

## **APPENDIX 3**

---

### Overview of Oil Refining Process



## APPENDIX 3

### OVERVIEW OF OIL REFINING PROCESS

---

This appendix provides a high-level, non-project specific description of the refining process as it generally occurs at the Chevron Richmond Refinery (Facility or Project site).

The refining process begins when *crude oils* or *externally sourced (purchased) gas oils* are delivered to the Facility as raw materials or feedstocks. These feedstocks are then refined in five main process steps:<sup>1</sup>

- *Distillation* occurs when crude oil is separated by “distilling” into various components, called “crude oil fractions;”
- *Treatment* occurs when crude oil fractions are “treated” to remove sulfur and other natural impurities;
- *Cracking* occurs when molecules in the heavier crude oil fractions are divided by *cracking* these larger molecules into smaller molecular forms that can become transportation petroleum products;
- *Reshaping* (also called “reforming”) occurs when these molecules are “shaped” to meet the specifications for various kinds of products (e.g., octane levels in gasoline); and
- *Blending* occurs in the final product production process, when multiple hydrocarbon fractions are blended to meet the specifications for particular products (e.g., higher octane versus lower octane gasolines). *Blending* occurs

---

<sup>1</sup> While these five major steps in the refining process are described as discrete steps, not all hydrocarbon molecules in the refining process go through each of these steps, and some of these refining process steps are actually repeated in later refining steps. For example, the first step in the process, *Distillation*, describes the process of applying heat to crude oil to separate it into “fractions,” or separate streams of hydrocarbon molecules that boil at different temperature ranges. The fractions are then piped on to different refinery processing steps to produce different products. While the major distillation process occurs as the first step in the refining process at the crude unit (described in the *Distillation* step below), smaller distillation units also operate at several later stages in the refinery process. For example, the hydrotreating process (described in the *Treatment* step below) results in some cracking (described in the *Cracking* step below), and the cracked hydrocarbon output then is run through a fractionator (a type of distillation unit) to again separate this output into fractions as needed for the next processing steps.

when different products are piped into tanks and typically does not involve mechanical mixing.

The refining process as a whole is depicted in Figure A3-1, *Facility Process Diagram*. A description of the feedstocks processed by the Facility is provided below, followed by a description of each of these major processes.

### 3.1 FEEDSTOCKS

Crude oil is the Facility's primary "feedstock," which is the raw material used to make refined petroleum products. A partially refined crude oil fraction called "gas oil" is also received by the Facility and is purchased from external sources (i.e., other refineries). Crude oil and gas oil are described below.

### 3.2 IMPORTANT CHARACTERISTICS OF CRUDE OIL

Crude oil is found deep beneath the earth's surface in natural underground reservoirs. Crude oil is believed to have been formed from a mixture of mud and very small plants and animals (algae and zooplankton) that lived in ancient seas and oceans millions of years ago. Crude oil was created from this mix through a combination of temperature, pressure, and time.

Crude oil is recovered primarily from oil extraction wells, and it is often temporarily stored near extraction areas before being transported (primarily by pipelines and ships) to refineries for processing. Unlike many other refineries in the United States, the Facility is not connected to crude oil supplies through pipelines. Instead, the Facility receives crude oil via tankers and barges that discharge at the Project site over the Long Wharf. Crude oil is stored in tanks at the Project site before being processed in the Facility.

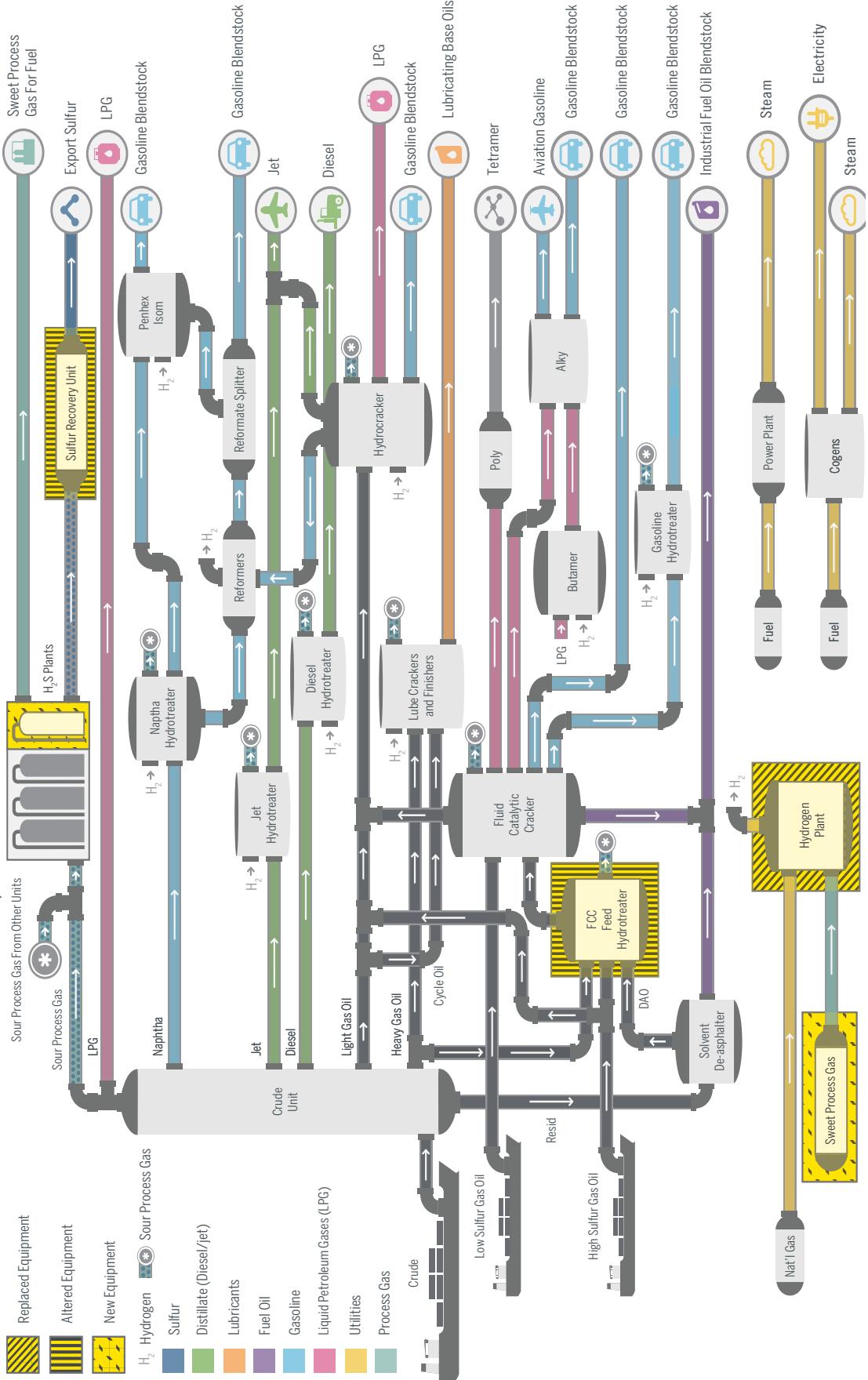
Crude oil is not a single chemical compound. Instead, crude oil is a mixture of different chemical compounds, the vast majority of which include a combination of hydrogen and carbon atoms, and are thus called "hydrocarbons." Other atoms, including nitrogen and sulfur atoms, can also be part of hydrocarbon molecules. Crude oil hydrocarbons may also contain small amounts of metals. Crude oil also typically includes small amounts of non-hydrocarbon contaminants, such as sediment, salt, and water.

The different hydrocarbon compounds in crude oil have different boiling points (the temperature at which liquids "boil"). Heating crude oil and condensing the heated vapors causes it to be physically separated into different streams of hydrocarbons (called "fractions") through a simple distillation process (described further below).

## What's Changing at the Chevron Refinery



The flow chart below illustrates the main process units and general process flow of the Chevron Richmond Refinery, highlighting what facilities and processes would either be built, replaced or altered in the Refinery Modernization Project. The vast majority of refinery functions will not be affected.



Source: Chevron (T39r2)

02.25.2014 P.111-005 CVRN PRODUCTS/DEIR Figures Appx. B: Refinery 101 A3-1\_FacilityProcessDiagram

Figure A3-1  
Chevron Refinery Modernization Project EIR  
Facility Process Diagram

One of the hydrocarbon fractions produced in the Facility's refining process is "gas oil," which is produced during the distillation process and various other processes. In addition to producing gas oil from crude oil feedstocks, Chevron imports surplus gas oil from other refineries. The Facility imports gas oil because it contains equipment that can refine more gas oil than what can be produced economically from its crude oil feedstock. In other words, the crude unit, the solvent de-asphalting unit (SDA unit, described below), and other process units that produce gas oil produce a smaller amount than later steps in the refinery processes can refine due to that equipment's greater capacity. Because a refinery's "efficiency" (also discussed in greater detail below) is directly linked to maximizing utilization of refinery equipment, Chevron imports purchased gas oil to efficiently utilize available Facility capacity.

### 3.2.1 Density or "Gravity" of Crude

"Density" is the amount of mass contained in a certain volume. The density of a crude oil is determined by the average weight (or "gravity") of its component molecules. "Heavy" crude oil is denser than "light" crude oil because the hydrocarbon molecules in heavy crude oil are larger and have more carbon atoms than those in light crude oil.<sup>2</sup> Atoms in a larger molecule are tightly bound together and take up less space than the same number of atoms spread out across multiple smaller molecules. Thus the atoms in heavy crude oil are more tightly packed together, taking up less space (volume) and making heavy crude oil denser than light crude oil.

Less dense (or "light") crudes generally have more light hydrocarbons, and light hydrocarbons are the constituents of higher-value refinery products such as gasoline, jet fuel, and diesel. Similarly, the denser ("heavier") crudes generally contain more of lower-value products like gas oil, tar, and bunker fuel commonly used in shipping.

When a refinery processes light crudes, higher-value products can be produced in fewer steps. For example, a light crude may only need to be "distilled" (the first step in the refinery process, described below) to produce large amounts of gasoline *blendstocks*. In contrast, a heavy crude may need to go through all of the refinery processes explained below (*Distillation, Treatment, Cracking*, and

---

<sup>2</sup> Heavy crude oil can also be denser than light crude oil because a higher proportion of the hydrocarbon molecules are in a denser form. (This characteristic is identified by the percentage of naphthenes in the crude.) Hydrocarbon molecules that are highly naphthenic can have molecules with the same number of carbon atoms, but those atoms are shaped like a circle rather than a straight chain. The circular structure is more dense than the straight chains.

*Reshaping*) to produce the same amount of gasoline or other light products. It should be noted that the *very* light hydrocarbons, at the other end of the gravity range, also have limited value. The ultimate light hydrocarbon is methane gas ( $\text{CH}_4$ ), which is the primary component of natural gas. It can be quite a bit less valuable than even crude oil because natural gas is generally widely available. Therefore, the price paid for a “condensate” (a very light combination of hydrocarbons), can be less than a crude oil with significant mid-range hydrocarbon molecules.

The density or gravity of crude oil is important to the refining process in several ways. As mentioned above, when the mixture of compounds in crude oil is heated, lighter hydrocarbon compounds will begin to vaporize (turn into gas), and heavier compounds will not. As the temperature within this initial crude processing step is increased, heavier hydrocarbons will begin to vaporize.<sup>3</sup> This physical characteristic of crude oil is key to the first step in the refining process: *Distillation*, in which crude oil (which has been desalted as described below) is heated in a furnace and sent to a large steel column to separate out the different hydrocarbons.

Different hydrocarbons boil at different temperature ranges and are grouped together in “fractions” based on these temperature ranges. The typical boiling temperatures of different fractions are shown in Figure A3-2, *Typical Boiling Temperatures (Cut Points) for Different Hydrocarbon Fractions*. Larger molecules contain more carbon atoms, are generally denser, and have a higher boiling point. Conversely, compounds with a lower carbon count are less dense and boil at a lower temperature.

