, and compressors, rather than the leakless or low-leak versions that are available and satisfy BACT. The ITC should be revised to explicitly require the use of leakless and low leak fugitive components throughout the facility.

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[11] Definitions and Details of Flanges; http://www.wermac.org/flanges/flanges_general_part1.html; Fundamentals of Professional Welding; http://www.waybuilder.net/free-ed/BldgConst/Welding01/welding01_v2.asp.

B. Flare

The flare emissions are based on an elevated flare. However, flare exposure to wind significantly reduces combustion efficiencies, resulting in much higher emissions than assumed in the emission inventory. Methane emissions, for example, could be substantially higher than assumed in the GHG calculations.

The Bay Area Air Quality Management District ("BAAQMD") in California, where five large petroleum refineries are located, identifies use of an enclosed ground flare as BACT for flare emissions. The BAAQMD also assigns an assumed VOC destruction efficiency of 98.5% to an enclosed ground flare, higher than the assumed destruction efficiency of 98% assumed by the BAAQMD for all other flares. This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds. Thus, an enclosed ground flare is BACT for the Emery flare.

Very Truly Yours,

/s/

Phyllis Fox, Ph.D., PE

Exhibit 3

MEMORANDUM

To Emery Refining LLC Source File

Through: Reginald Olsen, Permitting Branch Manager RDO 6/20/13

Through: Tim Andrus, NSR Section Manager TA 6/20/13

From: Tim DeJulis, NSR Engineer TMD

Date: June 19, 2013

Subject: Response to Public Comments

Emery Refining LLC requested an approval order to establish a new petroleum processing plant. The new plant will be located approximately 5 miles west of Green River in Emery County. The processing plant will consist of distillation towers, process heaters, boilers, storage tanks, a flare device, wax crystallizers, material loading/unloading racks, and various pollution control devices. The plant will be capable of processing up to 20,000 barrels of crude oil per day.

An Approval Order (AO) for this source was proposed with a public comment period from February 4, 2013 to March 7, 2013. Written comments were received from Grand Canyon Trust and from J. Phyllis Fox, under Grand Canyon Trust cover letter. Each individual comment was considered as indicated below before final issuance of the AO. All comments are attached to this memo.

The comments received are summarized below along with the Utah Division of Air Quality's (DAQ) response to the comment.

General Response to Comments

1. A number of comments requested additional information about economic impacts and environmental impacts that may be caused indirectly by the facility, e.g., by increased truck traffic. While the analyses of the type requested by the commenters are often part of an environmental impact statement or environmental assessment required under the federal National Environmental Policy Act (NEPA), NEPA does not apply to air permitting actions taken by the State of Utah. There is no requirement in the state air quality statutes or rules for a permittee to address these matters and DAQ has no authority to require the requested analyses. It should be noted that in no instance associated with these comments did a commenter provide any information about a statutory or regulatory requirement that had not been met.

2. A number of comments requested information and consideration about matters that are outside of DAQ's jurisdiction. Generally, if a matter is not required by DAQ statute or rule, it cannot be required by a DAQ permit. Requirements established by other agencies or programs must also be met but are under the jurisdiction of that particular agency and outside the authority of the DAQ to regulate. Again, it should be noted that in no instance associated with these comments did a commenter provide any information about a statutory or regulatory requirement that had not been met.

Written Comments

Comment #1: By approving a refinery [that] processes oil shale and tar sands oil, Utah is making a short sighted choice for its energy future and for the future of the American southwest. Rather than aggravate a serious situation, we strongly urge that Utah become a leader in cooperation within the Colorado River basin by rejecting the development of immature fuels.

Response: The energy policy of the state is beyond the scope of this permitting action which is outlined in Utah Administrative Code (UAC) R307-401. In addition, this comment does not address any specific terms or conditions of the Intent-to-Approve (ITA), so no changes were made.

Comment #2: The commenting parties urge DAQ to take a hard look at whether DAQ's ITA sufficiently monitors and limits HAP emissions to ensure that endangered fish species both in the Green River and in downstream populations on the Colorado River are not harmed.

