



# WASHINGTON OIL REFINERY RACT

## Technical Support Document

### Prepared for:

Washington State Department of Ecology  
Petroleum Refinery Greenhouse Gas Emissions Requirements Rule

### Developed by:

Northwest Clean Air Agency,  
Puget Sound Clean Air Agency,  
and Washington State Department of Ecology

DRAFT - September 9, 2013

Publication no. xx-xx-xxx

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## Section 1: Introduction

The reasonably available control technology (RACT) determination process described in this document was undertaken in response to a March 27, 2012, Remedy Order entered in the United States District Court – Western District of Washington at Seattle (Case No. C11-417 MJP, Washington Environmental Council, et al. vs. Sturdevant, et al.). In that order, the Washington State Department of Ecology (Ecology), Puget Sound Clean Air Agency (PSCAA), and Northwest Clean Air Agency (NWCAA) (collectively referred to as “the Agencies” in this document) were ordered to complete a RACT determination process pursuant to Revised Code of Washington (RCW) 70.94.154 within 26 months addressing greenhouse gases (GHGs) for each of five Washington State petroleum oil refineries owned and operated by the following companies: BP PLC (BP), Phillips 66 Company (Phillips 66), Shell Oil Company (Shell), Tesoro Refining & Marketing Company (Tesoro), and US Oil & Refining Company (US Oil). The locations and capacities of these five refineries are presented in Table 1-1. This document provides the technical background and conclusions reached during the RACT determination process.

**Table 1-1 Washington State Refinery Locations and Capacities**

<b>Owner/Operator</b>	<b>Location</b>	<b>Capacity (barrels/day)</b>
<b>BP</b>	Cherry Point	234,000
<b>Phillips 66</b>	Ferndale	107,500
<b>Shell</b>	Anacortes	149,000
<b>Tesoro</b>	Anacortes	125,000
<b>US Oil</b>	Tacoma	42,000

## Section 2: Air Contaminants of Concern

In establishing RACT requirements, Ecology and local authorities must address, where practicable, all air contaminants deemed to be of concern for that source or source category. The purpose of this section is to identify the air contaminants of concern for the RACT determinations for the five Washington State petroleum oil refineries.

In RCW 70.94.030, air contaminant is defined as “dust, fumes, mist, smoke, other particulate matter, vapor, gas, odorous substance, or any combination thereof.” For the purpose of this analysis, the definition specifically refers to the following pollutants:

1. Particulate matter (PM) and precursors (i.e., organics and ammonia):
  - a. PM<sub>10</sub>: PM with an aerodynamic diameter less than or equal to a nominal 10  $\mu\text{m}$
  - b. PM<sub>2.5</sub>: PM with an aerodynamic diameter less than or equal to a nominal 2.5  $\mu\text{m}$
2. Carbon monoxide (CO)
3. Nitrogen oxides (NO<sub>x</sub>) including nitrogen dioxide (NO<sub>2</sub>)
4. Sulfur dioxide (SO<sub>2</sub>)

5. Ozone precursors, including volatile organic compounds (VOCs), as defined by the US Environmental Protection Agency (EPA), and NO<sub>x</sub>
6. Lead
7. Hazardous air pollutants (HAPs) – 187 compounds defined in Section 112 of the Federal Clean Air Act (USCAA)
8. Toxic air pollutants (TAPs) – approximately 350 compounds as defined in Washington Administrative Code (WAC) 173-460
9. GHGs:
  - a. Carbon dioxide (CO<sub>2</sub>)
  - b. Methane (CH<sub>4</sub>)
  - c. Nitrous oxide (N<sub>2</sub>O)
  - d. Hydrofluorocarbons (HFCs)
  - e. Perfluorocarbons (PFCs)
  - f. Sulfur hexafluoride (SF<sub>6</sub>)

Many of these pollutants are produced by refinery emission sources. All of the Washington State oil refineries are major sources (as defined by Title V Operating Permit thresholds) of NO<sub>x</sub>, CO, SO<sub>2</sub>, VOCs, and HAPs; the four larger oil refineries (i.e., all but the US Oil refinery) are also major sources of PM.

## Section 3: Federal Programs

In determining the air contaminants of concern for a RACT determination, it is useful to review the existing regulatory programs that apply to the source or source category being reviewed. As detailed below, oil refineries in Washington State are subject to many federal, state, and local air quality regulations.

### 3.1 National Ambient Air Quality Standards

The 1970 USCAA established EPA and directed it to develop and enforce regulations for all air pollutants that might reasonably be anticipated to endanger public health or welfare. Section 109 of the USCAA required that EPA set primary National Ambient Air Quality Standards (NAAQS) to protect human health with an adequate margin of safety and secondary NAAQS to protect against other effects, such as damage to vegetation, structures, ecosystems, and visibility.

EPA has set primary NAAQS<sup>1</sup> for PM<sub>10</sub>, PM<sub>2.5</sub>, CO, NO<sub>2</sub>, SO<sub>2</sub>, ozone precursors, and lead. No NAAQS have been set for GHGs. There are also secondary standards for all pollutants except CO. For the Washington State oil refineries, the NAAQS are implemented and enforced through the regulations of NWCAA, PSCAA, Ecology, and EPA.

Compliance with the NAAQS is determined through the measurement of ambient air quality using specific instrumentation and methods. In Washington State, the network of ambient air quality monitoring stations is accessible by the public online

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<sup>1</sup> Additional information on the NAAQS can be found on the US EPA webpages, including; <http://www.epa.gov/air/criteria.html>

(<https://fortress.wa.gov/ecy/enviwa/>). Areas that are identified as being out of compliance with one or more NAAQS are classified as “nonattainment,” while those areas that have no evidence of noncompliance are classified as “attainment.” Once an area has fallen into nonattainment, a plan is developed to identify and address the air quality problem and return the area to attainment status.

### 3.1.1 Nonattainment – Historical

The area under the jurisdiction of the NWCAA, which has the four largest oil refineries in the state, has met ambient air quality standards continuously since the NAAQS were first established by EPA.

In contrast, the area of Pierce County that is the site of the US Oil refinery, and under PSCAA jurisdiction, has been identified as a CO nonattainment area (once), ozone nonattainment area (twice), and PM<sub>10</sub> nonattainment area (once). Each of these previous incidences of nonattainment has been addressed, and Pierce County currently meets all ambient air quality standards with the exception of PM<sub>2.5</sub>.

Sections 172(c)(1) and 182 of the USCAA require that states that fail to meet the NAAQS to submit plans to EPA that “provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national primary ambient air quality standards.”

To facilitate the submittal of approvable State Implementation Plans (SIPs) for nonattainment areas, EPA developed and published a number of Control Technique Guideline (CTG) documents. The control equipment and strategies in these publications were considered presumptive RACT and included the following CTGs for petroleum refineries:

- Control of Refinery Vacuum Producing Systems, Wastewater Separators and Process Unit Turnarounds (EPA-450/2-77-025)
- Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals (EPA-450/2-77-026)
- Control of Volatile Organic Compound Emissions from Storage of Petroleum Liquids in Fixed Roof Tanks (EPA-450/2-77-036)
- Control of Volatile Organic Compounds from Petroleum Refinery Equipment Leaks (EPA-450/2-78-036)
- Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks (EPA-450/2-78-047)
- Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (EPA-450/2-78-051)

In 1980, PSCAA adopted and incorporated the VOC rule language from these documents into PSCAA Regulation II as part of its ozone SIP submittal to EPA (at the time, Snohomish, King, and Pierce Counties were nonattainment for ozone). Because of continued nonattainment issues, in 1991, some of these PSCAA SIP rules were revised to be more

stringent. EPA approved both the 1980 and 1991 SIP submittals, determining that the PSCAA rules were RACT. EPA determined that PSCAA's standards for PM were RACT as part of the PM<sub>10</sub> SIP submitted in the 1990s. These rules remain as part of PSCAA Regulation II.

Ecology also adopted the VOC rule language from the CTGs into WAC 173-490<sup>2</sup> (Emissions Standards and Controls for Sources Emitting VOCs), which applies to any ozone nonattainment area in the state.

Even though the area in NWCAA jurisdiction was not identified as an ozone nonattainment area in the early 1990s NWCAA also adopted the Ecology rules. NWCAA also included similar rules in its regulation (NWCAA regulation Section 580). The NWCAA regulation is SIP-approved.

### **3.1.2 Nonattainment – Current**

The only current Washington nonattainment area that includes an oil refinery is the “Wapato Hills-Puyallup River Valley Nonattainment Area” which resulted from PM<sub>2.5</sub> monitoring data that was in excess of the 24-hr average standard. Efforts to develop an attainment plan have been underway for several years. The combined efforts of Ecology, PSCAA, the Clean Air Task Force, and other partners have led to development of a SIP, which will be submitted to EPA for review and approval. In the plan for this area, the PM<sub>2.5</sub> nonattainment status has been identified as a wood smoke issue associated with residential heating practices. Thus, the focus of the attainment plan is the wood smoke issue; the plan does not include any emission reductions from US Oil (or other industrial sources) because the technical evaluation concluded they were not significant contributors to the nonattainment condition. The most up-to-date information available regarding this and other potential nonattainment issues in Washington is available to the public at <http://www.ecy.wa.gov/programs/air/nonattainment/nonattainment.htm>.

## **3.2 Federal New Source Performance Standards Requirements**

Section 111 of the USCAA requires that EPA promulgate standards of performance for new stationary sources (i.e., the New Source Performance Standards [NSPS]), “which reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” These standards, which are generally considered to be at least as stringent as RACT, are specific to the criteria pollutants and, for ozone, its precursors (VOC and NO<sub>x</sub>). Although the rules apply to criteria pollutants, collateral emission reductions are achieved when a hazardous or toxic air pollutant is also a criteria pollutant. Examples of this include benzene and toluene, which are VOCs. GHG emissions reductions may be also achieved in cases where more-efficient combustion devices are installed to achieve compliance with criteria pollutant emission

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<sup>2</sup> WAC 173-490-040 (requirements), -200 (Petroleum refinery equipment leaks), -201 (Petroleum liquid storage in external floating roof tanks), and -202 (Leaks from gasoline transport tanks and vapor collection systems); WAC 173-491-040 (Gasoline vapor control requirements)

limits. Such reductions are difficult to quantify and generally would vary by installation. Furthermore, although the rules affect only new, modified, or reconstructed stationary sources, many of the rules have been in place for years. Substantial portions of equipment at the oil refineries as they now exist are subject to NSPS. The following NSPS (promulgated under 40 CFR Part 60) apply to affected facilities (as defined in the regulations) at the Washington State petroleum oil refineries:

- Subpart A      General Provisions  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil
- Subpart Db    Standards of Performance for Industrial-Commercial-Institutional  
Steam Generating Units  
Applies at: BP, Phillips 66, and Tesoro  
Pollutants addressed: PM,<sup>3</sup> NO<sub>x</sub>, and SO<sub>2</sub>
- Subpart J      Standards of Performance for Petroleum Refineries  
Applies at: BP, Tesoro, Shell, Phillips 66, and US Oil  
Pollutants addressed: CO, PM, and SO<sub>2</sub>
- Subpart Ja    Standards of Performance for Petroleum Refineries for which  
Construction, Reconstruction, or Modification Commenced after  
May 14, 2007  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: CO, NO<sub>x</sub>, PM, and SO<sub>2</sub>
- Subpart Kb    Standards of Performance for Volatile Organic Liquid Storage  
Vessels (Including Petroleum Liquid Storage Vessels) for which  
Construction, Reconstruction, or Modification Commenced after  
July 23, 1984  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: VOCs
- Subpart UU    Standards of Performance for Asphalt Processing and Asphalt  
Roofing Manufacture  
Applies at: Tesoro  
Pollutant addressed: PM
- Subpart XX    Standards of Performance for Bulk Gasoline Terminals  
Applies at: BP and Shell  
Pollutant addressed: VOCs
- Subpart GGG   Standards of Performance for Equipment Leaks of VOC in  
Petroleum Refineries for which Construction, Reconstruction, or  
Modification Commenced after January 4, 1983, and on or  
before November 7, 2006.

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<sup>3</sup> PM in this list of NSPS regulations indicates PM<sub>10</sub> and/or PM<sub>2.5</sub> and is rule-specific depending on promulgation date and source.

Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: VOCs

- Subpart GGGa Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after November 7, 2006.  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: VOCs
- Subpart QQQ Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: VOCs
- Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: CO, NO<sub>x</sub>, PM, VOCs
- Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines  
Applies at: Does not apply currently to any Washington refinery but might be triggered by a new spark ignition engine.  
Pollutant addressed: CO, NO<sub>x</sub>, PM, VOCs

### 3.3 Federal Hazardous Air Pollutant Requirements

Section 112 of the USCAA requires EPA to promulgate national emission standards for HAPs (NESHAPs). For major sources of HAPs (including refineries), these standards require that “The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator.” For the specific pollutants regulated therein, the requirements promulgated pursuant to Section 112 of the USCAA exceed the threshold for RACT.

The initial NESHAPs were promulgated under 40 CFR Part 61. Eight HAPs were addressed under 40 CFR Part 61 before EPA changed the NESHAP methodology and began issuing NESHAP rules under 40 CFR Part 63. The following rules, which affect Washington State petroleum refineries, were issued under 40 CFR Part 61:

- Subpart A General Provisions  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil
- Subpart J National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene  
Applies at: BP, Shell, Tesoro  
Pollutant addressed: Benzene

- Subpart M National Emission Standard for Asbestos  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: Asbestos
- Subpart V National Emission Standard for Equipment Leaks (Fugitive Emission Sources)  
Applies (by reference from Subpart J) at: BP, Shell and Tesoro  
Pollutants addressed: Volatile HAPs
- Subpart FF National Emission Standard for Benzene Waste Operations  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutant addressed: Benzene

The 1990 amendments to the USCAA redirected EPA to promulgate technology-based standards for 188 HAPs, reflecting “the average emission limitation achieved by the best performing 12 percent of the existing sources.” These standards can apply to both new and existing sources and therefore are in effect at substantial portions of the refineries. Section 112(f)(2) of the USCAA requires that EPA review the residual risk within 8 years of the promulgation of the standards “in order to provide an ample margin of safety to protect public health... or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect.” If the standards “do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million,” EPA is required “to promulgate standards under this subsection for such source category.”

Nearly 130 such NESHAPs (also referred to as maximum achievable control technology [MACT] standards) have been promulgated, including the following that affect petroleum refineries:

- Subpart A General Provisions  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil
- Subpart Y National Emission Standards for Marine Tank Vessel Loading Operations  
Applies at: BP  
Pollutants addressed: HAPs
- Subpart CC National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: HAPs
- Subpart UUU National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: HAPs

- Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: HAPs
- Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters  
Applies at: BP, Phillips 66, Shell, Tesoro, and US Oil  
Pollutants addressed: HAPs
- Subpart GGGGG National Emission Standards for Hazardous Air Pollutants: Site Remediation  
Applies at: Tesoro and US Oil  
Pollutants addressed: HAPs

### 3.4 New Source Review Requirements

Part C of the USCAA requires that EPA establish a permitting program for new major sources and major modifications<sup>4</sup> of existing sources. The Prevention of Significant Deterioration (PSD) permitting program is designed to accommodate growth while protecting air quality, preventing potential future violations of NAAQS, and preventing impacts to national parks and wilderness areas. Sources are required to employ the best available control technology (BACT). BACT means that an "emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 [NSPS] or 7412 [NESHAP] of this title."

Both BP and Phillips 66 have obtained PSD permits for modifications to their oil refineries. US Oil obtained early (1979) PSD permit approval for a project that was never constructed.

### 3.5 Regional Haze Program<sup>5</sup>

In 1999, EPA announced a major effort to improve air quality in national parks and wilderness areas. The Regional Haze Rule calls for state and federal agencies to work

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<sup>4</sup> At refineries, major modifications include projects resulting in a net emission increase greater than: 100 ton/yr of CO; 40 ton/yr of VOC, NO<sub>x</sub> or SO<sub>2</sub>; 25 ton/yr of PM; 15 ton/yr of PM<sub>10</sub>; 10 ton/yr of PM<sub>2.5</sub>; 0.6 ton/yr of lead; 7 ton/yr of sulfuric acid mist; or 10 ton/yr total reduced sulfur. Under the 2009 Tailoring Rule, this list was expanded to include projects resulting in a net emission increase greater than 75000 ton/yr of GHG.

<sup>5</sup> <http://www.epa.gov/airquality/visibility/actions.html>

together to improve visibility in 156 national parks and wilderness areas. In Washington, initial best available retrofit technology (BART) determinations have been issued by Ecology and submitted to EPA for review and approval. Ecology has issued BART orders that establish reductions pursuant to the Regional Haze Rule for NO<sub>x</sub>, SO<sub>2</sub>, and PM to BP (Order 7836 and amendments) and Tesoro (Order 7838).

## 3.6 State and Local Programs

### 3.6.1 General Regulations

General regulations are developed and adopted by Washington State air quality agencies to address regional needs. The general regulations support the maintenance of ambient air quality standards, and many of these regulations have been submitted to and approved by EPA for incorporation into the SIP. The general regulations for the NWCAA and PSCAA jurisdictions (where the five Washington State refineries are located) include emission limits for PM, visible emissions, and SO<sub>2</sub>. The general emission requirements are detailed in WAC 173-400 (for Ecology), NWCAA Regulation Sections 450-470, and PSCAA Regulation I. The various emission limits and other regulations that help limit emissions are included in each refinery's air operating permit as applicable and enforceable requirements.

### 3.6.2 Minor New Source Review Requirements

Section 70.94.152 of the Washington State Clean Air Act (WCAA) goes beyond the USCAA PSD program requirements by requiring permits for all new sources and modifications, even those that are minor.<sup>6</sup> Moreover, the minor new source review program also includes approximately 400 TAPs. Even the smallest of the local refineries (i.e., the US Oil refinery) has nearly five dozen such permits covering an even greater number of emission units. Similar to the PSD program, BACT is a requirement for permit approval.

BACT is no less stringent than RACT and is often considerably more stringent. Per RCW 70.94.030(6), BACT means that "an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under this chapter emitted from or that results from any new or modified stationary source, that the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such a pollutant. In no event shall application of BACT result in emissions of any pollutants that will exceed the emissions allowed by any applicable standard under 40 C.F.R. Part 60 [NSPS] and Part 61 [NESHAP], as they existed on July 25, 1993, or their later enactments as adopted by reference by the director by rule."

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<sup>6</sup> Per RCW 70.94.152(11), "No person is required to submit a notice of construction or receive approval for a new source that is deemed by the Department of Ecology or board to have *de minimis* impact on air quality." Per RCW 70.94.152(12), *de minimis* means "new sources with trivial levels of emissions that do not pose a threat to human health or the environment."

RCW 70.94.153 (adopted in 1991) requires the acquisition of permits for the replacement or substantial alteration of emission-control technology. RACT is required for permit approval. (Projects that result in an emissions increase are subject to RCW 70.94.152 and its BACT requirements for the pollutants for which emissions have increased.) Per RCW 70.94.030(20), RACT means that “the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls.”

Each of the five Washington State refineries has obtained a large number of Notice of Construction (NOC) orders of approval under these statutory requirements. These NOC applications are reviewed by the local air authorities (NWCAA and PSCAA), sometimes in coordination with associated PSD permit reviews (completed by Ecology). Over time, the number of emission units operating under the authority of specific orders of approval (and case-specific BACT/RACT decisions, as described in the previous paragraphs) has continued to increase. To illustrate the level of NOC application processing for each of the refineries, a summary of NOC activity is presented in Table 2-1.

**Table 3-1 Historical Notice of Construction Application/Approval Activity**

<b>Company</b>	<b>Total Number of NOC Orders Issued</b>	<b>Total Number of Active NOC Orders</b>	<b>Total Number of NOC Orders Issued since January 1, 2001</b>
<b>BP</b>	106	33	38
<b>Phillips 66</b>	45	21	27
<b>Shell</b>	82	29	37
<b>Tesoro</b>	73	38	50
<b>US Oil</b>	68	54	24

Data on file as of 12/31/12 at NWCAA and PSCAA

### 3.7 Determination of Air Contaminants of Concern

#### 3.7.1 Traditionally Regulated Contaminants

Petroleum refineries are one of the most heavily regulated source categories in the US faced with ongoing compliance demonstration with regulations that involve hundreds of requirements. For the traditionally regulated air contaminants (i.e., PM, CO, NO<sub>x</sub>, SO<sub>2</sub>, ozone precursors, lead, HAPs, and TAPs), the existing requirements cover many of the activities, facilities and equipment at Washington State refineries, are more stringent than RACT, and are achieving significant reductions in emissions. These requirements for the five refineries are included in their respective Title V Air Operating Permits.

Annual stationary-source emissions of PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, and VOCs from the five Washington State oil refineries from 2001 through 2011 are shown in Figures 3-1 through 3-4, respectively.

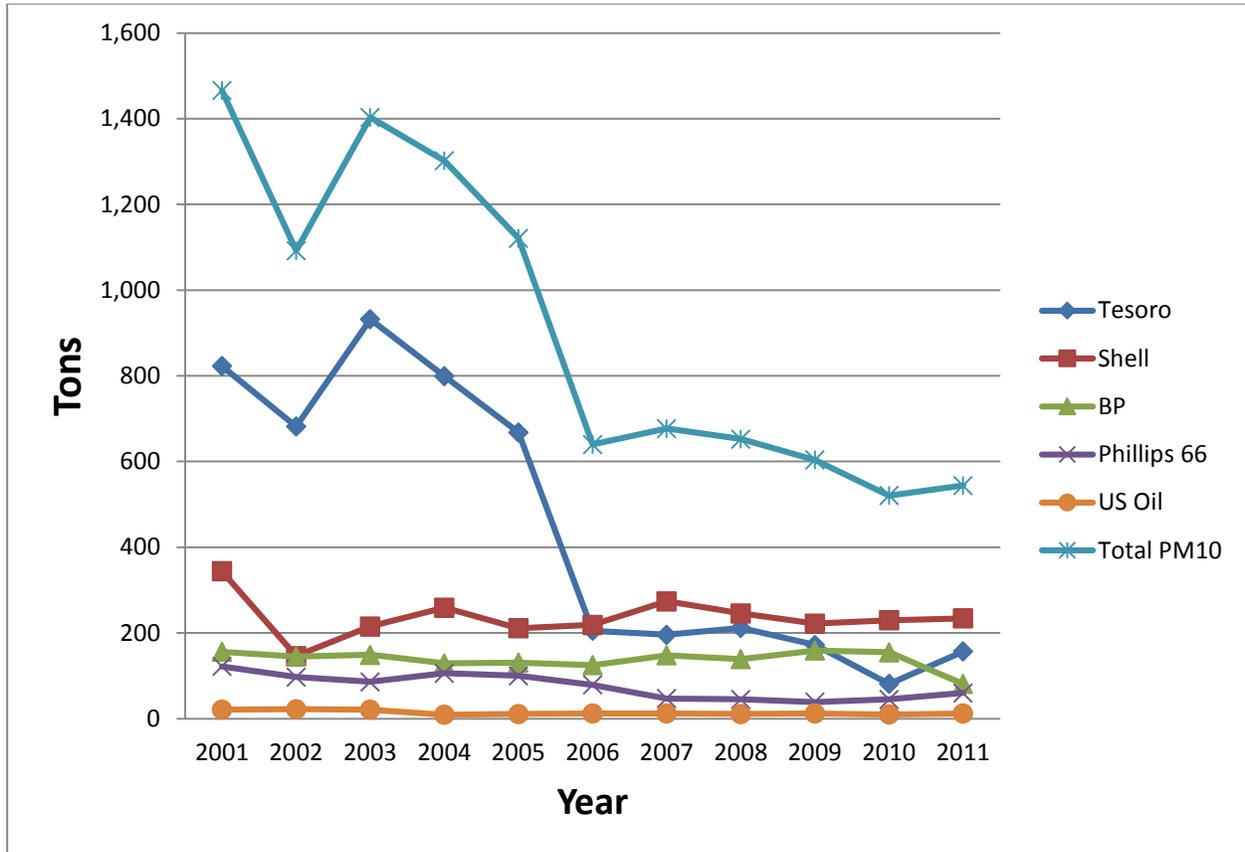


Figure 3-1 Annual PM<sub>10</sub> Emissions for Five Washington State Refineries from 2001 to 2011

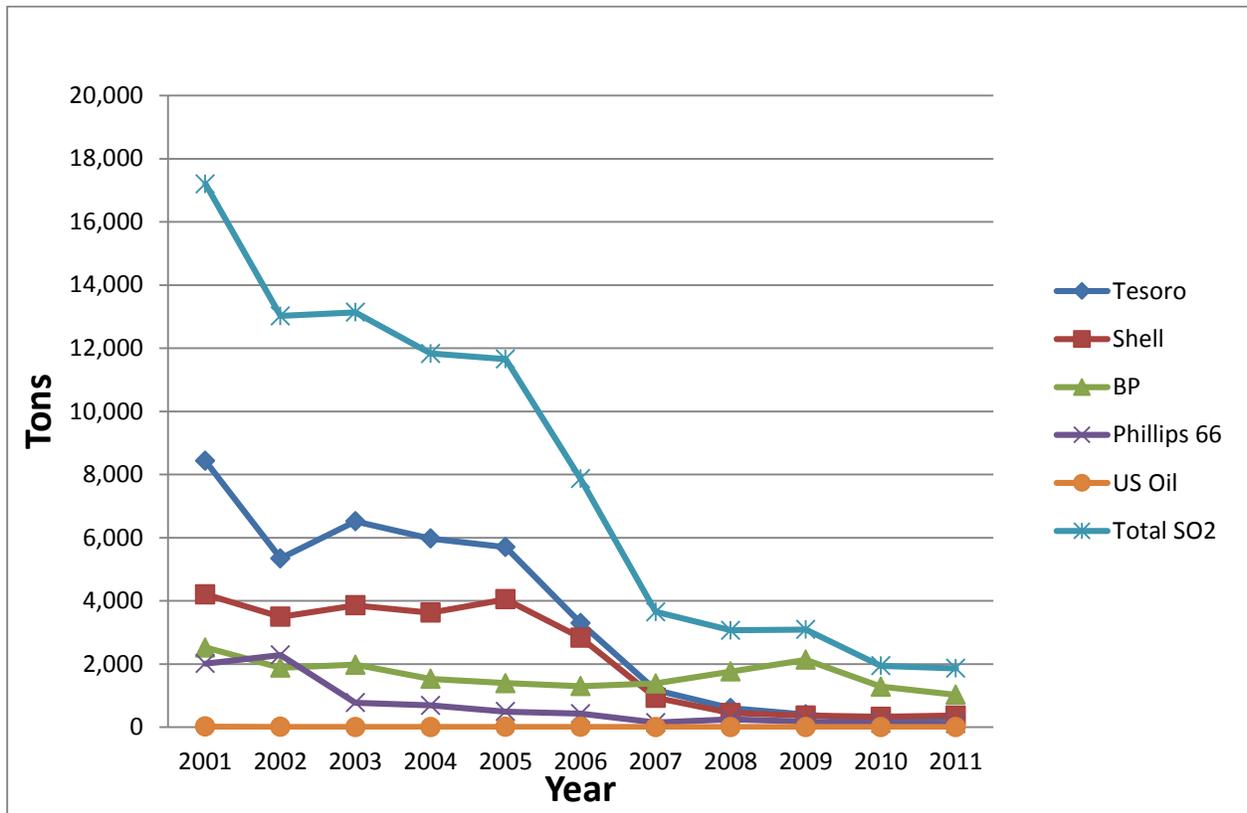


Figure 3-2 Annual SO<sub>2</sub> Emissions for Five Washington State Refineries from 2001 to 2011