For example, “gas oil” is the term used to describe the fraction of crude oil that is heavier than common refined products like gasoline, diesel, and kerosene or jet fuels—but lighter (less dense) than the heaviest fractions, which are called “residue” or “residuum.” Petroleum scientists devised a unique name for measuring the density, or weight, of a given hydrocarbon compound, called “American Petroleum Institute (API) gravity.” API gravity describes the density of a crude oil compared to the density of water. The lower the API gravity, the heavier the crude.<sup>4</sup> The API gravity can be used to categorize crude as “heavy, intermediate, or light” as discussed in Section 4.0.3 of the *Chapter 4, Introduction to Chapter and Methodology*. Definitions for “light” and “heavy” crude oils are based

---

<sup>3</sup> This is different from water—a single chemical compound of two hydrogen atoms and one oxygen atom, or  $\text{H}_2\text{O}$ —which would eventually all boil away into steam at the constant temperature of 212°F at normal pressures.

<sup>4</sup> For comparison, water has an API gravity of 10 degrees. Generally, hydrocarbons with an API gravity above 10 degrees are lighter than water and will float.

on their specific gravity<sup>5</sup> or API gravity.<sup>6</sup> The following are generally accepted definitions for the crude oil gravities (CEC, 2006):

- **Heavy Crude.** Crude oils with API gravity of 18 degrees or less are characterized as heavy. The oil is viscous and resistant to flow, and tends to have a lower proportion of volatile components.
- **Intermediate Crude.** Crude oils with an API greater than 18 and less than 36 degrees are referred to as intermediate.
- **Light Crude.** Crude oils with an API gravity of 36 degrees or greater are referred to as light. Light crude oil produces a higher percentage of lighter, higher-priced premium products.<sup>7</sup>

### 3.2.2 Sulfur Content in Crude Oil

Another important natural characteristic of crude oil is that different types of crude oil have differing amounts of sulfur content. Sulfur occurs naturally in crude oil, but sulfur content is restricted by federal and State air quality laws in refined products (e.g., there are standards limiting the amount of sulfur that can be present in refined products like gasoline). To meet these regulatory restrictions on sulfur content in refined products, sulfur is removed from the various fractions of crude oil during the refining process.

When an oil has less sulfur, it is referred to as being “sweet.” Crudes with more sulfur are referred to as being “sour.” Although there is no regulatory threshold of sulfur content for dividing sweet crude oils from sour crude oils, oils with less than 0.5% sulfur content are generally referred to as “sweet.”

Most sulfur present in crude oil is bonded within hydrocarbon molecules, although some is present as hydrogen sulfide ( $H_2S$ ) gas . This is different from “elemental” or pure sulfur (a yellow crystalline substance when at room temperature), which is a usable product. During the refining process, the sulfur atom is removed from the hydrocarbon molecule. This process is called

---

<sup>5</sup> The specific gravity equals the weight of the compound divided by weight of an equal volume of water.

<sup>6</sup> The API gravity, measured in degrees (°), is defined as equal to (141.5 divided by specific gravity)—131.5. As a result, the higher the API gravity, the lighter the compound. Note that water has an API gravity of 10°, so any hydrocarbon crude with an API gravity greater than 10° is less-dense (lighter) than water.

<sup>7</sup> These API breakpoint values are not applied universally. Other petroleum industry sources use varying breakpoints for heavy and light crude oils. The term “intermediate” is also used interchangeably with the term “medium” when referring to mid-range gravity crudes.

“hydrotreating” because it includes the use of hydrogen. The hydrocarbon fractions are combined with hydrogen in the presence of a catalyst and elevated temperatures and pressures. The catalyst, temperature, and pressure separate the sulfur from the hydrocarbon molecule and the sulfur combines with the available hydrogen to produce a gas called hydrogen sulfide ( $H_2S$ ). This hydrogen sulfide gas is then treated, as explained below, to create “elemental” sulfur, which is sold as a product by Chevron. The Modernization Project includes several components to allow Chevron to remove more sulfur from the Facility's feedstocks and thereby refine higher sulfur crude oil and gas oil in the future.

### 3.3 CUTTER AND BLENDSTOCKS

In addition to feedstocks imported by the Facility for processing into transportation fuels and base oils, the Facility imports a small amount of blendstocks to be used in making final products that leave the Facility. The Facility imports two main types of blendstocks, a fuel oil blendstock called “cutter” and light product blendstocks, both of which are imported over the Long Wharf. Once on-site, blendstocks are not processed by the Facility, but rather serve as one of the components when mixing other Facility-produced blendstocks into finished products.

Cutter is used by the Facility to lower the viscosity of fuel oil product. The Facility has several process units that create material that can be used as cutter (e.g., cycle oil) and the Facility can always produce sufficient quantities to meet the Facility's overall cutter demand. As a result, cutter import is unrelated to refinery utilization. Nevertheless, there are times, such as when another facility has a surplus of cutter, in which the Facility may import material from other facilities (including other Chevron facilities) to be used as cutter instead of using internal sources.

Similarly, light product blendstocks can be imported, dependent on market conditions, into the Facility to supplement the various blendstocks or products that are produced by the Facility process units. These blendstocks (e.g., iso-octane) are used in the blending of finished products such as gasoline, but again are not used as feed to the Facility process units.

### 3.4 OVERVIEW OF THE REFINING PROCESS

#### 3.4.1 Distillation: Separating the Fractions of Crude Oil with Heat

##### 3.4.1.1 Crude Oil is First Pre-Heated and Treated to Remove Contaminants

Before crude oil goes through the first major step of the refining process, *Distillation*, it is preheated and treated to remove contaminants. First, the crude oil is delivered on ships, pumped into holding tanks, and then pumped from those tanks to the crude unit. En route, the crude oil is heated in a series of “heat

exchangers,” where heat from steam or already-heated product is transferred to the incoming cooler crude oil feedstock. (See below for a description of heat exchangers.)

Crude oil typically contains a small percentage of water and salts dissolved in the water. Because the salts are considered contaminants, after the pre-heating process the heated crude oil is next sent to a “desalter,” where these contaminants are removed. This protects the downstream equipment from potential plugging and corrosion mechanisms that can be associated with salts in crude oils.

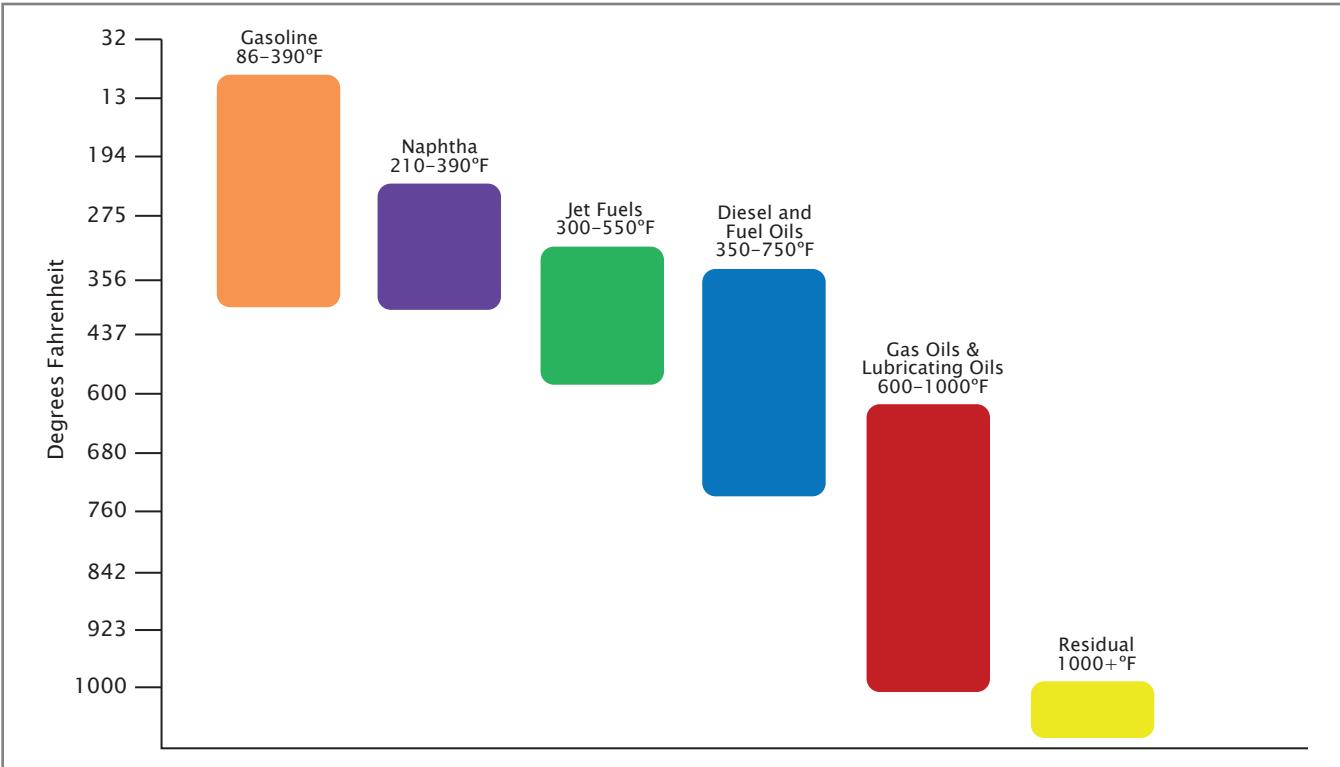
A desalter is a large cylindrical vessel laid horizontally. The desalter removes contaminants from crude oil by first emulsifying (mixing together) the crude oil with wash water to promote thorough contact of the water and oil. The salts dissolve in this water phase. After the oil has been washed and mixed as an emulsion of oil and water, electrostatic fields are used to break the emulsion, separating the crude oil and water again (Johnson, 2014). The mixture of contaminants and water that has been separated from the crude oil is pumped into a wastewater treatment plant as described below.

Next, the crude oil is further pre-heated in heat exchangers and charged to a pre-flash tower. Light ends are flashed off (rapidly heated), and bypass the furnace. By pre-heating the feedstock and flashing off light ends, the process unit furnaces do not have to work as hard to heat the feedstock, saving energy. The remaining crude oil passes through a furnace where it is heated to a temperature of approximately 700°F. At this temperature, typically about half of the crude oil changes from liquid to vapor (see *Figure A3-3, Flow Diagram from Wharf to Crude Unit*). This combination of liquid and vapor is then ready for *Distillation*, the first major step in the refining process, described below.

#### 3.4.1.2 The Primary Distillation Process Occurs in the Crude Unit

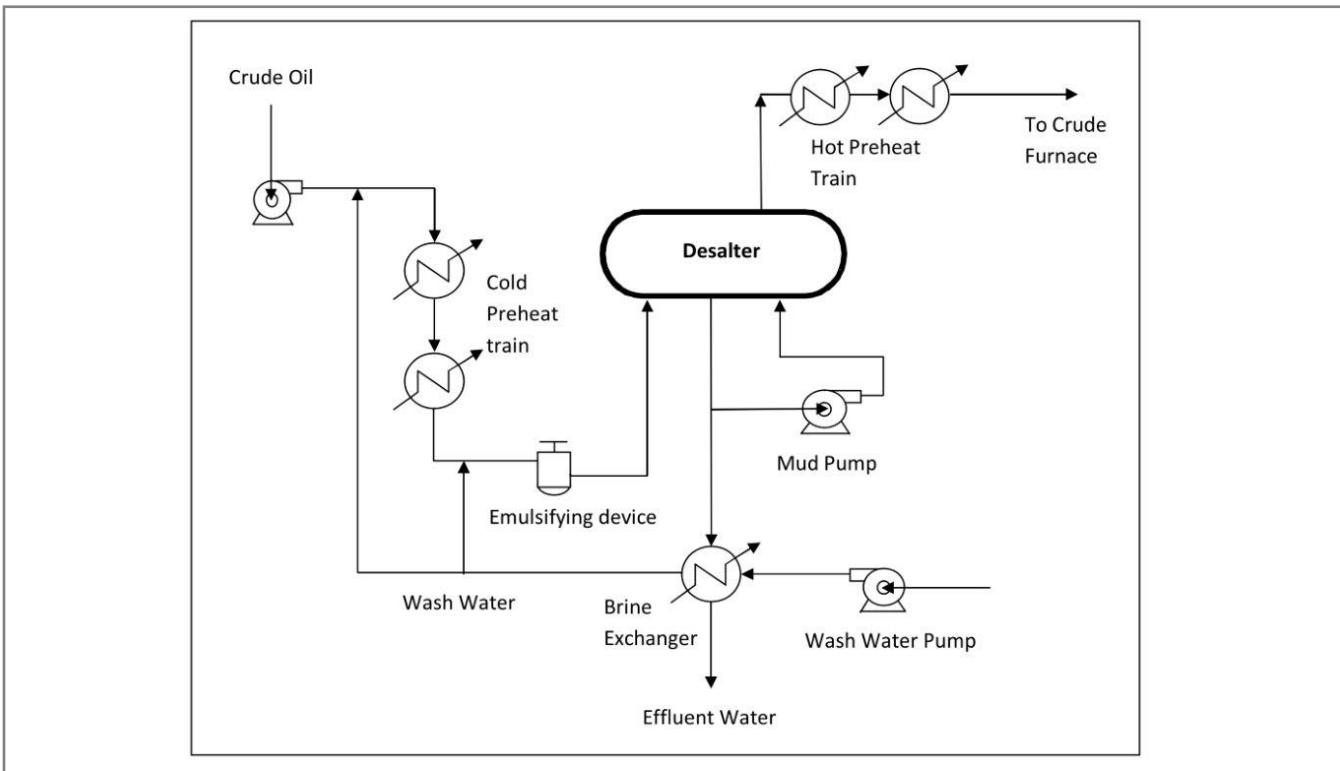
*Distillation* is the process of using heat to separate crude oil into different hydrocarbon streams by boiling point (called “cut points”). These separated “fractions” of crude oil are sent on to different parts of the Facility for further processing. Crude oil *distillation* occurs in the Facility’s crude unit. The lighter compounds such as butane, gasoline, jet fuel, and diesel “boil off” (vaporize) at lower temperatures, and as the temperature increases, the heavier compounds such as gas oil vaporize last. The material that does not vaporize is referred to as “residuum.”