Response: HAPs from this project are emitted through combustion, leaks, and from evaporation as shown in the emissions portion of the Notice of Intent (NOI). The total potential emissions of HAPs are calculated to be 2.71 tpy. None of the estimated HAPs emissions triggered further review under R307-410-5, which is a modeling rule. Emissions from tanks subject to 40 Code of Federal Regulations (CFR) 60 Subpart Kb are controlled by seals in accordance with the requirements found in 40 CFR 60 Subpart Kb. Emissions from some tanks are controlled by routing the emissions to the flame zone of combustion equipment. Condition II.B.7.a of the Intent-to-Approve will be clarified to show which tanks are subject to this control. Emissions of HAPs from combustion are controlled by proper combustion. Typical monitoring for this level of emissions (2.71 tpy) includes:

- Inspection of seals in accordance with 40 CFR 60 Subpart Kb,
- Inspection of generator emissions in accordance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ,
- Implementation of a leak detection and repair procedure in accordance with 40 CFR 60 Supbart GGGa and
- Inspection of the maintenance of equipment

With respect to water pollution and any impact on endangered species, please see General Response to Comment No. 2 above. This comment does not address any term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #3: There is no discussion of the source(s) of water to be used during construction and operations at the proposed refinery, whether the facility that it will be taken to is company owned, how the facility will store the waste water, and whether the Utah State Plan for Implementation of Emission Controls for Municipal Solid Waste Landfills (SECTION I) is being implemented.

Response: Water rights and solid waste emission controls are not within DAQ's jurisdiction; please see General Response to Comment No. 2. These issues are outside the scope of this permitting action as outlined in UAC R307-401. This comment also does not address any specific term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #4: There is no company history to evaluate the ability of the company to construct and function correctly. There are no assessments for financial or economic viability.

Response: There is no requirement in the state air quality statutes or regulations for a permittee to demonstrate the adequacy of its financial resources. Also, the commenter did not provide any information about a statutory or regulatory requirement that had not been met. This comment does not address any term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #5: The Company must provide an independent assessment of the wider environmental and economic costs to the town of Green River, Emery County and the state for building new and maintaining existing infrastructure within accepted environmental, sanitation, and safety standards.

Response: See General Response to Comment No. 1. This comment does not address any specific term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #6: Construction of the proposed refinery will have significant environmental impacts in terms of air quality, dust, visibility, increased truck and commercial traffic. Abatement plans need to be put in place in the notice of intent. The Emery Refining notice of intent needs to include an assessment of the estimated costs of construction and the costs of refining a barrel of finished product.

Response: With respect to dust and visibility, fugitive dust control is required by rule UAC R307-205. This rule requires control of fugitive dust at all times. Traffic issues are not within the scope of this permitting action under UAC R307-401. There is no requirement in rule for the suggested abatement plan or the cost assessment and the commenter did not provide a reference to any such requirement. See General Response to Comment No. 1. With respect to the request for costs of refining a barrel of finished product, there is no requirement in the state air quality statutes or regulations for a permittee to provide this information. The commenter did not provide any information about a statutory or regulatory requirement that had not been met and this comment does not address any specific term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #7: Diesel emissions from hundreds of truck trips have profound health impacts.

Response: Mobile emissions are regulated separately under various Federal regulations for on-road and off-road mobile sources, not as part of an approval order for stationary sources under UAC R307-401 and corresponding federal rules. There is no requirement in the state air quality statutes or regulations for a permittee to address this issue for a project of this size. The commenter did not provide any information about a statutory or regulatory requirement that had not been met. See also General Response to Comment No. 1. This comment does not address any specific term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #8: Federal regulations should be directly incorporated into the ITA.

Response: While there is no requirement in UAC R307-401 to include federal requirements, they are included as an informational item and the source is subject to the appropriate standards, regardless of whether they're listed in the Approval Order. The federal requirements are identified as currently codified as the requirements may change without any modification of the Approval Order. The final version of the AO reflects all requirements that DAQ has the authority to impose. Therefore, no changes were made as a result of this comment.

Comment #9: The public must be given the opportunity to comment on additions to the record as a result of this comment period.

Response: DAQ does not agree with this comment. The commenters suggested approach would create a circularity that would make the permitting process impossible. It should also be noted that DEQ statutes anticipate that information will be added after the comment period without going back out for public comment. See Utah Code Ann. Section 19-1-301.5(8)(b)(vi) and (vii). DEQ statutes also provide a standard and a remedy with respect to added information. See Utah Code Ann. Section 19-1-301.5(8)(c). In this case, DAQ requested additional information on the greenhouse gas emissions and the unpaved areas. DAQ reviewed the response to those requests and added the corrected emission totals for greenhouse gases, PM_{10} and $PM_{2.5}$. DAQ also added a new requirement for gravel to be applied to the unpaved areas of the source.