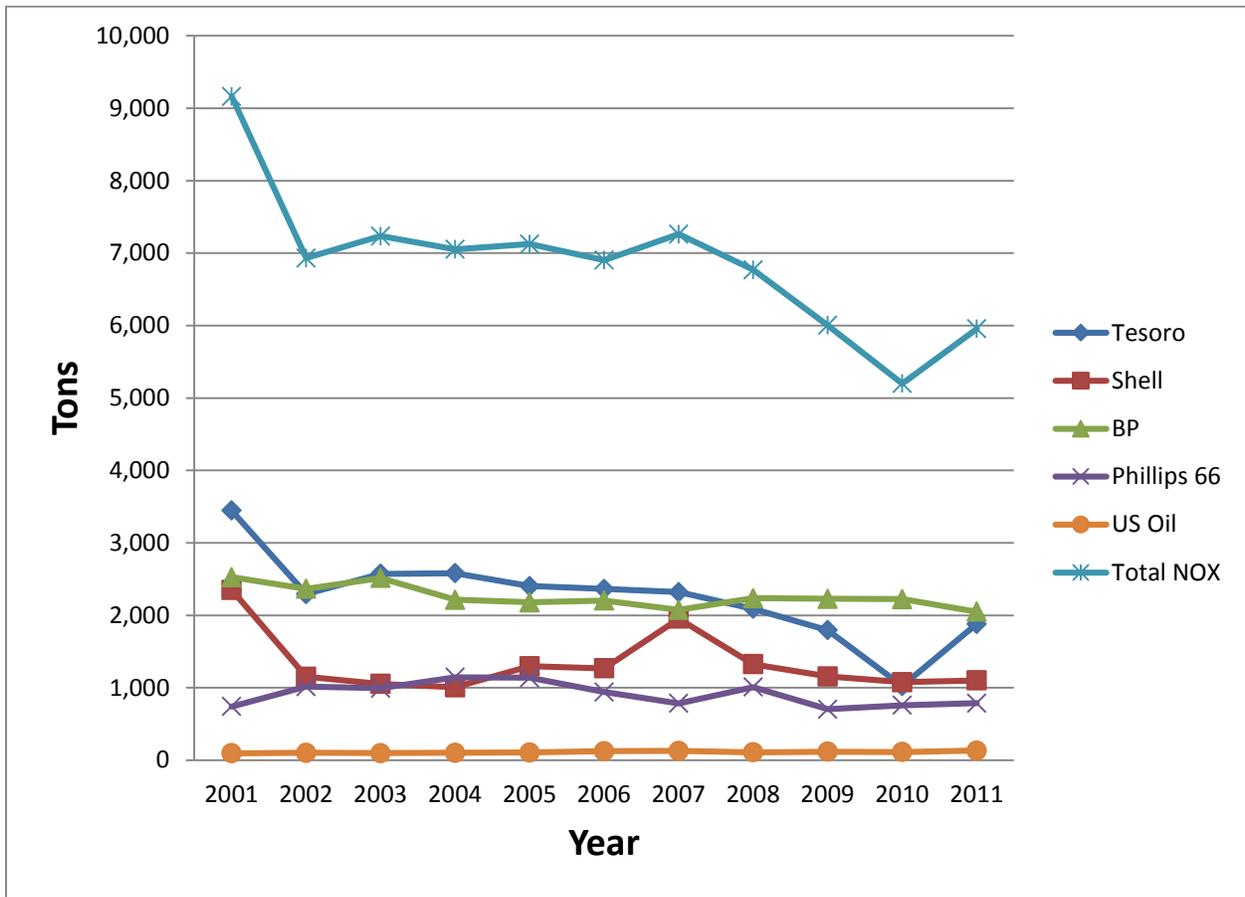
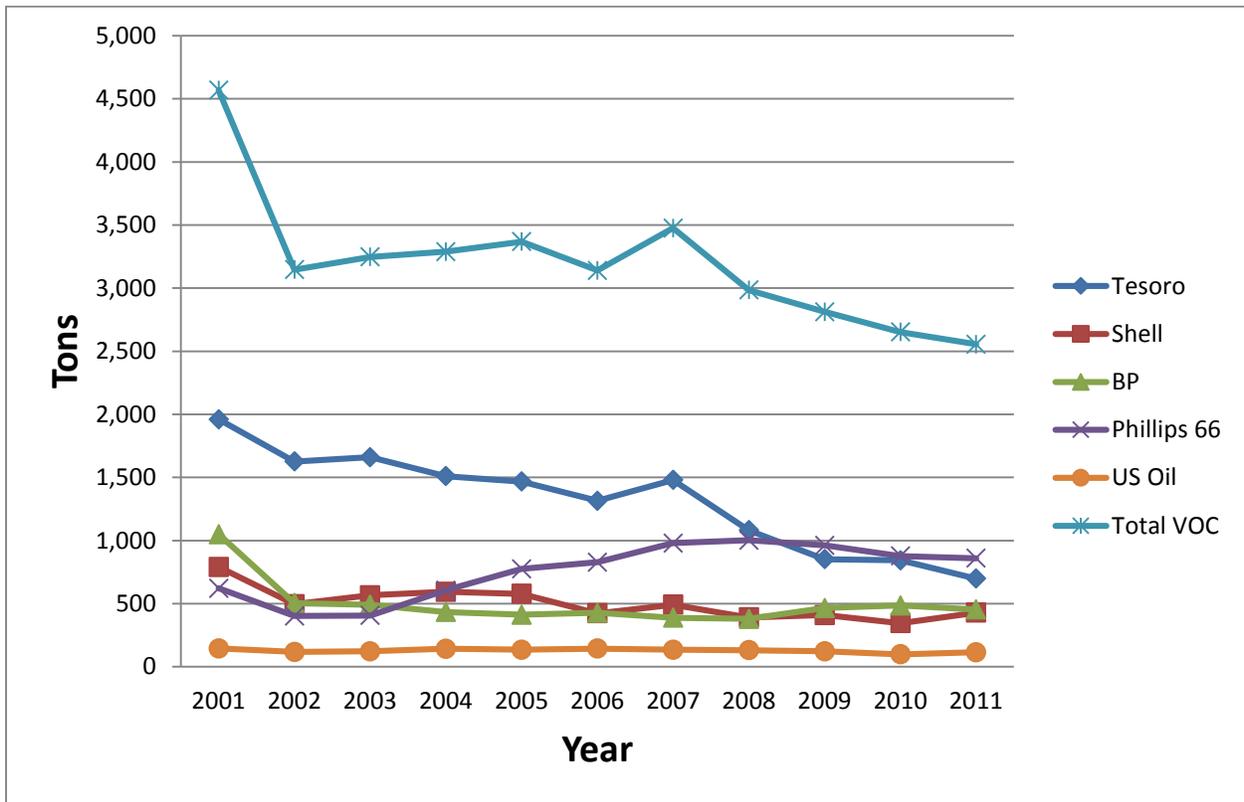


Figure 3-3 Annual NO<sub>x</sub> Emissions for Five Washington State Refineries from 2001 to 2011



**Figure 3-4 Annual VOC Emissions for Five Washington State Refineries from 2001 to 2011**

As shown in these figures, annual emissions of PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, and VOCs from these refineries have decreased dramatically since 2001. These emissions reductions are the result of the installation of control equipment combined with work practices to comply with increasingly stringent regulations as described in the previous sections. Furthermore, EPA’s National Refinery Enforcement Initiative has also resulted in SO<sub>2</sub>, PM, NO<sub>x</sub>, and VOC/HAP emission reductions over the past 10 years. Settlements resolving non-compliance issues at the BP, Phillips 66, Shell, and US Oil refineries are accessible to the public online (<http://www.epa.gov/enforcement/air/oil.html>).

The five Washington State refineries are either located in attainment areas (BP, Phillips 66, Shell, and Tesoro) or don’t contribute to non-attainment (US Oil). Furthermore, the measured air quality in the areas with the four largest Washington State refineries typically receives the best (i.e., cleanest) EPA air quality rating of “good,” meaning that “air pollution poses little or no risk.”<sup>7</sup>

For these reasons, the Agencies conclude that PM (including both PM<sub>10</sub> and PM<sub>2.5</sub>), CO, NO<sub>x</sub>, SO<sub>2</sub>, ozone precursors, lead, HAPs, and TAPs are not air contaminants of concern for this categorical RACT evaluation. It is possible that collateral reductions in these pollutants will be achieved through the implementation of a RACT standard for GHGs. It is also possible

<sup>7</sup> <http://airnow.gov/index.cfm?action=airnow.main>.

that a plant-specific RACT evaluation might identify and require specific emission reductions of one or more traditionally regulated pollutants.

It should be stressed that this conclusion is not a RACT determination in itself and is only used to scope further work to be included in the RACT analysis for use in a RACT determination. The Agencies are aware of other air quality issues that may lead to further analyses, separate from this review. These issues would likely be addressed by other programs or standards, including, but not limited to the following:

- **Regional Haze Program** – This ongoing program has many facets. Initial BART determinations have been issued by Ecology and submitted to EPA for review and approval. Additional emission reductions may be required to achieve reasonable progress in meeting the Class I area visibility goals. Visibility goals are unrelated to GHG issues. Therefore, it is logical that visibility issues would be resolved through a separate mechanism. This court-ordered RACT process only addresses refineries; whereas regional haze issues involve several source categories.
- **SO<sub>2</sub> 1-Hr Standard** – EPA has promulgated a 1-hr standard for SO<sub>2</sub>, but the guidance for states regarding how to complete the analysis for an attainment/nonattainment determination is still pending. Thus, it is not yet clear whether Washington State will have SO<sub>2</sub> nonattainment areas, where they might be located, or which sources might be identified as contributors to that determination. A RACT analysis that meets the requirements of a nonattainment area RACT determination might be needed. However, the SO<sub>2</sub> RACT determination process first requires a determination that the source is causing or contributing to actual or potential nonattainment, and such a determination has not yet been made.
- **NO<sub>x</sub> 1-Hr Standard** – EPA also has a new 1-hr standard for NO<sub>x</sub> based on roadside continuous monitoring results. While the SO<sub>2</sub> standard described in the previous paragraph has is based in part on dispersion modeling, this standard is based on monitoring. Monitoring for this standard has not yet begun. Similar to the SO<sub>2</sub> standard, once a nonattainment area is identified through monitoring, the nonattainment area RACT determination process will address any sources identified as causing or contributing to nonattainment.

### 3.7.2 Greenhouse Gases

On December 7, 2009, the EPA Administrator issued two distinct findings regarding GHGs under Section 202(a) of the USCAA:

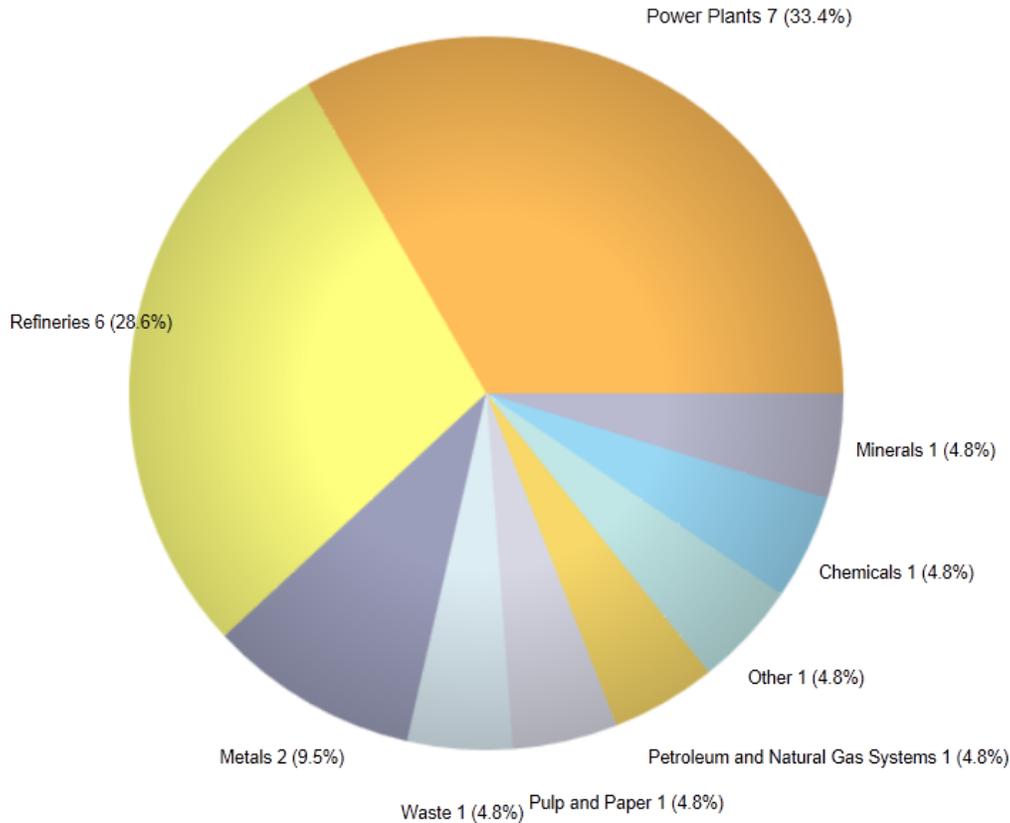
- **Endangerment Finding** – The Administrator finds that the current and projected concentrations of the six key well-mixed GHGs — CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, HFCs, PFCs, and SF<sub>6</sub> — in the atmosphere threaten the public health and welfare of current and future generations.
- **Cause or Contribute Finding** – The Administrator finds that the combined emissions of these well-mixed GHGs from new motor vehicles and their engines contribute to the GHG pollution, which threatens public health and welfare.

These findings do not themselves impose any requirements on industries or other entities. However, these actions were a prerequisite for implementing GHG emissions standards for vehicles. In collaboration with the National Highway Traffic Safety Administration, EPA finalized emission standards for light-duty vehicles (2012 to 2016 model years) in May of 2010 and heavy-duty vehicles (2014 to 2018 model years) in August of 2011. The final vehicle emission standard rule that became effective on January 14, 2010 prompted including GHGs as regulated pollutants.

Of the six GHGs, oil refineries emit primarily CO<sub>2</sub>, with small amounts of CH<sub>4</sub> and N<sub>2</sub>O. HFCs, PFCs, and SF<sub>6</sub> are not reported as being emitted from oil refineries in Washington State. Over 99% of GHG emissions from oil refineries are CO<sub>2</sub>. CH<sub>4</sub> and N<sub>2</sub>O (CO<sub>2</sub> equivalent mass basis [CO<sub>2</sub>e]) emissions are approximately 0.4% and 0.3%, respectively, of the total GHG emissions reported by oil refineries. Figure 3-5 shows the relative distribution (%) of reported GHG emissions from large stationary sources in Washington State during 2011, as well as the number of facilities by industry (EPA, 2013).<sup>8</sup>

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<sup>8</sup> The EPA GHG reporting rule includes large stationary source emissions of at least 25,000 mtons/yr of CO<sub>2</sub>e. It does not include emissions from the transportation sector (e.g., cars, trains, planes, or ships).



Source: EPA, 2011

**Figure 3-5 Relative Distribution of Washington State Stationary-Source GHG Emissions during 2011**

The EPA database indicates that nationally, oil refining accounts for <6% of GHG emissions from large stationary sources. In contrast, oil refining is the second largest portion (28.6%) of stationary-source GHG emissions in Washington State, according to the data collected by EPA for 2011.

For the purpose of this RACT review, GHGs (calculated as CO<sub>2</sub> equivalents [CO<sub>2</sub>e]) are deemed to be a pollutant of concern for the refinery source category in Washington State based on the following:

- GHGs have only recently been classified as air pollutants under federal regulations, so there has been little if any historical regulation of GHGs at refineries. There is only one known GHG requirement for Washington State refineries. The NWCAA was the first air quality regulatory agency in the country to establish both a GHG emission limit and a continuous monitoring requirement for oil refineries, which was applied to the BP refinery in 2010 (NWCAA, 2010).<sup>9</sup>

<sup>9</sup> BP Order of Approval to Construct 1064 includes terms for GHG mitigation and monitoring for a hydrogen plant.

- Oil refineries are the second largest stationary source of GHGs in Washington State.
- The March 27, 2012 Remedy Order requires the Agencies to conduct a RACT analysis to address GHGs at oil refineries in Washington State.

Nothing in this discussion of the air contaminants of concern included for the purpose of this RACT review precludes the performance of a separate RACT analysis to support other rulemaking actions (e.g., those related to regional haze or future NAAQS attainment).

## Section 4: Defining Oil Refinery Facilities

Oil refineries are integrated facilities that often dovetail operations with industrial units at the periphery of the facility. This is clearly the case for Washington State oil refineries. For the purpose of this RACT review, the “boundary” of the oil refinery is defined by the ownership status for each company.

The definition of a stationary source as provided in EPA Title V guidance was considered for the RACT review boundary. That boundary would include all industrial emission units operating in a location that is contiguous and adjacent to and under common control of the facility as defined in the EPA guidance. Applying this standard would result in the inclusion of three additional plants: the hydrogen plants operated by Air Liquide and Linde Gas and the sulfur recovery unit (SRU) operated by General Chemical, all located on March’s Point. However, the inclusion of these units was dismissed for this determination for the following reasons: The SRU GHG emissions are relatively small when compared with overall refinery GHG emissions, and no hydrogen unit-specific RACT-level efficiency strategies were identified during this review.

Determining the universe of individual emission sources to be considered for RACT analysis within the facility boundaries is facilitated by assuming a *de minimis* threshold. This is reasonable because at a sprawling industrial site, such as a refinery, there is a wide range of emissions sources, from small laboratory instrument vents that emit a few hundred pounds (lbs) of CO<sub>2e</sub> per year to massive fluidized catalytic cracking unit (FCCU) stacks that emit 500,000 to 1,000,000 tons per year [tpy] of CO<sub>2e</sub>. The following discussion of refinery processing uses traditionally regulated facility emission sources that historically have been reported on facility emissions inventories to determine where these emissions sources stand with regard to the proposed *de minimis* threshold. The traditionally reported sources of air emissions at the refineries are the largest stationary sources at the facilities for all pollutants, including GHGs.

A potential-to-emit threshold of 75,000 tpy CO<sub>2e</sub><sup>10</sup> is used to identify the sources to be considered for equipment-specific RACT development for two reasons: 1) The GHG

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<sup>10</sup> On June 29, 2012, EPA issued a final rule (77 FR 41050 published July 12, 2012) that did not revise the GHG permitting thresholds that were established in Step 1 and Step 2 of the GHG Tailoring Rule. The GHG Tailoring Rule emissions thresholds determine when USCAA permits under the New Source Review PSD and Title V Operating Permit programs are required for new and existing industrial facilities. The Tailoring Rule requires new facilities

Tailoring Rule is the only regulatory action that requires a control technology review that addresses stationary sources of GHG emissions; and 2) PSD thresholds have traditionally been used to identify sources subject to a RACT determination. The federal 75,000 tpy CO<sub>2e</sub> threshold was based on an economic analysis of the impacts of new permitting and controls requirements. The threshold was adopted by EPA with the understanding that the economic impact of the application of GHG BACT is reasonable and will be incurred by an industry that can absorb the costs of review and the installation of controls. EPA expected the threshold to account for approximately 70% of the stationary-source GHG emissions.

The Washington State Environmental Policy Act (SEPA) GHG guidance document (Ecology, 2011) was also reviewed as a potential basis for a *de minimis* threshold. The guidance uses two thresholds that result in three categories of projects:

1. Projects expected to produce <10,000 metric tpy (mtpy) CO<sub>2e</sub><sup>11</sup> are not required to address GHGs.
2. Projects expected to produce >10,000 mtpy CO<sub>2e</sub> but <25,000 mtpy CO<sub>2e</sub> are required to address GHG emissions qualitatively.
3. Projects expected to produce >25,000 mtpy CO<sub>2e</sub> must address GHG emissions quantitatively and may be considered significant.

Washington State SEPA guidance was not used as a *de minimis* threshold for this RACT analysis for two primary reasons. First, the EPA GHG Tailoring Rule rejected the thresholds of 25,000 and 50,000 tpy CO<sub>2e</sub> for PSD (and BACT) review due, in part, to the large number of projects that would be included, which would overwhelm the permitting agencies. These projects were expected to be accompanied by potentially high implementation costs for a relatively small amount of emissions addressed (<3%). The RACT process includes an economic component that is generally less stringent than BACT in that it applies to a group of existing separate sources constructed over a period of time. In contrast, BACT addresses only new equipment (or groups of related equipment) at the time of construction. It is presumed that the RACT economic impact analysis would likely reject the same sources that were rejected by BACT based on the same cost-benefit rationale.

Second, Washington State SEPA guidance thresholds are based on “expected” emissions, not potential emissions. Expected emissions are analogous to the “projected actual emissions” used in federal major source permitting programs and generally result in emissions that are lower than the potential emissions estimated for a source based 8,760 hrs of operation at maximum rate. Thresholds based on expected emissions do not provide

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with GHG emissions of at least 100,000 tpy CO<sub>2e</sub> and existing facilities with at least 100,000 tpy CO<sub>2e</sub>, making changes that would increase GHG emissions by at least 75,000 tpy CO<sub>2e</sub> to obtain PSD permits. Facilities that must obtain a PSD permit anyway, to cover other regulated pollutants must also address GHG emissions increases of 75,000 tpy CO<sub>2e</sub> or more. New and existing sources with GHG emissions above 100,000 tpy CO<sub>2e</sub> must also obtain Title V Operating Permits.

<sup>11</sup> RCW 70.94.151(5) emission reporting threshold.

adequate certainty for the regulated community with regard identifying which specific emission units are included or excluded from review.

The 75,000-tpy CO<sub>2e</sub> threshold (as potential to emit) is discussed in Section 7, Proposed RACT.

## **Section 5: Petroleum Oil Refining Processes**

### **5.1 General Process Overview**

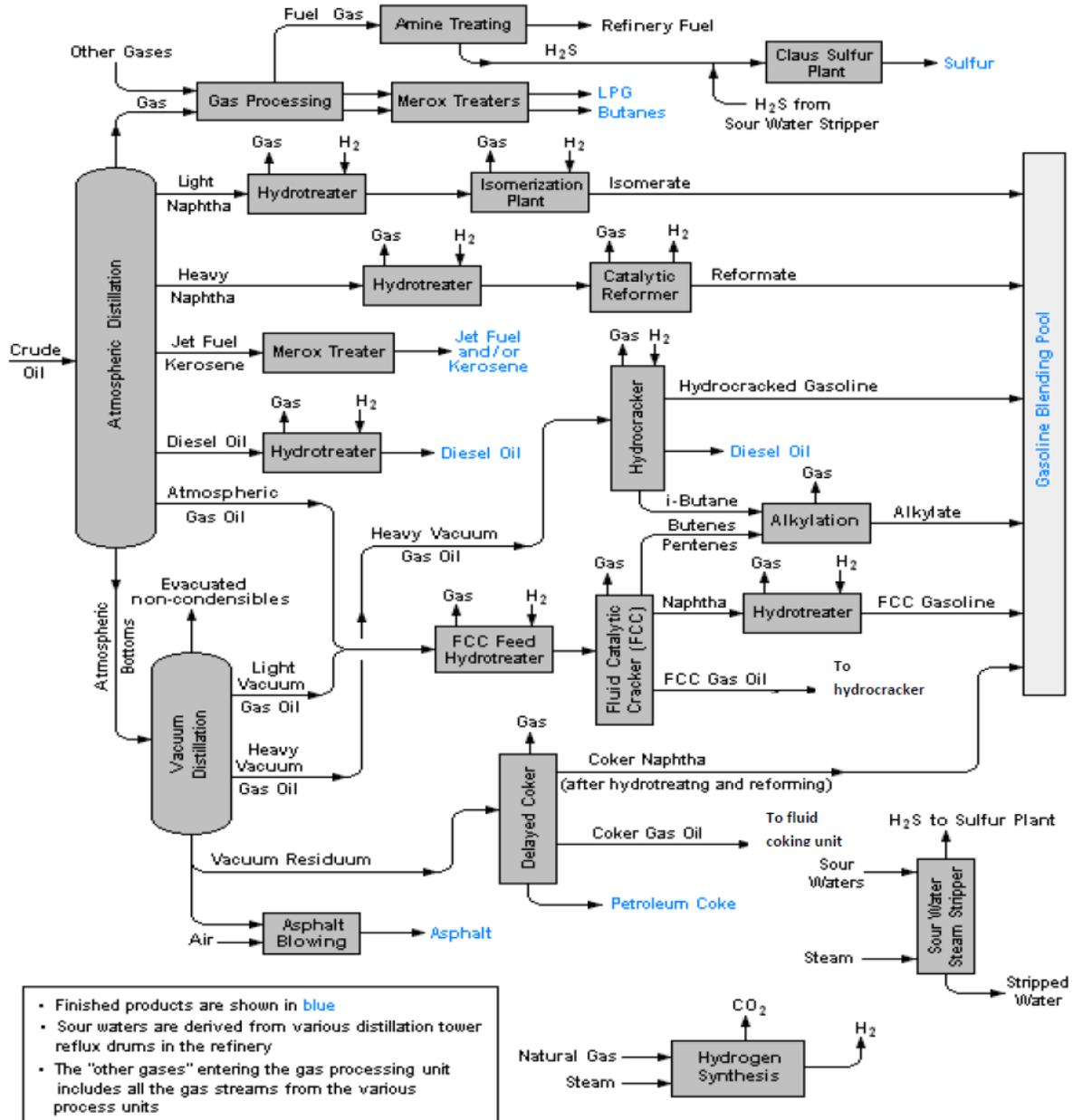
This section provides a brief overview of the petroleum refining process. This discussion is not intended to be comprehensive but rather to provide the reader with a basic understanding of the process steps involved in refining, how they fit together, and the complexity of the operating issues, as well as to identify the largest sources of GHG emissions within each of the refinery process units.

An oil refinery, or petroleum refinery, is an industrial process plant where crude oil is separated and transformed into more useful petroleum products, such as gasoline, diesel fuel, asphalt base, heating oil, kerosene, and liquefied petroleum gas (LPG). Oil refineries are typically large industrial complexes that are composed of processing units with extensive piping throughout the facility. The process units are highly integrated, with materials passing through and among the various units at each stage of processing, as well as for heat recovery.

Of importance for this discussion is the fact that no two refineries are identical. Each refinery is designed and operated to process a certain crude oil blend into an array of products. Each type of crude oil (identified by the geographical location of extraction) has specific properties that are unique; these include density (the content defined by small vs. long carbon chains), acidity, and metal contamination. Each refinery is designed for a certain range of crude oil feedstock (i.e., crude slate) properties. The crude slate options available to a given refinery are further limited by the chemical compatibilities among the crude oils (which affects the propensity for fouling during the refining process) and the compatibility of the crude oils with the metals composition of the refinery equipment and the reactor catalysts. Within these constraints, the crude slate is targeted for those crudes that are the most economically attractive and available to the refinery on an hourly basis. The products produced by each refinery are largely determined by the characteristics of the crude slate because the processing equipment has limited flexibility with respect to operating conditions and capacity.

Although each facility is unique in terms of its specific equipment, all refineries use the same basic continuous closed process that requires an input of energy to transform crude oil into usable products through a series of steps: separation, conversion, treatment, and blending. These steps are used to create "process units," groups of equipment assembled together to accomplish a specific process task. Most refinery operations involve the performance of more than one of these steps and all refineries operate multiple process

units to produce final products. Figure 5-1 shows a typical refinery layout with common feedstocks, processing units, and products. Brief descriptions of the four steps follow.



