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Assessment of Energy Efficiency Improvement in the United States Petroleum Refining Industry

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Disclaimer

Efficiency Improvement in the United States Petroleum Refining Industry

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Contents

LIST OF ACRONYMS

***General Acronyms*:**

CCS - Carbon Capture & Sequestration
DOE - Department of Energy
EIA - Energy Information Administration
EPA - Environmental Protection Agency
GHG - Greenhouse Gas
IAM - Integrated Assessment Model
LBNL - Lawrence Berkeley National Laboratory
LCFS - Low-Carbon Fuel Standards
LP - Linear Programming
NexGen - Next Generation
OGJ - Oil & Gas Journal

RFS - Renewable Fuel Standards
SOTA - State of the Art

***Process Acronyms*:**

AC - Air Cooling
ACU - Atmospheric Crude Unit
AGR - Acid Gas Removal
AGS - Acid Gas Removal & Sulfur Recovery Systems
AKU - Alkylation Unit

BFW - Boiler Feed Water

CCU - Catalytic Cracking Unit
CDU - Crude Distillation Unit
CKU - Coking Unit
CRU - Catalytic Reforming Unit
CTU - Cat-Feed Treating Unit
CW - Cooling Water

DTU - Diesel Treating Unit

GPU - Gas Processing Unit
GTU - Gasoline Treating Unit

HCU - Hydrocracking Unit
HTU - Hydrotreating Unit
HYS - Hydrogen Production & Recovery Systems

ISU - Isomerization Unit

ISBL - Inside Battery Limits

KTU - Kerosene Treating Unit

LPG - Liquefied Petroleum Gas

NTU - Naphtha Treating Unit

OSBL - Outside Battery Limits

PSA - Pressure Swing Adsorption

RGS - Refinery Gas Processing & Flare Systems

SFA - Sulfuric Acid
SMR - Steam Methane Reforming
SPS - Steam & Power Systems
SRU - Sulfur Recovery Unit
SWS - Sour Water Stripper

VCU - Vacuum Crude Unit
VRC - Vacuum Reduced Crude

WTS - Water Treatment & Delivery Systems

***<u>Acronyms for Dimensional Units</u>*:**

BPCD - Barrels Per Calendar Day

M - 1,000
MM - 1,000,000

SCFD - Standard Cubic Feet per Day

ABSTRACT
Adoption of efficient process technologies is an important approach to reducing CO_2 emissions, in particular those associated with combustion. In many cases, implementing energy efficiency measures is among the most cost-effective approaches that any refiner can take, improving productivity while reducing emissions. Therefore, careful analysis of the options and costs associated with efficiency measures is required to establish sound carbon policies addressing global climate change, and is the primary focus of LBNL's current petroleum refining sector analysis for the U.S. Environmental Protection Agency. The analysis is aimed at identifying energy efficiency-related measures and developing energy abatement supply curves and CO_2 emissions reduction potential for the U.S. refining industry. A refinery model has been developed for this purpose that is a notional aggregation of the U.S. petroleum refining sector. It consists of twelve processing units and accounts for the additional energy requirements from steam generation, hydrogen production and water utilities required by each of the twelve processing units. The model is carbon and energy balanced such that crude oil inputs and major refinery sector outputs (fuels) are benchmarked to 2010 data. Estimates of the current penetration for the identified energy efficiency measures benchmark the energy requirements to those reported in U.S. DOE 2010 data. The remaining energy efficiency potential for each of the measures is estimated and compared to U.S. DOE fuel prices resulting in estimates of cost-effective energy efficiency opportunities for each of the twelve major processes. A combined cost of conserved energy supply curve is also presented along with the CO_2 emissions abatement opportunities that exist in the U.S. petroleum refinery sector. Roughly 1,200 PJ per year of primary fuels savings and close to 500 GWh per year of electricity savings are potentially cost-effective given U.S. DOE fuel price forecasts. This represents roughly 70 million metric tonnes of CO_2 emission reductions assuming 2010 emissions factor for grid electricity. Energy efficiency measures resulting in an additional 400 PJ per year of primary fuels savings and close to 1,700 GWh per year of electricity savings, and an associated 24 million metric tonnes of CO_2 emission reductions are not cost-effective given the same assumption with respect to fuel prices and electricity emissions factors. Compared to the modeled energy requirements for the U.S. petroleum refining sector, the cost effective potential represents a 40% reduction in fuel consumption and a 2% reduction in electricity consumption. The non-cost-effective potential represents an additional 13% reduction in fuel consumption and an additional 7% reduction in electricity consumption. The relative energy reduction potentials are much higher for fuel consumption than electricity consumption largely in part because fuel is the primary energy consumption type in the refineries. Moreover, many cost effective fuel savings measures would increase electricity consumption.