Comment #10: "The ITA Does Not Impose Federally Enforceable Limits on Emery LLC's Potential to Emit VOCs."

Response: Federally-enforceable limits are included for the production amounts of various products in the refinery and these limits serve as a surrogate, or replacement control, for emissions. The emissions were, in-turn, calculated based on those production quantities. A BACT (Best Available Control Technology) review was performed in accordance with UAC R307-401 (see pages 9-11 of the NOI and page 4 of the Engineering Review). A review of applicable federal regulations and the respective controls was also completed (see page 12 of the NOI and pages 14-22 of the Engineering Review). This combined process resulted in federally-enforceable conditions that limit VOC emissions. Other emissions cannot be exceeded because of the design capacity of the equipment. Potential to Emit (PTE), as defined in UAC R307-101-2, includes both emissions limited by design and those limited by enforceable conditions.

Comment #11: VOC emissions were underestimated. The source used emission factors published in 1995 (AP-42) with very aggressive control efficiencies. This approach and these factors have been widely discredited in numerous field studies in which VOC emissions were measured.

Response: DAQ disagrees with this comment. Most of the VOC emissions were calculated using the current version of EPA's AP-42, entitled "Compilation of Air Pollutant Emissions Factors." While the Fifth Edition of AP-42 was published in January 1995, since then EPA has published supplements and updates to the chapters and made them available on their website (www.epa.gov/ttnchie1/ap42). These updated factors were used in calculating emissions. The oil-water separators reflect the 96% control given in AP-42 Table 5.1-2. Tank emissions were calculated with an approved version of the EPA TANKS program using 40 CFR 60 Subpart Kb controls where applicable. The emissions from leaks were calculated utilizing EPA published emission factors (EPA 453/R-95-017 for Connectors and Sampling Connections) as indicated in the NOI (page 33). Leaks are controlled by a Leak Detection and Repair (LDAR) program as required by 40 CFR 60 Subpart GGGa. At this point in time, the EPA has not chosen to pursue the incorporation of any of the referenced field studies into AP-42 or into any of the appropriate federal regulations. DAQ chose to rely on officially published EPA documents. Compliance with the federal regulations and the conditions of this approval order are sufficient to control the emissions of VOCs to non-major source thresh-hold levels.

Comment #12: "The ITA Fails to Ensure that the Green River Refinery's Emissions Will Not Interfere with Attainment or Maintenance of the National Ambient Air Quality Standards"

Response: This comment specifically addresses the Ozone and CO NAAQS and suggests that there should be emission limits on the same time averaging period as the standard (9 ppm on an 8-hour average and 35 ppm on a 1-hour average for CO; 0.075 ppm on a 8-hour average for Ozone). A determination that the NAAQS are protected can be achieved by several methods, of which modeling is but one option. However, the levels of emissions from this project do not require modeling under R307-410 for CO, NO_x or VOC (NO_x and VOC being precursors to Ozone).

The NAAQS impact is determined at and outside the source boundary, not the stack exit where a limit would be presumably measured and enforced. In general, limits, work practices and monitoring are useful when an add-on control technology is used to reduce emissions. In this case, there are no CO controls to monitor. In addition, since the maximum uncontrolled CO emissions are below modeling thresholds, there is no evidence that the NAAQS will be violated.

For Ozone, there is no technical way to attribute ozone levels to an individual emission unit or source as ozone is formed through a chemical reaction in the atmosphere. Here again, the ozone NAAQS is protected based on the low level of emissions of the precursors (NO_x and VOC as described above) and the typically low background levels found in this part of the state (vic. Green River – see Dave Prey email of May 9, 2013 attached).

Comment #13: "The ITA Must Incorporate Monitoring for Criteria Pollutants and Greenhouse Gases to Ensure that the Green River Refinery Emissions Remain Within the Permitted Limits"

Response: This comment focused on the emissions from the flare and other combustion equipment, specifically the NO_x, CO, and CO_2 emissions. The commenter also suggests that there should be CEMs for all combustion equipment and for VOCs on the loading racks. While the monitoring of sulfur compounds from the flare is feasible (because the sulfur compound emissions can be calculated from the sulfur content of the gas going to the flare), the remaining combustion products cannot be calculated in this manner. However, the DAQ is not aware of any technical or feasible method to monitor the requested pollutants of NO_x, CO and CO_2 from the flare. Emissions based on approved emission factors are acceptable as the information used in the calculations can be verified through methods other than direct monitoring. (See discussion above on AP-42 and other sources of emission factors).