Source: CARB, 2013

**Figure 5-1 Typical Refinery Layout**

**5.1.1 Separation**

Hydrocarbon mixtures are typically separated into their components by exploiting differences in relative volatility (i.e., boiling point), most frequently by fractional distillation. In the distillation column, lower-boiling-temperature components (i.e., those that are lighter, with a lower number of carbon atoms) are converted to a vapor and rise to the top

of the vessel, where they are removed, while the higher-boiling-temperature components (i.e., those that are heavier, with a higher number of carbon atoms) pass out the bottom of the column or are extracted from some intermediate point on the column. Alternatively, a hot vapor stream can be cooled to “knock out” the heavier, lower-boiling-temperature material. Separation processes are performed at different pressures in order to expand the range of boiling points over which materials can be separated. Distillation columns are usually equipped with a reboiler, which is a process heater on the bottom stream of the column that provides the heat energy needed to perform the separation.

Wash water is used and collected in many refinery process units and must be removed from hydrocarbon products and intermediates. Water is removed in settling vessels, where over time, gravity causes the water and oil to separate into two phases. Water is usually removed from the process equipment from the bottom and is often referred to as “blow down.” This process water is always contaminated with some amount of residual hydrocarbons and must be routed into the facility’s wastewater collection system and treated in an onsite treatment plant.

#### **5.1.2 Conversion**

Conversion is the process that thermally or catalytically converts a low-value hydrocarbon component to a more useable product. For example, “cracking” is the process whereby heavy, long-chain hydrocarbons are converted to lighter, shorter-chain hydrocarbons. Conversion processes often take place under high pressures, higher than atmospheric pressure. The catalysts used in conversion can be liquids or solids; solid catalysts can be in the form of fixed beds (in which the catalysts are contained in a vessel with process fluids passing through them) or fluidized (in which the catalyst particles are entrained in the liquid).

Refinery process units that include conversion equipment are typically identified by the conversion portion of the unit (e.g., the FCCU). The FCCU also incorporates separation equipment, as well as treatment and blending equipment within the process unit.

#### **5.1.3 Treatment**

Intermediate and product streams contain contaminants such as sulfur and nitrogen that must be removed to protect downstream catalysts and meet final product specifications. Treatment processes remove these contaminants, most commonly through hydrogenation. Organically bound sulfur reacts with hydrogen at high pressure and temperature to form hydrogen sulfide (H<sub>2</sub>S) gas, which is then separated and further treated to remove the sulfur (in non-toxic elemental form).

#### **5.1.4 Blending**

Some process unit feed streams (e.g., crude oil) and final products are created by blending streams to meet the required product specifications. Refineries operate many individual tanks connected by complex pumping and piping systems (i.e., “tank farms”) to accommodate the blending of each component.

### 5.1.5 Refinery General Air Emission Categories

Air emissions are generally categorized as point sources, which are identified individually in the facility emissions inventory, and fugitive sources, which are generally identified as a group or area of emissions. Following the general refinery process discussion, the specifics of the five refineries operating in Washington are provided in Section 5.

Refinery process units are equipped with pressure relief valves (PRVs) that release system pressure during emergency conditions. These devices may release to the atmosphere or be connected to the facility's flare system. In either case, PRV emissions are not specifically addressed in this document because they do not release normal or routine process emissions.

Every refinery is equipped with a flare header system, a large system of pipes that collects process vent and PRV emissions. The collected material may be piped to a recovery system (i.e., compressors) in order to recycle the material back into the process as fuel gas, or it may be combusted by a flare, which is designed and built to suit the needs of the each individual facility. Flares, which are essentially large burners, are equipped with pilot flames, steam injections (for mixing the flame), and monitoring devices to sure that the pilot flames are operating. Flares can combust large volumes of process vent emissions, including hydrocarbons and sulfur, converting them to less dangerous compounds with regard to flammability and toxicity (e.g., H<sub>2</sub>S to SO<sub>2</sub>).

Refineries also feature a variety of vessels, heaters, heat exchangers, and distillation columns that are connected by an intricate system of piping and associated components (e.g., valves, pumps, and compressors) that control flow rate and direction. Each of these components has the potential to leak process material; and if the material is volatile, it will be released to the atmosphere. Equipment component leak emissions are grouped together and characterized as fugitive (non-point source) emissions.

## 5.2 Refinery Process Unit Descriptions

### 5.2.1 Crude Distillation Unit

The crude distillation unit separates crude oil (including some recycled stocks) by distilling material into fractions according to their boiling-point range. The resulting fractions are sent to storage and/or other refinery process units.

Crude oil from onsite storage tanks is first desalted (water-washed) to remove contaminants that could cause downstream fouling or corrosion. The desalted crude is then heated and pumped to the crude column, where it is distilled into fractions; the fractions are routed to other process units and/or storage tanks. The crude column is also known as the atmospheric column because it operates at approximately atmospheric pressure.

The atmospheric column overhead liquid, which contains LPG- and gasoline-range material, is subjected to further distillation before being sent to other refinery process units. Products in the gasoline and gas-oil boiling ranges are routed to storage and/or treatment processes. The highest-boiling-point (i.e., heaviest) fraction, straight-run residue, is generally fed to the vacuum flasher.

The largest emissions point sources from the crude unit are the crude heaters. The emissions are combustion products.

### 5.2.2 Crude Residue Vacuum Distillation Unit (Vacuum Flasher)

The vacuum flasher separates heavy straight-run residue into fractions under vacuum. The distillation takes place under vacuum conditions because otherwise, the high temperatures required to fractionate the residue at high pressure would result in the thermal cracking of the residue and coke formation in the process equipment. The recovered distillates are fed to the FCCU; the remaining fraction, pitch, is sent on for further processing or may be blended into fuel oil or asphalt binder.

The largest emissions point sources from the vacuum unit are the combustion units associated with heating the feed stream to the distillation column.

### 5.2.3 Hydrotreaters

Hydrotreaters, also known as hydrodesulfurization units, are conversion units that are identified by their feed stream characteristics (e.g., diesel hydrotreater). Hydrotreaters use hydrogen and a fixed-bed catalyst to remove contaminants, such as sulfur, nitrogen, and metals, from their feed. The feed stream to the hydrotreaters is generally heated prior to passing into the catalyst vessel. The treated product is then separated, and streams are routed for further processing. The hydrotreated product may be fed to other process units (e.g., gasoline-range products to the catalytic reformer [CR]) or used as blending components in fuel products. The hydrotreater catalyst is typically removed from the process reactor vessel and regenerated offsite.

The largest emissions from hydrotreating/hydrodesulfurization are combustion products from the process heaters.

### 5.2.4 Catalytic Reformer

A CR is a conversion unit that uses a system of heaters and fixed-bed catalytic reactors to increase the octane rating of its gasoline-range feed. The resulting product is sent to gasoline component storage for use in fuel blending. The reforming reaction generates hydrogen, which is recovered and used in other process units, including the hydrotreaters. The CR catalyst requires periodic regeneration to maintain activity. The regeneration process involves removing coke from the catalyst through combustion and adding chlorine to the catalyst via a chloriding agent.

Emissions from the catalytic reformers are primarily combustion products from process heaters. Much smaller amounts of combustion products that may have chlorine from the regeneration process are also emitted from the CR unit.

### 5.2.5 Benzene Reduction Units

Multiple patented technologies are used to reduce benzene in gasoline products, including catalytic benzene hydrogenation and fractionation schemes. Benzene reduction is necessary to meet mobile source air toxic regulations. Heating may be required in the process and may be accomplished through the use of steam or direct-fired heaters.

The primary point source emissions from benzene reduction units are combustion products from process heaters, when they are used.

#### 5.2.6 Fluidized Catalytic Cracking Unit

The FCCU uses a circulating fluidized solid catalyst at elevated temperatures and pressures to convert heavy gas-oil feeds into lighter materials, such as gasoline. Liquid- and vapor-phase products are separated from the catalyst and sent on for further processing. Coke formed as a reaction product remains on the catalyst and is removed through combustion in a low-oxygen environment in the FCCU regenerator. Regenerator flue gas is then passed into CO boilers, completing the conversion of CO to CO<sub>2</sub>, destroying residual organic HAPs, and generating steam.

The FCCU regenerator vent is one of the largest sources of emissions at a refinery. FCCU emissions include combustion products with potentially high levels of CO, SO<sub>2</sub>, particulates, and NO<sub>x</sub>. At the Washington State refineries, FCCU regenerator exhaust gases pass through CO boilers and are treated in flue gas scrubbers (FGSs). The FGSs remove SO<sub>2</sub> and PM through contact with a caustic solution. Other refineries may have alternative control devices, such as electrostatic precipitators.

In addition to the regenerator vent, the FCCU may have additional process heater point sources emitting combustion products and catalyst handling operations emitting particulates.

#### 5.2.7 Hydrocracking

Hydrocracking is a process that uses high temperature, high pressure, hydrogen, and catalyst to convert gas oil materials into product streams such as gasoline, blending components, reformer feeds, and jet fuel. Similar to hydrotreating, hydrocracking removes sulfur and nitrogen compounds. The value of the process is that it produces more-valuable lower-molecular-weight hydrocarbons. Butane and refinery fuel gas are byproducts of this process.

The primary point sources of emissions from hydrocracking are heaters, which emit combustion gases.

#### 5.2.8 Isomerization

Two isomerization processes are used in petroleum refining: one that uses butane (C<sub>4</sub>) and one that uses pentane/hexane (C<sub>5</sub>/C<sub>6</sub>). Isomerization is a process that converts n-butane, n-pentane, and n-hexane into their respective isoparaffins, which have substantially higher octane numbers. Isomerization accomplishes the conversion of n-butane into isobutane, to provide feedstock for alkylation units, and the conversion of normal pentanes and hexanes into higher-branched isomers for gasoline blending.

The primary emission point from isomerization units is the process heater, which emits combustion products.

### 5.2.9 Alkylation

The alkylation plant uses sulfuric acid or hydrofluoric acid as a catalyst to make alkylate, a high-octane gasoline blending component, from low-octane naphtha intermediates. Alkylate is sent to gasoline component storage following fractionation and in-plant treatment.

There are no point sources of emissions from the alkylation process.

### 5.2.10 Delayed Coking

Delayed coking is the only main process in a modern petroleum refinery that is a continuous-batch process. Delayed coking units process heavy feed material, converting it into light hydrocarbons (i.e., coker gas) and solid coke. Coker feed enters the system through the lower portion of the main fractionator distillation column (sometimes referred to as the combination tower), where it combines with drum recycle prior to entering the coker heater. Feed heated in the coker heater then passes to one of the coke drums, where it thermally cracks to form solid coke (roughly 50% conversion) and lighter hydrocarbons. Flow through the feed heater is continuous, with the heated stream being switched between at least two drums. While one drum is on line filling with coke, the other drum is being steam-stripped, cooled, decoked, pressure checked, and warmed up. Coke drum overhead vapors flow to the fractionator distillation column and are generally recycled to other refinery units. The solid coke is cut out of the drum using high-pressure water drilling and then dropped into a pit to dewater. The solid coke is then sold as a product or may be further processed.

The main air pollutant emissions from the coking process include combustion products from the coker heater, coke drum venting volatile organic compounds (including toxic air pollutants), and particulates from coke handling operations.

### 5.2.11 Treating

Treating process operations remove contaminants from various process streams so that the streams can be used in other refinery processes or blended into finished products.

Circulating amine solution (e.g., methyl diethanolamine), is used to remove acid gases, primarily H<sub>2</sub>S, from fuel-gas-range streams (methane [C<sub>1</sub>] to C<sub>4</sub>). In the amine regenerator, recovered acid gases are steam-stripped from the rich amine solution and routed to sulfur recovery (discussed separately). The stripped (lean) amine solution is recirculated. Treated fuel gas is routed to the refinery fuel gas system for use in the refinery.

Fuel streams that carry sulfur contamination, particularly "straight run" fuels that are collected directly from the crude atmospheric column, (including gasoline, jet, and diesel) are treated for removal of H<sub>2</sub>S, mercaptans and naphthenic acids. In general, the treatment processes do not require significant heating. Caustic soda is used to remove H<sub>2</sub>S and mercaptans from propane (C<sub>3</sub>) and it is also used to remove H<sub>2</sub>S, mercaptans, and organic acids from FCCU gasoline streams. Merox (mercaptan oxidation) treating is also used to convert FCCU gasoline mercaptans to disulfides. The majority of spent caustic streams from these treaters are recovered and shipped offsite or treated in the refinery wastewater treatment plant.

Treating units do not have large sources of emissions. However, they may be significant energy consumer units, using steam and power.

#### **5.2.12 Hydrogen Production**

Hydrotreating and hydrocracking units consume hydrogen. Hydrogen is produced as a by-product in catalytic reforming units. Hydrogen may also be produced in captive or merchant hydrogen production units, which typically use steam methane reforming (SMR) techniques.

The hydrogen processes used in the Washington refineries involve both the older-style and modern units. The older-style SMR unit at the BP facility has scrubbing and methanation for purification of the hydrogen product stream. Newer hydrogen plants recover the product through pressure swing absorption (PSA).

Hydrogen production emissions consist of combustion products from the SMR furnace.

#### **5.2.13 Sulfur Recovery**

Acid gases from the amine treatment process (described in section 4.2.11) are routed to SRUs. The most common SRU is a Claus process unit, which recovers and produces elemental sulfur from acid gas. Tailgas from the Claus process unit is treated in a secondary recovery process unit to reduce SO<sub>2</sub> emissions. Secondary recovery processes include Shell Claus off-gas treating (SCOT) units that convert residual H<sub>2</sub>S to elemental sulfur and units that scrub the sulfur out of the tailgas stream and recycle it back to the Claus unit.

The primary air emission point in the sulfur recovery process is an incinerator that is used to ensure that any residual sulfur is oxidized to SO<sub>2</sub>.

#### **5.2.14 Fuel Gas Blender**

The fuel gas blending system mixes process gases recovered from refinery process units with propane, butane, or purchased natural gas, as needed, to supply fuel for the refinery's furnaces. Fuel gas is collected in a header system and routed to a fuel gas blending vessel (the fuel gas blend drum) prior to distribution to combustion units.

A continuous emissions monitoring system analyzes the blended fuel gas sulfur concentration (primarily in the form of H<sub>2</sub>S) to demonstrate compliance with fuel H<sub>2</sub>S and stack SO<sub>2</sub> emission standards. The monitoring system is typically installed on the outlet of the fuel gas blend drum (i.e., on a single monitoring location instead of each heater and boiler combusting fuel gas) in order to minimize the cost of monitoring. Refinery fuel gas is combusted within the refinery and is generally not sold for use by other facilities. The exception is when a refinery has an associated electricity/steam cogeneration plant, and the refinery provides fuel and receives steam in return.

#### **5.2.15 Logistics**

Raw materials, process intermediates, blending components, process chemicals and additives, and finished products are stored in a variety of storage tanks and vessels at the refinery. Gasoline blending, all petroleum product shipments and receipts, and some of the

process chemical/additive shipments and receipts take place outside of the process unit boundary limits.

Examples of the modes of transportation employed in the movement of petroleum and process chemicals, and the materials moved, include:

- Marine shipments and receipts: includes crude oil, process intermediates (e.g., FCCU feed), blending components, finished liquid products, and coke
- Pipeline shipments and receipts: includes crude oil, finished liquid products, process intermediates, H<sub>2</sub>S, and acid transfers
- Rail shipments and receipts: includes crude oil, LPG, fresh and spent caustic, asphalt binder, coke, sulfur, and catalytic cracking catalysts
- Truck shipments and receipts: includes finished liquid products, asphalt binder, process chemicals, catalysts and additives, sulfur, fresh and spent caustic/acid, and coke

### 5.2.16 Utilities

The refining process requires a significant amount of steam. Steam used at a refinery may be generated in onsite boilers, either as direct-fired boilers or waste-heat boilers. Direct-fired boilers are typically operated as a utility unit. Alternatively, steam may be generated by electricity/steam cogeneration facilities consisting of a combustion turbine (linked to an electrical generator) and a heat recovery steam generator (HRSG). For refineries that operate FCCUs, the CO boilers recover waste heat from CO combustion and can be fired with auxiliary fuel to generate large volumes of steam. Other boilers generate steam exclusively from waste heat within a process unit (e.g., FCCU catalyst coolers). The steam generated by the boilers is generally delivered to the users at multiple pressure levels that range from 650 to 15 pounds per square inch gauge (psig). Recovered condensate is recycled for boiler feed water (BFW) treatment. Air pollutant emissions from the direct-fired boilers and turbines are combustion products.

BFW treatment prepares makeup water and recycled steam condensate for use in the refinery steam generators. Ionic species present in makeup water are removed by regenerable strong acid ion exchange, decarbonation, and regenerable strong base ion exchange. The treated makeup water is mixed with recovered steam condensate, deaerated to remove dissolved gases, treated with chemicals to prevent fouling and corrosion in the boilers and downstream equipment, and pumped to the boilers.

Utilities are typically a large portion of the facility-wide combustion emissions at an oil refinery.

### 5.2.17 Wastewater Treatment Plant

The wastewater treatment plant (WWTP) protects the environment from potentially harmful discharges of waterborne material by treating wastewater generated in the refining process. Process wastewater streams, domestic wastewater, and surface runoff from non-process areas are routed through the WWTP. The WWTP may also receive oil/water mixtures from offsite facilities, such as marketing locations and pipeline stations, and may also receive ballast water from marine vessels.

In general, process area wastewater is collected in individual drain systems and routed to an oil/water separator (commonly known as an American Petroleum Institute [API] separator) system via closed sewers. The water leaving the API separator is combined with treated domestic wastewater and routed to clarifiers for further oil/solids removal. The clarified water is then biologically treated in aeration basins to remove remaining organics. The treated effluent water is combined with non-process surface runoff (storm water) and is discharged via a National Pollutant Discharge Elimination System (NPDES)-permitted outfall. Oil recovered at the WWTP is recycled to refinery process units; recovered solids are removed, concentrated, and shipped offsite for disposal, except for biological solids, which are typically applied to land.

Air emissions from the wastewater collection and treatment system include leaks of hydrocarbons from the sealed portions. The biological treatment portion of the system can be a source of odorous air emissions and methane.

## **Section 6: Washington State Refineries-Specific Information**

Five refineries operate in the State of Washington:

- BP Cherry Point refinery
- Phillips 66 Ferndale refinery
- Shell – Puget Sound refinery
- Tesoro Anacortes refinery
- US Oil Tacoma refinery

This section summarizes the common air pollution sources at the refineries and highlights the important differences between the facilities. Table 5-1 is an overview of the five Washington State refineries. The sources of this information are noted.

**Table 6-1 Overview of Washington State Refineries**

Refinery	Process Capacity (bbls/day) <sup>a</sup>	Footprint (acres) <sup>b</sup>	Year Built	Crude Slate Source? (generalized) <sup>c</sup>	Total Facility CO <sub>2</sub> e (mtons) <sup>d</sup>	
					2010	2011
<b>BP</b>	234,000	3,300	1971	ANS + global + Canadian	2,536,736	2,429,027
<b>Phillips 66</b>	107,500	900	1954	ANS + Canadian	880,729	1,004,379
<b>Shell</b>	149,000	800	1958	ANS + Canadian	2,047,238	2,085,203
<b>Tesoro</b>	125,000	900	1955	Canadian + global + Bakken	588,102 <sup>e</sup>	1,164,665
<b>US Oil</b>	42,000	136	1957	ANS + Canadian	185,406	147,116

<sup>a</sup> Crude unit capacity in bbls/day (EIA, 2012).

<sup>b</sup> Approximate areas reported in state and local water quality and air quality permits and technical support documents.

<sup>c</sup> Crude slate reported in Agency permit technical support documents. ANS = Alaska North Slope.

<sup>d</sup> 2010 and 2011 EPA GHG emission inventory data.

<sup>e</sup> The Tesoro refinery was shut down for approximately 6 months in 2010 following a fire.

## 6.1 Boilers

There are 14 permanent utility boilers in operation at Washington State refineries for a total heating capacity of approximately 3,000 million British thermal units per hour (MMBtu/hr). The boilers are primarily operated using refinery fuel gas, followed by natural gas (or natural gas as supplemental fuel) and fuel oil. Based on emissions inventory documents, all boilers except one in operation in Washington State are able to use refinery fuel gas. The exception is Tesoro's F-753, which can only be fired using natural gas or propane. Based on the refineries' air operating permits, in addition to fuel gas, one boiler at US Oil (B-4) and two boilers at Tesoro (F-751 and F-752) are equipped to fire fuel oil. Table 5-2 summarizes the boiler capacity and related emissions at the five Washington State refineries. A detailed list of the utility boilers operating at Washington State refineries is included as Appendix A.

**Table 6-2 Washington State Refinery Boiler Overview**

Refinery	Utility Boiler Capacity (MMBtu/hr) <sup>a</sup>	Emissions		
		Annual Potential CO <sub>2</sub> e (tons) <sup>b</sup>	Actual 2010 CO <sub>2</sub> e (tons) <sup>c</sup>	Actual 2011 CO <sub>2</sub> e (tons) <sup>c</sup>
<b>BP</b>	1,169	666,588	281,057	282,622
<b>Phillips 66</b>	525	299,366	137,681	191,033
<b>Shell</b>	390	222,386	45,958	56,458
<b>Tesoro</b>	756	431,087	119,409	202,406
<b>US Oil</b>	179	102,070	53,995	34,902

<sup>a</sup> Excludes cogeneration capacity.

<sup>b</sup> Assumes 8,760 hrs of operation at capacity (firing fuel gas) – 40 CFR Part 98 Subpart C emission factors.

<sup>c</sup> 2010 and 2011 EPA GHG emission inventory data except for US Oil data, which were reported directly to NWCAA.

Shell operates an electricity/steam cogeneration facility within the Anacortes refinery. The cogeneration unit operates two combustion turbines that burn natural gas and refinery fuel gas as their primary fuels to produce steam and electricity. The cogeneration unit electricity output is tied into the regional power grid, with 100% of the produced electricity being sold to Puget Sound Energy (PSE). The refinery then purchases its operating power back from PSE. The unit is capable of producing a nominal 140 megawatts of electricity, while the refinery receives approximately 300,000 lbs/hr of steam from the HRSG. Duct burners are installed at the inlet of the HRSG to provide addition steam, and they are configured to burn natural gas and/or refinery fuel gas.

The refineries also have numerous waste heat boilers within the process units. These boilers also provide steam to the header systems (described in more detail in the next paragraphs) for use throughout the plant. Some waste heat boilers require supplemental fuel firing; others have no supplemental fuel.

Some of the refineries also receive steam into the header system from offsite sources. Shell purchases steam from the adjacent Air Liquide hydrogen plant. The Phillips 66 refinery has an adjacent facility (Tenaska) that operates a cogeneration unit that occasionally provides steam to the refinery.

Utility boilers, along with cogeneration units, waste heat boilers (e.g., CO boilers and catalyst coolers), and offsite steam sources, operate as integrated units, providing steam to refinery, as needed, via a complex piping, or “header,” system. The header systems include two to four delivery pressures of steam via extensive interconnected piping systems. The high-pressure portions of the header systems are fed by the utility boilers and high-heat process units, such as the FCCU. In general, the lower-pressure headers collect spent high-pressure steam and are augmented by waste heat boilers in lower-heat-rate units.

Often, backup steam generation (in the form of a boiler running at idle) is available in the system for rapid response. The steam system in the refinery is essential for normal processing and for bringing the units into and out of operation (starting up and shutting

down the units). Therefore, all refineries maintain excess steam capacity for emergency events (e.g., unit upsets or boiler upsets).

Improvements in operating efficiencies or steam load requirements can be realized throughout the entire steam system. Therefore, the utility steam system is most effectively approached as a group, and emissions considered as a combined total.

## 6.2 Process Heaters

The five Washington State refineries operate 79 process heaters, with a combined total of approximately 9,500 MMBtu/hr of potential heat input. A detailed list of the refinery process heaters is included as Appendix B. A summary of their capacities and CO<sub>2</sub>e emissions is presented in Table 5-3. The majority of the heaters are gas-fired, burning either treated refinery fuel gas or purchased natural gas. A few of the heaters (i.e., five [three at Tesoro and two at US Oil]) have the capability or are permitted to fire fuel oil; however, fuel oil is rarely used in those units.

**Table 6-3 Washington State Refinery Process Heater Overview**

Refinery	Total Heater Capacity (MMBtu/hr) <sup>a</sup>	No. of Heaters with Capacity >75,000 tpy CO <sub>2</sub> e <sup>b</sup>	Total Potential CO <sub>2</sub> e (tons) <sup>c</sup>	Actual 2010 CO <sub>2</sub> e (tons) <sup>d</sup>	Actual 2011 CO <sub>2</sub> e (tons) <sup>d</sup>
<b>BP</b>	4,900	10	2,779,000	1,547,171	1,388,417
<b>Phillips 66</b>	990	3	565,000	381,810	413,809
<b>Shell</b>	1,730	5	986,482	662,339	551,558
<b>Tesoro</b>	1,500	5	831,000	55,793	166,832
<b>US Oil</b>	290	0	165,000	145,589	119,773

<sup>a</sup> Individual heater capacities from Agency records.

<sup>b</sup> Number of individual heaters or aggregated heaters operating together

<sup>c</sup> Assumes 8,760 hrs of operation at capacity (firing fuel gas) – 40 CFR Part 98 Subpart C emission factors

<sup>d</sup> 2010 and 2011 EPA GHG emission inventory data, except for US Oil data, which were reported directly to the Agencies.

Unlike the steam system, process heaters generally function independently and serve a specific purpose. Heater duty varies with demand within the process unit. Process heat demand is based on feed rate and composition, as well as catalyst life cycle and equipment limitations.

The principal energy-using processes in refineries (in order of overall energy consumption based on the national oil refining sector) are crude (or atmospheric) distillation, hydrotreating, reformer, vacuum distillation, alkylate production, catalytic cracking, and hydrocracking (Worrell and Galitsky, 2005). The energy use for each of these processes is predominantly associated with the unit's heaters and steam demand. The five Washington State refineries are generally consistent with this energy-use profile.

### 6.3 Fluidized Catalytic Cracking Units

Three of the Washington State refineries operate FCCUs: Phillips 66, Shell, and Tesoro. The units are detailed in Table 5-4. It is important to note that the Tesoro FCCU operated for only a portion of the year in 2010.

**Table 6-4 Washington State Refinery Fluidized Catalytic Cracking Unit Overview**

Refinery	FCCU Capacity (bbls/day) <sup>a</sup>	Type of Pollutant-Control Equipment Installed	Regenerator CO <sub>2</sub> e (tons) <sup>b</sup>		Supplemental Fuel CO <sub>2</sub> e (tons) <sup>b</sup>	
			2010	2011	2010	2011
Phillips 66	36,100	SO <sub>2</sub> and PM – caustic scrubber NO <sub>x</sub> - ESNCR	336,501	439,591	37,235	38,316
Shell	57,900	SO <sub>2</sub> and PM – caustic scrubber	635,166	703,522	6,336	6,049
Tesoro	52,000	SO <sub>2</sub> and PM – caustic scrubber	276,459	563,329	60,561	124,074

<sup>a</sup> Capacity as reported by EIA (2012).

<sup>b</sup> EPA GHG emission inventory data.

### 6.4 Delayed Coking

Two of the Washington State refineries operate delayed cokers: BP and Shell. Air emissions from the cokers are primarily from the feed heaters, which were discussed in Section 5.2. The remaining GHG emission sources are methane emissions from the blowdown system and venting that occurs at the end of drum depressurization. GHG emissions consist only of methane, which is converted to CO<sub>2</sub>e emissions in the Table 5-5.