A typical distillation schematic in Figure A3-4, *Distillation Schematic*, shows the separation of crude oil into fractions, from lighter at the top to heavier at the bottom. Figure A3-5, *Distillation Curve*, provides a typical distillation curve,



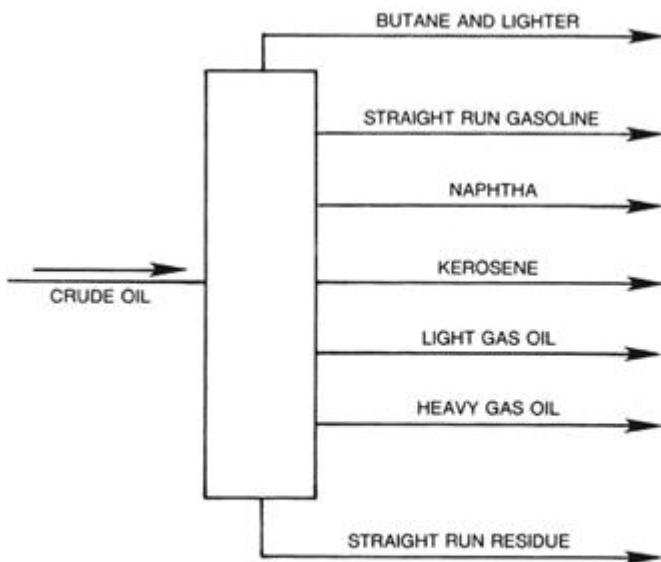
02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B\_Refinery 101\Draft\CVRN Figure A3-2 & A3-3.pdf  
Source: Turner, Mason & Company, 2011

**Figure A3-2**  
**Chevron Refinery Modernization Project EIR**  
**Typical Boiling Temperatures (Cut Points) for Different Hydrocarbon Fractions**



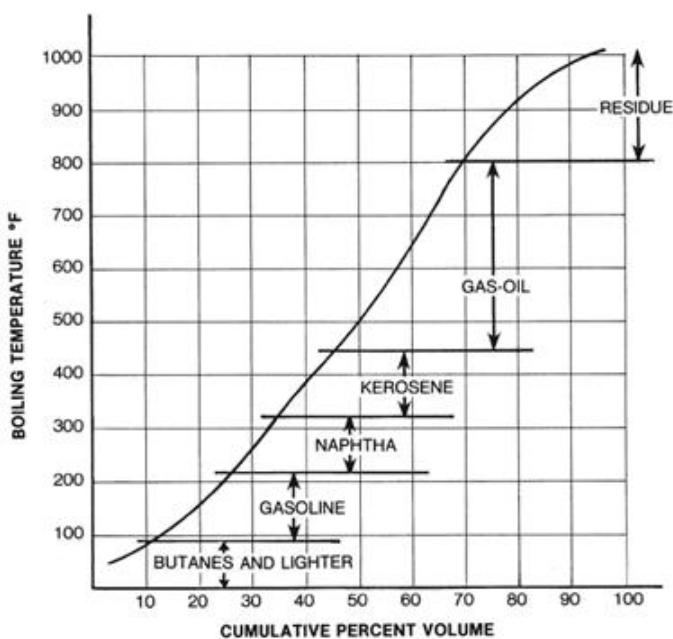
02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B\_Refinery 101\Draft\CVRN Figure A3-2 & A3-3.pdf  
Source: Enggyclopedia, 2014

**Figure A3-3**  
**Chevron Refinery Modernization Project EIR**  
**Typical Flow Diagram from Wharf to Crude Unit (Including Desalter, Heat Exchangers, Pipes)**



02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B\_Refinery 101\Draft\CVRN Figure A3-4 & 5.pdf  
 Source: Petroleum Refining in Nontechnical Language, 2008

**Figure A3-4**  
**Chevron Refinery Modernization Project EIR**  
**Distillation Schematic**



02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B\_Refinery 101\Draft\CVRN Figure A3-4 & 5.pdf  
 Source: Petroleum Refining in Nontechnical Language, 2008

**Figure A3-5**  
**Chevron Refinery Modernization Project EIR**  
**Distillation Curve**

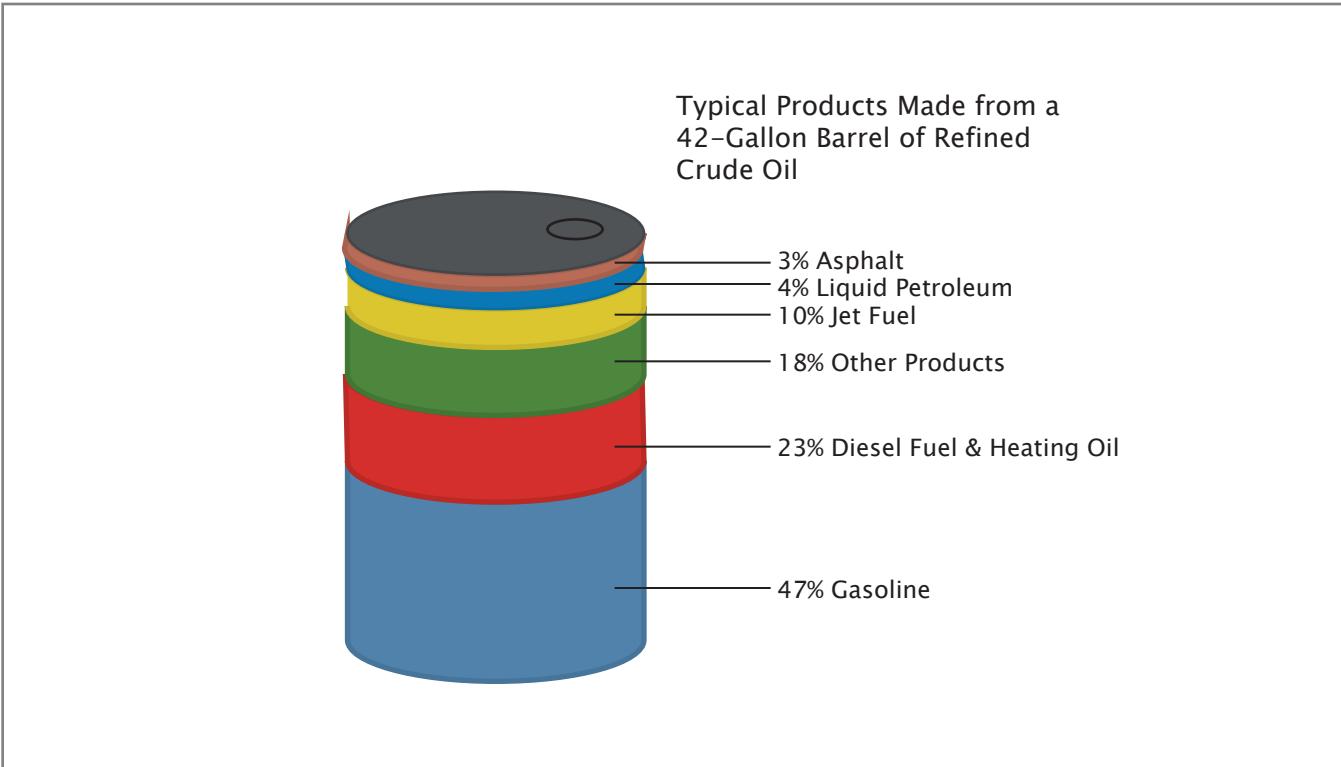
showing volume and boiling temperatures (or “cut points”) for the various fractions of crude oil.

Crude oil fractions in the higher boiling point range require more complex equipment to process into transportation fuels and base oils that are in highest demand in the market. Crude oil fractions with lower boiling points still require further processing to meet finished product specifications, but typically require less complex refining. Figure A3-6, *Breakdown of a Typical Crude Oil Distillation Yield*, shows a typical breakdown of the composition of a barrel of crude oil according to the United States Energy Information Administration (EIA). Although this distillation process separates significant quantities of the lower boiling point fractions such as gasoline, by further refining the higher boiling point fractions, such as gas oils, more of the crude oil can be converted to desirable transportation fuels and base oils.

The crude unit is comprised of several pieces of equipment, as depicted in Figure A3-7, *Crude Unit Overview*, each of which is discussed below. The first distillation column in the crude unit at the Facility is the “atmospheric distillation column,” which is named “atmospheric” because the pressure in the unit is similar to the outside atmosphere. It operates on the physical principle of temperature to separate different hydrocarbon fractions and send them to different parts of the Facility for further processing. This is possible because, as discussed above, the different groups of hydrocarbon compounds or “fractions” found in crude oil have different boiling points.

Within the column, the vaporized hydrocarbons rise and the liquid hydrocarbons fall in a column consisting of perforated trays located at 24- to 30-inch intervals. The vapors rise through the perforations in the trays and bubble up through the liquids. As the vapors bubble up through the trays of liquid, some of the heavier (denser) hydrocarbons in the vapor condense (turn back into liquid) and collect on the trays. At several levels on the column, there are “side cuts” that drain liquid forms of hydrocarbons – with lighter products drawn off from the upper parts of the column and heavier liquids drawn from the trays closer to the bottom. Figure A3-8 below, *Distillation Column: Crude Oil Separation by Heat into Fractions* shows a typical separation of crude oil into these fractions, along with general boiling points of these fractions. Each fraction is then sent to different areas of the Facility for further processing.