Finally, the emission requirements from 40 CFR 60 Subpart Ja (60.102(a)-(d)) that the commenter suggested should be required only apply to a process unit (FCCU) that is not present at this refinery.

Comment #14: "An Emissions Impact Analysis Should Be Required Because the PM_{10} Limits May Exceed the Limits Set Forth in R307-410-4"

Response: The comment suggests that since the PM_{10} emissions exceed the threshold of 5 tpy an emissions impact analysis (modeling) should be required. Commenter also expressed a concern that there is no threshold for VOC in UAC R307-410-4. The total PM_{10} emissions of 10.92 tpy includes ALL PM_{10} emissions, from fugitive AND point sources. The fugitive portion of the PM_{10} emissions does not exceed the modeling threshold of 5 tpy in UAC R307-410-4, Table 1. Likewise, non-fugitive PM_{10} emissions are below the 15 tpy threshold. (See NOI Appendix C updated May 6, 2013). (NOTE: The updated emissions data for PM_{10} was submitted as a result of a query from the DAQ in response to the comment.)

Commenter's concern over the lack of a VOC threshold in R307-410 is noted, but a rule change is not within the scope of this permitting action. This comment does not address any term or condition of the Intent-to-Approve (ITA), so no changes were made.

Comment #15: The Record Does Not Support DAQ's BACT Determination Thoroughly Enough.

Response: The top-down approach to BACT is one way to conduct a BACT analysis; it is not a required methodology spelled out anywhere in state or federal air rules. Additionally, in cases such as this where emissions are not large, it goes far beyond what is necessary. BACT is defined at UAC R307-401-2. A BACT analysis does not need to translate to a specific emissions limit but may result in a control requirement or work practice standard to limit emissions. The comments suggest that other technologies should be considered, but only provide one example (see below). While there may be technologies or practices that may achieve lower emission rates at other locations in the world, that technology may not be directly related nor relevant to this project due to feed-stock makeup, sizes or products being produced. Additionally, BACT does not require the most stringent level of control available, but the best available (see definition in UAC R307-401-2). The single NO_x control equipment suggested in the comment is produced by a single company and appears to be focused on coal combustion (see case studies at http://www.ftek.com/en-US/products/apc/low-nox-burners). The equipment at the source under review is fired by gas, not coal. Based on this information, the transference of fuel type is suspect.

Comment #16: BACT was not required on all emission units, particularly the equipment leaks and the flare. Additionally, an article from the internet concerning a welded system should be considered. Also for the process connections, a fully sealed system is indicated. In the case of the process flare device, a ground-based unit should be prescribed over an elevated flare. See the article at http://www.waybuilder.net/free-ed/bldgconstr/welding01/welding01_v2.asp.

Response: First, the referenced web link is apparently invalid as it did not lead to the referenced article. As a result, DAQ was unable to validate the assertions stated in the comment. Moreover, based on DAQ's experience, a welded system as described in the comment would not be feasible or practical and could instead be a safety risk. In this case, a leak detection and repair (LDAR) program or system is required to minimize emissions. The source may choose to weld connections to reduce the number of locations that must be monitored. With regard to flare design, while there are several types of flares, only one AP-42 factor exists for all flares and that factor was used for the BACT analysis.

Comment#17: Monitoring and Regulation of the Flare System Is Inadequate and projected emissions in the NOI do not include breakdowns.

Response: The flare at this source is for emergency decompression of the plant as shown in Condition II.A.6. Advanced flare control technology, such as flare gas compression, is available but has been typically applied as part of consent decrees for larger and more complex refineries. The example cited in the comment (Lion Oil Company El Dorado refinery) is not comparable. The *reductions* in emissions obtained at that refinery through the 2003 Consent Decree (not BACT) are an order of magnitude larger than the *total* emissions from this source. The currently-permitted emissions for the El Dorado refinery are, in tpy: PM_{10} 322.6; NO_x 614.8; CO 1440.3; VOC 9896.4. This is after the Consent Decree reductions of 200 tpy in PM_{10}, 530 tpy in NO_x and 650 tpy in SO2. The Emery Refinery emissions are calculated to be, in tpy: PM_{10} 10.9; NO_x 21.1; CO 73.2; VOC 36. An approval order under UAC R307-401 is issued for normal operations. By definition, a breakdown is random and not expected. There is no way to include such emissions in an annual emission estimate. The source must comply with the breakdown rule at UAC R307-107 and actual emissions, including those from breakdowns, must be reported in accordance with UAC R307-150.