**Table 6-5 Washington Refinery Delayed Coking Overview**

Refinery	Coker Capacity (bbls/day) <sup>a</sup>	Coker CO <sub>2</sub> e Emissions (tons)		Uncontrolled CO <sub>2</sub> e Blowdown (tons)	
		2010	2011	2010	2011
BP	58,000	84	69	6,597	4,217
Shell	25,300	245	245	3,007	2,694

<sup>a</sup> Capacity as reported by EIA (2012).

### 6.5 Catalytic Reformers

Each of the five refineries in Washington State operates one or more CRs. The reformers vary in size and design. The majority of the emissions from CR units come from the heaters. However, a small amount of emissions result from catalyst regeneration. Catalyst regeneration schedules vary significantly based on the design of the unit, ranging from semi-continuous to multi-year cycles. Regeneration emissions reported by Washington State refineries are summarized in Table 5-6.

**Table 6-6 Washington State Refinery Catalytic Reforming Overview**

Refinery	CR Capacity (bbls/day) <sup>a</sup>	Regeneration CO <sub>2</sub> e Emissions (tons)	
		2010	2011
<b>BP</b>	65,000	3	4
<b>Phillips 66</b>	17,400	not reported	Not reported
<b>Shell</b>	33,300	9	23.4
<b>Tesoro</b>	26,000	23	61
<b>US Oil</b>	6,800	11	0

<sup>a</sup> Capacity as reported by EIA (2012).

## 6.6 Coke Calcining

BP operates a coke calcining unit. Coke calcining is a process used to improve the quality and value of “green” coke from the delayed coker. Coke is calcined to convert green coke to a more valuable “needle” coke and to reduce sulfur and VOC content. Green coke is fed to one of three calciner kilns, each with a rotating hearth that heat the coke to 2,400 to 2,700 °F. The calcined coke leaves the kiln and goes through a water spray cooler. The cooled coke is then conveyed by covered belt to the calcined coke storage barns, where it is stored until it is loaded to rail cars or trucks. Waste heat from the calciner is recovered in a steam generator. The calciner waste heat steam generators may be used to generate steam directly from fuel gas combustion (while not processing coke). Additional materials processed in the calciner include WWTP-recovered slop oils and recovered coke and coke fines.

Air pollutant emissions from the calciners are primarily combustion pollutants with high amounts of SO<sub>2</sub> and PM. Flue gases from the calciner hearths are routed to caustic scrubbers followed by wet electrostatic precipitators in two parallel systems; hearth 1 and 2 flue gases are combined and routed to stack 1; hearth 3 flue gases are routed to stack 2. BP calciner GHG emissions were reported to the EPA GHG inventory for 2010 to be 443,932 tons CO<sub>2</sub>e plus an additional 9,533 tons CO<sub>2</sub>e from the combustion of fuel gas in the waste heat boilers. For 2011, BP reported 490,945 tons CO<sub>2</sub>e from the calciners plus an additional 11,035 tons CO<sub>2</sub>e from the combustion of fuel gas in the waste heat boilers.

## 6.7 Sulfur Recovery Units

Each of the five Washington State refineries has associated SRUs, four of which are located onsite. The Tesoro refinery does not operate an SRU onsite but instead contracts with General Chemical to treat the facility’s acid gas. General Chemical typically uses a portion of the acid gas stream for its sulfuric acid plant and also operates an SRU that treats excess acid gas as well as during times when the acid plant is off-line. The SRU at General Chemical is owned by Tesoro but operated by General Chemical through a contract agreement. The SRUs associated with the Washington State refineries are presented in Table 5-7.

**Table 6-7 Washington State Refinery Sulfur Recovery Overview**

Refinery	SRU Technology	CO <sub>2</sub> e Emissions (tpy)	
		2010	2011
BP	Claus/SCOT/ CanSolve®	27,332	32,645
Phillips 66	Claus/SCOT	2,169	6,957
Shell	Claus/SCOT	18,106	20,529
Tesoro <sup>a</sup>	Claus/SCOT	1,809	3,867
US Oil	Claus/LO-CAT®	482	710

<sup>a</sup> Tesoro contracts with General Chemical to treat acid gas onsite.

## 6.8 Flares

Flaring can account for a large portion of the GHG emissions from refineries if a facility upset requires the relief of system pressure. However, the four largest Washington State refineries operate recovery systems that recycle the emissions back to the facility fuel gas header for use in combustion devices. Table 5-8 summarizes the amount of flaring at the Washington refineries.

**Table 6-8 Washington State Refinery Flare Overview**

Refinery	Recovery Capacity?	Flare GHG Emissions (tons CO <sub>2</sub> e)	
		2010	2011
BP	Yes	53,882	34,923
Phillips 66	Yes	22,960	6,493
Shell	Yes	13,336	14,982
Tesoro	Yes	42,960	8,404
US Oil	No	4,022	5,746

## 6.9 Hydrogen Production

Two Washington State oil refineries use hydrogen production, both via steam methane reforming: BP and Shell. The total hydrogen capacity for these refineries was reported as 122 million standard cubic feet per day (MMscfd) in 2012 (EIA, 2012). Additional hydrogen capacity at both the Shell and BP refineries has been permitted recently, so the available hydrogen production capacity for 2013 is expected to increase. The GHG emissions from hydrogen production are presented the Table 5-9. The BP hydrogen reformer heater emissions are also included in the process heater totals. Hydrogen for the Shell refinery is produced by Air Liquide and Linde Gas.

**Table 6-9 Washington State Refinery Hydrogen Production Overview**

Facility	GHG Emissions (tons CO <sub>2</sub> e)	
	2010	2011
BP	308,712	428,823
Air Liquide	Not reported	69,599
Linde Gas (March 2013 startup)	Not applicable	Not applicable

## 6.10 Refinery Complexity

The Nelson Complexity Index (NCI) is an index that reflects the capital investment in the secondary conversion capacity of a petroleum refinery. The larger the NCI for a given refinery, the more capacity that facility has to upgrade crude oil using complex units such as reforming, catalytic cracking, and isomerization. The most complex refineries in the world are reported to have NCIs of 14 to 15, while the US average NCI is about 9.5 and the European average NCI is 6.5 (Wikipedia, 2013).

The NCI was developed by Wilbur L. Nelson in a series of articles in *Oil & Gas Journal* in the early 1960s and updated in 1976.<sup>12</sup> The NCI calculation assigns a complexity factor to each major type of process unit in the refinery based on its operational complexity and investment cost as compared to the crude distillation unit, which is assigned a complexity factor of 1.0. The complexity of each process unit is then calculated by multiplying its complexity factor by its throughput ratio as a percentage of crude distillation capacity. Adding up the complexity values assigned to each process unit, including crude distillation, determines a refinery's complexity on the NCI.

The Agencies calculated the NCI using publicly available information for the purpose of identifying the relative complexity of the five Washington State refineries. The Washington State refineries rank (in order of least to most complex) according to the Agencies calculation as follows: US Oil, Tesoro, Phillips 66, BP, and Shell. The average NCI for the five Washington State refineries as calculated by the Agencies is 8, with a range of 5 to 10.5.

The process units that contribute most to the NCI are also the units that are most energy intensive. That energy intensity is reflected in facility GHG emissions. Therefore, two facilities with equal crude throughput ratings that have NCIs that are significantly different will likely have significantly different levels of GHG emissions. Other factors that are not complexity related could also influence GHG emissions for a facility, such as what type of steam generation system is operated (e.g., cogeneration verses conventional boilers).

## Section 7: Identify and Evaluate Control Technologies and Strategies

This section generally describes the GHG reduction strategies currently in use in the oil refining sector and then focuses more closely on how the strategies may apply at the five Washington State oil refineries. For each GHG reduction strategy that is identified, an evaluation and reasoning for rejecting or pursuing further each strategy is explained.

The reasons for eliminating technologies or strategies include that the option is technological infeasible, not commercially demonstrated, requires changes of existing laws, applies to equipment outside the refinery boundary as stipulated in this RACT review,

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<sup>12</sup> The *Oil & Gas Journal* article is available from the publisher for a fee.

and/or requires a process redesign. A given strategy may be rejected for one or more of these reasons.

In this document, redesign means substantially altering or reengineering the structural design of an existing process unit. While reengineering a process unit can reap efficiency benefits and CO<sub>2</sub> emission reductions, such approaches are not considered as potential RACT candidates. Redesign projects present a number of insurmountable challenges for a RACT determination including process safety implications, process performance specifications, the complexity of economic analysis, and the precedent that air quality regulations do not dictate the operations of a manufacturer, but rather set the applicable emissions standards<sup>13</sup>.

The use of redesign projects would be appropriate by regulated facilities to improve efficiency in order to meet a broader goal, such as a unit-specific or facility-wide benchmark or benchmark improvement. The refinery may use these redesign projects to meet an overall goal for efficiency as is feasible on a facility specific basis.

The possible RACT candidates identified only one proposed technology solution in the traditional sense of air pollution control, where a pollutant is collected and either destroyed or transferred to a non-atmospheric media; the use of carbon capture and sequestration (CCS) (such as underground storage or deep sea injection). In addition, there are a number of control *strategies* that result in GHG reductions by improved efficiencies. It is appropriate that this GHG RACT determination take such strategic approaches into account. The intent of the strategies is to reduce GHG emissions through the application of technology, either as equipment upgrades or in improved operating methods.

## 7.1 Carbon Capture and Sequestration

CCS is a set of technologies that controls CO<sub>2</sub> emissions from large industrial sources, including refineries. CCS systems generally include the three-step process that follows:

1. Capture CO<sub>2</sub> from power plants or industrial processes.
2. Transport the captured and compressed CO<sub>2</sub> (usually in pipelines).
3. Use underground injection and geologic sequestration to store the CO<sub>2</sub> in deep underground rock formations.<sup>14</sup>

EPA notes that CCS can significantly reduce emissions from large stationary sources of CO<sub>2</sub>, which include coal- and natural gas-fired power plants, as well as ethanol and natural gas processing plants. According to the GHG reporting program, CO<sub>2</sub> is currently being captured

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<sup>13</sup> In the Prevention of Significant Deterioration permitting process, the determination of BACT is restricted from redefining the source, as discussed in *Desert Rock Energy Company, LLC, PSD Appeal No. 08-03 et al., Slip. Op.* (Environmental Appeals Board [EAB] Sept. 24, 2009), *Sierra Club v. EPA*, 499 F.3d 653, 655-6 (7th Cir. 2007) (on appeal of EAB's Prairie State decision), EPA NSR manual and others.

<sup>14</sup> These formations are often a mile or more beneath the surface and consist of porous rock capable of reacting with and holding the CO<sub>2</sub>. Overlying these formations are impermeable, non-porous layers of rock that trap the CO<sub>2</sub> and prevent it from migrating upward.

at over 120 facilities in the US; this CO<sub>2</sub> is primarily used for enhanced oil recovery (EOR), with smaller amounts being used in food and beverage manufacturing, pulp and paper manufacturing, and metal fabrication.

Ecology has evaluated the potential for geologic sequestration in Washington State (Norman and Stormon, 2007). The review identified no readily accessible sequestration opportunities. The major points of the report are summarized as follows:

- Little is known about any potential deep basins in Washington State that could be used to sequester CO<sub>2</sub> because there has been relatively little exploration for oil and gas in the state.
- Little is known about any potential deep saline aquifers or geological structures in Washington State due to the lack of deep drilling.
- Saline aquifers capable of sequestering CO<sub>2</sub> in western Washington might exist but these aquifers might not be capable of achieving the goal of permanent sequestration due to the extensive faulting and fracturing of rock and the proximity of volcanoes.
- Known coal deposits in Washington State are too shallow to use for storing CO<sub>2</sub>. Currently, the West Coast Regional Carbon Sequestration Partnership and TransAlta are investigating deeper coal beds in the Centralia area for potential use to sequester CO<sub>2</sub>.
- Geologic sequestration in eastern Washington basalt is under investigation. However, basalt sequestration has not yet been demonstrated to be commercially viable.

According to the Massachusetts Institute of Technology (MIT) (2013a) and US Department of Energy (DOE) National Energy Technology Laboratory (NETL) (2013), as of April 2013, approximately 25 to 30 CCS projects were underway worldwide. At least one project included in these databases involves an SMR unit where the captured CO<sub>2</sub> is used for injection/EOR purposes at a nearby oil well in Texas (MIT, 2013b).

The Pacific Northwest lies approximately 1,000 miles from the nearest oil fields east of the Rockies. This distance to oil and gas fields would require the development of a pipeline system to carry the collected CO<sub>2</sub> to the fields or a sequestration site. Based on review of the documented projects, none of the CCS technologies have been proven in the Pacific Northwest; and none are being demonstrated as common production practices in other regional areas.

In Washington:

- There is no demonstrated, technically feasible CO<sub>2</sub> sequestration site.
- There is no ongoing oil and gas development in Washington State that could use the collected oil and gas.
- There is no demonstrated location that meets Ecology's definition of "permanent storage" in WAC 173-407.

**For these reasons, CCS is not considered to be a technically feasible option for RACT-level GHG reductions at the oil refineries in Washington State.**

CO<sub>2</sub> capture and utilization efforts focus on pathways and novel approaches for reducing CO<sub>2</sub> emissions by developing beneficial uses for CO<sub>2</sub>, converting it to useful products such as chemicals, cements, or plastics. Revenue generated from the used CO<sub>2</sub> could also offset a portion of the capture costs.

Many of the current CO<sub>2</sub> uses are small-scale efforts, and many emit the CO<sub>2</sub> to the atmosphere after use, which results in no reduction in overall CO<sub>2</sub> emissions. Some of the more significant current and potential uses of CO<sub>2</sub> are in cement manufacturing (Biello, 2008), polycarbonate production, and enhanced oil and gas recovery. The bioconversion of CO<sub>2</sub> to fuel products has been, to date, a small-scale effort; and ultimately, the CO<sub>2</sub> is emitted upon fuel combustion.

Praxair, Inc., operates a CO<sub>2</sub> purification and compression/liquification facility that produces CO<sub>2</sub> for the beverage industry. The facility is adjacent to the BP refinery and reported collecting approximately 90,000 tons of CO<sub>2</sub> in 2012. However, the end use ultimately emits the CO<sub>2</sub> to the atmosphere, resulting in no reduction in overall CO<sub>2</sub> emissions. The beneficial use replaces the generation of the 90,000 tons of CO<sub>2</sub> needed for the product.

**The requirement for beneficial use is not an appropriate option for RACT control.**

The beneficial use of CO<sub>2</sub> is an entirely separate process from refining, which is reflected in their separate Standard Industrial Classification (SIC) codes<sup>15</sup>. A beneficial use facility would not be considered a support facility under the Title V program because the refinery could operate independent of the beneficial use facility. Because beneficial use facilities are a separate source category, they are beyond the scope of this RACT determination.

## 7.2 Equipment-based Efficiency Strategies

Nearly all GHG reduction strategies are, in their simplest form, energy efficiency improvement strategies. In general, these strategies include multiple levels of approach. This section describes the strategies specific to pieces of equipment or groups of equipment at Washington State oil refineries.

For complex industrial process plants such as oil refineries, there are four general categories for energy efficiency improvement:

- Improved operating practices, including process control and variability reduction
- Equipment upgrade
- Process integration
- Process modification

The amount of available literature that provides GHG reduction information specific to the oil refinery sector is limited. Of the available literature that discusses GHG reductions and/or efficiency improvements at refineries, the discussions are often generalized or aggregated

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<sup>15</sup> SIC codes are numerical codes used by government to classify industries.

to protect confidential business information. However, in cases where this information has been found, the documents are cited in this description. This RACT determination relies on the efforts undertaken by other refineries and reported in these publications, which then serve as a baseline that is evaluated for application at the five oil Washington refineries.

Among the most recent relevant government-issued publications is an EPA 2010 oil refining-sector efficiency white paper (EPA, 2010), which provides a summary of GHG reduction opportunities. The following discussion is closely aligned with the recommendations/findings of that publication.

For complex facilities such as oil refineries, there are many combinations of equipment upgrades or alterations that could result in efficiency improvements that have the effect of reducing GHG emissions. However, to further complicate matters, that same equipment upgrade implemented at different facilities would not necessarily have the same result. An approach that is successful in improving efficiency at one facility could result in neutral or even negative efficiency impacts at another facility.

Some of the general approaches that typically yield efficiency improvements have been highlighted by EPA through the 2005 Energy Star<sup>®</sup> guide for refineries (Worrell and Galitsky, 2005) and the 2010 refinery and boiler white papers (EPA, 2010 and EPA, 2010) as well as by energy efficiency experts in the field.<sup>16</sup>

Energy use in the refineries has two sides: the demand for energy (in the form of steam, fuel, or electricity) for process operations and the generation side to meet that demand in the form of steam, fuel, or electricity. Process energy demand is integral to the operating practices, controls, equipment configuration and design, crude slate, product slate, and other factors. The supply of energy is usually considered under the broad category of “utilities.” Utilities deliver energy to the process units based on demand. Traditionally, most industrial energy efficiency projects, including those in refineries, focus on the utilities side of energy use. This approach is limited in its effectiveness because the utility system will always have to meet the process energy demand (in order for the process to function). Therefore, efficiency gains within the process (i.e., reducing the overall demand for energy for a given production rate) must be considered in order to fully realize the potential for reducing GHG emissions from the facility.

Utility equipment at oil refineries includes:

- Cogeneration units and electricity production equipment
- Steam generating boilers
- Process heaters and hot oil loops
- Cooling towers and cooling loops
- Air coolers
- Process flares

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<sup>16</sup> ABB Limited, KBC Process Technology Ltd, Kumana & Associates, Refining Process Services.

A refinery utility system is ideally designed to be thermodynamically integrated with the process heating and cooling profiles. However, four of the five Washington State oil refineries were constructed in the 1950s and have undergone multiple process modifications that have significantly altered the heat balance and utility demands. Even the newest facility, the BP Cherry Point refinery, which was built in the 1970s, has made process modifications that have resulted in altered heat balances at the facility. Although engineering designs take heat balance into account at the time of construction, as with most projects, over time, there will likely be additional opportunities to make improvements and ensure the continued performance of the overall system..

### 7.2.1 Cogeneration and Power Recovery

Combined heat and power (CHP), or cogeneration, has an overall energy efficiency of approximately 80% (EPA, 2010). By comparison, a standard power plant (Rankine cycle) has a power generation efficiency of up to 35%. A well-tuned standard boiler has a steam generation efficiency of about 83%. The benefit of CHP is that 40% of the energy output of the unit is in the form of electricity, which has a value that is approximately 4 times greater than steam (primarily because of its versatility). Therefore, for complex facilities that use significant amounts of power as well as steam, the installation of appropriately sized CHP equipment would represent a significant boost to the efficiency profile of the overall facility.

However, the installation of cogeneration requires significantly higher capital investment than that for conventional boilers. Most importantly, in order for cogeneration to be a successful investment, the energy demand (or market) must be available. In other words, the unit must be sized correctly to meet the needs of the application. In western Washington, several cogeneration projects have been either abandoned, delayed/tabled or, upon completion, have operated at low rates (DOE, 2003; Ecology, 2010; EFSEC, 2013).

A July 2013 white paper from the American Council for an Energy-Efficient Economy (Hayes et al., 2013) stated that the energy intensity of the US industrial sector appears to be improving slightly overall, but there is a clear backsliding in cogeneration. The paper did not include specific references to the oil refining industry. However, refining is among the most energy-intensive industrial processes in the US. The report went on to note that if the US energy efficiency trajectory continues at the current pace, the country may fall behind in the global economy.

Nine of twenty-one State of California oil refineries have reported operating cogeneration units (EPA, 2011). A total of 21 of 146 US oil refineries have reported operating cogeneration units. One Washington State refinery (i.e., Shell) operates a cogeneration unit. The Shell cogeneration plant operates at nearly full capacity, and the electricity production from that unit accounts for approximately 9% of the total Washington State refinery CO<sub>2</sub> emissions.

Cogeneration is technically feasible for the installation of new steam-generating units. However, cogeneration is not a technically feasible option for the retrofit of existing boilers.

**Therefore, CHP are not evaluated further as a potential RACT candidate.**

Power recovery equipment such as turbo expanders or steam turbines can be installed on high-pressure and/or high-temperature equipment to produce electricity. The turbines are most commonly driven by pressure let-down and/or HRSG steam. However, power generators are considered to be a process redesign, significantly affecting the pressure and heat balance of the process unit. **Therefore, power generators are not considered further as RACT candidates.**

The use of power recovery can improve facility energy efficiency and may be economically viable, particularly for new equipment installations. However, Washington State law effectively prohibits industries from considering the introduction of power recovery into the process. The rule is commonly referred to as the “net metering rule” (RCW 80.60.030(4)(b)) and limits a power customer to 100 kW of generation capacity.<sup>17</sup>

### 7.2.2 Utility Boilers

Steam production at the Washington State refineries accounts for approximately 11% of the total CO<sub>2</sub> emissions from the facilities. Steam production is a common industrial source; therefore, there is a relatively large amount of information available on efficiency improvements for these systems.

Utility boilers, along with cogeneration units, waste heat boilers (e.g., CO boilers and catalyst coolers), and offsite steam sources, operate as integrated units, providing steam to the refinery via a header system as needed. The header system includes two to four delivery pressures of steam. The high-pressure systems are fed by the utility boilers and high-heat process units, such as the FCCUs. In general, the lower-pressure loops collect spent high-pressure steam and are augmented by waste heat boilers in lower-heat-rate units.

Often, backup steam generation (in the form of a boiler running at idle) is available in the system for rapid response. The steam system in the refinery is essential for normal processing and for bringing the units into and out of operation (i.e., starting up and shutting down). Therefore, all of the refineries maintain immediately available excess steam capacity for emergency events (e.g., unit upsets or boiler upsets resulting in unplanned shutdown events).

Improvements in operating efficiencies or steam load requirements are realized throughout the entire the steam system. Therefore, the utility steam system is most effectively approached as a group, and emissions considered as a combined total.

All five Washington oil refineries operate steam systems that have the potential to emit greater than 75,000 tpy CO<sub>2</sub>e.

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<sup>17</sup> “Not more than a total of one hundred kilowatts shall be aggregated among all customer-generators participating in a generating facility under this subsection” (RCW 80.60.030(4)(b)).

All boilers in use at the Washington State refineries are water tube/water wall-type boilers. Two of the major parameters that impact energy efficiency in boilers are flue gas temperature (which should be as low as possible) and percent oxygen in the flue gas.

Table 6-1 lists efficiency measures identified in the EPA boiler white paper (EPA, 2010) that are applicable for the Washington State refinery steam generation systems.

**Table 7-1 Efficiency Improvement Projects for Steam Systems**

Measure	Applicability	Efficiency Improvement (%)	CO <sub>2</sub> Reduction (%)	Capital Costs	Notes/Issues
Replace/upgrade burners	All, except for stoker-type boilers and fluidized bed boilers	Up to 4 to 5%	Up to ~ 6%	\$2,500 to \$5,100 per MMBtu/hr	Site-specific considerations (retrofit ability) and economic factors may affect the installation of burners
Tuning	All	CO from 1,000 to 2,000 to <200 ppm Unburned carbon (UBC) from 20 to 30% to 10 to 15%	up to ~3%	Up to \$3,000	Manual tuning with parametric testing
Optimization	All	0.5% – 3.0%	up to ~ 4%	\$100,000	Neural network-based
Instrumentation and controls	All, especially at large plants	0.5 to 3.0% (in addition to optimization)	up to ~ 4%	>\$1 million	System integration, calibration, and maintenance
Economizer	Units with capacity over 25,000 lbs steam/hr	40 °F decrease in flue gas temperature equals 1% improvement	Relates to efficiency gain in boiler	\$2.3 million (for 650 MMBtu/hr)	Larger units; must consider pressure loss, steam conditions
Air preheater	Units with capacity over 25,000 lbs of steam per hour	300 °F decrease in gas temperature represents about 6% improvement	~ 1% per 40 °F temperature decrease	\$200,000 to \$250,000 (for 10 MMBtu/hr)	Used in large boiler applications, not widely used due to increase in NO <sub>x</sub>
Insulation	All, most suitable for surface temperatures above 120 °F	Dependent on surface temperature	Up to 7%		Radiation losses increase with decreasing load

Measure	Applicability	Efficiency Improvement (%)	CO <sub>2</sub> Reduction (%)	Capital Costs	Notes/Issues
Reduce air leakages	All	1.5 to 3% potential (effect similar to reducing excess air)	Up to ~ 4%	Site-specific	Requires routine maintenance procedures
Capture energy from boiler blowdown	Most suitable for units with continuous boiler blowdown exceeding 5% of steam rate	Site-specific depending on steam conditions Up to ~ 7%	Up to ~ 8%		Water quality issue important
Condensate return system	All; however, larger units more economical to retrofit	Site specific; depends on condensate temperature and % recovery	Same as efficiency improvement; ratio of Btu/hr saved from condensate to Btu/hr input	\$75,000	Energy savings is the energy contained in the return condensate; condensate quality affects use
BFW preparation	Use of reverse-osmosis membrane treatment	70 to 90% reduction in blowdown loss than lime water softening	Up to 10%	2- to5-year payback	
Reduce slagging and fouling of heat transfer surfaces	Water tube boilers	1 to 3%; site-specific; fuel quality/operating condition have large impact	Up to ~ 4%	\$50,000 to \$125,000	Downtime/economic factors, regain lost capacity
Insulating jackets	Surfaces over 120 °F	3 to 13% of boiler emissions	Same as efficiency improvement	Depends on length/type of insulation required for implementation	No deployment barriers
Reduce steam trap leaks	All			None to cost of maintenance program	No deployment barriers
Combined heat and power	All	Overall efficiency improves from 30 to 50% to 70 to80%		\$1,000 to 2,500/kW	High capital investment

Because utilities are a typical focus of efficiency improvements, the actual total efficiency realized from the improvements listed in Table 6-1 is likely to be small overall (e.g., a maximum of 5%) for a boiler system that is operated by trained, competent personnel with a sufficient budget.

The EPA oil refinery information collection request (ICR)<sup>18</sup> included a request for energy efficiency measures for electricity and steam generation information (ICR Question 5, Table 1-2). Table 6-2 is a summary of the efficiency information provided in responses to ICR Question 5, Table 1-2. The boiler efficiency measures surveyed by the ICR indicate that the Washington State refineries have implemented significantly more measures than either the national average or the California average.

**Table 7-2 EPA Refinery ICR Responses for Steam System Efficiency Measures**

Type of Energy Efficiency Measure	Total Unit Installations		Washington Unit Installations		California Unit Installations	
	No.	%	No.	%	No.	%
None	116	1	1	3	3	0
Insulation on boiler	1248	16	23	62	164	12
Insulation on distribution lines	1354	17	19	51	215	15
Oxygen monitors used to control excess oxygen	494	6	21	57	55	4
Intake air monitors to optimize fuel/air mixtures	189	2	10	27	32	2
Combustion air preheat from flue gas	134	2	11	30	12	1
BFW preheat from flue gas	372	5	11	30	74	5
Blowdown steam recovery system for low-pressure needs	385	5	16	43	46	3
Steam trap maintenance	1,078	14	20	54	217	16
Steam condensate return lines to boiler	926	12	16	43	214	15
Steam expansion turbines	364	5	6	16	65	5
Boiler maintenance program to reduce scaling	727	9	9	24	188	13
Boiler maintenance program to maintain burners	405	5	14	38	76	5
<b>Total number of units reported</b>	<b>7,872</b>		<b>37</b>		<b>1,396</b>	

These boiler efficiency measures are readily demonstrated in practice and include both equipment standards and work practices. Some of these strategies are codified in federal rules such as the Boiler MACT (40 CFR Part 63 Subpart DDDDD). **Therefore, these measures are potential RACT candidates.**

### 7.2.3 Process Heaters

Process heaters are located in nearly every refinery unit. The Washington State refineries operate a total of 79 process heaters, ranging in capacity from 5 to 1,075 MMBtu/hr.