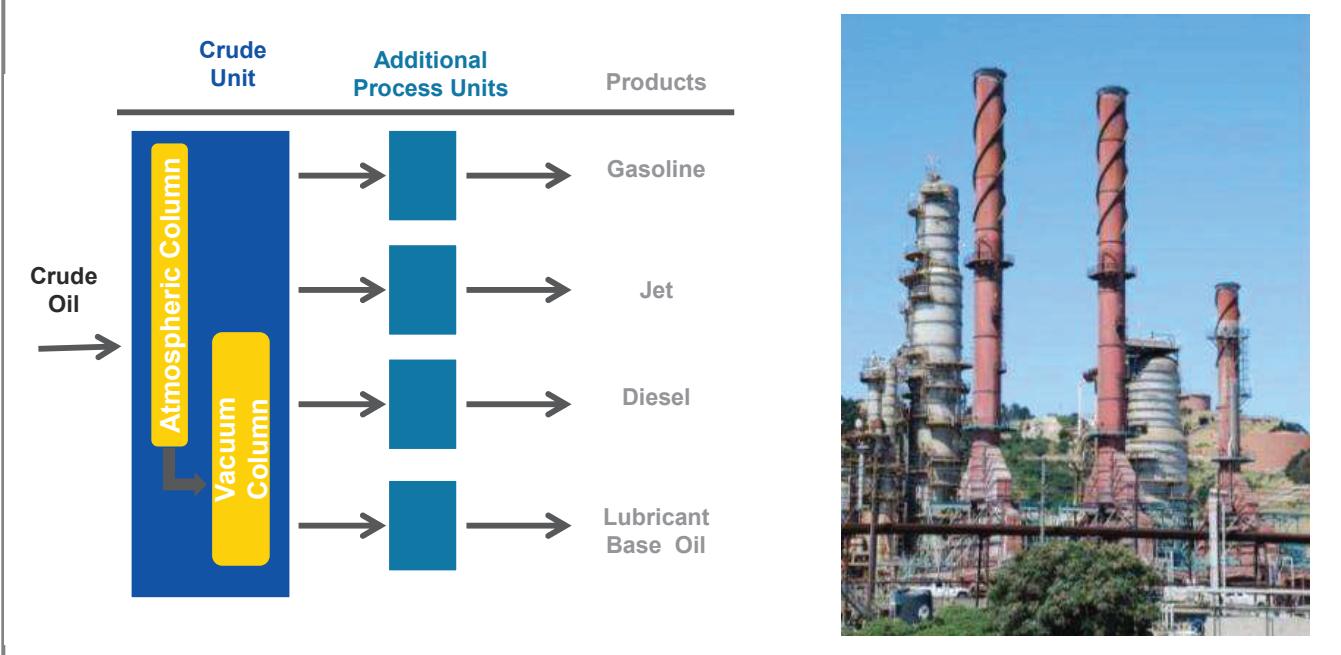
As shown in the distillation curve in Figure A3-5 above, not all of the hydrocarbon fractions would have vaporized even at the highest temperatures reached in the atmospheric distillation column.



02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx\_B\_Refinery 101\Draft  
Source: U.S. Department of Energy, 2014

Figure A3-6  
Chevron Refinery Modernization Project EIR  
Breakdown of a Typical Crude Oil Distillation Yield

## Crude Unit Overview



02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx\_B\_Refinery 101\Draft  
Source: Chevron, 2012

Figure A3-7  
Chevron Refinery Modernization Project EIR  
Distillation Column: Crude Oil Separation by Heat into Fractions

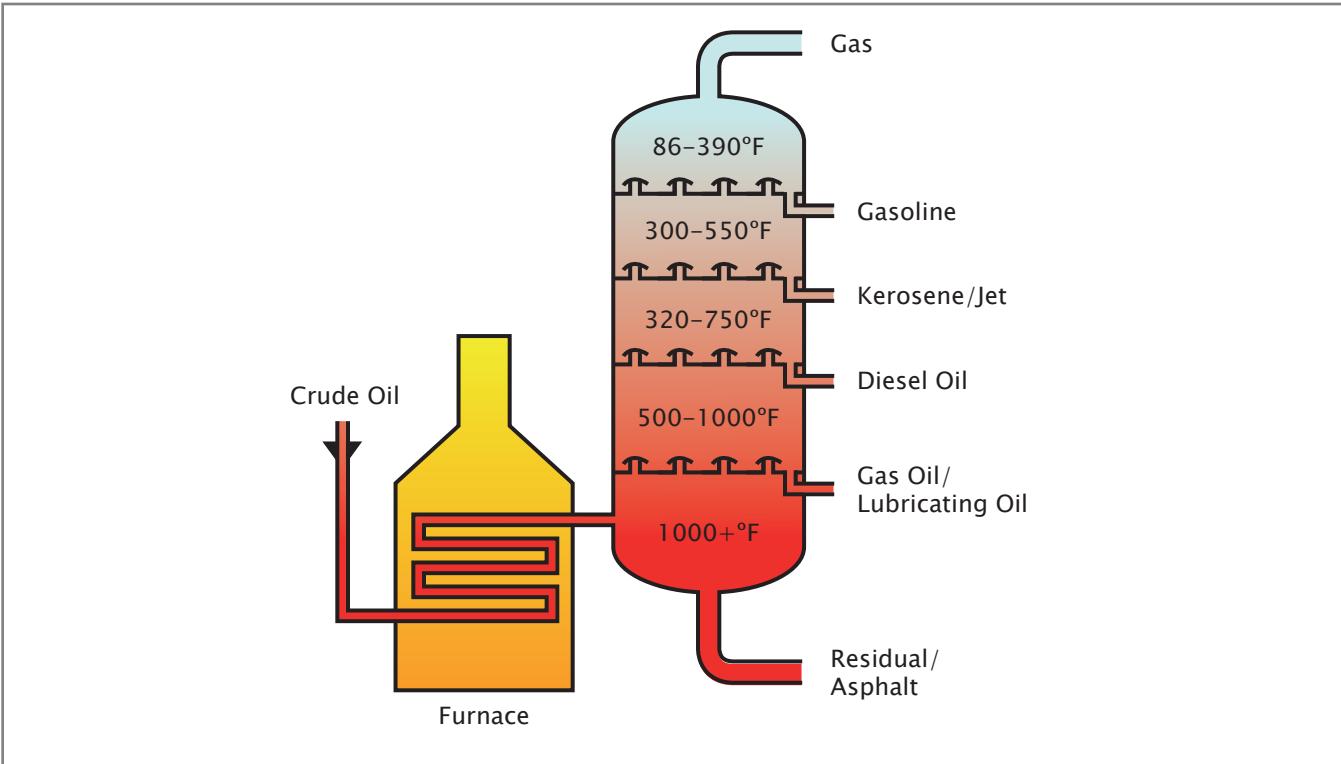
A different process, called “vacuum distillation,” is used to help distill these heavier fractions by creating a vacuum condition, which is a pressure below atmospheric pressure. This decreased pressure allows the heavier fractions to boil at lower temperatures (just like water boils at a lower temperature in “thin air” that can be found at high mountain elevations) and be converted to vapor and separated.

At the Facility, this vacuum distillation process for separating the heaviest crude fractions is handled at a second distillation column, called the vacuum distillation column (see Figure A3-9, *Vacuum Distillation Process*), which is also part of the crude unit. The vacuum column construction is slightly different from the atmospheric column to minimize pressure loss in the column. The column includes several sections filled with “packing” material, sheets of metal or ceramic rings to allow the gas and liquid in the column to contact each other. There are trays in the column where light and heavy vacuum gas oil are drawn off. The bottoms from the column are residuum and are fed to the SDA unit (described below) to further separate the gas oil from the residuum.

The heaviest fraction from the vacuum distillation column, the residuum, goes through one more *separation* step before moving on to other processes. To remove the remaining gas oil from the residuum, the Facility uses an SDA unit. The SDA unit uses solvent to chemically dissolve the remaining gas oil molecules in the residuum. The gas oil and solvent mixture is sent to a column that operates at lower pressure. At the lower pressure, the gas oil separates from the solvent. The solvent is reused and the gas oil molecules are sent for further processing in the Facility's fluid catalytic cracker feed hydrotreater (FCC FHT) and fluid catalytic cracker unit (described below). The portion that is not absorbed by the solvent leaves the SDA unit as heavy residuum and leaves the Facility as a fuel oil blendstock product. The solvent is recycled back to the SDA process, where it is reused.

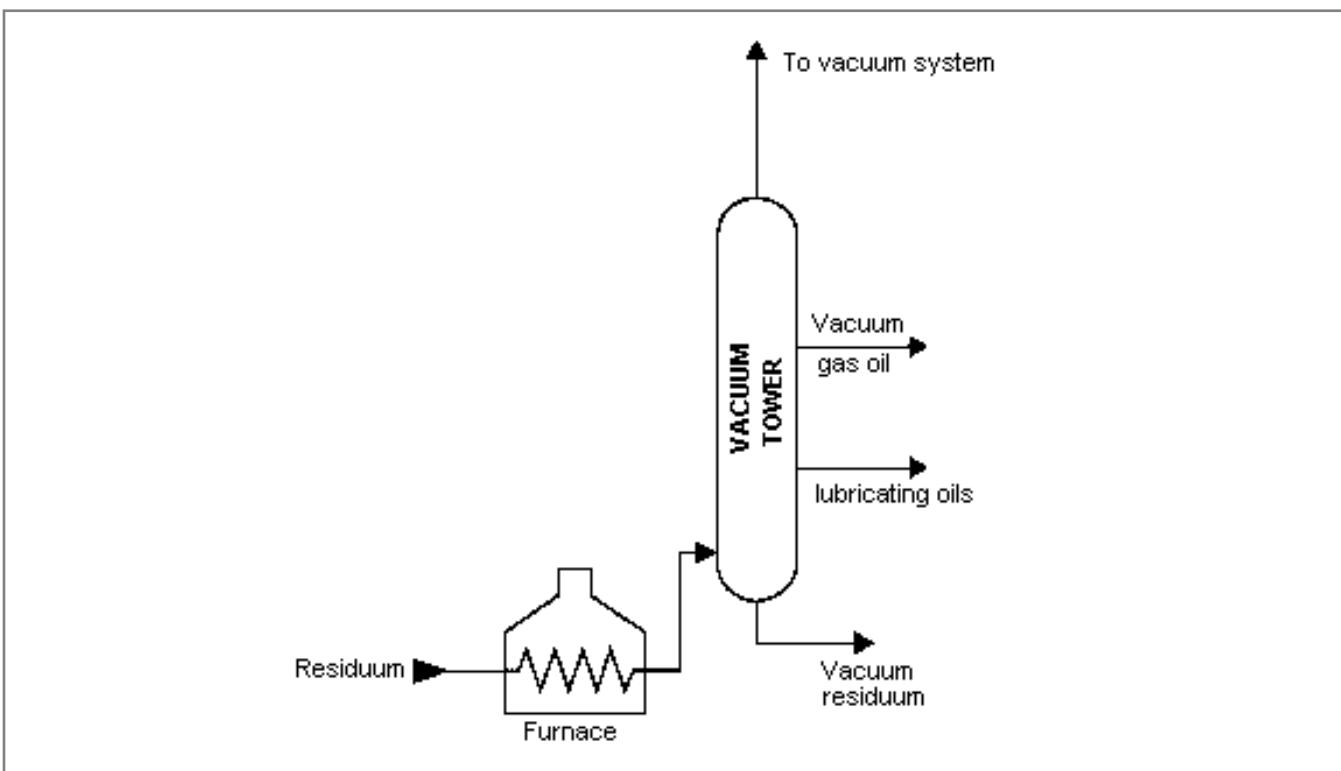
### **3.4.2 Treatment: Removing Sulfur and Other Natural Impurities**

Hydrocarbons separated in the crude unit distillation process and SDA unit contain naturally occurring sulfur and other natural impurities such as nitrogen and metals. One of the key later steps in the refinery process involves chemical reaction processes that include a “catalyst” – a material that promotes or speeds up chemical reactions to produce either a finished product or another interim material to be processed further, such as in the *Cracking* step. These impurities can interfere with the *cracking* processes. In addition, they also reduce the quality and performance of finished transportation products and without sufficient removal may not comply with finished fuel regulatory standards such as Ultra Low Sulfur Diesel and California's stringent “clean fuel” gasoline standards.



02.25.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx\_B\_Refinery 101\Draft  
Source: Turner, Mason & Company, 2011

**Figure A3-8**  
Chevron Refinery Modernization Project EIR  
Distillation Column: Crude Oil Separation by Heat into Fractions



03.04.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx\_B\_Refinery 101\Draft  
Source: Set Laboratories, Inc., 2014

**Figure A3-9**  
Chevron Refinery Modernization Project EIR  
Vacuum Distillation Process

The purpose of the *Treatment* step is to largely remove non-hydrocarbon components like sulfur, metals, and nitrogen. *Treatment* primarily occurs when the separated hydrocarbon fractions are sent to “hydrotreaters.” The Facility currently operates five hydrotreaters. Each hydrotreater processes different fractions of the crude oil. The diesel hydrotreater (DHT) treats diesel from the crude unit, the jet hydrotreater (JHT) treats jet fuel from the crude unit, and the gasoline hydrotreater (GHT) treats a gasoline product from the fluid catalytic cracker unit, a unit described in *Section 3.4.8* below. These three hydrotreaters—the GHT, DHT, and JHT—are “finishing” units that produce material used in fuel blending for finished products (see *Section 3.4.12* below).