Comment #18: Monitoring and Regulation of Fugitive Emissions Is Inadequate

Response: Fugitive emissions of VOC are regulated under 40 CFR 60 Subpart GGGa by establishment of the required leak detection and monitoring program. Fugitive emissions of VOC from wastewater systems are regulated under 40 CFR 60 Subpart QQQ. Fugitive emissions of PM_{10} are regulated under UAC R307-205. Every approval order also contains a requirement for proper operation and maintenance of emission units, implementing the requirement under UAC R307-401-4(1). Vapor continuing to escape from tanks beyond the applied controls is accounted for in the approved of TANKS 4.0 program that will be used to calculate actual emissions for the requirements of UAC R307-150. The papers that were referenced in the comment do not form the regulatory basis for additional measures to be considered in the rules, as the papers have not been promulgated at either the state or federal level for use in permitting. It is not typical to require the same level of monitoring for sources such as Emery, with VOC emissions of 36 tpy, as for much larger sources. (For comparison, the VOC emissions from refineries in the Salt Lake/Davis County are Tesoro 793 tpy; Holly 121.72 tpy.) The comment provides no persuasive reason to treat Emery Refining the same as much larger refineries.

Comment #19: The greenhouse gases were underestimated. The calculated GHG emissions only include the emissions from the combustion sources and do not include the fugitive sources. The fired sources burn natural gas, predominantly methane, and the calculations do not include a provision for this to include the fugitive releases of the methane gas from this source.

Response: GHG emissions were calculated from the combustion sources according to EPA's Greenhouse Gas reporting rule at 40 CFR 98, Subpart C which address combustion units. However, Emery Refining used an incorrect reference for the calculations. The correct reference is 40 CFR 98, Subpart Y, which addresses refinery GHG emissions including methane emissions from tanks, equipment leaks, etc. These additional emissions covered in Subpart Y were not included in the original NOI. However, based on revised calculations from the source using 40 CFR 98 Subpart Y, the maximum GHG emissions are 90,096 tons per year, CO_2e. The revised greenhouse gas emissions still show that the source will be below the 100,000 tpy threshold for designation as a major source for either PSD or Title V purposes.

Tim Andrus <tandrus@utah.gov>

Re: Green River backgrounds?

1 message

Dave Prey <dprey@utah.gov> Thu, May 9, 2013 at 6:19 PM
To: Tim Andrus <tandrus@utah.gov>
Cc: Tom Orth <TORTH@utah.gov>

Tim,

The 8-hr 98% Ozone is 67 ppb, from the UDAQ Price monitor.
The 1-hr 98% NO2 is 35 ppb, also from the Price monitor.

On Thu, May 9, 2013 at 5:59 PM, Tim Andrus <tandrus@utah.gov> wrote:

> Do you have a concentration for ozone and/or NOx background in the area of Green River handy?
>
> Thanks,
> Tim

http://www.epa.gov/compliance/resources/cases/civil/caa/lionoil.html
Last updated on Wednesday, August 01, 2012

Civil Enforcement Cases and Settlements

You are here: EPA Home Enforcement Civil Cases and Settlements Lion Oil Civil Judicial Settlement

Lion Oil Civil Judicial Settlement

The U.S. Justice Department and the Environmental Protection Agency on March 11, 2003, agreed to a comprehensive Clean Air Act settlement with Lion Oil Company to reduce harmful air emissions from the company's El Dorado, Ark., refinery by 1,380 tons per year. The State of Arkansas has joined EPA in the settlement. The agreement addresses air pollutants —nitrogen oxides, sulfur dioxide and particulate emissions—that can cause serious respiratory problems and exacerbate cases of childhood asthma, as well as carbon monoxide, which can be harmful to the cardiovascular system.