<sup>18</sup> On April 1, 2011, EPA sent a comprehensive industry-wide ICR to all US petroleum facilities. The ICR was designed to collect information on processing characteristics, crude slate, emission inventories, and limited source testing to fill known data gaps. The template for the ICR letter sent to the refineries, general instructions and the response database are available at <https://refineryicr.rti.org/>.

Process heater emissions account for approximately 39% of Washington refinery CO<sub>2</sub> emissions. Twenty of the process heaters operating at the five Washington refineries each have potential emissions greater than 75,000 tpy CO<sub>2</sub>e. These 20 process heaters accounted for 69 and 66% of the total heater emissions in 2010 and 2011, respectively.

There are a few situations where feed to a single refinery unit is split between multiple heaters. For example, Tesoro’s crude unit is fed through a team of three process heaters, only one of which has a potential to emit (PTE) of greater than 75,000 tpy CO<sub>2</sub>e. BP operates the north and south vacuum heaters as a parallel team. These three team-operated units results in a total of 23 individual process heaters with a PTE of greater than 75,000 tpy CO<sub>2</sub>e.

There are a few general approaches for improving efficiency in process heaters. Table 6-3 is a summary of process heater efficiency projects from the EPA refinery white paper (EPA, 2010).

**Table 7-3 Process Heater Efficiency Measures**

<b>GHG Control Measure</b>	<b>Description</b>	<b>Efficiency Improvement/ GHG Reduction</b>	<b>Retrofit Capital Cost</b>	<b>Payback Time (years)</b>	<b>Other Factors</b>
<b>Combustion air controls: limit excess air</b>	O <sub>2</sub> monitors and intake air flow monitors used to optimize the fuel/air mixture and limit excess air	1 to 3%		6 to 18 months	
<b>Heat recovery: air preheater</b>	Compact air-to-air heat exchanger installed at grade level; hot stack gas exchanges heat with the incoming combustion air	10 to 15% over no preheat	Natural draft heaters must be converted to mechanical draft		May increase NO <sub>x</sub>

Source: EPA (2010).

Table 6-4 is a summary of the EPA refinery ICR responses for process heater efficiency measures. However, the Washington State unit installations are updated using the ICR response information received directly from the Washington State refineries and was submitted under confidential business information (CBI) provisions. Therefore, the data comparisons may be skewed by CBI information withheld at EPA.

**Table 7-4 EPA Refinery ICR Responses for Process Heater Efficiency Measures**

Type of Energy Efficiency Measure	Total Unit Installations		Washington Unit Installations <sup>a</sup>		California Unit Installations	
	No.	%	No.	%	No.	%
None	251	8	4	6	48	10
Oxygen monitors used to control excess oxygen	1,436	45	57	86	191	40
Intake air monitors to optimize fuel/air mixtures	199	6	0	0	19	4
Maintenance program to reduce scaling	236	7	23	35	23	5
Maintenance program to maintain burners	1,104	35	55	83	153	32
Finned or dimpled tubes to increase heat transfer	701	22	44	67	125	26
Air preheat	107	3	16	24	0	0
<b>Total number of units reported</b>	<b>3,168</b>		<b>66</b>		<b>478</b>	

<sup>a</sup> Washington unit installation information was updated from facility information submitted to EPA, not from the ICR database.

The theoretical maximum efficiency for a process heater efficiency (using highest heating value) is estimated to be 92% (Petrick and Pellegrino, 1999), while the average thermal efficiency of industrial furnaces (with heat recovery in the convection section) is between 75 and 90%. For the Washington State oil refineries, each 1% of the total annual emissions reduction from heaters equals approximately 28,000 tons of GHG. Therefore, a 5% improvement in overall heater efficiency could result in up to 142,000 tons of actual GHG reductions in Washington State.

The Energy Star<sup>®</sup> refinery manual (EPA and DOE, 2005) highlights the management of excess air, either through control or increased maintenance activity to improve heater efficiency. Such maintenance activities might include intake air plenum checks and air-leak-minimization projects. These activities are similar to air control projects but require only temporary monitoring and ongoing maintenance to maintain tight fittings on heaters and the proper adjustment of intake air plenums. For each 1% reduction of excess air, energy efficiency improves up to 3%.

The installation of air pre-heat devices (also known as economizers) could also result in efficiency improvements. These devices allow the transfer of waste heat from the unit stack to the incoming air – allowing more combustion heat to be used in the process. The use of air pre-heat devices in the refining industry is limited, as reported in the refinery ICR (EPA, 2011).

Common to all combustion devices, including process heaters and boilers, is the selection of fuels. Some oil refinery combustion units operate on liquid fuels. For these units, significant GHG reductions (>20%) could be achieved by switching to gaseous fuels. The

average CO<sub>2</sub> emissions from each fuel type are noted in 40 CFR Part 98 Subpart C, Table C-1. In general, heavy distillate fuel emission factors average approximately 75 kg CO<sub>2</sub>/MMBtu versus 53 kg CO<sub>2</sub>/MMBtu for natural gas and 59 kg CO<sub>2</sub>/MMBtu for fuel gas.

In the recent settlement agreement with environmental advocacy groups Flint Hills Resources Pine Bend Refinery agreed to CO<sub>2</sub> emission limits for some refinery heaters (MCEA, 2013). Compliance with the CO<sub>2</sub> limit is demonstrated by using only natural gas fuel.

The Washington State refineries operate primarily on gaseous fuels with a few of the 79 units permitted to burn liquid fuels. However, Washington State refineries reported no liquid fuels burned in 2010 according to the refinery ICR (EPA, 2011).

Each of these approaches is demonstrated and technically feasible. Some of these strategies are being included in federal rules, such as the Boiler MACT (40 CFR Part 63 Subpart DDDDD), which applies to process heaters at major sources, including oil refineries. **Therefore, these measures are potential RACT candidates.**

#### 7.2.4 Flares

All five of the Washington State refineries operate flares. As noted Table 5-9, all of the facilities reported flare emissions of <75,000 tpy CO<sub>2e</sub> for each year, 2010 and 2011. Four of the five facilities operate fuel gas recovery systems that minimize flaring. The 2 years of reported data include upset events at all of the facilities.

The refinery ICR lists a total of 798 flares nationally. Of that total, 196 flares (25%) reported the installation of some amount of gas-recovery equipment. The installation of flare gas recovery equipment is a potential opportunity for overall facility efficiency improvement and reduced GHG.

For comparison purposes, in California, of the total number of reported refinery flares, 48 flares (27%) have gas recovery systems. Some local California air quality regulations require flaring minimization to reduce VOC and HAP emissions (BAAQMD, 2012 and SCAQMD, 2009). These regulations impose a mandatory reporting requirement for all flaring events, as well as a root cause analysis with corrective actions implemented to minimize future flaring events. Furthermore, facilities are required to develop and implement flare minimization plans to address excess flaring.

Of the total number of Washington State refinery flares reported in the refinery ICR (i.e., 17 flares), 10 flares (59%) have some type of gas recovery equipment. None of the Washington State refineries operate with flaring volume limits. NWCAA regulations require the performance of a root cause analysis and corrective actions for all excess emissions events, including those at the flares.

The use of refrigerated condensers is also listed in the EPA refinery white paper (EPA, 2010). However, the paper provides no estimates of efficiency improvements, costs, or payback times.

The prevention of flaring provides immediate GHG emission reductions by minimizing the amount of gases released to the flares. These reductions can occur at the source, within the process, or through the installation of recovery equipment on the headers, which then routes the gases into the fuel gas system for heat recovery in process heaters and boilers.

Flare gas recovery compressors are becoming increasingly commonplace. Flare gas recovery equipment is complex, and the operation of gas recovery equipment is not simple. The effects of introducing flare gases into the fuel gas system can have broad effects on fuel gas composition and the stability of that composition. However, similar to fuel switching, the installation and operation of flare gas recovery has been demonstrated in practice and proven effective in the reduction of flaring. **Therefore, limitations on flaring, including the use of flare gas recovery is considered as a technically feasible RACT option.**

Although the effective prevention of material going to the flare is clearly the first line of GHG emissions management, the next step is the proper combustion of hydrocarbon (particularly methane) once it reaches the flare in order to reduce its GHG-forming potential. The EPA white paper for refinery efficiency (EPA, 2010) also includes proper flare operation, during which the heat content of the flare gas and steam/air-assist rates are controlled. Federal regulations regarding the heat content for flare gas impose minimum requirements that are used for enforcement purposes (EPA 2012). Proper operation in accordance with the existing regulations (40 CFR 60.18 and 63.11) results in high destruction efficiencies.

The proper combustion of hydrocarbon (particularly methane) at the flare in order to reduce its GHG-forming potential, including the control of the heat content of the flare gas and steam/air-assist rates, have been demonstrated in practice. The current regulations regarding heat content for flare gas impose minimum requirements to assure proper combustion and destruction of hydrocarbons. **Proper operation in accordance with the existing regulations<sup>19</sup> results in high destruction efficiencies and is considered as a technically feasible RACT candidate.**

#### 7.2.5 Process Cooling

To a great extent, process cooling in refining is accomplished through non-contact heat exchange with streams that require heating. The excess heat from the hot stream is passed to a stream that requires heat (and has a suitable heat driving force profile) located within a reasonable proximity. Heat exchange is discussed in more detail in the optimization section of this report.

However, at some point, additional cooling using air coolers or cooling water is required. Once the energy is transferred through these units, it is lost from the system. Any energy exiting the process in this way erodes the facility's efficiency, and so their use should only be considered for those applications where no other option for cooling exists.

Air cooler maintenance consists primarily of cleaning the fins/coils to remove fouling debris (e.g., sand, dirt, animal remains). Foaming cleaning products are the most effective for

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<sup>19</sup> 40 CFR 60.18 and 63.11.

alleviating the need for high-pressure washing that can cause physical deformation of the fins or coils.

Cooling towers operate continuously with variable loads, including both product and seasonal influences. The installation of adjustable-speed drives on the fans and circulation pumps can result in energy savings. As with other heat transfer mechanisms, the proper design of cooling water heat exchange networks is the most significant opportunity for efficiency improvements by optimizing the supply-demand relationship, thereby minimizing the need for cooling.

Process cooling focuses on operating procedures, controls, and equipment such as fin-fans, and heat exchanger networks. These types of equipment are either not direct GHG emission sources or are insignificant sources (e.g., small internal combustion engines) at Washington State refineries. **Therefore, process cooling optimization requirements are not considered RACT candidates.**

#### 7.2.6 Fluidized Catalytic Cracking Units

Energy recovery from elevated temperature and pressure units such as the FCCU is identified in the EPA refinery white paper (EPA, 2010). Most facilities currently employ a waste heat boiler and/or a power recovery turbine or turbo expander to recover energy from the FCCU catalyst regenerator exhaust. The three Washington State FCCUs operate waste heat boilers in the units for steam generation.

The installation of a power generator on an FCCU is a significant process change that would significantly affect the pressure and heat balance of the FCCU system. **Therefore, they are not technically feasible RACT candidates.**

For new units, the installation of high-efficiency regenerators allows for the complete combustion of coke deposits without the need for a post-combustion device to reduce the auxiliary fuel combustion associated with a CO boiler. However, use of a high-efficiency regenerator involves the redesign and replacement of the existing catalyst regenerators of the FCCU. **Therefore, this is not a technically feasible RACT candidate.**

FCCUs are significant fuel gas producers. As such, FCCU operation can significantly alter the fuel gas balance of the refinery and could cause the refinery to be fuel gas rich (i.e., produce more fuel gas than it consumes), resulting in excess fuel gas needing to be flared or an increase in the frequency of fuel gas system over-pressurization. If the FCCU is linked to increased flaring, GHG reduction measures, including flare gas recovery, for the impacted flare(s) have been demonstrated to be successful. **Therefore, flare gas recovery on flare systems affected by FCCU operation is further considered as a technically feasible RACT candidate.**

Finally, inasmuch as FCCUs are the largest single CO<sub>2e</sub> emission sources at Washington State refineries, carbon capture techniques could be applied if there was an opportunity for sequestration. However, **CCS is not a feasible RACT candidate for FCCU GHG emissions in this analysis.**

### 7.2.7 Coking and Coke Calcining

Emissions from delayed coking and coke calcining account for approximately 7% of the total CO<sub>2</sub>e (approximately 500,000 tpy CO<sub>2</sub>e) from Washington State refineries. For example, at the BP refinery, coker blowdown comprises less than 1% of the coking CO<sub>2</sub>e emissions, and 96% is from the coke calcining process.

Emission reduction strategies for cokers include options for heaters and steam systems, as well as limiting the amount of blowdown. Limiting the opening pressure of the coker drums (through the vent system) to 2 to 5 psig, results in fewer methane emissions. **Limiting coker blowdown pressure is a demonstrated and technically feasible RACT candidate.** However, emissions from coker blowdown represent an insignificant portion of all Washington State oil refinery GHG emissions.

Efficiency and GHG reduction projects for coke calcining are not published and thus not readily available. At least one cogeneration project has been conducted under the DOE's Industrial Technologies Program (ITP). The final report for that project will be available approximately 3 months following the expected completion of this project (August 2013). **Therefore, it is assumed there are no technically feasible control strategies specific to rotary hearth coke calcining.** However, general combustion strategies, such as waste heat recovery (as steam generation) and combustion optimization, might be appropriate to improve the efficiency of the process.

### 7.2.8 Steam-Methane Reforming – Hydrogen Production

Hydrogen production by SMR accounted for 6% of the total Washington State refinery CO<sub>2</sub>e emissions in 2011. In April 2013, the BP refinery started up a second SMR unit with the potential to emit 480,000 tpy CO<sub>2</sub>e. In addition, the Shell refinery purchases hydrogen from the Air Liquide facility, whose CO<sub>2</sub>e emissions in 2011 were reported as 70,000 tons, and a new Linde Gas hydrogen plant (which started up in March 2013), which reported a PTE of 65,000 tpy GHG. Taking into account the new SMR unit at BP and the Air Liquide and Linde Gas emissions, hydrogen production are projected to be about 14% of the total refinery CO<sub>2</sub>e emissions in 2014.

Table 6-5 summarizes the efficiency measures for hydrogen production units.

**Table 7-5 Hydrogen Production Unit Efficiency Measures**

<b>GHG Control Measure</b>	<b>Description</b>	<b>Efficiency Improvement/ GHG Reduction</b>	<b>Retrofit Capital Cost</b>
<b>Hydrogen production optimization</b>	Implement a comprehensive assessment of hydrogen needs and consider using additional catalytic reforming units to produce hydrogen		
<b>Combustion air and feed/steam preheat</b>	Use heat recovery systems to preheat the feed/steam and combustion air temperature	5% of total energy consumption for hydrogen production	Natural draft heaters must be converted to mechanical draft
<b>Cogeneration</b>	Use cogeneration of hydrogen and electricity: hot exhaust from a gas turbine is transferred to the reformer furnace; the reformer convection section is also used as a HRSG in a cogeneration design; steam raised in the convection section can be put through either a topping or condensing turbine for additional power generation		
<b>Hydrogen purification</b>	Evaluate hydrogen purification processes (i.e., pressure-swing adsorption, membrane separation, and cryogenic separation) for overall energy		

Source: EPA (2010).

New hydrogen plants are generally using PSA for the purification technology. PSA produces hydrogen at a very high purity, which is not needed for hydrotreating or hydrocracking. An alternative use of solvent absorption/stripping technology could produce an adequately pure hydrogen product for a lower energy use such as the process owned by Advanced Extraction Technologies, Houston, Texas.

With the exception of the combustion air and feed preheat (which is common to all combustion units), the strategies identified for hydrogen production are process-redesign or new equipment installation projects. **Therefore, there are no hydrogen production specific RACT candidates identified.**

As noted in Section 6.1 carbon capture technology has been demonstrated on at least one SMR unit. However, CCS is not a feasible RACT candidate in this analysis.

**7.2.9 Sulfur Recovery**

Sulfur recovery accounts for approximately 1% of the CO<sub>2e</sub> emissions from Washington State refineries. The only proposed efficiency improvements for sulfur recovery in the

refinery white paper (EPA, 2010) is the selection of efficient technology for installation. No new SRUs or significant expansions are currently proposed at Washington State refineries.

**Since this approach is a redesign or replacement of the existing process equipment, it is considered technically infeasible as a RACT candidate.**

#### **7.2.10 Leak Detection and Repair**

All US oil refineries are subject to process line leak detection and repair (LDAR) requirements under federal regulations. However, only a few facilities include their refinery fuel gas and natural gas systems in the program.

Equipment leaks that emit volatile hydrocarbons, including methane, account for only a very small amount of total GHG emissions, less than 1% (estimated as methane) for refineries, which is well below the 75,000-tpy threshold. All five Washington State refineries report refinery-wide equipment leak emissions to be <1,000 tpy CO<sub>2</sub>e.

Washington State and federal leak detection standards apply to equipment in VOC or organic HAP service (i.e., containing these materials). Refinery fuel gas and natural gas contain significant amounts of methane, which is neither a VOC nor a HAP. Therefore, the equipment in fuel gas service is typically exempt from the LDAR program. However, several facilities have agreed to include their fuel gas systems in LDAR programs as part of federal enforcement settlements. The inclusion of the fuel gas systems is a positive step towards improving efficiency and reducing GHG emissions; however, fuel gas system leaks are not considered significant sources of GHG reductions in this RACT determination.

**Inclusion of fuel gas in LDAR programs is demonstrated and a technically feasible RACT candidate.**

#### **7.2.11 Optimization**

Process information reviews can be used to identify the most effective efficiency improvements for equipment and optimize a refinery's energy performance. Three items can be adjusted to improve optimal performance: operating procedures, process controls, and equipment.

The first step is to verify that the existing equipment is being used to its fullest advantage by examining operating data and identifying process input and throughput instabilities, as well as equipment bottlenecks.

Operating procedures can vary widely from operator-to-operator or from shift-to-shift. Automating a plant can help significantly, but automation is of limited value if the operators take control and run the plant (or portions of the process) in manual mode. A thorough review of both written and implemented operation practices is essential to determine what, if any, additional technology improvements are needed.

In a typical processing plant, such as an oil refinery, there are hundreds or even thousands of control loops. Each control loop (which generally consists of process monitoring devices, computing hardware and software, control devices [primarily valves] and the associated wiring circuits) is responsible for controlling one part of the process, such as maintaining a

temperature, level, or flow. Most importantly, if the inputs to the process are not well controlled, significant amounts of energy can be wasted in reacting to the input instability. For example, crude feed temperature swings can negatively impact the desalter operation, as well as crude tower separation efficiency. In order to make up heat in the crude unit, high-quality steam is generally used at the expense of utility demand. However, if the crude feed temperature is controlled in the feed tank, low-quality steam is used in the tank heaters, with no added expense for utilities.

Once the inputs are stabilized or at least predicted, if the control loop is not properly designed and tuned, the process runs below its optimum level, the process will be more expensive to operate, and equipment will wear out prematurely. For each control loop to run optimally, the identification of sensor, valve, and tuning problems is important.

A continually developing and powerful technique for identifying overall facility and process unit efficiency improvements is using process integration (also referred to as pinch analysis). Pinch analysis is a method of characterizing energy profiles to identify pinch points where energy is limited. The boundaries of process integration are flexible in order to meet whatever objective is identified – from a single heat exchanger network to a larger section of a process unit or facility. A pinch analysis produces clues as to how energy might be better managed through improved heat exchanger network layout or pump sizing or the installation of new heat recovery equipment or other process equipment.

However, in order for optimization to be successful, a system-wide perspective is essential. High equipment efficiency (which can come at a premium costs) does not necessarily result in high system efficiency if that piece of equipment is not the efficiency bottleneck.

Equipment that refineries use in the greatest numbers and has the greatest effect on energy consumption are distillation columns, heat exchangers, pumps, and compressors. Optimizing techniques for each group of equipment are discussed generally here.

In the case where a distillation column creates an energy bottleneck, the principal way to reduce energy consumption in distillation is to use more-efficient trays or packing, which reduces the reflux ratio to achieve the same product specification. This approach has a relatively high capital cost and requires equipment downtime while the new column equipment is being installed. The next option for improving column efficiency is to increase the feed temperature to the distillation column up to (or above, in some cases) the bubble point. This is usually accomplished outside the column by increasing heat recovery in the feed preheat train.

Heat exchangers play a critical role in minimizing thermal energy (fuel) use from utilities. A heat exchanger neither consumes nor converts energy. Heat exchangers only transfer heat from a hot fluid stream to a colder one. Therefore, traditional efficiencies cannot be used to describe heat exchanger operation. However, heat exchangers rarely operate alone but are generally used in a series, and the concept of efficiency can be applied to these heat exchanger networks. Heat exchanger network efficiency can be defined as achieving the process temperature objectives at the least total annualized cost for both utilities and capital. Heat exchanger network efficiency can be improved by matching hot and cold

streams according to the temperature-driving force profile in the process. Pinch analysis is useful to identify bottlenecks for heat transfer in heat exchanger networks and predict which individual heat exchanger needs to be improved for the overall network to operate more effectively.

Improved heat exchanger operation may include a change in the maintenance program for that exchanger in order to optimize the cleaning schedule. Alternatively, the standard shell and tube exchanger may need to be replaced with a new type of exchanger, such as a spiral, or helical coil. More comprehensive heat exchanger network configuration changes might be needed to meet the heat transfer needs of the system, either by rerouting streams or changing flow rates through the system. The heat exchanger network optimization goal should be to maximize the performance of the network as a whole, with individual exchangers modified only if and when necessary.

A large amount (estimated maximum of 95%) of power consumption within industrial facilities (including refineries) is used for electric motors. The five Washington State refineries are significant electricity consumers: in 2011, the facilities purchased approximately 1,300 GWH combined. The refineries are among the top 50 power consumers in Washington State. Many new refinery projects are expanding the use of purchased electricity, replacing steam-driven or fuel-driven equipment with electricity-driven equipment. These projects may not always result in efficiency improvements, depending on the process variability, steam production technology, source of electrical power, and distance from the electricity provider.

For pumps and compressors, the design of the piping is critical to minimizing pressure drop. For retrofit projects within existing units, this priority is challenged by limited space and existing pipe racks.

Manufacturers of electric motors offer a range of efficiencies for most motor sizes. The cost differential is typically not significant in the context of the overall capital investment. Installation costs for high- versus low- efficiency motors do not vary. The creation of a state minimum efficiency standard for new equipment is one option for driving the move toward investing in high-efficiency equipment.

Traditionally, industrial pumps and fans have been installed using a fixed-speed motor with a throttling valve or damper to control flow. This configuration results in extremely low efficiencies (in terms of energy used per pound of fluid delivered) during turndown operations. For example, the pump remains at full speed but flow is restricted or recycled back to the pump intake line.

The installation of adjustable-speed drives provides an opportunity for improving the efficiency of rotating equipment. Adjustable and variable speed drives can be mechanical, electromechanical, hydraulic, or electric.

Adjustable-speed drives are becoming more common as solutions for improving efficiency. Information sources available to the public (including Wikipedia) have reported on some of these improvements: "Some adjustable speed driven applications use less energy than

fixed-speed operated loads, variable-torque centrifugal fan and pump loads being by far the world's most energy-intensive. Since most of the energy used for such fan and pump loads is currently derived by fixed-speed machines, use of efficient adjustable speed drives for these loads in retrofitted or new applications offers the most future energy savings potential. For example, when a fan is driven directly by a fixed-speed motor, the airflow is invariably higher than it needs to be. Airflow can be regulated using a damper but it is more efficient to directly regulate fan motor speed. According to affinity laws motor-regulated reduction of fan speed to 50% of full speed can thus result in a power consumption drop to about 12.5% of full power." (Wikipedia, 2013).

Variable frequency drive (VFD) technology has expanded in the past 10 years, such that the cost of this technology is becoming competitive. VFDs are electro-mechanical drive systems used to control motor speed and torque by varying motor input frequency and voltage.

Similar to high-efficiency motors, the installation of adjustable-speed drive technology could be used to meet a minimum efficiency requirement for new or modified equipment.

Optimization focuses on operating procedures, controls, and equipment such as distillation columns, heat exchanger networks, and rotating equipment. These types of equipment at Washington State refineries are either not direct GHG emission sources (e.g., electric or steam-driven) or insignificant sources (e.g., internal combustion). **Therefore, non-combustion equipment-specific optimization requirements are not considered RACT candidates.**

However, when using a benchmarking standard, optimization has the potential to provide significant GHG emission reductions through the reduction of process energy demand. The focus of energy efficiency within a refinery is reducing the energy intensity of the process (i.e., the overall energy demand per unit of production). Optimization provides the framework for identifying the most-effective equipment upgrades to meet the goal of reducing GHG emissions.

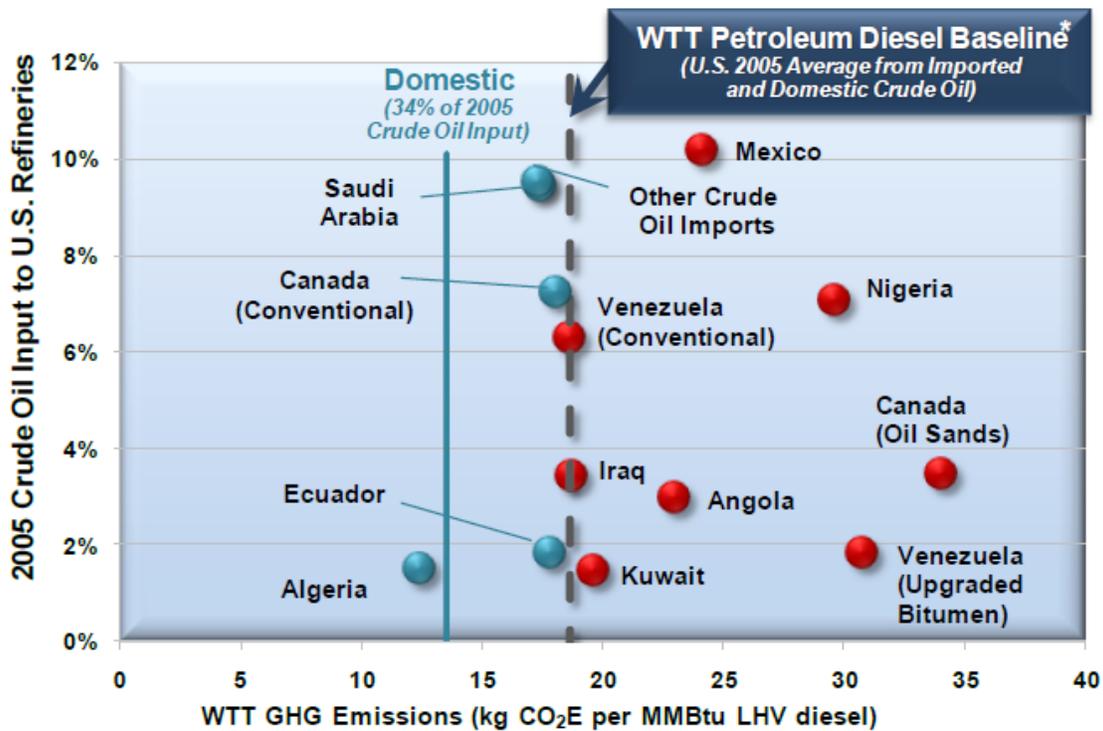
#### **7.2.12 Crude Oil Constraints**

Commenters within the Washington State refinery GHG RACT stakeholder group, as well as commenter to the California Air Resources Board (CARB) regarding AB 32 have proposed including crude slate characteristics as potential GHG reduction strategies at oil refineries.