The other two hydrotreaters, the naphtha hydrotreater and the fluid catalytic cracker feed hydrotreater (FCC FHT), primarily function as pre-treaters for petroleum fractions to be used as feeds to other units at the Facility for further processing before turning into finished products. The naphtha hydrotreater treats naphtha, a lighter-end fraction of crude oil distilled and routed from the crude unit to the naphtha hydrotreater. The FCC FHT treats gas oil from the crude unit and gas oil that is purchased from other refineries. The FCC FHT is labeled “FCC feed hydrotreater” because the gas oil it treats is primarily fed into the next unit in the process, called the fluid catalytic cracker, or FCC unit, which is involved in another step in the process, described below in *Section 3.4.8*. See hydrotreaters labeled in Figure A3-1, *Facility Process Diagram*.

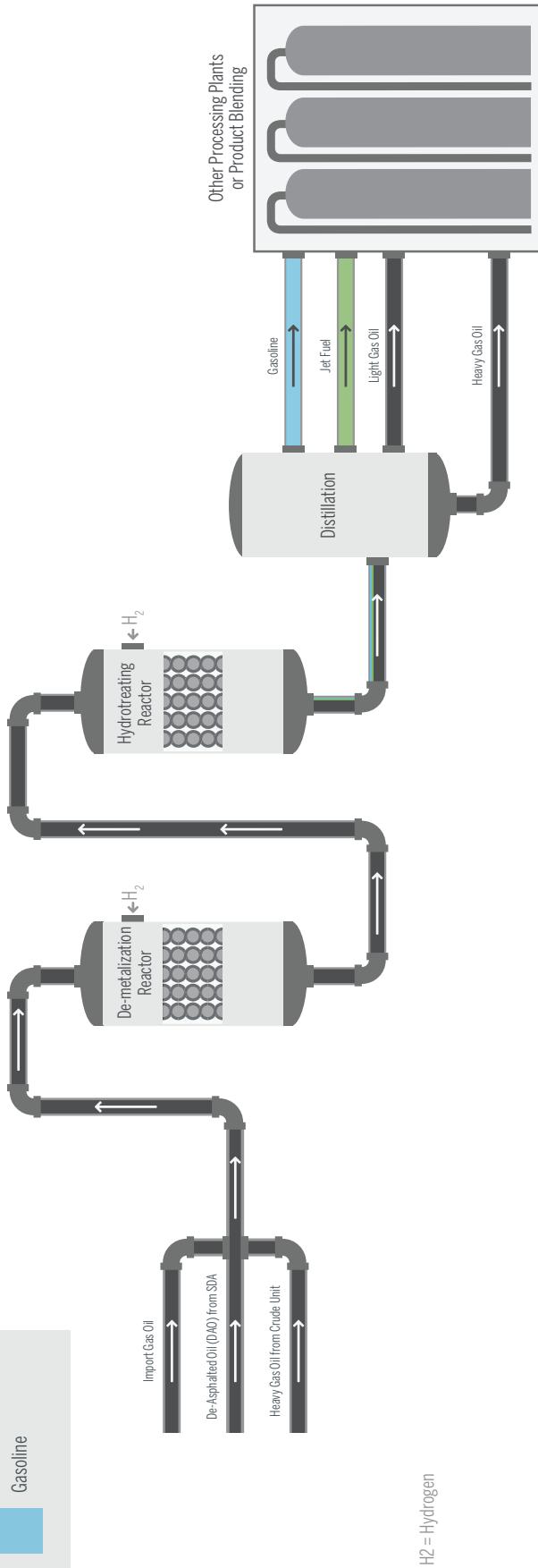
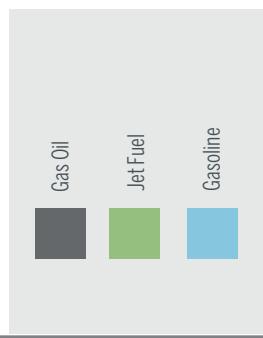
### **3.4.3 Hydrotreating Removes Sulfur by Reacting Sulfur with Hydrogen to Create Hydrogen Sulfide**

In the hydrotreating process, a hydrocarbon stream is fed through a furnace and the hot hydrocarbon and hydrogen gas are charged to a pressurized reactor that contains a catalyst, usually in a pellet form. The combination of catalyst, temperature, pressure, time, and hydrogen causes a chemical reaction in which the sulfur atoms on the hydrocarbon molecule are removed and hydrogen replaces them on the hydrocarbon molecule. The sulfur reacts with the free hydrogen to produce H<sub>2</sub>S.

The hydrotreating process requires an excess amount of hydrogen to be present to ensure the greatest removal of the sulfur and nitrogen. Rather than allow the valuable excess hydrogen to be sent to the fuel gas system and burned as a refinery fuel, the excess hydrogen gas from the hydrotreaters is removed in a hydrogen separator and recycled to the process. The output from the reactor is charged to a fractionator to remove the light ends (which now include a combination of usable hydrocarbons, hydrogen, and H<sub>2</sub>S). The hydrotreating process is depicted in Figure A3-10, *FCC Feed Hydrotreating Process*.

## The FCC Feed Hydrotreating Process

The FCC Feed Hydrotreater (FCC FHT) is designed to remove metals as well as denitrify and desulfurize gas oils prior to being processed by the FCC unit. Some incidental "cracking" occurs during the hydrotreating process, creating a relatively small amount of lighter products such as gasoline blendstocks and jet fuel.



Source: Chevron (T39r2)

03-04-2014 P:111-005 CVRN PRODUCTS\DEIR\Figures\Apdx 3\_Refinery 101\Draft

Figure A3-10  
Chevron Refinery Modernization Project EIR  
FCC Feed Hydrotreating Process

As shown in the hydrotreating figure, the hydrotreating process relies on hydrogen. As discussed further below, hydrogen comes from four sources at the Facility. It is manufactured at the existing hydrogen plant, it is produced at the reformers, it is recycled when the unreacted hydrogen is recovered from the hydrotreating processes in the Facility, and it is also recovered from process gas through pressure swing adsorption (PSA).

The hydrotreating process occurring in the FCC FHT processing unit also results in some minor incidental cracking, where a catalytic reaction in the presence of hydrogen breaks heavier, longer chain hydrocarbons into lighter, shorter chains like gasoline and jet fuel (“light ends”). This hydrocracking (breaking longer hydrocarbon molecules into smaller ones in the presence of catalyst, temperature, pressure, and hydrogen) is a byproduct of the hydrotreating process. This same cracking phenomenon occurs in all of the hydrotreaters but is less pronounced in the lower pressure hydrotreaters including the NHT, GHT, JHT, and DHT. This “cracking” process is explained further in the next section, since *Cracking* is another major step in the refining process.

### 3.4.4 Hydrotreating Removes Nitrogen by Creating Ammonia

Similarly, nitrogen atoms on the hydrocarbon molecules are replaced by hydrogen in a chemical reaction, and the nitrogen reacts with free hydrogen to produce ammonia ( $\text{NH}_3$ ).

Hydrocarbon outputs from the various units are frequently steam-stripped (i.e., contacted with steam) or water-washed (contacted with water). The condensed water from steam injected into the processes and water from the water washing process absorb ammonia and some  $\text{H}_2\text{S}$  that were produced in the various units. This water/ammonia/ $\text{H}_2\text{S}$  mixture is charged to a vessel and some of the water is boiled off, yielding concentrated “sour water.” The ammonia and  $\text{H}_2\text{S}$  in the concentrated sour water are removed in sour water strippers that heat the sour water and separate the  $\text{H}_2\text{S}$  and ammonia from the water. The water from the sour water stripper is reused or sent to the water treatment facility. The  $\text{H}_2\text{S}$  stream is sent to the sulfur recovery unit. The ammonia is captured and stored for sale or used in the Facility.<sup>8</sup>

---

<sup>8</sup> Ammonia can be used for removing NOx from furnace stacks in a process called selective catalytic reduction, among other applications..

### 3.4.5 Amine Treatment Units Remove the Hydrogen Sulfide from Usable Hydrocarbons

As noted above, the *Treatment* step in the refining process also creates byproducts including H<sub>2</sub>S that must also be managed. At the Facility, the H<sub>2</sub>S gas created by the hydrotreaters is routed to a unit called an “H<sub>2</sub>S absorber,” which contains a solvent—diethanolamine (DEA)—designed to absorb the H<sub>2</sub>S molecules and separate them from hydrogen and hydrocarbon gas streams. DEA liquid is mixed with the hydrogen sulfide rich gas in the H<sub>2</sub>S absorber.

The H<sub>2</sub>S absorber produces a liquid consisting of a mixture of H<sub>2</sub>S and DEA, which is then piped to an “amine regenerator.” The amine regenerator is a vessel where a lower pressure plus heat added by a steam reboiler “flashes” off the H<sub>2</sub>S. In the amine regenerator, the H<sub>2</sub>S is stripped from the DEA. The DEA is recycled to be used again, and the H<sub>2</sub>S gas (no longer containing hydrogen, hydrocarbons, or DEA) is then sent to a sulfur recovery unit, as described below (see Figure A3-11, *Amine Treatment Process*).

### 3.4.6 Sulfur Recovery Units Convert Hydrogen Sulfide H<sub>2</sub>S Gas into Usable Elemental Sulfur

The separated H<sub>2</sub>S stream is sent from the amine regenerator to one of three sulfur recovery units, where it is turned into elemental sulfur, using a process known as the “claus process” as depicted in Figure A3-12, *Sulfur Recovery Process*, below. Some H<sub>2</sub>S is burned or oxidized in a furnace, creating sulfur dioxide (SO<sub>2</sub>) from the H<sub>2</sub>S ( $H_2S + \frac{1}{2}O_2 = SO_2 + H_2O$ ). The SO<sub>2</sub> produced further reacts with the unreacted H<sub>2</sub>S to produce elemental sulfur ( $H_2S + \frac{1}{2}SO_2 = \frac{1}{2}S + H_2O$ ). The second step, which produces the elemental sulfur, occurs partially in the reactor furnace and partially in the catalytic reactors. The gases that exit the reactor furnace are routed to a heat exchanger where the elemental sulfur produced in the burner/furnace is condensed and sent to storage. The heat exchanger produces steam for use in the Facility. The gases from the heat exchanger are sent to a vessel that contains a catalyst to continue the conversion of the H<sub>2</sub>S to elemental sulfur. The process at the Facility has two conversion stages to produce the majority of the elemental sulfur. The process gas that still contains unconverted H<sub>2</sub>S is routed to the equipment called the Wellman-Lord tail gas recovery units, where remaining H<sub>2</sub>S is oxidized to SO<sub>2</sub> and returned to the catalytic reactors for further conversion to elemental sulfur. The elemental sulfur that is produced is stored in a tank in a liquid form. It is shipped out of the Facility as a salable product in liquid form by truck.

## Amine Treatment Process

An amine solution treats process gases containing hydrogen sulfide (sour gases) generated in the Facility's processing units. The treated gas is used within the Facility as a fuel source and the removed hydrogen sulfide is further treated into an elemental sulfur product.