The settlement requires Lion Oil to spend more than $21.5 million to install state-of-the-art pollution control technology to significantly reduce emissions from a catalytic cracking unit (its largest emissions unit), heaters, boilers, wastewater vents, flares, and leaking valves throughout its refinery. With this settlement, the company will continue its operations and continue meeting the public's demand for fuel and increased production capacity. Lion Oil also will pay a $348,000 civil penalty, which the State of Arkansas will share, and spend more than $450,000 on supplemental environmental projects designed to further reduce emissions from the refinery. Under the settlement, Lion Oil will cut air emissions by using innovative control technologies, incorporating improved leak detection and repair practices, and making other emission control upgrades at the El Dorado refinery. Currently the refinery has a processing capacity of more than 58,000 barrels of oil per day. These improvements will reduce annual emissions of nitrogen oxide (NOx) by approximately 530 tons, sulfur dioxide (SO_2) by approximately 650 tons, particulate matter (PM) by approximately 200 tons, and significantly reduce carbon monoxide (CO) emissions from process units at the El Dorado refinery.

This settlement one of multiple global agreements reached under this Administration's efforts to assure the petroleum refining industry's compliance with major provisions of the Clean Air Act. During the past few years, petroleum refiners, like Lion Oil, have voluntarily entered into global discussions with the United States. Those companies include Koch Petroleum, BP Exploration and Oil, Motiva Enterprises, Equilon Enterprises LLC, Deer Park Refining Limited Partnership, Marathon Ashland Petroleum LLC, Conoco, and Navajo Refining. Together these settlements provide for a comprehensive and cooperative approach to addressing environmental problems across the industry. The settlement will be lodged with the U.S. District Court in Fort Smith, Ark., for 30 days to allow for public comment.

- Press Release (3/11/03)
- Consent Decree (PDF) (127 pp, 663K, About PDF)
- Complaint (PDF) (31 pp, 105K, About PDF)
- First Amendment to Lion Oil Consent Decree (PDF) (9 pp, 52K, About PDF)

Enforcement Priorities

- EPA Petroleum Refinery Initiative

For additional information, contact:

Patrick W. Foley
Senior Environmental Engineer
U.S. Environmental Protection Agency (2242A)
1200 Pennsylvania Ave., N.W.
Washington, DC 20460-0001
(202) 564-7978
foley.patrick@epa.gov

ISTEPS - Total Facility Permitted Emissions

AFIN	Facility Name	City	County
70-00016	LION OIL COMPANY	EL DORADO	UNION

CAS Code	Pollutant Description	Limit Tons/Yr	Limit Lbs/Hr
100414	ETHYL BENZENE	43.6	0
106990	1,3-BUTADIENE	5.1	0
108883	TOLUENE	148.7	0
108952	PHENOL	9.8	0
110543	HEXANE	314.5	0
111422	DIETHANAOLAMINE	4.4	0
127184	TETRACHLOROETHYLENE	4.9	0
1319773	CRESOLS (MIXED ISOMERS)	14	0
1330207	XYLENE (MIXED ISOMERS)	341.8	0
463581	CARBONYL SULFIDE	4.5	0
50000	FORMALDEHYDE	7.1	0
540841	2,2,4-TRIMETHYLPENTANE	56.2	0
71432	BENZENE	67.9	0
75150	CARBON DISULFIDE	4.4	0
7647010	HYDROCHLORIC ACID	48.6	0
7664939	SULFURIC ACID	88.3	0
7782505	CHLORINE	26.7	0
7783064	HYDROGEN SULFIDE	364.3	0
7783064	HYDROGEN SULFIDE -- Form R	364.3	0
91203	NAPHTHALENE	6.6	0
92524	BIPHENYL	9.5	0
98828	CUMENE	10.2	0
CO	CARBON MONOXIDE	1440.3	1100.5
NH3		62.1	0
NOX		655.9	288.6
PM10-PRI		309.7	102.8
PM-PRI		884.8	0.2
SO2	SULFUR DIOXIDE	547.2	180.1
VOC	VOLATILE ORGANIC COMPOUNDS	9817.4	8181.3

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Permit matching
Refinery to ISTEPS summary.
Permit is 839 pages.
Full Permit at
www.ADEQ.STATE.AR.US/home/pdssql/
pds.aspx

ADEQ
ARKANSAS
Department of Environmental Quality

SEP 9 2011

George Garten, Environmental Engineer
Lion Oil Company
1000 McHenry Drive
El Dorado, AR 71730