Crude slate is the crude oil mix that is purchased and fed into a refinery. The end products of each refinery are largely determined by the characteristics of the crude slate, because the processing equipment has limited flexibility with respect to operating conditions and capacity. Heavier (longer-chain hydrocarbons), dirtier (higher sulfur and nitrogen content) crude oils require more energy to process than do lighter, cleaner crudes oils in producing the majority of refinery end products, such as gasoline and diesel fuel. The measurement of density for hydrocarbons, particularly crude oil is API gravity. API gravity is an inverse scale of the relative density of the material (e.g., heavier crude oils have lower API gravities).

Crude slate management typically encompasses the work of an entire department within any given refinery. This department is purchasing and selling crude shipments, scheduling deliveries, and projecting product demands on an hourly basis in order to meet the facility's operational goals.

Each crude oil considered for processing by any given refinery has a lifecycle GHG footprint – from production and transportation through refining. Information published by the DOE's National Energy Technology Laboratory (DOE, 2009) and others (Lattanzio, 2013; Mui et al., 2010) provide insight into how the selection of crude by a given refinery impacts the overall GHG emissions for a given fuel product. Figure 7-1 illustrates the results of an analysis that was performed by the DOE in 2005 (DOE, 2009).



Source: DOE, 2009.

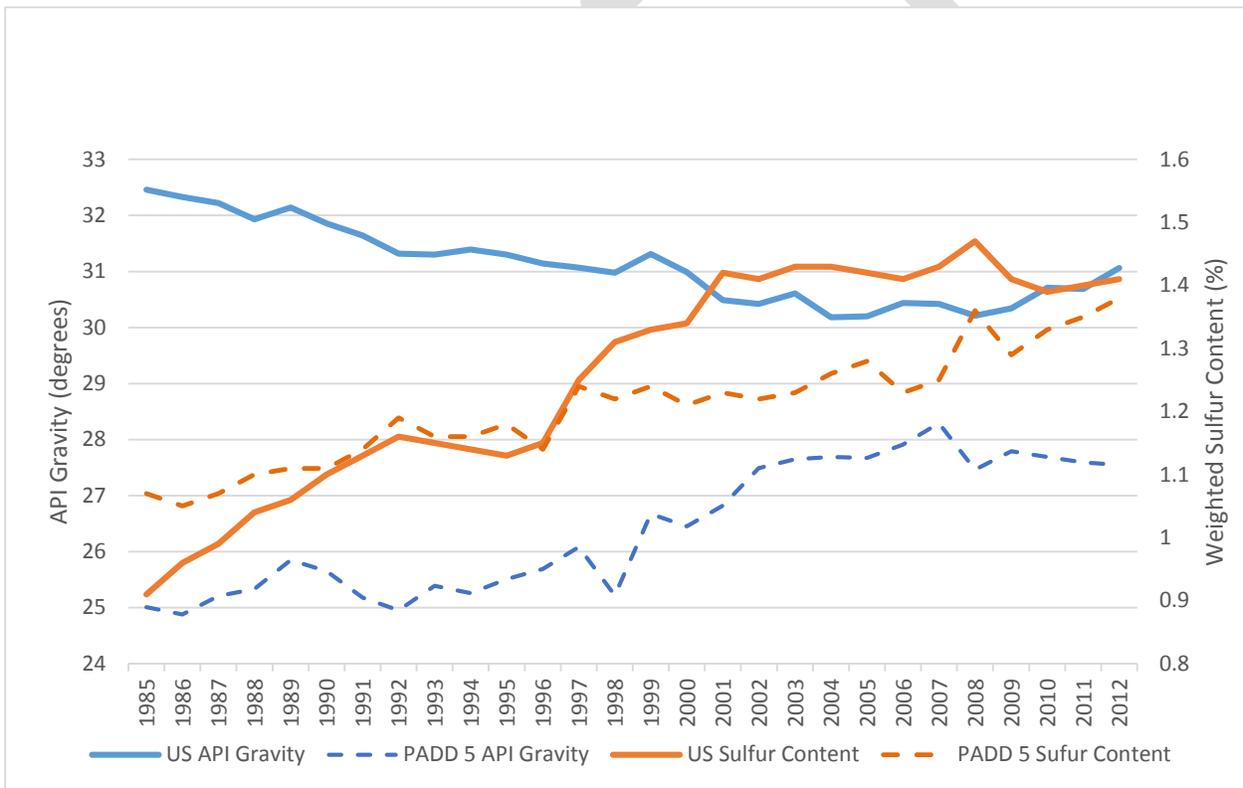
**Figure 7-1 Life-Cycle Well-to-Tank GHG for Diesel Production from Specific Crude Sources**

The information shown in Figure 7-1 is somewhat outdated and does not reflect new domestic production from unconventional sources, which has been on the rise since 2011 with the opening of the North American mid-continent shale reserves. However, the figure does show the relative GHG implications of choosing different crude oils. For example, using Venezuelan bitumen crude oil produces well-to-tank GHG emissions that are more than twice those of conventional domestic-sourced crude oil.

However, for the purpose of this RACT analysis, the boundary of the refinery facility is the scope of the GHG emissions analysis. Therefore, the GHG emissions from the production

and transportation of crude oil to the refineries is outside the scope of this RACT analysis and thus not discussed further in this RACT determination.

Domestic refining trends have historically been that the average sulfur content of refining crude oil is increasing while the average API gravity is decreasing. Crude oils with higher sulfur and lower API gravity are generally considered to be lower-quality crude oils. The US Energy Information Administration (EIA) collects information on crude oil used in the US refining industry. Those data are presented in Figure 7-2 and have been used as a basis for energy intensity and GHG implication studies. It should be noted that as of the early 2000s, the quality of the crude oil purchased by US refineries was becoming more stable. For the West Coast refineries, which are identified as the Petroleum Administration for Defense District [PADD] 5<sup>20</sup> and represented by the dashed lines in Figure 7-2, crude sulfur content has been generally consistent with the national average. However, the average API gravity of the crude oil input to the West Coast refineries has traditionally been significantly lower than the national average, though is generally increasing over time.



Source: EIA, 2013

**Figure 7-2 Refined Crude Quality for US Refineries**

Beginning in the early 2010s, the North American mid-continent crude oils began entering the market. The overall impact of that event on the total average weighted sulfur content

<sup>20</sup> PADD 5 includes refineries in Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

and API has not yet been published for 2013. Quality information for Bakken crude oil at Clearbrook, Minnesota has been reported by Argus (2013) as 0.17 to 0.20% sulfur and 40 to 42 degrees API gravity. Platts (2010) reported that the Bakken blend has 0.5% sulfur and 38 to 40 degrees API gravity.

A facility's crude slate impacts the energy intensity of the process, with lower-quality crude requiring more energy to process. Both sulfur removal and cracking processes are energy intensive. The general trend toward the use of lower-quality crude could provide motivation to consider crude slate as a potential GHG RACT candidate.

Although the energy intensity of any given refinery is impacted by the crude slate being processed, the concept of using crude slate as a mechanism for GHG emissions has challenges. The decision must consider the following:

- No two refineries are identical. Each refinery is designed and operated to process a certain crude oil blend (having a specific range of properties) into an array of specific products.
- Each crude oil (identified by geographical location of extraction) has specific properties that are unique, including density (small carbon chain versus long carbon chain), acidity, and metal contamination.
- Each refinery is designed for a certain range of crude oil feedstock properties, which limits the blend ratio with respect to chemical compatibility among crude oils (which affects fouling propensity), with the metallurgy of the refinery equipment, and with reactor catalysts.
- Within these constraints, the crude slate for each facility must be optimized on the basis of economics and availability on an hourly basis.
- The products from each refinery are largely determined by the characteristics of the crude slate because the processing equipment has limited flexibility with respect to operating conditions and capacity.
- Significant changes away from the design crude oil blend or the product slates would require the physical modification of equipment, typically at a high capital cost.

A potential RACT control strategy that dictates crude slate in any way would significantly impact the core operation and economics of the facility. **Therefore, crude slate requirements are rejected as a potential RACT control strategy.**

### 7.3 Programmatic GHG Reduction Strategies

Integrated efficiency improvement programs are implemented at a facility-wide level, a corporate level, or, in the case of government programs such as cap-and-trade, a national or international level.

#### 7.3.1 Facility- and Corporate-level Programs

Many large corporations, including oil companies, promote programs that focus on improving overall plant efficiency through the implementation of specific tools (e.g., energy management systems [EnMS]), as well as the establishment of performance targets.

Performance targets may be based on specific corporate goals or industry benchmarks. The implementation of these programs varies from facility to facility.

#### **7.3.1.1 Energy Management Systems**

EnMS are business frameworks for managing energy and promoting continuous improvement. The EPA refinery white paper (EPA, 2010) indicated that EnMS are available from the American National Standards Institute (ANSI) and International Organization for Standardization (ISO). However, based on a review of their available products, neither the ANSI nor ISO standards are refinery-specific, therefore they are not considered in this RACT analysis.

A total of 72 of the 146 US oil refineries (including two of the Washington State refineries, Shell and Phillips 66) reported on the EPA ICR that they have energy management plans.

**EnMS are technically feasible RACT options as work practice standards.** However, these programs are likely better suited for implementation by facilities on an as-needed basis to meet a regulatory standard.

#### **7.3.1.2 Benchmarking**

Benchmarking is the process of comparing the energy performance of a single site over time or comparing that sites performance with an industry-wide range of performance. Plant energy benchmarking is typically performed at a facility-wide or site level in order to capture the synergies of different technologies, operating practices, and operating conditions.

Benchmarking enables companies to set informed and competitive goals for plant energy improvements. Benchmarking also helps companies prioritize the areas in which to invest in order to improve performance while possibly learning from the approaches used by top performers. Post-project benchmarking can provide valuable feedback to help determine how well a given project succeeded in meeting the prescribed goals.

When benchmarking is conducted across an industrial sector, a benchmark that defines best-in-class energy performance can be established. There are few established energy benchmark systems in the refining industry, and none are publically available at this time. The most prominent benchmarking system identified during this review is owned by Solomon Associates LLC (Solomon) in Dallas, Texas. Solomon is a specialized firm that has developed a widely used trademark benchmarking system for energy efficiency unique to the refining industry – the Solomon Associates Energy Intensity Index® (EII®).

Benchmarking can also be a powerful tool within the confines of a process unit to identify opportunities for energy efficiency improvement. Best performance information for individual equipment groups can be compared with actual performance to identify the poorest performing part of a system. When benchmarking is implemented in tandem with process integration, energy efficiency improvements can be identified and assessed, using modeling tools to prioritize and determine the best capital spending options available to achieve the goals of the facility.

**A benchmarking approach is a technically feasible RACT candidate for Washington State refineries.**

**7.3.1.3 Industrial Technologies Program**

DOE's ITP<sup>21</sup> leads the national effort to improve industrial energy efficiency and environmental performance. Under their BestPractices<sup>®</sup> program, ITP works with companies to implement energy management practices by providing a number of resources for corporate executives, plant managers, technical staff, and the general public. The BestPractices program provides software tools, industry best practices tip sheets, training to certify energy experts in specific energy-intensive processes, and energy assessments. Case studies that present the results of a plant-wide assessment or demonstration project are available from the BestPractices program. ITP's latest program, announced in 2009, is Save Energy Now<sup>®</sup>, a national initiative that aims to achieve a reduction of 25% or more in industrial energy intensity in 10 years. Under this program, any company can partner with ITP to participate in a no-cost onsite plant assessment to help improve energy efficiency and increase productivity. The ITP website provides a list of large plants that have participated in Save Energy Now<sup>®</sup> assessments and posts their assessment reports. As of April 2013, no Washington refineries were listed as participating with either of these ITP programs.

**A requirement to participate in a DOE ITP is a technically feasible RACT option if the federal agencies are willing to participate.**

**7.3.1.4 Energy Star<sup>®</sup>**

Energy Star<sup>®</sup> is a joint program between EPA and DOE that dates back to 1992. Energy Star<sup>®</sup> began as a voluntary labeling program to identify and promote products that reduce GHGs. Since its inception, the program has expanded to include industrial processes, including oil refining. The refining industry program began in 2006. As of January 2013, nine oil refineries had earned the right to use Energy Star<sup>®</sup> labeling. None of these refineries are located in Washington State or on the West Coast.

In 2005, the Energy Star<sup>®</sup> program produced a guide for the oil refining industry, *Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries* (EPA and DOE, 2005). The guide identifies energy efficiency opportunities for petroleum refineries and, when available, typical payback periods.

The guide goes on to say, "*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*

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<sup>21</sup> DOE, Energy Efficiency and Renewable Energy, ITP website (<http://www1.eere.energy.gov/industry/saveenergynow/assessments.html> and [http://www1.eere.energy.gov/industry/saveenergynow/energy\\_experts.html](http://www1.eere.energy.gov/industry/saveenergynow/energy_experts.html)).

*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.*" Specifically, the guide identifies a few companies with demonstrated success in GHG reduction projects; including BP, Petro-Canada, ExxonMobil, Shell, and Texaco and cautions that results of efficiency programs will vary significantly for any given facility. While the *Energy Guide* provides examples for improving facility energy efficiency, it is not a roadmap for achieving Energy Star® labeling.

The Energy Star® program certification has developed benchmarks establishing best-in-class performance for specific industrial sectors. The benchmarks are known as plant Energy Performance Indicators (EPIs) for specific industrial sectors and are publicly available at [www.energystar.gov/industrybenchmarkingtools](http://www.energystar.gov/industrybenchmarkingtools). Using several basic plant-specific inputs, the EPIs calculate a plant's energy performance, providing a score from 0 to 100. EPA defines the average plant within the industry nationally at the score of 50; energy-efficient plants score 75 or better. Energy Star® offers recognition for sites that score in the top quartile of energy efficiency for their sector using EPIs.

Energy Star® has not developed EPIs for the refining sector. Oil refineries requesting Energy Star® labeling are reviewed using an analogous benchmarking system. The facility compliance status with respect to EPA programs is first reviewed to determine that the facility has no significant non-compliance issues. Those refinery applicants found to be in good compliance standing are then asked to provide certification through a private company, Solomon Associates. EPA relies upon the Solomon certification to indicate that the applicant facility is in the top quartile of performers for energy efficiency among similar-sized US oil refineries. The data set used to set the benchmark performance is from 2006. EPA has reviewed the Solomon EII® benchmarking approach and found it to be equivalent to the EPI benchmarking system developed for and used by other industries. The refineries that successfully complete this process are given the Energy Star® recognition.

The Energy Star® program in and of itself is not an appropriate RACT level of control because by definition, only the top 25% of performers can meet the requirements, and the remaining 75% cannot ever achieve RACT, assuming the performance thresholds are periodically updated. One way to recognize the program and its efforts would be to consider any facility that demonstrates a commitment to efficiency by achieving Energy Star® certification as meeting or exceeding the requirements of a RACT rule.

### **7.3.2 Existing Federal Rules**

On January 31, 2013, the final version of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) was published (78 FR 7138; 40 CFR 63.7480). During initial GHG RACT stakeholder meetings, the use of the Boiler MACT was suggested as a GHG RACT strategy. However, the regulation does not compel the affected facilities to implement any of the findings of the energy assessment. Furthermore, there are no quantitative estimates of the reductions achieved to date – either in EPA or industrial literature. When, as part of

this RACT process, the five refineries in Washington State were asked to estimate the GHG reductions that would result from Boiler MACT implementation, no estimates were provided.

Table 3 of 40 CFR Part 63 Subpart DDDDD states,

“4. Existing boilers or process heaters must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:

- a. A visual inspection of the boiler or process heater system.
- b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
- c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
- d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
- e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
- f. A list of cost-effective energy conservation measures that are within the facility's control.
- g. A list of the energy savings potential of the energy conservation measures identified.
- h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.”

There is no requirement for the facility to submit the information to the regulatory agency, but rather to maintain the results on file for subsequent inspection.

These rules do not require the implementation of any identified project; instead, it is presumed that other factors, such as cap-and-trade or energy-cost economics will compel the source to undertake the projects. However, the energy assessments required for units subject to Boiler MACT are expected to identify projects pursuant to compliance with this rule.

This state-wide rule could set priorities, thresholds, and deadlines for the implementation of the projects identified by the Boiler MACT. The challenge with this approach is that the identified projects could be process redesign projects, which the Agencies have specifically precluded from being within the purview of this review. In examining the remaining list of

RACT-level actions, the efficiency measures under consideration would be included in the Boiler MACT assessment. The rules are not in conflict, and the assessment required under the Boiler MACT would be beneficial for identifying GHG reduction projects at the oil refineries. **Therefore, the federal Boiler MACT rule is not evaluated further as a RACT candidate.**

### 7.3.3 Electric Utility Efficiency Incentive Programs

Washington State law requires the assessment and subsequent distribution of funds to improve industrial efficiency, which is implemented through utility efficiency incentive programs (also referred to as energy conservation projects). These programs are run by the utility that serves each facility, with assistance from the Bonneville Power Administration for the public utility districts (PUDs). BP, Shell, and Tesoro are served by the Puget Sound Energy. Phillips 66 is served by the Whatcom County PUD. US Oil is served by Tacoma Power (Tacoma PUD).

Each power provider is required to assess a tariff for the specific purpose of funding energy efficiency projects. For the top purchasers of power, such as the refineries, the tariff fund is reserved on an individual facility basis for the reimbursement of projects approved by the power provider. The tariff fund is earmarked for the facility a specific period of time, during which each facility can be reimbursed for the amount that they paid in. Once that time period has passed, unclaimed funds become available to any facility in the program, typically through a competitive bid process.

The power providers have in-house industrial energy experts available to assist the facilities in identifying and scoping potential projects eligible for the reimbursement program. However, according to the electric utility experts, the program has historically been underutilized by Washington State refineries; the refineries have not consistently applied for tariff funds to offset projects, thereby allowing the funds to pass on to other applicants through the competitive bid process.

**A requirement to participate in the electric utility efficiency incentive programs is a technically feasible RACT candidate if the utilities are willing to participate.**

### 7.3.4 Cap-and-Trade Programs

Wikipedia provides the following succinct summary: "Emissions trading or cap-and-trade is a market-based approach used to control pollution by providing economic incentives for achieving reductions in the emissions of pollutants. A central authority (usually a governmental body) sets a limit or cap on the amount of a pollutant that may be emitted. The limit or cap is allocated or sold to firms in the form of emissions permits which represent the right to emit or discharge a specific volume of the specified pollutant. Firms are required to hold a number of permits (or allowances or carbon credits) equivalent to their emissions. The total number of permits cannot exceed the cap, limiting total emissions to that level. Firms that need to increase their volume of emissions must buy permits from those who require fewer permits. The transfer of permits is referred to as a trade. In effect, the buyer is paying a charge for polluting, while the seller is being rewarded for having

reduced emissions. Thus, in theory, those who can reduce emissions most cheaply will do so, achieving the pollution reduction at the lowest cost to society.” (Wikipedia, 2013).

Benchmarking has been the primary approach used to date to address GHG emissions at oil refineries. Although there are no existing regulations that specifically limit GHG emissions at oil refineries, several cap and trade programs do include regulations intended to reduce GHG emissions over time. The background documentation for cap and trade rulemaking in Europe and North America indicates that governing bodies have found benchmarking to be the most appropriate approach for characterizing the performance of a complex process for energy efficiency. Complex industrial facilities manage energy in diverse ways. For example, even if a facility has the most efficient onsite power production available, if the equipment that uses that power is inefficient, the overall impact is limited

California's Global Warming Solutions Act (AB 32)<sup>22</sup> imposes a cap-and-trade governance of GHG emissions in the state, which addresses large sources such as refineries, power plants, industrial facilities, and transportation systems. AB 32 provides a fixed limit on GHG emissions from the sources responsible for about 85% of the state's total GHG emissions. AB 32 reduces GHG emissions by applying a declining aggregate cap on GHG emissions and creates a flexible compliance system through the use of tradable instruments (i.e., allowances and offset credits). AB 32 became effective January 1, 2012.

The allowances for oil refineries for the first few years of the AB 32 program (2012 to 2014) were based on the Solomon Associates EII<sup>®</sup> benchmarking product directly. For 2015 to 2020, the State of California will be shifting to use of the Solomon Associates CO<sub>2</sub> weighted tonne<sup>™</sup> (CWT<sup>™</sup>) metric for calculating allowances.

In 2012, CARB released a notice of regulatory amendment (CARB 2013) to link the State of California's cap-and-trade program with a similar program in Québec. California and Québec have been working together to ensure that both systems' operations are compatible. To that end, the link between California and Québec will need to be effective as of January 1, 2014.

On December 14, 2011, the Government of Québec adopted a cap-and-trade system for GHG emission allowances. On December 12, 2012, the Government of Québec adopted a regulation to amend the regulation in order to better align Québec's system with California's system, as well as those of future partners such as Ontario and British Columbia. British Columbia passed GHG cap legislation in 2008 but has yet to promulgate a trading regulation. Ontario has not yet passed cap and trade regulations.

The Canadian government in conjunction with the Canadian Petroleum Products Institute (now known as the Canadian Fuels Association) has also taken separate steps to reduce GHG emissions from oil refineries. The Canadian Industry Program for Energy Conservation involved all 21 oil refineries operating in Canada. The refiners made a commitment to reduce the energy intensity (using the Solomon EII<sup>®</sup> score) of production by at least 1% per

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<sup>22</sup> California Code of Regulations Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 5, Subarticle 9 §95891 Allocation for Industry Assistance.

year from 1995 to 2000. The commitment was met and extended to 2004. The Canadian Fuels Association (2013) reported a resulting decrease in CO<sub>2</sub> emissions of 20% between the 1990 base year and 2010.

Considering the GHG reductions achieved by Canadian oil refineries and the expectations from California and Europe for GHG reductions, there are likely opportunities for measurable GHG reductions within the US oil refining sector, including the Washington State refineries.

The European Union (EU) elected<sup>23</sup> to use the CWT™ metric that was developed by Solomon specifically to characterize GHG emissions from refinery operations at the 98 EU refineries for the EU cap-and-trade program. The CWT™ development effort was spearheaded by the oil companies' European association for safety and environment in refining and distribution, Conservation of Clean Air and Water in Europe (CONCAWE). CONCAWE has 42 member companies, including BP, Phillips 66, and Shell.

Several researchers and public policy centers have written about ways in which cap-and-trade or market-oriented approaches to controlling GHGs could be established under existing USCAA requirements. These include the New York University Institute for Policy Integrity (Chettiar and Schwartz, 2009), the Pew Center on Global Climate Change (PCGCC, 2011), and World Resources Institute (Bianco, et. al., 2011). The NYU paper suggested that BACT determinations would be difficult to integrate into a cap-and-trade system. The other papers directed their attention at other parts of the law. None suggested that BACT determinations offer a potential means for market-based approaches to GHG control. Since RACT determinations are made using an approach similar to BACT, the same concerns would likely apply. But even if further study showed that RACT could be a market-based approach to controlling GHGs, this evaluation has not focused on that alternative because of the small number of oil refineries in Washington State. It seems unlikely that a viable market could be established among five refineries. **Therefore, cap and trade is not evaluated further as a RACT candidate.**

## 7.4 Potential Future Information Sources

California's AB 32 also directed CARB to prepare a scoping plan that identifies how to best reach the 2020 GHG limit. The Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities (i.e., the Energy Efficiency Assessment Regulation)<sup>24</sup> required high-GHG-emitting stationary industrial facilities (including oil refineries) to identify their energy consumption and associated GHG emissions, determine potential opportunities for improving energy efficiency and reducing GHG emissions, and identify potential future actions for obtaining further reductions in GHG emissions. Each facility was required to submit to CARB a report that specified the results of the study and provided an action plan. CARB is compiling that information as this report is being

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<sup>23</sup> April 27, 2011, commission decision determining transitional Union-wide rules for harmonised free allocation of emission allowances pursuant to Article 10a of Directive 2003/87/EC of the European Parliament and of the Council (notified under document C(2011) 2772), (2011/278/EU).

<sup>24</sup> California Code of Regulations Title 17, Division 3, Chapter 1, Subchapter 10, Article 4, Subarticle 9 §95600 to 95612

developed. Those reductions will be used to meet each plant's GHG cap as it is set in the future.

CARB released the Phase 1 report (CARB, 2013) with the following preliminary summary statistics:

- The 12 refineries subject to the Energy Efficiency Assessment Regulation identified over 400 energy efficiency improvement projects.
- The total GHG reductions associated with these projects is estimated to be approximately 2.8-million metric tons (MMT) CO<sub>2</sub>e.
- Approximately 78% of the estimated GHG reductions (2.2 MMT CO<sub>2</sub>e) is from completed projects, with 63% (1.4 MMT CO<sub>2</sub>e) being from projects completed before 2010 (and therefore already accounted for in the 2009 emissions inventories) and 37% (0.8 MMT CO<sub>2</sub>e) being from projects completed during or after 2010.
- Approximately 22% of the estimated GHG reductions (0.6 MMT CO<sub>2</sub>e) is from projects that are scheduled (7%) or under investigation (15%).
- Corresponding reductions of NO<sub>x</sub> and PM are 2.5 and 0.6 tons per day (tpd), respectively, with approximately 50 to 60% of the reductions from projects completed before 2010 and 40 to 50% of the reductions from projects that were either completed during or after 2010, scheduled, or under investigation.

CARB anticipates that more information will be released in the phase 2 report of the series due out at the end of 2013.

On May 23, 2012, EPA and the BP Whiting refinery entered into a consent decree that includes a study of energy efficiency measures to reduce GHG emissions at the refinery and the expenditure of \$9.5 million to implement GHG-reducing measures. Subsequent to undertaking the efficiency projects, the facility will conduct a study of the energy efficiency measures implemented and the effect of such practices on the reduction of GHG emissions. The results of the study, to the extent that they are made public, will shed light on current opportunities for the reduction of GHG emissions.

## 7.5 Summary of GHG Reduction Strategy Findings

In summary, the following GHG reduction strategies are dismissed as RACT candidates for one or more reasons:

1. CCS
2. Carbon capture and utilization
3. CHP or cogeneration
4. Power recovery – power generators
5. Process cooling optimization
6. FCCU high-efficiency regenerator design
7. Hydrogen plant design optimization
8. Sulfur plant design optimization
9. System optimization (process integration/pinch analysis)
10. Crude oil feed (crude slate) constraints

11. EPA Energy Star® certification
12. 40 CFR Part 63 Subpart DDDDD

The following strategies are found technically feasible to effectively reduce GHG emissions at oil refineries:

For boilers

1. Burner replacement/upgrades
2. Tuning
3. System modeling and optimization
4. Air leakage reduction/maintenance
5. Instrumentation and controls (particularly air:fuel ratio)
6. System insulation
7. Condensate system maintenance and improved recovery
8. Steam trap maintenance
9. Air/BFW preheaters/economizers

For heaters

10. Burner maintenance
11. Combustion air instrumentation and controls; particularly air:fuel ratio
12. Optimization, including heat exchange network design minimizing pump power requirements
13. Scaling reduction maintenance
14. Air preheaters/economizers
15. Heat transfer system upgrades (finned or dimpled tubes)

Others

16. Flaring limits
17. Flare gas recovery
18. Flare design and operation specifications
19. Coker blowdown pressure limitations
20. Inclusion of fuel gas components in LDAR programs
21. EnMS
22. Benchmarking
23. Participation in DOE ITPs
24. Participation in utility efficiency programs

RACT determinations on an equipment-specific basis are impractical for the Agencies due to the diversity and inter-relatedness of the sources and the complexity of the potential RACT rule. Based on the agency review, a facility-wide approach is expected to achieve GHG reductions of at least as much as implementation of equipment-based standards. Utilizing a facility-wide approach is generally expected to reduce the average cost of compliance because facilities can evaluate the entire plant and select those projects that are most economical and appropriate for their situation.