The model also has the potential to be used to examine the costs and benefits of the other CO_2 mitigation options, such as combined heat and power (CHP), carbon capture, and the potential introduction of biomass feedstocks. However, these options are not addressed in this report as this report is focused on developing the modeling methodology and assessing fuels savings measures. These opportunities to further reduce refinery sector CO_2 emissions and are recommended for further research and analysis.

1. INTRODUCTION

Adoption of efficient process technologies is an essential component of any comprehensive strategy for improving energy efficiency and reducing CO_2 emissions associated with combustion. In many cases, energy efficiency measures are among the most cost-effective investments that an industrial concern can make to improve productivity, while simultaneously decreasing its carbon footprint. Therefore, careful analysis of the technical options and costs associated with implementing efficiency measures is required to establish sound energy policies that improve industrial cost-effectiveness and address global climate change concerns.

1.1 Purpose of Study

An earlier Energy Star® report prepared for the U.S. EPA concluded that: "Further research on the economics of energy-efficiency measures, as well as the applicability of these to individual refineries, is needed to assess the feasibility of implementation of selected technologies at individual plants" [Worrell et.al. 2005]. The analysis documented in this report helps address this need for the U.S. petroleum refining industry, and has three primary objectives:

1) To develop a robust methodology for estimating process performance, energy requirements, CO_2 emissions, and costs of abatement measures applicable to petroleum refining in the U.S. MS-Excel based spreadsheet models coupling empirical data and engineering calculations for U.S. refinery processes were developed in this study, allowing the complexity of U.S. refineries and the impact of process integration on overall refining efficiency to be assessed. The refinery models are constrained to satisfy a U.S. aggregated product demand slate (e.g., quantity of gasoline, diesel, jet fuel, etc.) using a composite crude oil assay representative of the average crude oil composition processed in the U.S.. The refinery models are carbon balanced allowing carbon to be tracked and CO_2 emissions estimated as fuels are consumed throughout the refinery processes.

2) To establish representative baseline data of production, energy, CO_2 emissions and costs to be used in the models. Detailed information on the performance of individual petroleum refineries is generally not available at the process level, making it difficult to ascertain the current, and more importantly, the future state of the industry in regards to energy usage and emissions. Required modeling parameters, when not available in the open literature, were deduced by reverse engineering, starting from reported aggregate data, or inferred from descriptive accounts of past, current and future technologies.

3) To couple the information assembled on refinery process efficiency and existing and future abatement measures, identifying cost effective measures for each individual refinery process and for the refinery as a whole, and to generate cost of conserved energy supply curves and estimate associated CO_2 abatement. However, the variability between individual refineries in the U.S. in regards to size, complexity, and crude inputs and product slate outputs are not addressed by this analysis. Instead, this analysis treats the whole U.S. refinery sector as an aggregate.

1.2 Report Organization

The development and demonstration of a robust methodology for estimating energy-abatement supply curves for the U.S. petroleum refining sector is complicated by a number of issues unique to refining [Gary 2007, Worrell 2010]. The refining sector is diverse with refineries distributed across the U.S. No two refineries are identical; all were built at different times and therefore employ technologies of different vintage and make. The last green-field refinery constructed in the U.S. was commissioned in 1979, and the average age of the existing refinery fleet is well over fifty years old. However, the existing fleet is not obsolete with each refinery evolving independently. Capacity at individual refineries has increased over time, form an average crude oil capacity of less than 100,000 Barrels per Calendar Day (BPCD) in the early 1990s to roughly 120,000 BPCD today. Thus, refineries are continuously being expanded and modernized, and at any moment in time, there exist a distribution in refinery performance in regards to product yields and energy efficiency. For this analysis, a notional model using MS Excel for a generic U.S. refinery was developed. Yield and energy consumption data used in the model are based on a review of multiple literature and private sources spanning the period from 1975 to the present.

In this study, an MS-Excel spreadsheet based model for a generic U.S. refinery was developed and is presented in Section 2. The performance of this refinery is based upon yield and energy consumption data circa. 1995. Additional data gathering and statistical analysis was performed to establish the current performance status of the U.S. refinery fleet for the analysis baseline year 2010.