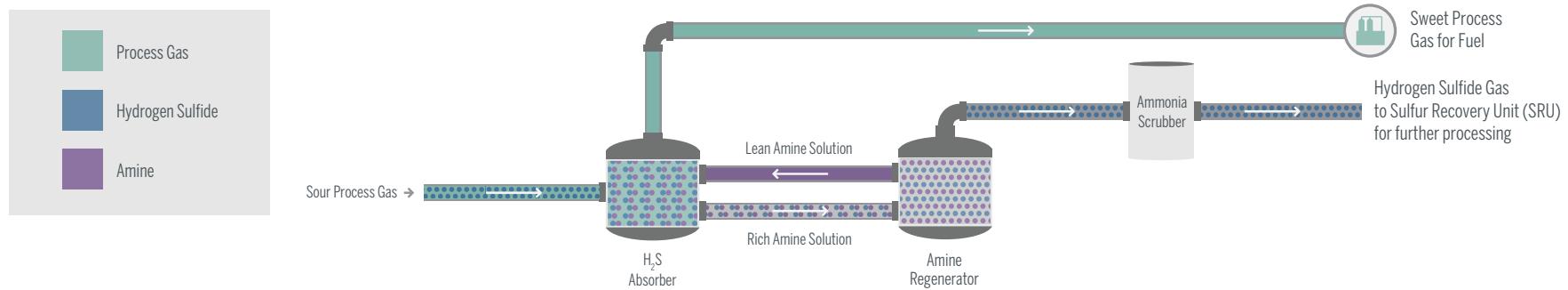
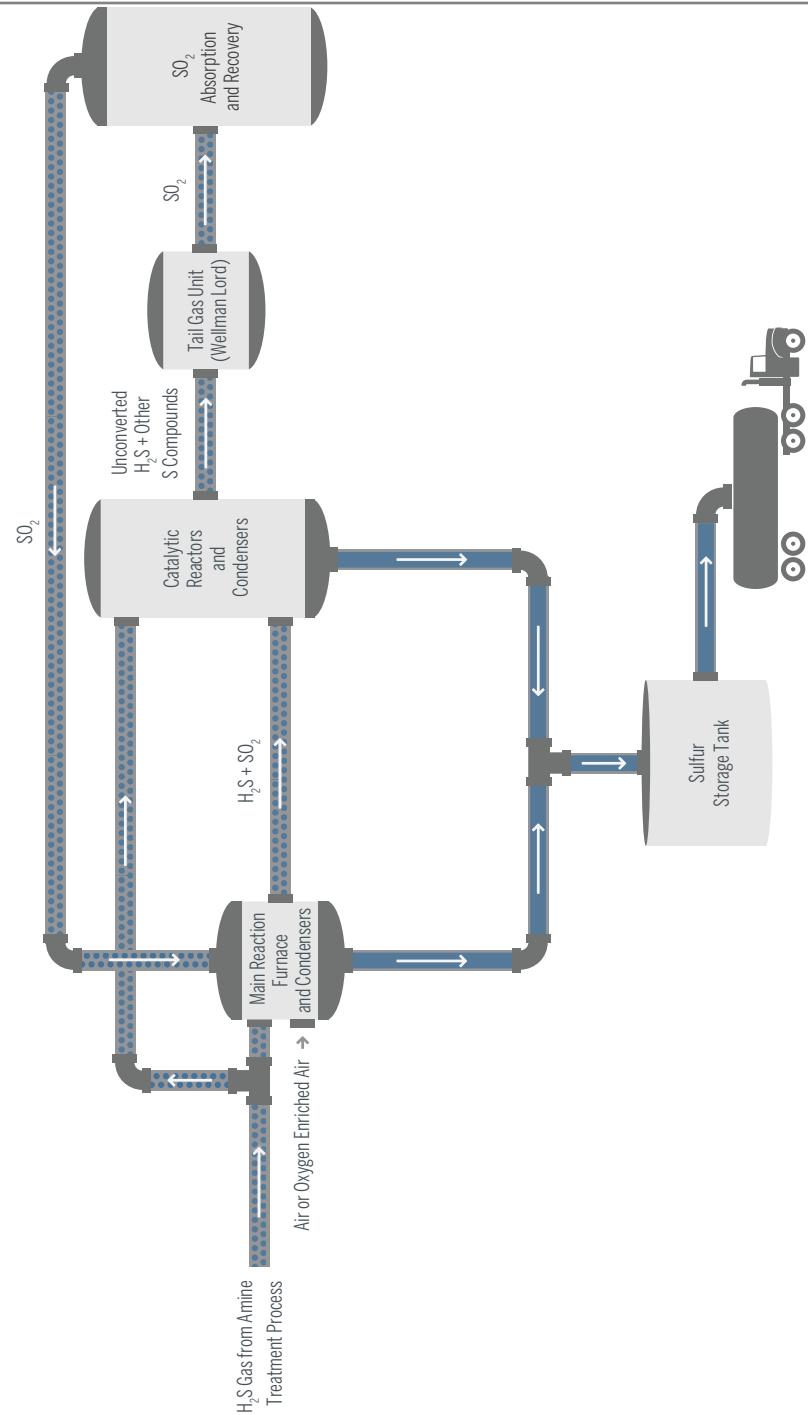
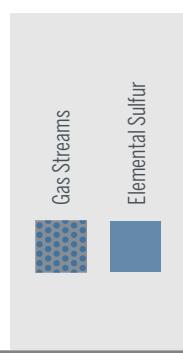


Figure A3-11  
Chevron Refinery Modernization Project EIR  
Amine Treatment Process

## Sulfur Recovery Unit

The Sulfur Recovery Unit (SRU) recovers elemental sulfur from gas containing hydrogen sulfide. The elemental sulfur leaves the refinery as a salable product.



03-04-2014 P-111-005 CVNR PRODUCTS DEIR Figures Appx 3\_Refinery 101 Draft

Source: Chevron (T39r)

Figure A3-12  
Chevron Refinery Modernization Project EIR  
Sulfur Recovery Process

### 3.4.7 Conversion: “Cracking” Remaining Heavy Hydrocarbon Molecules into Light Hydrocarbons

After hydrotreating to remove natural impurities including sulfur, many of the crude oil fractions processed by the Facility are suitable for *Blending* prior to sale as products (e.g., gasoline, diesel, jet fuel), or are ready to be blended into specialty products (e.g., lubricating base oils).

However, gas oil fractions must undergo an additional refining process—thermally or chemically “cracking” the long chains of hydrocarbon molecules that comprise these hydrocarbon fractions—to produce gasoline, diesel, and other high-demand petroleum products.

The Facility uses two types of “cracking” technology: catalytic cracking and hydrocracking.

### 3.4.8 Catalytic Cracking

The Facility's fluid catalytic cracking unit is the fluid catalytic cracker. Catalytic cracking, or “cat cracking,” involves heating gas oil fractions to temperatures of around 1,000°F when exposed to a “catalyst” at relatively low pressures (20 to 30 pounds per square inch [psi]) to “crack” the long chain hydrocarbon molecules into shorter chains, and thereby produce lighter hydrocarbons like gasoline. When the long-chain molecules of heated gas oil come into contact with the surface of the catalyst in this chamber, the molecular chains “crack” and become multiple, shorter-chained, lighter hydrocarbon molecules (see Figure A3-13, *Fluid Catalytic Cracking Process*).

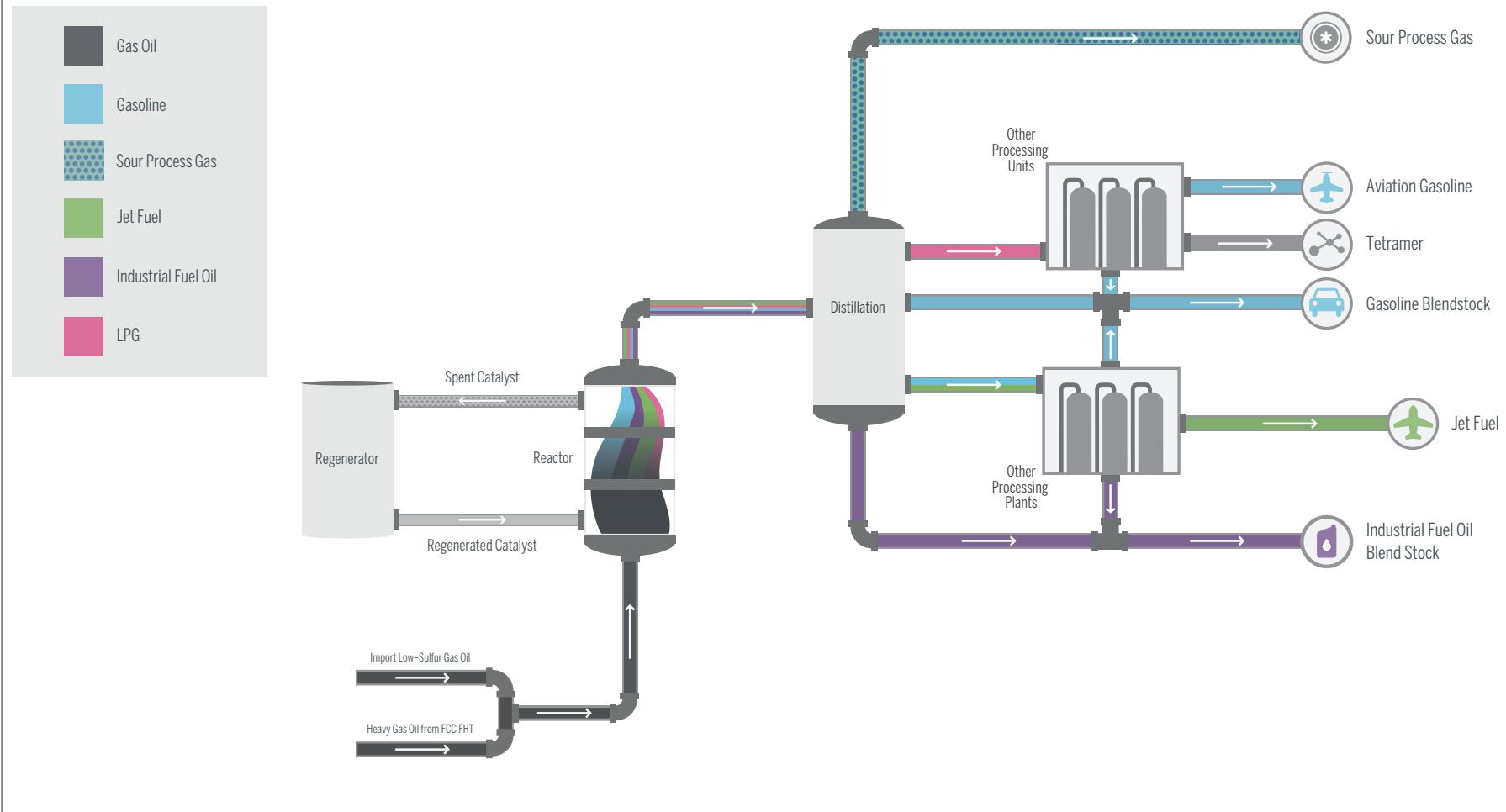
The catalyst in the fluid catalytic cracker itself is a chemical compound with the appearance of a very fine powder. Although it comes into contact with the gas oil, the catalyst remains chemically unchanged and can be used again and again. The Facility's catalytic cracker is called a “fluid catalytic cracker” because the reaction takes place in a vessel where the catalyst particles behave like a liquid.

As the hydrocarbons crack, some of the carbon atoms from the cracked hydrocarbons deposit on the surface of the catalyst, which reduces the catalyst's ability to promote chemical reactions. (This deposit of carbon is often called “coking”.) To regenerate the catalyst, air is mixed with the catalyst in a heated environment, and a chemical reaction – the oxidation of coke (essentially burning) – takes place that removes the coke from the catalyst and allows it to be reused.

The fluid catalytic cracker unit receives gas oil from (1) the hydrotreatment process described above, which removes sulfur and other natural impurities; and (2) imported

## Fluid Catalytic Cracking Process

The Fluid Catalytic Cracker (FCC) Unit uses catalyst, which moves “fluidly” with the feedstock, to convert larger gas oil molecules into gasoline and other smaller hydrocarbons.



03.04.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appendix B\_Refinery 101\Draft\CVRN Figure A3-13.pdf

Source: Chevron (T39r2)

Figure A3-13  
Chevron Refinery Modernization Project EIR  
Fluid Catalytic Cracking Process

purchased gas oil to the extent that it is already low in sulfur and thus does not require hydrotreatment.

### 3.4.9 Hydrocracking (TKN Isomax Unit)

The second method of cracking used at the Facility, *hydrocracking*, involves chemical reactions between hydrogen gas and hydrocarbons in the presence of a catalyst, and occurs in a vessel operated at very high pressures on the order of 1,000 to 3,000 psi. The Facility's hydrocracker is called a "TKN Isomax."

Hydrocracking converts gas oil into lighter hydrocarbon fractions. Unlike cat cracking, hydrocracking does not produce significant coke because it adds hydrogen atoms to the cracked molecules instead of releasing carbon atoms. (Hydrogen is used in the TKN Isomax unit in this cracking process and is an example of a refinery process where hydrogen is used in a manner that is unrelated to sulfur.) See Figure A3-14, *The Hydrocracker Process*.