Many control strategies that reduced GHG emissions at oil refineries were deemed potential redesigns of the refining processes. It is not appropriate for a regulatory agency to impose such redesigns as RACT requirements. However, the redesign strategies hold the largest potential for GHG reductions across the industry because they are associated with the energy demand side of the process, and fundamentally, energy demand accounts for all energy use within a facility. A facility-wide approach allows for the use of redesign projects to meet the overall objective of meeting industry benchmarks and/or reducing GHG emissions.

## **Section 8: Proposed RACT**

A large number and diverse range of technically feasible equipment-specific options are identified in this determination. The Agencies also identified a complex network of equipment and processes from which GHG reductions could be realized. Therefore, the Agencies focused on identifying an approach that requires facilities to apply reasonably available technology and work practice standards to achieve GHG reductions, while providing facilities with the flexibility necessary to meet the requirement and recognizing those facilities that are already implementing these efficiency measures.

The Agencies propose that the GHG RACT for the five Washington oil refineries be a dual-path process as follows:

- A refinery may demonstrate reasonably available energy efficiency performance by scoring in the top 50th percentile of similar sized US refineries, or
- A refinery must implement projects or work practices to achieve GHG emission reductions that cumulatively add up to 10% of the baseline-year facility GHG emissions, with those reductions allowed to occur over approximately a 10-year period, whichever path is completed first

The Agencies propose to use the Solomon EII<sup>®</sup> scoring system for the oil refineries as the benchmark demonstration of an investment in energy efficiency measures at the facility. Specifically, if a facility is among the top performing half (i.e., top 50%) of US similar-sized refineries, according to the Solomon EII<sup>®</sup> score, the facility has demonstrated compliance with GHG RACT.

For a facility that does not meet the energy efficiency benchmark of the top 50<sup>th</sup> percentile, the required GHG reduction is calculated as 10% of the total facility GHG emissions in the baseline year of 2010. An alternative year of 2011 may be used as the baseline emissions year in the event that 2010 is not representative of typical facility operation due to extended process outages (i.e., greater than 30 days).

Based on information from the refineries, the baseline year for each refinery on the GHG emission reduction path, is:

- BP – 2010
- Phillips 66 – 2010
- Shell – 2010

- Tesoro – 2011
- US Oil – 2011

The baseline year for the Tesoro and US Oil refineries is 2011; while the baseline year for the BP, Phillips 66, and Shell refineries is 2010. Tesoro was shut down for approximately 6 months after a refinery fire that occurred in April 2010, and US Oil underwent a major turnaround in 2010, shutting down for approximately 5 weeks in 2010.

If GHG emissions reductions projects undertaken by a refinery result in an EII<sup>®</sup> score that meets the 50<sup>th</sup> percentile performance benchmark, the facility can submit that demonstration at any time during the 10-year completion period. Once the refinery has demonstrated that it has achieved the benchmark, the 10% emission reduction is no longer an applicable requirement.

## 8.1 Setting the RACT Performance Bar

WAC 173-400 defines “reasonably available control technology (RACT)” as “the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account the impact of the source upon air quality, the availability of additional controls, the emission reduction to be achieved by additional controls, the impact of additional controls on air quality, and the capital and operating costs of the additional controls. RACT requirements for any source or source category shall be adopted only after notice and opportunity for comment are afforded.”

In very general terms, the performance goal of a given pollutant RACT rule is that when control technology is applied to units that are large enough to impact regional air quality, the average air quality of that region is maintained within the NAAQS, excluding other sources. This GHG determination is different from previous RACT determinations in many respects, including the fact that there are no GHG NAAQS against which to measure progress, and GHG emissions reductions are a result of efficiency improvement measures analogous to pollution prevention, not control device installations. In short, the goal of this RACT determination can be restated as: to define a reasonably efficient refinery operation in Washington State in the 2010-2012 timeframe.

The proposed RACT defines a reasonably efficient refinery as a refinery that demonstrates an average energy efficiency performance comparable to or above those of similar-sized US refineries as established in 2010 or GHG emissions reductions through the implementation of reasonably available technology and/or work practice standards that cumulatively amount to 10% of the facility overall emissions, whichever milestone is met first.

The proposed efficiency performance and GHG emissions reductions can be achieved by implementing control strategies that have been demonstrated in practice. The proposed RACT provides the flexibility to choose from any control strategy, including but not limited to those listed in this determination that can be implemented over a 10-year period. The proposed 10-year compliance period allows facilities to further reduce the capital costs of

compliance by allowing planning time over approximately two turn-around cycles. The facility boundary for the efficiency performance of GHG reductions is defined as the refinery fence line.

## 8.2 Basis for Benchmark Demonstration of Compliance

The Agencies believe that the investment in equipment and resources necessary to achieve a reasonably efficient process should be encouraged at any and all times during the proposed 10-year phase-in period. It is also reasonable to allow facilities to use operational demonstrations for the years prior to the RACT rule issuance back to 2006; the Energy Star Program data set year establishing the performance benchmarks.

The Agencies propose to use the Solomon EII<sup>®</sup> scoring system as the measurement and demonstration of energy efficiency at the refineries. If a facility is within the top 50% of the Solomon EII<sup>®</sup> scores of all similar-sized US refineries as established in the EPA Energy Star Program, the facility has demonstrated that it is a reasonably efficient refinery.

The Solomon EII<sup>®</sup> score reflects an individual facility's energy intensity. To be in the top 50% of similar-sized US refineries, a facility is presumed to have implemented procedures that maintain equipment efficiency and already invested in basic capital projects to improve energy efficiency. Energy costs are estimated to account for approximately 60% of non-feedstock operating expenses in the average refinery. Therefore, minimizing these costs is essential to the refinery's competitive operation. It is reasonable to assume that refineries motivated to improve energy efficiency will choose to implement the most cost-effective, low-capital projects first, followed by moderate- and then high-capital projects. However, in general, refineries do not undertake large-capital investment projects for energy efficiency gains alone; rather, larger investments are driven by other goals, such as capacity or yield increases, with efficiency gains being a corollary benefit.

Thus, facilities that are already performing in the top half of their peer group have a narrowing scope of potential efficiency improvements available, and those energy efficiency projects that are available are likely to require increasingly greater capital expense to accomplish.

For facilities in the lower half of US refinery EII<sup>®</sup> performance, the scope of potential energy efficiency improvements and associated GHG emissions reductions is broad and includes basic equipment upgrades and no-to-low-cost operational improvements. This approach is generally considered to be on the level of RACT.

A potential criticism of a benchmarking approach is that there is no guarantee that a refinery that demonstrates compliance with this approach has implemented *all* reasonably available energy efficiency measures. Based on the information reviewed in this determination, the Agencies believe that the proposed benchmark reflects the implementation of reasonably available technology and work practices specific to any given Washington refinery. The implementation of all possible control technologies is not a typical outcome of any RACT determination. For any RACT evaluation, the process is designed to identify the best control option, weighing its cost, effectiveness, and other impacts.

Any facility has the ability to improve its Solomon EII<sup>®</sup> score by investing in the equipment and practices necessary to improve efficiency (Hileman, 2001). An improvement in a facility's Solomon EII<sup>®</sup> score indicates improved energy efficiency and a reduction in CO<sub>2</sub>e emissions based on that facility's production. One particular advantage of Solomon EII<sup>®</sup> is that 90% of US refineries already subscribe to the service and would thus incur no additional cost for monitoring and compliance demonstration.

The Agencies propose using US refineries nationwide as the comparison group because they are subject to similar regulations and represent a reasonably large number of facilities for comparison. US refineries also experience similar energy prices, overall economic climates, and fuels markets. The global refinery pool was rejected as the comparison group for two primary reasons: a wide range of energy prices directly influence the economics of efficiency and fuel market product specifications and prices vary significantly on a global scale. In addition, refineries around the world are also subject to different environmental and labor regulations. A more local supply region (i.e., PADD 5) was also rejected as a potential facility pool because of the relatively small number of facilities available for comparison. There are 32 operating refineries in PADD 5 versus 139 nationwide according to EIA (2013).

Energy Star<sup>®</sup> certification for level-of-efficiency performance (i.e., top 25th percentile of the Solomon EII<sup>®</sup>) was rejected as a compliance demonstration because it would set a bar that is beyond the expectation of RACT. Press releases for facilities receiving Energy Star<sup>®</sup> certification provide an indication of the types of projects that were undertaken to achieve certification, including the following:

- Phillips 66 (formerly ConocoPhillips) set a corporate-level energy reduction goal of 10% between 2007 and 2012. The Billings, Montana, refinery press release credited common energy efficiency measures applied to an uncommon extent and noted the installation of a new cogeneration facility (Johnson, 2007). The press release for the Bayway refinery in Linden, New Jersey, reported that the refinery improved its energy efficiency by 11% between 2002 and 2012 by strategically managing energy consumption and making cost-effective improvements to the plant, such as replacing a large crude oil unit furnace, replacing the sulfur recovery plant, and upgrading various energy recovery systems (Phillips, 2013).
- In 2002, Marathon set a goal of a 10% energy efficiency improvement in 10 years. The Canton refinery surpassed the 10-year goal within 5 years by improving insulation and installing new heat exchangers (Energy Star<sup>®</sup> 2013).
- The ExxonMobil Baton Rouge refinery improved its energy efficiency by 12% between 2000 and 2007 using its global EnMS. Projects undertaken included heat exchanger monitoring, steam trap and steam leak repair programs, and upgraded furnace air pre-heaters (ExxonMobil, 2008).

Specifically, the installation of new cogeneration, crude oil furnaces and sulfur plants have been determined to be beyond RACT. Air preheaters and heat exchanger upgrades might be RACT-level projects, depending on the efficiency of the existing equipment at any given refinery. The levels of efficiency improvement (10 to 12%) reported here are demonstrated in 5 to 7 years.

A component of the Energy Star® Program is included in this RACT proposal. Energy Star® uses categories of similar-sized refineries for the calculation of the 25% performance goal. The size categories provide a fair comparison of operations because the EII® statistic is affected by economies of scale in refining. For example, larger refineries with multiple processing trains have significantly more opportunities for heat exchanger networks. The Agencies propose that the RACT performance demonstration use the refinery size categories already established in the Energy Star® program to serve as EII® benchmarks that can be fairly assessed for varying refinery capacities.

There may be perceived drawbacks to using the Solomon EII® benchmark. The system is proprietary and considered to be highly sensitive commercially. Neither the basis data nor the calculation methodology are available to the public for review. However, the integrity of the global business of Solomon weighs against compromising the calculation, and the data submitted to Solomon is under the direction of a licensed professional engineer who is held to strict ethical standards that are similar to those established for responsible official certification under the Title V program. The data that are provided to Solomon can be reviewed by the Agencies. Furthermore, the Agencies have not been able to identify a comparable alternative to the Solomon EII® benchmark. Although the EII® benchmark is widely used, Solomon also has a number of other efficiency-based indexing products available to the refining industry. Among those products are alternatives that may be acceptable or better-suited to the proposed method for RACT determination. However, if proposed, the use of an alternate index would require additional review.

### **8.3 Efficiency Benchmark Compliance Demonstration**

The procedure for demonstrating compliance with the benchmark standard is proposed as follows:

1. A facility interested in obtaining certification would provide baseline year data to Solomon using the appropriate forms certified by a professional engineer.
2. Solomon would perform the EII® calculations and provide certification to the facility, which could then be forwarded to the Agencies. The certifying letter would include statements that the facility had demonstrated energy efficiency performance in the top 50% of similar-sized US refineries.

The certification from Solomon ensures that the facility has been compared using a set target EII®. The EII® target will be calculated by Solomon for each refinery size category using 2006 data from participating US refineries. These performance targets will be held for the duration of this program, inasmuch as it would be inappropriate to recalculate performance targets at later dates under this rule because it could result in a moving RACT standard. RACT standards are determined at a point in time and are reviewed periodically to determine if the standard should be updated. The approach of designating a performance target year is consistent with RACT policy. In addition, in discussions with Solomon technical experts, the Agencies have learned that the performance thresholds of the Energy Star® program have been stable for the past 6 to 8 years.

This type of system is also in place in California for Phase 1 of the cap-and-trade regulation to determine initial carbon allocations. The EII<sup>®</sup> is submitted to CARB as the basis for GHG allocations.

As a whole, Washington State refineries implement more efficiency measures on boilers and heaters than reported by other US refineries (see Section 6 of this determination). Based on this information, the Agencies expect that some (and possibly all) Washington State refineries will demonstrate above-average energy performance within the first few years of this program. However, demonstrations have not been provided by the Washington State refineries to the Agencies at this time.

#### **8.4 Basis for GHG Reduction Goal**

Publications and reports reviewed by the Agencies have provided a basis for estimating potential efficiency improvements in oil refineries.

The CARB *Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources Refinery Sector Public Report* (CARB, 2013), which was released June 6, 2013, summarized the data provided by the State of California refineries pursuant to the CARB regulation. The baseline year for the assessment was 2009, during which the refineries reported total CO<sub>2</sub>e emissions of 31.4 MMT. In the assessment phase, the 12 California refineries identified more than 400 energy efficiency improvement projects that, once implemented, are projected to reduce GHG emissions by 2.8-MMT CO<sub>2</sub>e per year. Although no specific goal was stipulated for the process, on their first round of review, the refineries identified approximately 9% CO<sub>2</sub>e emission reductions. The projects were considered economically feasible by the facilities and many (80%) of the projects have already been completed, although there was no regulatory requirement to do so. The rule allowed for projects completed prior to the baseline year to be included. Most of the completed projects occurred between 2006 and 2011.

The Canadian Industry Program for Energy Conservation involved all 21 operating oil refineries in Canada. The refiners cooperatively made a commitment to reduce the energy intensity (based on the Solomon EII<sup>®</sup> score) of production by at least 1% per year from 1995 to 2000. The commitment was met and extended to 2004. The Canadian Fuels Association (2013) reported a resulting decrease in CO<sub>2</sub> emissions of 20% between the 1990 base year and 2010.

In a 2008 *Hydrocarbon Processing* report (Spoor, 2008), refineries were estimated to have 10 to 15% GHG reductions readily available, with project payback periods of 2 to 3 years. The report pointed to the use of benchmarking to identify potential areas of improvement and noted that efficiency improvements typically fall into three categories (similar to the areas described in Section 3 of this report): fired heater efficiency, power generation efficiency, and energy integration.

In 2010, *Hydrocarbon Engineering* published a report (Mertens and Skelland, 2010) that estimated that the carbon reductions achievable with a payback period of less than 4 years (excluding cogeneration) was approximately 15%. Cogeneration was estimated at an

additional 7% of potential emission reductions, depending on the site location and whether the application was new construction or a retrofit.

EPA's refining white paper (EPA, 2010) provides equipment-specific emissions reduction estimates. A sum of the total reduction potential for the various units listed far exceeds a 10% overall GHG emissions reduction.

In 2006, DOE published a paper (DOE, 2006) that included the following statement: "According to experts working in the field of petroleum refining and energy management, the plant-wide refinery energy savings potential is usually found to be around 30%." The report reviewed the top five energy-intensive refining processes (i.e., crude distillation, fluidized catalytic cracking, catalytic hydrotreating, catalytic reforming, and alkylation) and estimated that available potential energy savings for those processes to be 23 to 54%.

Based on the literature reviewed during this RACT process and the published GHG reductions (from 9 to 20%) demonstrated by oil refineries in Canada, California, and Europe, an average GHG reduction goal of 10% is achievable at a reasonable cost assuming that refineries have not already implemented the identified efficiency measures.

For those facilities needing assistance in finding efficiency projects, this RACT review identified participation in DOE's ITP and the energy assessment in the Boiler MACT regulation as likely resources.

The 10% GHG reduction is proposed as a goal over a 10-year timeframe. The Agencies expect that GHG reduction projects that involve capital expenditure will need sufficient time for planning (both engineering and financial), as well as implementation. The 10-year phase-in timeframe has been established to accommodate two major turnaround cycles. The industry's average turnaround cycle ranges between 3 and 5 years. There are also shorter, more frequent maintenance events and partial shutdowns during interim periods at most facilities, making equipment available for "quick fix" energy projects. Therefore, a facility's plan to comply with the proposed RACT rule is expected to include procedural reviews and maintenance activities in the near-term (i.e., within the plant manager's authority) followed by the review, prioritization, and funding of energy efficiency projects that require higher capital investment (i.e., approval by corporate management). This approach will allow facilities to schedule projects with minimum downtime.

## **8.5 GHG Reduction Compliance Demonstration**

The baseline year GHG emissions for facilities on the emission reduction compliance path will be determined from data submitted through the EPA GHG reporting program, which has consistent reporting calculation and format requirements.

Emissions generated by means of onsite cogeneration electrical power production must be treated separate from this RACT regulation. Cogeneration will increase GHG emissions from the facility offsetting greater emissions at the power plant where the purchased power would otherwise have been generated. On a global basis, therefore, correctly sized and operated cogeneration systems improve energy efficiency and reduce GHG emissions. This should be encouraged, and proper credit should be given to those facilities that do so.

One option is to evaluate projects similar to current air quality permitting practices, in which existing emissions are compared with projected post-project emissions, including upstream and downstream emission effects. For some projects, the monitoring of emissions would need to continue for a period of time after project completion to ensure that the implemented change resulted in an emissions reduction and is sustainable. For projects that have ongoing requirements, such as steam trap maintenance programs, certification that the program is in place might be sufficient for reporting.

Allowances for electrification upgrades (e.g., the replacement of a steam turbine with an electric motor) should also be provided for situations in which the upgrade improves efficiency. However, it would be inappropriate to credit 100% of the GHG emissions for a given project because power production would generate GHG at another facility. Thus, the power plant GHGs should be subtracted from the refinery credit for onsite emissions reductions. Electrical power is provided to the Washington State refineries by several sources (as presented in Table 8-1), with each facility reporting the carbon intensity of power generation.

**Table 8-1 Carbon Intensity for Local Power Providers**

Facility	Power Provider	Carbon intensity (lbs CO <sub>2</sub> e/kWh)	
		2010	2011
US Oil	Tacoma Power (PUD)	0.6 (NWPCC <sup>a</sup> )	Not reported
Shell <sup>b</sup>	Onsite cogeneration via PSE	0.43	0.43
Tesoro	PSE	1.03	0.87
Phillips 66	Whatcom County PUD	0.6 (NWPCC)	Not reported
BP	PSE	1.03	0.87

<sup>a</sup> NWPCC = Northwest Power and Conservation Council.

<sup>b</sup> Shell produces power at the facility cogeneration plant, sells the power to PSE, and buys back the refinery load. Thus the cogeneration carbon intensity is appropriate for the Shell refinery because it is essentially producing its own power.

The calculated emissions reduction at the refinery will correlate with the associated increase in emissions from the power provider when electrical equipment is used to replace direct-fired or steam-driven units. No credit is provided for electrical upgrades to electrical equipment. Those projects have separate economic incentives through the power providers, as described in Section 6.

## 8.6 Overlap with Existing Rules

During the initial information gathering meetings as part of this RACT analysis, the use of the Boiler MACT was suggested as a GHG RACT strategy. Although the Boiler MACT rule requires an efficiency review of the units subject to the regulation, it does not require any follow-up action on items identified during the review.

In examining the list of actions that the boiler MACT efficiency review would likely identify, it is evident that the efficiency measures under consideration would also generate emission reductions/efficiency improvements, meeting the proposed RACT rule. Therefore, the two

programs are not in conflict and would be mutually beneficial for GHG reductions. The state-wide RACT rule could set priorities, thresholds, and deadlines for the implementation of the projects identified by the Boiler MACT. However, the Agencies determined that such an approach is not warranted given the proposed RACT determination.

Similarly, the 40 CFR Part 60 Subpart Ja provisions were presented during initial stakeholder meetings. The flare gas recovery provisions of that rule further the overall efficiency of the facility and generate GHG emission reductions that will also contribute to the goals of the proposed RACT rule.

## 8.7 Economic Analysis

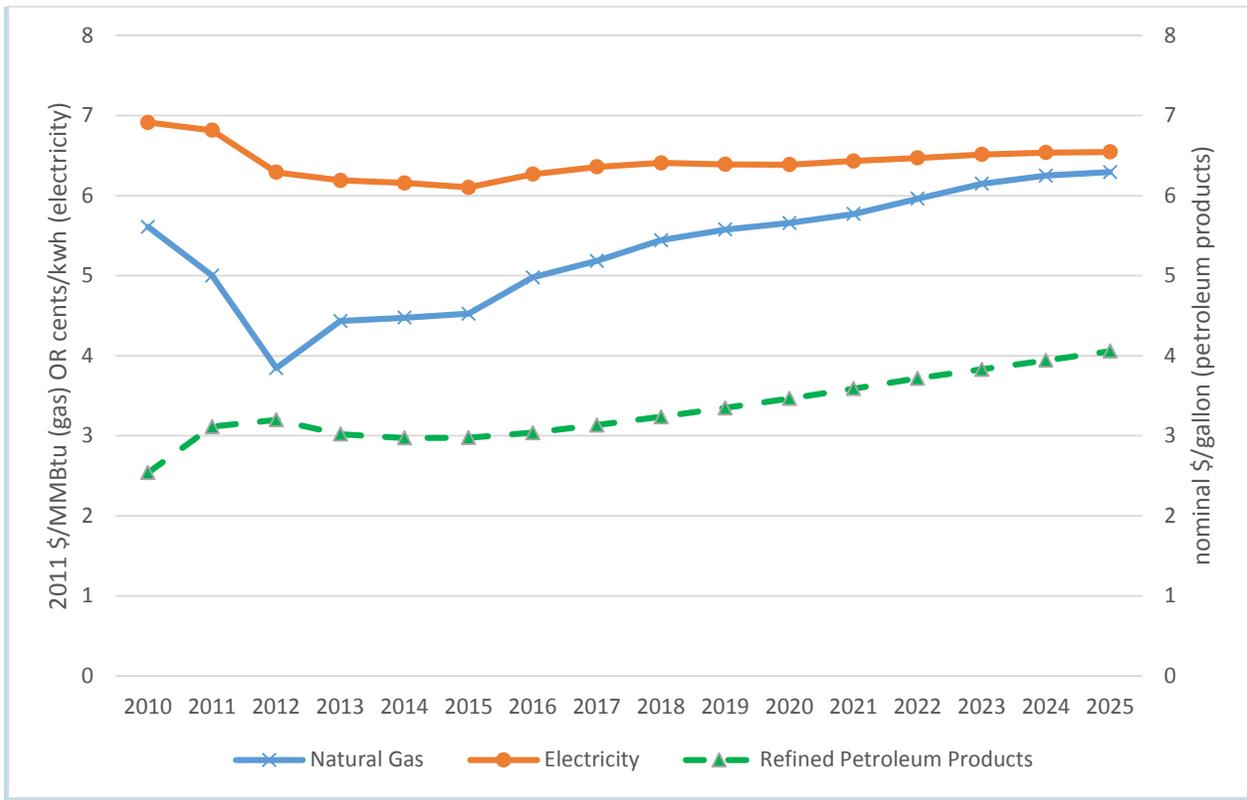
In a traditional RACT determination that includes an emission unit-by-unit and pollutant-by-pollutant review, the total capital investment and annual costs for control measures are included. The cost estimates are based on specific equipment installations, including heat and material balances (i.e., flowsheet calculations).

The economic analysis for the proposed GHG RACT differs from the standard air pollutant analysis in several ways:

- Instead of identifying the specific control devices to be applied to emission units, the Agencies identified numerous possible solutions that the facilities might implement (including process redesigns) to accomplish the efficiency reduction goal of 10%.
- This flexibility in strategies to reduce GHG emissions does not lend itself to the traditional flowsheet analysis and calculation of cost/ton that is typical for the RACT economics analysis.
- Energy efficiency projects typically reduce operational costs sufficiently that the facility not only recovers all the annual operating costs of the equipment or work practices but also recoups the initial capital investment.
- Almost all energy efficiency projects provide additional benefits, including reductions in water use, waste generation, and criteria air pollutant emissions.

The flexible compliance strategy proposed in this RACT analysis also compounds the complexity of the possible compliance option costs. However, there are overarching general concepts that can be applied to provide economic perspective.

Industry literature indicates that improved maintenance programs and basic equipment upgrades typically fall into a 2-to-4-year payback period. The cost of energy is the predominant factor in the payback analysis for energy efficiency projects. DOE projects energy prices for the US and provides those projections on the EIA website (EIA, 2012). As shown in Figure 8-1, in general, electricity prices are predicted to be stable through 2025, while natural gas and refinery product prices are predicted to rise.



Source: EIA (2012)

**Figure 8-1 DOE Energy Price Projections from 2010 to 2025**

Natural gas prices peaked in 2008 and fell through 2012. Looking forward, the projections show a moderately rising natural gas prices and commensurate electricity prices. The price of petroleum products is also projected to continue on a rising trend. Based on these trends, energy efficiency projects implemented in the future could pay for themselves more quickly than did those implemented during the period from 2008 to 2010, when a number of the California projects were undertaken (see more discussion below).

The Northwest Power and Conservation Council (NWPCC) February 2013 regional wholesale power price forecast (NWPCC, 2013) indicates that power prices in the area are likely to increase slightly over the next several years, with the primary caveat being natural gas prices. Fossil fuel-based power in the states that comprise the NWPCC’s northwest region (Washington, Oregon, Idaho, and Montana) comes primarily from coal, which is expected to be phased out and surpassed by natural gas in approximately 2021. Therefore, natural gas prices will heavily influence the cost of power in the region. This forecast is generally consistent with DOE projections.

The California Energy Assessment Rule required that facilities submit cost information with all identified improvement projects. The 2013 CARB report includes the total one-time capital costs, annual costs, and annual savings for the approximately 400 energy efficiency improvement projects identified in the refinery sector. The 400 projects represent a potential reduction of 2.8 MMT of GHG emissions annually (approximately 9% of the

reported 2009 total GHG emissions from the state's 12 oil refineries). The total estimated one-time costs for all of these projects (except for those identified as "Not Implementing") were estimated to be approximately \$2.6 billion, with annual costs of about \$17 million. These projects would also result in a net aggregate annual savings of approximately \$200 million. The 2013 CARB report does acknowledge that these estimates are preliminary and are not based on detailed engineering and cost analyses, which would be required to accurately estimate emission reductions, costs, and timing of the projects.

The information summarized for each of the 12 refineries included in the 2013 CARB assessment report is varied. Specific details regarding the extent of the individual projects were not made available in order to protect CBI. However, CARB did provide some general findings in their web presentation of the report to the public on July 9, 2013:

- The greatest opportunities for efficiency improvements were in the refinery processors, boilers, and other thermal equipment groups.
- Process changes, equipment upgrades, and new technologies were consistently cited as contributing to the greatest emission improvements for these equipment groups and others.

An article in *Hydrocarbon Engineering* (Zhu et al., 2011) reported on projects undertaken by UOP LLC for a number of refinery units, with payback periods of less than 3 years. One example of an integrated project involved 24 equipment modifications at a cost of \$36 million that had a combined pay-back period of 10.7 years (the pay-back periods for all but one project were less than 3 years), resulting in a 17% energy reduction. The article demonstrated the ability of low-capital-cost projects to improve efficiency and generate savings that could be used to fund higher-capital-cost projects and speculated that by building on previous projects, even more efficiency could be gained to provide additional savings.