Section 3 presents the methodology used to identify and characterize energy abatement measures for petroleum refining, and to quantify their efficiency and cost. Due to the highly integrated nature of the petroleum refinery, energy abatement measures will in general not be additive. A hierarchy of improvements exists, such that initial improvements limit the effectiveness of later improvements. Refineries are unique to most industrial sectors as they are self-sustaining for much of their fuel and electricity use. Most processing steps in the refining of crude oil into finished products produce fuel by-products, most notably fuel gas and catalyst coke, which are consumed within the refinery to supply heat and generate electricity. Therefore, reducing fuel consumption is not necessarily cost effective, if it is not matched with a reduction in fuel gas generation. If this caveat is over looked then efficiency potentials could be overestimated. Simply improving efficiency without corresponding reductions in fuel gas generation could result in excess fuel gas and catalyst coke requiring additional investments in combined heat and power generation systems to utilize these excess fuels.

Section 4 combines the energy requirements estimated using the 2010 refinery model with the energy measures and costs described in Section 3 to generate a preliminary cost curve for the U.S. refining sector. Section 5 provides conclusions drawn from the completion of the initial phase of research and provides a detailed list of recommendations for activities to be followed up on in the next phase of research.

1.3 Potential Applications

The primary application for the cost curves generated in this project can be for inclusion in integrated assessment models (IAM), which require accurate bottom-up representation of energy efficiency technologies; otherwise, it will be difficult to estimate with confidence, the costs and benefits of reducing GHG emissions by adopting sector-based efficiency standards. The baseline information, cost curve data and models developed in this analysis can have other applications. The lists of energy efficiency measures developed provide a database of potential cost-effective measures that can be taken by industry to improve their energy efficiency and to mitigate GHG emissions. The refinery model developed is general and has the potential to be used to explore the benefits and costs of other GHG mitigation options. For example, the model framework is capable of examining the impact of introducing renewable fuels on the cost and emissions from petroleum refining, and the cost and effectiveness of future carbon capture technologies in a petroleum refinery setting. While this capability has not been modeled explicitly for this body of analysis, adding this capability would be an incremental addition to the core model framework.

2. ASSESSMENT METHODOLOGY

2.1 Conceptual Framework for Refinery Modeling

Petroleum refineries consist of a complex interconnected set of processing units. Although no two refineries are exactly the same due to historical development of each refinery given its crude oil inputs and product outputs, this analysis focuses on twelve core processes that dominate energy consumption within the U.S. refinery sector. Figure 1 is a simplified diagram showing the major hydrocarbon flows between the twelve unit processes evaluated in this analysis. Additionally, refinery "off-site" (e.g., utilities such as steam and electricity generation, and hydrogen production) contribute to refinery sector energy consumption and in this analysis their energy consumption is allocated to the twelve processing units shown in Figure 1. The allocation methodology is based on the energy (i.e., fuel, steam, electricity, etc.), as well as the hydrogen and gas processing requirements of each processing unit. Where steam or hydrogen is utilized in processing units, fuel and electricity requirements for steam generation and hydrogen production are assigned to the individual units according to their proportion to the total steam and hydrogen production of the entire refinery. For each processing unit, fuel and electricity consumption can be direct (e.g., fired heaters and pumps) which is designated "inside the battery limits" (ISBL) for the unit, or fuel and electricity consumption can be indirect (e.g., steam and hydrogen) which is designated "outside the battery limits" (OSBL).

Table 1 below presents estimated energy consumption for the twelve modeled unit processes for the year 2010. This estimate is based on 2010 process throughput [EIA 2013], and engineering modeling of energy required to produce the 2010 U.S. petroleum refinery aggregated output product slate (i.e., gasoline, diesel, jet fuel, etc.). In addition, the energy (fuels, steam, and electricity), energy associated water-usage (process, cooling, and waste) and hydrogen production are also modeled. The U.S. petroleum refinery sector is first modeled without energy efficiency (i.e., vintage 1995) and current penetration rates are estimated to reflect 2010 aggregate energy consumption. The remaining potential for energy efficiency measures are presented and discussed in this report.

Additional analytical capacity for considering biomass based (renewable) feedstocks or carbon capture technologies could be added to this model framework. For example, specific treatment of these feedstocks or technologies could introduce a new processing unit to the block flow diagram (in the example of adding biomass feedstocks processing), or be modeled inside one of the units depicted in Figure 1 (in the example of adding carbon capture technologies).