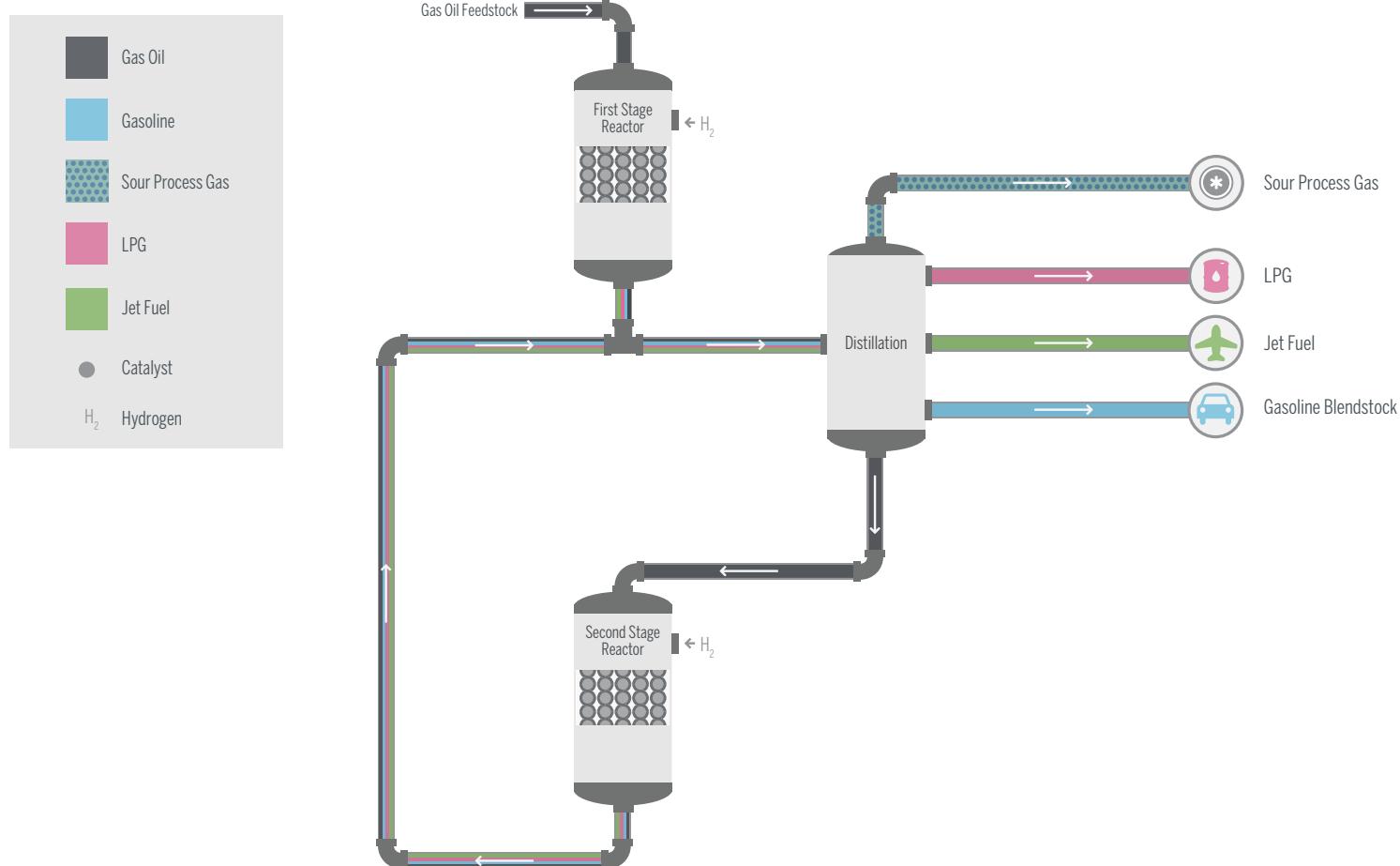
The hydrocracking in the Facility's TKN Isomax unit is a two-stage process that removes impurities from gas oil in the first stage and then "cracks" the gas oil in the second stage. The first stage is called the TKN (Taylor Katalytic DeNitrification). The second stage is called the Isomax. The name of the combined TKN Isomax is typically shortened to just "TKN" because essentially all of the material fed to the TKN is subsequently fed to the Isomax. The TKN unit receives the lighter gas oils produced by the crude unit and treats it to remove impurities, similar to the FCC FHT, which treats the heavier gas oils. The treated gas oil flows from the TKN to the Isomax where the gas oil is cracked into gasoline, jet fuel, and diesel.

The TKN *Treatment* stage removes impurities in a similar fashion as the hydrotreaters. Catalyst, temperature, pressure, and time remove the impurities and hydrogen reacts with sulfur, nitrogen, and hydrogen-deficient hydrocarbons producing H<sub>2</sub>S gas and ammonia. As with hydrotreaters, the H<sub>2</sub>S produced by the TKN is absorbed in a H<sub>2</sub>S absorber by a DEA solvent for further treatment and recovery of elemental sulfur product through the amine regenerators and ultimately the sulfur recovery units. The TKN unit operates at temperatures and pressures that allow the sulfur and nitrogen in the gas oil feed to be converted to H<sub>2</sub>S and ammonia for eventual recovery as either salable sulfur or ammonia product.

In the hydrocracking (Isomax) stage, a catalytic reaction in the presence of hydrogen cracks the bigger gas oil molecules into smaller gasoline, jet fuel, and diesel molecules. Since both units use hydrogen, there is some incidental cracking in the TKN and there is some incidental removal of impurities in the Isomax.

## The Hydrocracker Process

A Hydrocracker unit uses hydrogen and catalyst to convert ("crack") larger hydrocarbon molecules into jet fuel, gasoline and other smaller hydrocarbons.



03.04.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx B\_Refinery 101\Draft\CVRN Figure A3-14.pdf

Source: Chevron (T39r2)

Figure A3-14  
Chevron Refinery Modernization Project EIR  
The Hydrocracker Process

Neither catalytic cracking nor hydrocracking creates or destroys hydrogen, carbon, nor any other atom. As larger hydrocarbon molecules are broken, they create larger numbers of smaller molecules. Those smaller molecules have the same molecular weight as the sum of the initial larger molecule plus the very light hydrogen gas, but the smaller molecules collectively take up more space (or volume) than the initial, larger, more dense molecule from which they were created. This expansion of volume through the hydrocracking process is called “processing gain” and it results in production (by volume) of slightly more hydrocarbon lighter end products than the volume of gas oil introduced to hydrocracker units. U.S. refinery processing gain averaged about 6.2% from 1996 through 2010. In 2012, about 44.98 gallons of refined products were produced for every 42 gallon barrel of oil input into U.S. refineries.

### 3.4.10 Reforming: Increasing Octane Levels in Gasoline

Reforming is a process primarily designed to increase the “octane” of gasoline. Octane is a characteristic of gasoline related to the tendency to “self-ignite” under pressure.<sup>9</sup> Engines are rated based on their ability to run lower- or higher-octane gasolines. High-performance engines generally need higher-octane gasoline. If the octane level in the gasoline is not suitable for the engine, premature ignition of the gasoline occurs in the cylinder—a condition known as “engine knock” because of the knocking sound that is made when the gasoline ignites too early in the engine’s compression stroke. Octane ratings in commercial gasoline range from about 85 anti-knock index (AKI) in regular gasoline in high altitudes like Denver, Colorado, to over 100 for aviation gasoline.

Severe knock causes severe engine damage, such as broken connecting rods, melted pistons, and melted or broken valves and other components. An octane rating is a measure of how likely a gasoline or liquid petroleum fuel is to self-ignite. The higher the number, the less likely an engine is to pre-ignite and suffer damage. California allows a range of octane levels at the pump (87, 89, and 91), and buyers can choose the octane level that is appropriate for their car and budget. Higher octane ratings are typically recommended for higher-performance engines, and higher octane levels also cost more per gallon at the retail level than lower octane levels.

The “reforming” process in the Facility takes hydrocarbons that are in the naphtha weight range but have low octane and changes their molecular structure into higher-octane gasoline molecules. The reforming process involves reshaping because the naphtha has the same number of carbon atoms before and after this

---

<sup>9</sup> Octane is also a name for some hydrocarbons that include eight carbon atoms.

part of the refinery process, but the molecules are “reshaped” into higher-octane gasoline molecules. This reshaping of molecules also releases hydrogen, which is then used in other Facility processes as part of the Facility's overall hydrogen supply.

The Facility has two catalytic reformer process units (#4 and #5 Rheniformer), each of which consists of four separate catalytic reactors. As with other refinery processes using catalysts, each of these reactors consists of a chamber containing the catalyst material, operated at controlled temperature and pressure levels. Naphtha from the naphtha hydrotreater (which removed sulfur from this naphtha hydrocarbon fraction) is fed through each reactor chamber in series. The feed is treated with perchloroethylene, a chemical that provides chloride atoms to control reforming catalyst activity.

The products of reforming are light gases and a high-octane gasoline component typically called reformate. Hydrogen gas, a by-product generated in this process, is recovered and used in other Facility processes. The light ends produced at the reformer are used in gasoline blending (normal butane), alkylation unit (iso-butane), liquefied petroleum gas (propane) or refinery fuel gas (methane or CH<sub>4</sub>). The reformers at the Facility are “semi-regenerative,” which means that they accumulate coke as hydrocarbons are passed over them and a small amount of cracking occurs. This coke must be burned off periodically, which is called “regeneration.” The frequency of the regeneration depends on the octane level achieved for the reformate. Higher octane results in more frequent regeneration. Typical regeneration cycles are every 6 to 24 months and regeneration only takes a few days, unless significant other work is required on the unit.

### **3.4.11 Specialty Operations: Lubricating Base Oil Production Process**

The Facility is also a major national producer of industrial lubricant base oils. This requires a specialty process consisting of gas oil hydrocracking. Gas oil from the crude unit is routed to the lube unit crackers. These are similar in operation to the FCC FHT, but instead of producing a primary output of gas oil for use in the fluid catalytic cracker, they produce material used as input to the lube hydrofinishingers. The lube hydrofinishingers also use hydrogen to treat this material and ultimately produce a base oil that is the primary building block in producing lubrication oil with the desired physical properties such as viscosity and density.

The base oil production process includes sulfur removal from the feed. The sulfur removal process is the same as the other hydrotreating units. Lighter ends that include H<sub>2</sub>S produced in the lube crackers are directed to a H<sub>2</sub>S absorber to

remove the H<sub>2</sub>S by absorption in DEA. The H<sub>2</sub>S rich DEA is regenerated in an amine regenerator and the H<sub>2</sub>S is changed to elemental sulfur in the sulfur recovery unit.

### 3.4.12 Blending and Final Product Production Process

The Facility processes produce hydrocarbon fractions that are products ready for shipment, and it also produces hydrocarbon fractions that require blending with other hydrocarbon fractions before being ready for shipment as products.

*Blending* typically occurs when hydrocarbon fractions are piped to a tank in specific quantities until required product specifications are achieved. All of the Facility's hydrocarbon products are produced either by one or more of the refinery process steps described above, or by blending hydrocarbons produced by one of the refinery process steps described above. How much of any particular product is produced varies based on market factors, but the Facility has consistently served as a primary supplier of gasoline, jet fuel, and base oils in the region.

## 3.5 OTHER REFINING PROCESS OPERATIONS

The Facility also includes other major equipment and activities that are integral to Refinery Operations but not technically part of the Facility's process for producing products. Other major categories of Refinery Operations described in this section include the Facility's hydrogen plant, furnaces, flaring system, power plant, wastewater treatment plants, and storage tanks.

### 3.5.1 Hydrogen Plant

As described above, hydrogen plays a critical role in the refinery process steps described above, including in the catalytic processes for removing sulfur in the *Treatment* processes, breaking bonds and forming new bonds in the *Cracking* processes, and the production of lubricant base oils. Hydrogen gas is produced on-site in an existing hydrogen plant as well as from the *Reshaping* process.

### 3.5.2 Hydrogen Manufacturing Technology

The current hydrogen plant produces hydrogen from a process known as “steam reforming.” The chemistry of the existing plant is relatively simple. Water (H<sub>2</sub>O) is combined with methane (CH<sub>4</sub>, the primary component of natural gas) which, through a chemical reaction, produces hydrogen, carbon dioxide (CO<sub>2</sub>), and carbon monoxide (CO). This steam reforming reaction is typically carried out using a nickel catalyst, which is packed into tubes of a reforming furnace.

In the mid-1980s, PSA generally replaced the older technology (Meyers, 2004). As explained further below, the primary difference between the two processes is that the final product from the steam reforming process described in the prior

paragraph (about 94% pure hydrogen) goes through an additional step in the newer technology in which it is sent to PSA vessel units, where the hydrogen is selectively absorbed at high pressure, leaving the impurities like CO<sub>2</sub> behind. The absorption mixture is depressured, and very pure (99%) hydrogen is all that is left. The impurities and some hydrogen left in the PSA units are burned in the furnace to provide heat for the reaction.