The US government provides a social cost of carbon (SCC) estimate to allow agencies to incorporate the social benefits of reducing CO<sub>2</sub> emissions into a cost-benefit analysis of regulatory actions that impact cumulative global emissions (US Government, 2013). The SCC is an estimate of the monetized damages associated with incremental increases in carbon emissions in a given year. The 2013 US Government report provided 5-year SCC estimates for varying discount rates as presented in Table 8-2.

**Table 8-2 Social Cost of CO<sub>2</sub> per metric ton CO<sub>2</sub> in 2007 dollars**

<b>Estimated Social Cost per metric ton of CO<sub>2</sub> in 2007 Dollars by Discount Rate</b>				
<b>Year</b>	<b>5.0% Avg.</b>	<b>3.0% Avg.</b>	<b>2.5% Avg.</b>	<b>3.0% 95<sup>th</sup> a</b>
<b>2010</b>	11	33	52	90
<b>2015</b>	12	38	58	109
<b>2020</b>	12	43	65	129
<b>2025</b>	14	48	70	144

<sup>a</sup> This column estimates the SCC across all three models used in the study at a 3% discount rate. It is included to represent the higher-than-expected impacts from temperature change further out in the SCC distribution.

Table 8-3 estimates the projected 10% emissions reduction from the 2010 baseline year for the Washington State refineries. The Tesoro refinery was shut down for approximately 6 months during 2010 due to a unit fire; and the US Oil facility underwent a facility turnaround in 2010, shutting down for approximately 5 weeks. Therefore, Tesoro and US Oil will have to use a different baseline year. The reductions included in Table 7-3 for both of these refineries are from 2011, rather than 2010. The Shell facility produces electricity from the cogeneration plant. The Agencies propose that cogeneration be handled separately; thus, GHG from electricity production is excluded from the baseline year and calculation of the 10% reduction for Shell. Efficiency gains realized through reduced electric demand should be considered analogous to the other facilities.

**Table 8-3 Estimated CO<sub>2</sub> Emission Reductions from 2010 Baseline and Social Benefit Calculation**

<b>Facility</b>	<b>10% Reduction (mtons/yr CO<sub>2</sub>e)</b>	<b>Social Benefit Calculation (2013 dollars)<sup>a</sup></b>
<b>BP</b>	253,674	\$12,298,096
<b>Phillips 66</b>	88,073	\$ 4,269,774
<b>Shell</b>	157,833 <sup>b</sup>	\$ 7,651,758
<b>Tesoro</b>	116,467 <sup>c</sup>	\$ 5,646,296
<b>US Oil</b>	14,712 <sup>c</sup>	\$ 713,218
<b>Total</b>	630,758	\$30,579,143

<sup>a</sup> Using the 3.0% average SCC and applying published consumer price index rates (Sahr, 2013).

<sup>b</sup> The Shell reduction calculation excludes the emissions from electricity production at the cogeneration unit.

<sup>c</sup> Reduction from 2011 emissions.

The Agencies expect that the proposed benchmark compliance demonstration procedure using the Solomon EEI<sup>®</sup> score for those facilities already implementing energy efficiency measures will bring down the overall cost of this RACT regulation. For a facility to have an EEI<sup>®</sup> score that is in the top 50% of scores among its peers, the facility must institute

standards and procedures that maintain equipment efficiency and have already invested in basic capital projects that improve efficiency. However, those facilities that have achieved a score in the top 50% have a narrowing scope of efficiency improvement options available, and those projects are likely to require significant capital expenditure.

For facilities with scores in the lower 50% of EII<sup>®</sup> scores among their peers, there is a broad scope of potential actions that would result in efficiency improvements and associated GHG emissions reductions. These include procedural improvements that have a low capital cost, as well as basic equipment upgrades. The Agencies have determined that such approaches are generally on the level of RACT.

The Solomon benchmarking service can be costly. However, 90% of US refinery capacity already subscribe to the service and would thus incur no additional cost for monitoring and compliance demonstration.

## 8.8 Rejected RACT Components

The proposed RACT structure does not include the concept of the *de minimis* emissions threshold discussed earlier in Section 3. A threshold for emissions sources is not necessary for the proposed structure and would limit options for compliance with the proposed emission reductions. The Agencies believe that the refineries should have the ability to choose any GHG emission point in order to achieve reductions that meet the proposed goal of this rule.

Emissions decreases on the part of the power provider as a result of electrical equipment upgrades (because more efficient equipment draws less power) were rejected for use as credits towards the emission reduction goal. Power conservation and efficiency at power plants are addressed under existing programs administered by the power providers with separate incentives. All refineries can take advantage of energy efficiency experts within their respective power providers as well as efficiency tariff funds to help offset the costs of these types of projects.

Most refineries do a periodic (e.g., monthly or quarterly) in-house calculation to estimate the facility's energy intensity. The use of these calculations for RACT compliance was rejected, primarily because they do not involve an independent third party who can certify the consistency of the calculations. Furthermore, the calculations are highly complex, well beyond the resources available within the Agencies to ensure reliable results.

The energy assessment audit requirements of the Boiler MACT are not aligned with the presumptions of a RACT rule and thus were rejected because they do not impose a requirement or an emission limit that is measurable. The energy assessment for units subject to Boiler MACT is expected to identify projects that would also contribute towards compliance with the proposed RACT rule. Therefore, the two programs are not in conflict and provide mutual benefit with no additional costs.

The proposed RACT standard and implementation options provide facilities with the opportunity to meet the reduction goals in the most cost-effective way while taking into consideration the specific requirements of each facility's operation.

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## Section 10: Definitions and Acronyms

### 10.1 Definitions

The definitions for the terms below are consistent with those included in RCW 70.94.030 and WAC 173-400-030.

“Baseline GHG emissions” means facility-wide total emissions of GHGs during 2010 or 2011. The year of GHG emissions chosen shall not have facility-wide operations of less than 11 months.

“Carbon dioxide equivalent” or “CO<sub>2</sub> equivalent” or “CO<sub>2</sub>e” means a measure for comparing CO<sub>2</sub> with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential factor.

“Cogeneration” or “Cogen” means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve the onsite generation of electricity and useful thermal energy and some form of waste heat recovery.

“Emissions Efficiency Benchmark” or “GHG emissions efficiency benchmark” means a performance standard that is used to evaluate GHG emissions efficiency between and among similar facilities or operations in the same industrial sector.

“Energy efficiency improvement project” means an undertaking that involves such activities as, but not limited to, improvement in maintenance or other practices, monitoring systems, specific processes, or new or improved technologies in order to increase energy efficiency at a facility.

“Greenhouse gas” or “greenhouse gases” or “GHG” means CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, SF<sub>6</sub>, HFCs, and PFCs.

“Metric ton” or “MT” or “Metric tonne” means a common international measurement for the quantity of GHG emissions, equivalent to about 2,204.6 pounds or 1.1 short tons.

“Operational control” means the authority to introduce and implement operating, environmental, health, and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the Agency or Ecology is considered to have operational control for purpose of this regulation.

“Petroleum refinery” or “refinery” means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum or through the redistillation, cracking, rearrangement, or reforming of unfinished petroleum derivatives.

“Professional engineer” means a person who, by reason of his or her special knowledge of the mathematical and physical sciences and the principles and methods of engineering analysis and design, acquired by professional education and practical experience, is qualified to practice engineering as defined in this section, as attested by his or her current legal registration as a professional engineer in Washington State.

“Process” means an action or series of actions performed in progressive and interdependent steps by equipment within a facility to produce or aid in the production of a product, such as cement, fuel, electricity, hydrogen, or other chemicals.

“Solomon Energy Intensity Index<sup>®</sup>” or “Solomon EII<sup>®</sup>” or “EII<sup>®</sup>” means a petroleum refinery energy efficiency metric that compares actual energy consumption for a refinery with the “standard” energy consumption for a refinery of similar size and configuration. The

“standard” energy is calculated based on an analysis of worldwide refining capacity as contained in the database maintained by Solomon Associates. The ratio of a facility’s actual energy to the standard energy is multiplied by 100 to arrive at the Solomon EII® for a refinery. “Solomon Energy Review” means a data submittal and review conducted by a petroleum refinery and Solomon Associates. This process uses the refinery energy utilization, throughput, and output to determine the Solomon EII® of the refinery.

## 10.2 Acronyms

ANS – Alaska North Slope

ANSI – American National Standards Institute

API – American Petroleum Institute

BACT – best available control technology

BART – best available retrofit technology

bbl - barrel

BFW – boiler feed water

PB – BP PLC

Btu/hr – British thermal units per hour

C<sub>1</sub> – methane (see also CH<sub>4</sub>)

C<sub>3</sub> – propane

C<sub>4</sub> – butane

C<sub>5</sub> - pentane

C<sub>6</sub> – hexane

CARB – California Air Resources Board

CBI – confidential business information

CCS – carbon capture and sequestration

CFR – Code of Federal Regulations

CH<sub>4</sub> – methane (see also C<sub>1</sub>)

CHP – combined heat and power

CO – carbon monoxide

CO<sub>2</sub> – carbon dioxide

CO<sub>2</sub>e – carbon dioxide equivalent  
CR – catalytic reformer  
CTG – Control Technique Guideline  
CWT –CO<sub>2</sub>-weighted ton  
DOE – US Department of Energy  
EAB – Environmental Appeals Board  
Ecology – Washington Department of Ecology  
EIA – US Energy Information Administration  
EII<sup>®</sup> – Energy Intensity Index  
EnMS – energy management systems  
EOR – enhanced oil recovery  
EPI – Energy Performance Indicator  
EPA – US Environmental Protection Agency  
ESNCR – enhanced selective non-catalytic reduction  
EU – European Union  
FCCU – fluidized catalytic cracking unit  
FGS – flue gas scrubber  
GHG – greenhouse gas  
H<sub>2</sub>S – hydrogen sulfide  
HAP – hazardous air pollutant  
HFC – hydrofluorocarbon  
hr - hour  
HRSG – heat recovery steam generator  
H<sub>2</sub>S – hydrogen sulfide  
ICI – Industrial Commercial Institutional  
ICR – information collection request

ISO – International Organization for Standardization

ITP – Industrial Technologies Program

kWh – kilowatt hour

lbs/hr – pounds per hour

LDAR – leak detection and repair

LPG – liquified petroleum gas

MACT – maximum achievable control technology

MIT – Massachusetts Institute of Technology

MMBtu/hr – million British thermal units per hour

MMscfd – million standard cubic feet per day

mtons/yr – metric tons per year

MMT – million metric tons

NAAQS – National Ambient Air Quality Standards

NCI – Nelson Complexity Index

NESHAPs – National Emissions Standards for Hazardous Air Pollutants

NETL – National Energy Technology Laboratory

NO<sub>x</sub> – nitrogen oxide

NO<sub>2</sub> – nitrogen dioxide

N<sub>2</sub>O – nitrous oxide

NOC – Notice of Construction

NPDES – National Pollutant Discharge Elimination System

NSPS – New Source Performance Standards

NWCAA – Northwest Clean Air Agency

NWPCC – Northwest Power and Conservation Council

PADD – Petroleum Administration for Defense District

PFC - perfluorocarbon

Phillips – Phillips 66 Company

PM – particulate matter

PM<sub>10</sub> – particulate matter with an aerodynamic diameter less than or equal to a nominal 10 µm

PM<sub>2.5</sub> – Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 µm

PRV – pressure relief valve

PSA – pressure swing absorption

PSE – Puget Sound Energy

psig – pounds per square inch gauge

PSCAA – Puget Sound Clean Air Agency

PSD – Prevention of Significant Deterioration

PTE – potential to emit

PUD – public utility district

RACT – reasonably available control technology

RCW – Revised Code of Washington

SCC – social cost of carbon

SCOT – Shell Claus off-gas treating

SEPA – State Environmental Policy Act

SF<sub>6</sub> – sulfur hexafluoride

Shell – Shell Oil Company

SMR – steam-methane reforming

SIC – Standard Industrial Classification)

SIP – State Implementation Plan

SO<sub>2</sub> – sulfur dioxide

SRU – sulfur recovery unit

TAP – toxic air pollutant

tpd – tons per day

Tesoro – Tesoro Refining & Marketing Company

tpy – tons per year

USCAA – United States Federal Clean Air Act

US Oil – US Oil & Refining Company

VFD – variable frequency drive

VOC – volatile organic compound

WAC – Washington Administrative Code

WCAA – Washington State Clean Air Act

WWTP – wastewater treatment plant

DRAFT

## APPENDICIES



**Appendix A**

**Washington Refinery Boilers**

7/22/13 - GHG RACT Background

**Potential to Emit (PTE)**

(Calculated assuming full load for 8760 hours per year)

Boilers	Description	Capacity (MMBtu/hr)	Construction	Potential to Emit (PTE)				
				CO <sub>2</sub> (mntons)	Methane (mntons)	N <sub>2</sub> O (mntons)		
BP	UTILITY BOILER #4	80	1991	41,347	0.70	0.07	41,384	45,618
BP	UTILITY BOILER #5	363	2004	187,613	3.18	0.32	187,778	206,990
BP	UTILITY BOILER #6	363	2007	187,613	3.18	0.32	187,778	206,990
BP	UTILITY BOILER #7	363	2007	187,613	3.18	0.32	187,778	206,990
	<b>Totals</b>	<b>1169</b>		<b>604,186</b>	<b>10.24</b>	<b>1.02</b>	<b>604,718</b>	<b>666,588</b>
Phillips 66	#2 BOILER 22F-1A	91	1953	47,032	0.80	0.08	47,074	51,890
Phillips 66	#3 BOILER 22F-1B	108	1953	55,819	0.95	0.09	55,868	61,584
Phillips 66	#4 BOILER 22F-1E	164	2004	84,762	1.44	0.14	84,836	93,516
Phillips 66	#1 BOILER 22F-1C	162	1996	83,728	1.42	0.14	83,802	92,376
	<b>Totals</b>	<b>525</b>		<b>271,341</b>	<b>4.60</b>	<b>0.46</b>	<b>271,580</b>	<b>299,366</b>
Tesoro	F 751 MAIN BOILER	268	1954	138,513	2.35	0.23	138,635	152,819
Tesoro	F 752 MAIN BOILER	268	1954	138,513	2.35	0.23	138,635	152,819
Tesoro	F 753 MAIN BOILER	220	1994	113,705	1.93	0.19	113,805	125,449
	<b>Totals</b>	<b>756</b>		<b>390,731</b>	<b>6.62</b>	<b>0.66</b>	<b>391,075</b>	<b>431,087</b>
Shell	BOILER #1 ERIE CITY	390	1958	201,568	3.42	0.34	201,745	222,386
	<b>Totals</b>	<b>390</b>		<b>201,568</b>	<b>3.42</b>	<b>0.34</b>	<b>201,745</b>	<b>222,386</b>
US Oil	B-4 GAS/OIL	99	1981	51,167	0.87	0.09	51,212	56,452
US Oil	B-5 GAS	80	1985	41,347	0.70	0.07	41,384	45,618
	<b>Totals</b>	<b>179</b>		<b>92,514</b>	<b>1.57</b>	<b>0.16</b>	<b>92,596</b>	<b>102,070</b>
<b>Boilers: Grand Total</b>		<b>14</b>		<b>1,560,340</b>	<b>26</b>	<b>3</b>	<b>2,518,712</b>	<b>2,776,405</b>

Calculation Factors	
PTE Operation Rate:	8760 hours
CO <sub>2</sub> e multi	1 8760 hours
	21 310 kg/MMBtu
	59 1.00E-03 1.00E-04 *assumed natural gas CH4 and N2O factors
	2204 lb/mton
	2000 lb/ton
	1.102 ton/mton

Appendix B

Washington Refinery Heaters

7/23/13 - GHG RACT Background

Potential to Emit (PTE)

(Calculated assuming full load for 8760 hours per year)

Facility	Description	Capacity (MMBtu/hr)	Construction	CO <sub>2</sub> (mtons)	Methane (mtons)	N <sub>2</sub> O (mtons)	CO <sub>2</sub> e (mtons)	CO <sub>2</sub> e (tons)
BP	CRUDE HEATER	720	1970/1977	372,125	6.31	0.63	372,453	410,559
BP	IHT HEATER	13	2004	6,719	0.11	0.01	6,725	7,413
BP	NORTH VACUUM HEATER*	77	1983	39,797	0.67	0.07	39,832	43,907
BP	SOUTH VACUUM HEATER*	207	1970/2005	106,986	1.81	0.18	107,080	118,036
BP	#1 REFORMER HEATERS	1075	1975/2000/2007	555,603	9.42	0.94	556,093	612,987
BP	#2 REFORMER HEATERS	330	1987	170,557	2.89	0.29	170,708	188,173
BP	NAPHTHA HDS CHARGE HEATER	110	1970	56,852	0.96	0.10	56,903	62,724
BP	NAPHTHA HDS STRIPPER REBOILER	86	1970	44,448	0.75	0.08	44,487	49,039
BP	1st STAGE HCR FRACTIONATOR REBOILER	198	1970/1992/2011	102,334	1.73	0.17	102,425	112,904
BP	2nd STAGE HCR FRACTIONATOR REBOILER	183	1970/1974/2003	94,582	1.60	0.16	94,665	104,350
BP	R-1 HYDROCRACKER REACTOR HEATER	121	1970/2006	62,538	1.06	0.11	62,593	68,997
BP	R-4 HYDROCRACKER REACTOR HEATER	60	1970	31,010	0.53	0.05	31,038	34,213
BP	COKER CHARGE HEATER #1 NORTH	190	1970/1999	98,200	1.66	0.17	98,286	108,342
BP	COKER CHARGE HEATER #2 SOUTH	190	1970/1999	98,200	1.66	0.17	98,286	108,342
BP	DIESEL HDS CHARGE HEATER	48	1970/2006	24,808	0.42	0.04	24,830	27,371
BP	DIESEL HDS STAB REBOILER	56	1970/2006	28,943	0.49	0.05	28,969	31,932
BP	DIESEL HDS CHARGE HEATER #2	35	2006	18,089	0.31	0.03	18,105	19,958
BP	DIESEL HDS CHARGE HEATER #3	28	2012	14,472	0.25	0.02	14,484	15,966
BP	REFORMING FURNACE 1401 (N H2 PLANT)	325	1970	167,973	2.85	0.28	168,121	185,322
BP	REFORMING FURNACE 1402 (S H2 PLANT)	325	1970	167,973	2.85	0.28	168,121	185,322
BP	SMR FURNACE #2 H2 PLANT	496	2012	256,353	4.34	0.43	256,579	282,829
<b>Totals</b>				<b>21</b>	<b>4873</b>	<b>511,672</b>	<b>512,123</b>	<b>564,518</b>
Phillips 66	CRUDE HEATER 1F-1	191	1953/1979	98,716	1.67	0.17	98,803	108,912
Phillips 66	#2 CRUDE HEATER 1F-1A	91	1972	47,032	0.80	0.08	47,074	51,890
Phillips 66	TAR SEPARATOR HEATER 4F-2	189	1953	97,683	1.66	0.17	97,769	107,772
Phillips 66	ALKYLATION HEATER 17 F-1	106	1953	54,785	0.93	0.09	54,833	60,443
Phillips 66	#2 HDF HEATER 14F-1,-2	70	1953	36,179	0.61	0.06	36,211	39,915
Phillips 66	#3 PRETREATER HEATER 18F-1	41	1972	21,190	0.36	0.04	21,209	23,379
Phillips 66	#3 REFORMER HEATER 18F-21-24	188	1972	97,166	1.65	0.16	97,252	107,201
Phillips 66	#3 REGEN HEATER 18F-26	26	1972	13,438	0.23	0.02	13,450	14,826
Phillips 66	(S-ZORB) FEED HEATER 38F100	40	2003	20,674	0.35	0.04	20,692	22,809
Phillips 66	DIESEL HYDROTREATER HTR. 33F-1	48	1992/1995/2001	24,808	0.42	0.04	24,830	27,371
<b>Totals</b>				<b>10</b>	<b>990</b>	<b>511,672</b>	<b>512,123</b>	<b>564,518</b>

Appendix B (continued)

Facility	Description	Capacity (MMBtu/hr)	Construction	Methane			CO <sub>2</sub> e (tons)		
				CO <sub>2</sub> (mtons)	N <sub>2</sub> O (mtons)	CO <sub>2</sub> e (mtons)	CO <sub>2</sub> (mtons)	N <sub>2</sub> O (mtons)	CO <sub>2</sub> e (tons)
Tesoro	F 101 CRUDE HEATER-GAS/OIL*	120	1955	62,021	1.05	0.11	62,075	68,426	
Tesoro	F 102 CRUDE HEATER-GAS/OIL*	120	1955	62,021	1.05	0.11	62,075	68,426	
Tesoro	F 103 CRUDE HEATER-GAS/OIL*	132	1963	68,223	1.16	0.12	68,283	75,269	
Tesoro	F 104 CGS HEATER	60	1972/2007	31,010	0.53	0.05	31,038	34,213	
Tesoro	F 201 VACUUM FLASHER HEATER	96	1955	49,617	0.84	0.08	49,660	54,741	
Tesoro	F 301 CAT CRACKER FEED HEATER	128	1955	66,156	1.12	0.11	66,214	72,988	
Tesoro	F-303 CAT CRACKER START-UP HEATER (dischal	69	1955	35,662	0.60	0.06	35,693	39,345	
Tesoro	F 652 DHT HEATER	67	1961	34,628	0.59	0.06	34,659	38,205	
Tesoro	F 654 CFH HEATER	15	1961	7,753	0.13	0.01	7,759	8,553	
Tesoro	F 6600 NHT HEATER	65	1972	33,595	0.57	0.06	33,624	37,064	
Tesoro	F 6601 NHT HEATER	68	1972	35,145	0.60	0.06	35,176	38,775	
Tesoro	F 6602 BENSAT HEATER	68	1972/2011	35,145	0.60	0.06	35,176	38,775	
Tesoro	F 6650 CAT REFORMER HEATER	143	1972	73,908	1.25	0.13	73,973	81,542	
Tesoro	F 6651 CAT REFORMER HEATER	143	1972	73,908	1.25	0.13	73,973	81,542	
Tesoro	F 6652 CAT REFORMER HEATER	67	1972	34,628	0.59	0.06	34,659	38,205	
Tesoro	F 6653 CAT REFORMER HEATER	38	1972	19,640	0.33	0.03	19,657	21,668	
Tesoro	F 6654 CAT REFORMER HEATER	32	1972	16,539	0.28	0.03	16,553	18,247	
Tesoro	F 6655 CAT REFORMER HEATER	27	1972	13,955	0.24	0.02	13,967	15,396	
<b>Totals</b>		<b>18</b>	<b>1458</b>	<b>753,553</b>	<b>12.77</b>	<b>1.28</b>	<b>754,217</b>	<b>831,382</b>	
Shell	VPS GAS OIL HEATER 1A-F4	157	1958	81,144	1.38	0.14	81,215	89,525	
Shell	VPS CHARGE HEATER 1A-F5	203	1958	104,919	1.78	0.18	105,011	115,755	
Shell	VPS CHARGE HEATER 1A-F6	206	1958	106,469	1.80	0.18	106,563	117,465	
Shell	VPS VACUUM TOWER HEATER 1A-F8	98	2000	50,650	0.86	0.09	50,695	55,882	
Shell	DCU HEATER 15F-100	124	1983/1998	64,088	1.09	0.11	64,145	70,707	
Shell	CRU 2 CHARGE HEATER 10H-101	90	1976	46,516	0.79	0.08	46,557	51,320	
Shell	CRU 2 INTERHEATER 1 10H-102	70	1976	36,179	0.61	0.06	36,211	39,915	
Shell	CRU 2 INTERHEATER 2 10H-103	45	1976	23,258	0.39	0.04	23,278	25,660	
Shell	CRU 2 STABIL/SPLIT--REBOIL 10H-104	70	1976	36,179	0.61	0.06	36,211	39,915	
Shell	CRU 1 CRUDE CHARGE HEATER 6D-F2	85	1987	43,931	0.74	0.07	43,970	48,469	
Shell	CRU 1 INTERHEATER 1 6D-F3	35	1987	18,089	0.31	0.03	18,105	19,958	
Shell	CRU 1 INTERHEATER 2 6D-F4	16	1987	8,269	0.14	0.01	8,277	9,124	
Shell	HTU 2 REACT CHARGE HTR--11H-101	65	1976	33,595	0.57	0.06	33,624	37,064	
Shell	HTU 2 STRIPPER REBOILER 11H-102	190	1976/1998	98,200	1.66	0.17	98,286	108,342	
Shell	HTU 2 FRACTIONATOR REBOILER 11H-103	51	1976/1998	26,359	0.45	0.04	26,382	29,081	
Shell	HTU 3 REBOILER HEATER 60-F201	62	2003	32,044	0.54	0.05	32,072	35,354	
Shell	HTU 1 CHARGE HEATERS-7C-F4	120	1991	62,021	1.05	0.11	62,075	68,426	
Shell	HTU 1 FRACTIONAOR REBOILER 7C-F5	120	1991	62,021	1.05	0.11	62,075	68,426	
<b>Totals</b>		<b>18</b>	<b>1807</b>	<b>933,930</b>	<b>15.83</b>	<b>1.58</b>	<b>934,753</b>	<b>1,030,389</b>	

Appendix B (continued)

Facility	Description	Capacity (MMBtu/hr)	Construction	CO <sub>2</sub> (mtons)	Methane (mtons)	N <sub>2</sub> O (mtons)	CO <sub>2</sub> e (mtons)	CO <sub>2</sub> e (tons)
US Oil	H-3 LIGHT CRUDE HEATER	19	2005	9,820	0.17	0.02	9,829	10,834
US Oil	H-11 LCU HEATER	106	1995	54,785	0.93	0.09	54,833	60,443
US Oil	H-201 LCVU HEATER	31	1983	16,022	0.27	0.03	16,036	17,677
US Oil	H-202 LCVU HEATER	12	2006	6,202	0.11	0.01	6,208	6,843
US Oil	H-801 CRU-2 A/B/C HEATER	42	1980	21,707	0.37	0.04	21,726	23,949
US Oil	H-804	2	1980	1,034	0.02	0.00	1,035	1,140
US Oil	H-901 DHT HEATER	18	2010	9,303	0.16	0.02	9,311	10,264
US Oil	H-1101 NAPHTHA HDS HEATER	13	1989	6,719	0.11	0.01	6,725	7,413
US Oil	H-1102 CRU-1 HEATER	14	1989	7,236	0.12	0.01	7,242	7,983
US Oil	H-1103 CRU-1 HEATER	12	1989	6,202	0.11	0.01	6,208	6,843
US Oil	H-1104 CRU-1 HEATER	5	1989	2,584	0.04	0.00	2,586	2,851
US Oil	H-6	16	1988	8,269	0.14	0.01	8,277	9,124
<b>Totals</b>		<b>12</b>	<b>290</b>	<b>149,884</b>	<b>2.54</b>	<b>0.25</b>	<b>150,016</b>	<b>165,364</b>
<b>Grand Total</b>		<b>79</b>	<b>9,418</b>	<b>4,867,599</b>	<b>165</b>	<b>17</b>	<b>5,384,012</b>	<b>5,934,857</b>

\*Heaters operating as a team

Calculation Factors	8760 hours
PTE Operation Rate:	21 310 kg/MMBtu
CO <sub>2</sub> e multi	59 1.00E-03 1.00E-04 *assumed natural gas CH <sub>4</sub> and N <sub>2</sub> O factors
	2204 lb/mton
	2000 lb/ton
	1.102 ton/mton