Dear Mr. Garten:

The enclosed Permit No. 0868-AOP-R9 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 4/26/2011.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 0868-AOP-R9 for the construction, operation and maintenance of an air pollution control system for Lion Oil Company to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Mike Bates

Mike Bates
Chief, Air Division

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0868-AOP-R9

IS ISSUED TO:

Lion Oil Company
1000 McHenry Drive
El Dorado, AR 71730
Union County
AFIN: 70-00016

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

November 28, 2006 AND November 27, 2011

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

SEP 9 2011
Date

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http://www.waybuilder.net/free-ed/bldgconstr/welding01/welding01_v2.asp - Windows Internet Explorer

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Of course we regret any inconvenience this has caused you.

Exhibit 4

Gmail by Google

Anne Mariah Tapp <annemariahtapp@gmail.com>

Fwd: Emery Refining Increase in Fugitive Dust PM10

1 message

Tim Dejulis <tdejulis@utah.gov> Mon, Jul 8, 2013 at 12:52 PM
To: Anne Mariah <annemariahtapp@gmail.com>

Part 1 of 3

Timothy DeJulis, P.E.
Division of Air Quality
195 N. 1950 W.
Salt Lake City, UT 84116
P: 801-536-4012
F:801-536-4000
tdejulis@utah.gov

---------- Forwarded message ----------
From: **Tim Andrus** <tandrus@utah.gov>
Date: Wed, May 15, 2013 at 12:05 PM
Subject: Re: Emery Refining Increase in Fugitive Dust PM10
To: David A Kopta <dmkenv@gmail.com>
Cc: Tim DeJulis <tdejulis@utah.gov>, Ron Chamness <RChamness@woodrock.com>, Hank Diesel <HDiesel@woodrock.com>

Hi Dave,

Regg and I discussed the 4.25 tpy increase and we believe that any corrections arising from the original comment period do not warrant going back out again.

Staff always tries to account for all emissions from a source, as sometimes it's the "little" things that add up. If Emery Refining can reduce the dust that easily, it would be a wise choice. It would also alleviate any concerns about the introduction of post-comment emissions. There will have to be dust control of some sort anyway. Just let Tim D know so he can include it as a condition in the final AO.

The assistant AG assigned has comments on our draft response to comments. We are waiting for his availability to review the response. Once that is completed, hopefully in the next 1-2 weeks, we can get the approval order to Bryce.

Tim

On Wed, May 15, 2013 at 11:34 AM, David A Kopta <dmkenv@gmail.com> wrote:

> Tim, I have heard that the increase in PM10 emissions that I submitted to you for fugitive dust (4.25 tons/yr) may be a problem because it is an increase in emissions that was not made available for public comment. If this is so, Emery Refining could commit to covering all of the disturber exposed land with gravel, to eliminate wind blown dust from open areas. This would leave .66 tons/yr from paved roads. I do not know what your current policy is for including the fugitive dust from paved roads in a permit application. My experience over the years has been that for an industrial site that does not have open areas or unpaved roads, the dust from paved roads in normally ignored. So, if the 4.25 ton increase is a problem, would reducing it to .66 tons of paved road dust only, solve the problem?

David A Kopta
DMK Environmental Engineering, Inc.
P.O. Box 461
Monticello, Utah 84535
DMKenv@Gmail.com
801-278-5133

Anne Mariah Tapp <annemariahtapp@gmail.com>

Fwd: Emery Refining CO2e

1 message

Tim Dejulis <tdejulis@utah.gov> Mon, Jul 8, 2013 at 12:52 PM
To: Anne Mariah <annemariahtapp@gmail.com>

Part 2 of 3

Timothy DeJulis, P.E.
Division of Air Quality
195 N. 1950 W.
Salt Lake City, UT 84116
P: 801-536-4012
F:801-536-4000
tdejulis@utah.gov

---------- Forwarded message ----------
From: **Tim Andrus** <tandrus@utah.gov>
Date: Mon, May 6, 2013 at 7:47 AM
Subject: Re: Emery Refining CO2e
To: David Kopta <dmkenv@gmail.com>
Cc: Tim DeJulis <tdejulis@utah.gov>, Reginald Olsen <rdolsen@utah.gov>, Ron Chamness <RChamness@woodrock.com>

I'm glad Dave. I am out today with unpleasantness. Tim D will review your calculations today.