### 3.5.3 Furnaces, Burners, Heat Exchangers and Thermal Oxidizers

Heating devices provide heat to various liquid or gas streams such as water, process streams (e.g., crude oil), or air. In general, these heating devices are referred to as “furnaces.” Sometimes, heating devices are given special names based on the stream being heated. For example, a heating device that boils water is commonly referred to as a “boiler.” A heating device that provides heat to non-water liquid streams is sometimes also referred to as a “process heater.” However, the general operation and the emissions associated with each are similar in concept.

These heating devices all include burner assemblies. The burners are where fuel (i.e., natural gas or refinery fuel gas) is combusted with oxygen to form a flame and hot combustion gases. (This is a larger scale version of the burners that one would find on a natural gas kitchen stove.) There are different ways a hydrocarbon stream may be heated during the refining process, depending on the configuration of the heating device and the technology of the refining process that the heating device serves. For example, a hydrocarbon stream being heated may pass through tubes that are surrounded by the hot combustion gas. In this case, the heat from the hot combustion gas transfers through the tube, increasing the temperature of the hydrocarbon stream within the tube. The flame component of the heating device may also be near the hydrocarbon stream, which would directly transfer additional radiant heat to the stream through the tubes.

In certain process units, burners are used to directly combust a refinery process stream (i.e., the material being processed through the Facility unit comes into direct contact with the flame from the burner) instead of using burners just as heaters. This occurs, for example, when hydrogen sulfide gas is combusted as part of the sulfur recovery unit process in the *Treatment* process for sulfur removal.

In addition, some burners are designed to combust volatile organic compounds (VOCs) in exhaust streams or fugitive emissions, converting the VOCs into CO<sub>2</sub> and water. Such devices are called thermal oxidizers. Thermal oxidizers are used, for example, to control VOC emissions from pumps and compressor seals at the Facility.

The combustion process for all heaters produces air emissions. The pollutants produced depend on the chemical composition of the fuel and combustion air and can include criteria air pollutants, toxic air contaminants, and greenhouse gases. The design of the device can influence the extent to which air emissions are generated. For example, low-NO<sub>x</sub> burners are designed to reduce NO<sub>x</sub> formation by controlling fuel and air mixing. Air emissions from burners are described in *Section 4.3, Air Quality*, and *Section 4.8, Greenhouse Gases*.

The combustion gas from a heating device typically remains hot even after transferring heat to the material being refined in the part of the refinery process served by the heating device. This combustion gas can be released as exhaust through a flue stack (subject to required air pollutant controls), or an “economizer” can be used to recover heat from the exhaust gas that would otherwise be released into the atmosphere. The recovered heat can be reused in the refining process to pre-heat a process stream or combustion air, which then results in lower fuel consumption because less fuel is used to bring the stream or combustion air up to operating temperature. An economizer is essentially a “heat exchanger” (described below) that reduces fuel consumption from the same device from which it derives its waste heat. The waste heat from the combustion gas could also be used to heat other streams derived from other units in a conventional heat exchanger.

A “heat exchanger” is a piece of equipment whereby a hotter process stream transfers heat to a cooler process stream. The two process streams do not come into direct contact with each other (i.e., they are not mixed). Rather, they are generally separated by a metal wall that conducts the heat from one stream to another. Heat exchangers are designed such that the surface area of the wall separating the two streams is maximized in order to maximize the amount of heat transferred. There are no emissions associated with heat exchangers because there is no combustion occurring. For example, the hot gases that exit the sulfur recovery unit enter into a heat exchanger where it transfers heat to a stream of water, converting the water to steam.

### 3.5.4 Flares

A refinery moves raw materials through a network of pipes and processing equipment. As described above, many of the refining processes involve using pressure and/or heat to change hydrocarbons and transporting heated or pressurized hydrocarbons through the different parts of a refinery. Flare systems are designed to provide for the safe disposal of hydrocarbons that are either automatically vented or manually drawn from process units at refineries. Hydrocarbons must be controlled in a safe and effective manner in the event of an operational upset. Flare systems gather vented gases and combust them to prevent releases of hydrocarbons directly into the atmosphere.

Flaring plays a critical safety role in refinery operations. A “flare” is usually a tall stack equipped with burner equipment that is designed to ignite hydrocarbon gas when it leaves the flare. This flare technology is designed to very quickly and very efficiently consume hydrocarbon gas (similar to a gas stove), with minimal air pollution. The primary function of the flaring system is to relieve pressure to prevent units from overpressure. Flares are primarily used for burning off flammable gas released by a “relief gas header” during either unplanned pressuring of refinery equipment, or during startups and shutdowns. A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. At the Facility, these are typically referred to as “relief gas headers,” since the system, which is generally at near-atmospheric pressure conditions, receives gases “relieved” from higher pressure operations within the unit.

The primary function of the relief gas header is safety. It provides the process unit with a readily available and controlled means of releasing gases to prevent over-pressurization of equipment (routing them to controlled locations for destruction by combustion). It also provides a controlled outlet for any excess vapor flow, nearly all of which is flammable and can be sent to a flare to be burned off, making it an essential safety feature of every refinery. Each relief gas header has connections for equipment depressurization and purging related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices and other safety control valves to handle upsets, malfunctions, and emergency releases.

The Bay Area Air Quality Management District (BAAQMD) has been a global leader in regulating the use of flares. Flaring is not required to operate a refinery's process units during normal operation, and the need for flaring at the Facility has been substantially reduced over time.

The Facility has identified situations or activities likely to cause flaring, including releasing gases to prevent equipment from becoming over pressured, as described below in more detail. Releases of relief gas to the flare result from an imbalance between the quantity of vent gas produced by the Facility and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds), and utilized as fuel gas. Situations that can lead to flaring can be grouped together based on similarity of cause. At the Facility, flares are used for three primary purposes:

- **Process unit startups and shutdowns and planned maintenance.** To prepare an individual equipment item or a block of refinery equipment for maintenance, it is necessary to isolate it from active operations and clear it of process fluids. Examples include unit shutdowns, working on equipment

and/or relief systems, catalyst change, plant leak repairs, and compressor maintenance or repairs. In order to avoid flaring, there must be a balance between producing and consuming fuel gas units. When either a block of equipment or an individual equipment item is removed from service, if it either produces relief gases or consumes fuel gases, then the balance of the fuel gas system is changed and adjustments are necessary to bring the system back into balance. If the net change in gas production or consumption is large and the adjustments in the rate at which gas is produced or consumed by other units cannot be made quickly enough, then flaring results.

- **Upset/malfunction.** An imbalance in the flare gas system can also result from upsets or equipment malfunctions that either increase the volume of flare gas produced or decrease the ability of the fuel gas handling system to accommodate it. Examples include relief valves lifting, pressure relief valve malfunction, equipment overpressure, loss of a utility system, and loss of air fins or condensers.
- **Emergency relief.** Pursuant to BAAQMD Regulation 12, Rule 12, Section 201, an emergency “is a condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.”

To address these situations, the Facility currently operates two flare gas systems, complete with flare gas recovery systems, one covering the “north yard” of the Facility and the other covering the “south yard.”

The operation of the Facility’s flare systems is governed by its flare management plan (FMP) submitted pursuant to the requirements of BAAQMD Regulation 12, Rule 12 (Reg. 12-12). The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Flaring is prohibited unless it is consistent with an approved FMP. Each refinery is required to submit a FMP annual update. The FMP defines a series of measures intended to reduce flaring to the extent that is feasible without compromising safety and necessary refinery operations and practices. It is the Facility's policy that flare events would only occur within the scope of Reg. 12-12, and it would adjust the operation of process units or implement corrective action to prevent flaring in accordance with the regulation.

### **3.5.5 Power and Steam Generation, Including Boilers**

The Facility is designed to generate on-site most of the power it needs to operate. During the baseline period of 2008-2010, the Facility imported an annual average of only 2 megawatts (MW) of electricity, compared to a total annual average of approximately 115 MW of electricity used by the Facility.

Electric power is generated at the Facility by two gas turbines, one steam turbine generator, and the fluid catalytic cracker power recovery system. The gas turbines generate electricity through the combustion of fuel which moves the blades of a turbine, providing mechanical power to operate the electric generator.

A steam turbine generator creates electricity when higher pressure steam is reduced to lower pressure steam, resulting in mechanical power to operate the electric generator. Steam is produced by two heat recovery steam generators at the co-generation unit as well as five fired boilers in the “No. 1 Power Plant.”<sup>10</sup> (The combination of the gas turbines, the heat recovery steam generators, and the duct burners comprise the co-generation facility.)

Steam is also generated by process units throughout the Facility. For example, steam is generated in a heat exchanger that takes in hot gases from the sulfur recovery unit, transfers the heat to a water stream, and converts that water to steam. In addition to being used to generate electricity in the steam turbine generator, steam is also piped throughout the Facility and is injected into various processing equipment to be used for heating in the refining process (similar to radiator heat in a house) or for direct contact with hydrocarbons during the refining process.

The Facility uses approximately 2.5 million pounds of steam per hour. However, the boilers in the No. 1 Power Plant generate only about 10% of that amount; the remaining steam is produced by refinery processes.

### **3.5.6 Cooling Towers**

Process streams require cooling that is usually provided by water in a heat exchanger. Water that picks up heat in the process is sent to a cooling tower where the water is dispersed into thin streams through which air is passed. The

---

<sup>10</sup> The five boilers are called the “No. 1 Power Plant” because the unit was built in the 1930s and used to generate electricity. However, “power plant” is a misnomer as the unit today consists of boilers only and generates only steam, not electricity.

air evaporates a small amount of the water and the evaporation cools down the water, which is then pumped back to the heat exchanger again for reuse.

### 3.5.7 Water Use and Treatment

The refining process results in industrial wastewater that is treated in a wastewater treatment facility. The Facility's process wastewater and most of the stormwater runoff is collected and managed in the Facility's existing industrial wastewater treatment system that is regulated by the RWQCB.

### 3.5.8 Storage Tanks

The Facility currently operates approximately 160 aboveground storage tanks (including pressurized spheres) containing raw materials, feedstocks, intermediate material, and final products. There is a number of small/auxiliary tanks located throughout the Project site that are not part of the primary Refinery Operations processes.

Most tanks store raw feedstocks (crude oil and gas oil), intermediate stocks, or finished products (gasoline, diesel, jet fuel, etc.). These tanks are located in areas of the Facility known as the Refinery Process and Tank Farm areas (see *Figure 3-2 in Chapter 3, Project Description*). Furthermore, some tanks store chemicals that are involved in Refinery Operations but are neither feedstocks nor product, such as perchloroethylene used in the reforming process.

The tanks range in capacity from under 1,000 barrels to over 650,000 barrels. Over long periods of time (e.g., annually) the average amount of material stored in tanks is approximately constant, but the quantity of material flowing through the tanks on any given day increases or decreases as the feedstock tanks are emptied into the Facility (or product is produced by the Facility feed rate and production volumes change).

### 3.5.9 Pipelines, Valves, Pumps, and Flanges

The Facility has a complex network of pipelines, and the pipelines have process components that each result in small emissions of hydrocarbons from the seals in the process components. These process components include approximately 5,000 miles of pipe, 105,000 valves (including pressure relief devices), 1,400 pumps and compressors, and 400,000 connectors such as flanges (which are used to connect two lengths of pipe).

## 3.6 REFERENCES—APPENDIX 3

California Energy Commission (CEC). 2006. Fossil Fuels Office, Fuels and Transportation Division, Sheridan, Margaret: California Crude Oil Production and Imports, p. 1, CEC-600-2006-006. April.

Greg Johnson, New Logic Research. 2014. *Petroleum Wastewater—Desalter Case Study*. Accessed March 4, 2014. [http://www.waterandwastewater.com/www\\_services/ask\\_tom\\_archive/petroleum\\_wastewater\\_desalter\\_case\\_study.htm](http://www.waterandwastewater.com/www_services/ask_tom_archive/petroleum_wastewater_desalter_case_study.htm).

Robert A. Meyers. 2004. *Handbook of Petroleum Refining Processes, Third Edition*, p. 67.