Tim A

On May 6, 2013 7:13 AM, "David A Kopta" <dmkenv@gmail.com> wrote:

> Sorry Tim, the calculations I sent are based on subpart Y, I just mistakenly called them subpart X.
> On May 5, 2013, at 4:08 PM, Tim Andrus wrote:
>
> > Subpart X is not correct, it is for ethylene, methanol, etc. Please read definitions of categories. Subpart Y is for naptha, lubes, etc. and the one to use here. This is the subpart I indicated in the response to comments.
> >
> > I expect we will add a CO2e limit to the AO of 99,000 tons to make sure this isn't PSD for GHG.
> >
> > We'll look for the Subpart Y calculations to arrive soon.
> >
> > Thanks,
> > Tim
> >
> > On May 5, 2013 3:49 PM, "David A Kopta" <dmkenv@gmail.com> wrote:
> >
> > > Tim, attached is a spreadsheet that estimates the emissions of CO2e from the Emery Refinery using the 40 CFR subpart x methodology. The storage tanks and equipment leaks are insignificant. The changes from the AP-42 method of the NOI calculations are all due to using an emission factor for refinery gas and LPG. The NOI used the natural gas emission factor for all combustion.

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P.O. Box 461
Monticello, Utah 84535
DMKenv@Gmail.com
801-278-5133

David A Kopta
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Gmail by Google

Anne Mariah Tapp <annemariahtapp@gmail.com>

Fwd: Fugitive Dust @ Emery Refining

1 message

Tim Dejulis <tdejulis@utah.gov> Mon, Jul 8, 2013 at 12:52 PM
To: Anne Mariah <annemariahtapp@gmail.com>

Part 3 of 3

Timothy DeJulis, P.E.
Division of Air Quality
195 N. 1950 W.
Salt Lake City, UT 84116
P: 801-536-4012
F:801-536-4000
tdejulis@utah.gov

---------- Forwarded message ----------
From: **Tim Andrus** <tandrus@utah.gov>
Date: Tue, May 7, 2013 at 1:37 PM
Subject: Re: Fugitive Dust @ Emery Refining
To: Tim Dejulis <tdejulis@utah.gov>

Have you advised Mr. Kopta that modeling is required? If not, please point that out to him ASAP.

Timothy R. Andrus
Environmental Program Manager

Utah Division of Air Quality
Minor New Source Review Section
tandrus@utah.gov
Phone 801.536.4429
Fax 801.536.4099

On Tue, May 7, 2013 at 1:18 PM, Tim Dejulis <tdejulis@utah.gov> wrote:

> Sorry, that should be 5.38 tpy fugitive, 10.92 tpy both kinds.
>
> Timothy DeJulis
> Division of Air Quality
> 195 N. 1950 West
> Salt Lake City, UT 84116
> P: 801-536-4012
> F:801-536-4000
> tdejulis@utah.gov
>
> On Tue, May 7, 2013 at 1:04 PM, Tim Dejulis <tdejulis@utah.gov> wrote:
>
>> Hi Tim,

Previously there were no fugitive haul road emissions because the haul roads were less than a hundred feet. Now, if we include these as fugitive emissions, then yes. They are above the 5 tpy total for fugitive releases (3.59+1.13+0.66=6.38 tpy). The total (fugitive and non-fugitive) is 5.54+6.38=11.92 tpy.

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On Tue, May 7, 2013 at 12:02 PM, Tim Andrus <tandrus@utah.gov> wrote:

So, when you add this with the other PM10 emissions, fugitive and not, does it now trigger modeling?

Timothy R. Andrus
Environmental Program Manager

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On Tue, May 7, 2013 at 11:43 AM, Tim Dejulis <tdejulis@utah.gov> wrote:

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---------- Forwarded message ----------
From: **David A Kopta** <dmkenv@gmail.com>
Date: Mon, May 6, 2013 at 12:36 PM
Subject: Fugitive Dust @ Emery Refining
To: Tim DeJulis <tdejulis@utah.gov>
Cc: Ron Chamness <RChamness@woodrock.com>

Tim, attached are calculations for fugitive dust from paved roads and open areas at the Emery Refinery. Originally the plan called for
no open areas, that has been modified there will now be 20 acres of open area. The rest will be paved or covered in gravel. Let me know if you need anything else. Thanks.

David A Kopta
DMK Environmental Engineering, Inc.

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