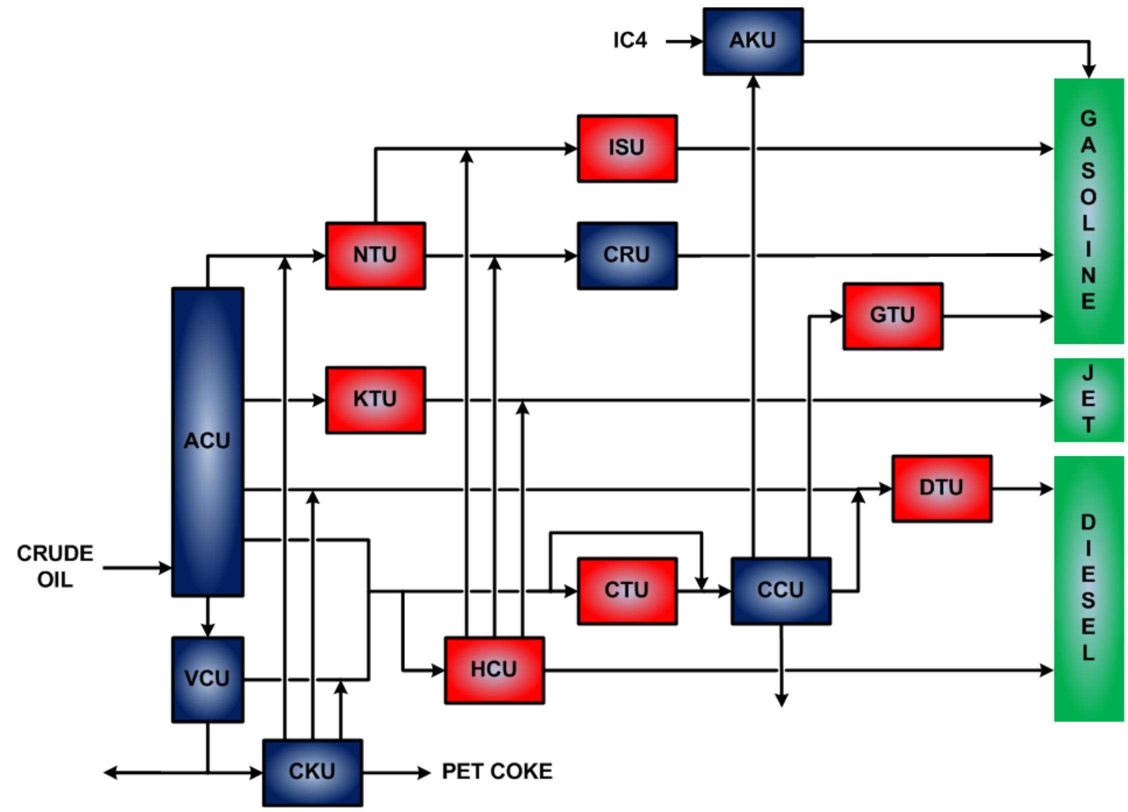


Figure 1 – Overall Process Block Flow Diagram for U.S. Refinery Model **(red denotes H_2 consuming unit processes). Refer to the list of acronyms at the beginning of the report for process unit definitions**

Table 1 – Estimated Energy Consumption for the U.S. Petroleum Refining Model circa.2010

Process	Throughput	Fuel (PJ, Primary)		Electricity (GWh, Final)	
	Million bbl/year	ISBL	OSBL	ISBL	OSBL
CDU	5,540	399	638	4,048	1,769
CKU	725	107	26	2,246	868
CTU	1,081	48	392	143	2,076
CCU	725	-335	42	2,305	2,081
HCU	474	92	471	61	2,251
DTU	1,033	51	243	150	1,225
KTU	575	29	53	401	376
NTU	1,213	103	100	176	423
CRU	992	313	119	979	1,507
ISU	147	6	28	21	9
GTU	419	34	136	60	423
AKU	170	0	35	4	500

Process	Throughput	Fuel (PJ, Primary)		Electricity (GWh, Final)	
	Million bbl/year	ISBL	OSBL	ISBL	OSBL
Total Modeled Energy Consumption		848	2,283	10,596	13,507

2.2 Conceptual Framework for Energy-Usage Abatement

Process Design Concepts

Figure 2 depicts a simplified, generic arrangement of process equipment (*i.e.* unit operations) that can be associated with most of the processing plants (*i.e.* unit processes) that make up a modern integrated petroleum refinery. The process feed stream is conveyed to the unit battery limits using a feed pump, and is then heated to the desired reaction temperature in a fired heater, before being fed to a reactor. In addition to this petroleum feed, a recycle gas is also co-fed to the reactor. The product from the reactor is cooled in a heat exchanger and separated into gaseous and liquid products, with the liquid hydrocarbon product being sent either to finished product blending or on to further processing steps. The overhead gas is typically purged of impurities, re-compressed, and recycled back to the reactor to be re-used in the chemical reactions. Additional make-up gas may also be required. Control valves are used throughout to maintain the desired flow rates of the streams within the process.

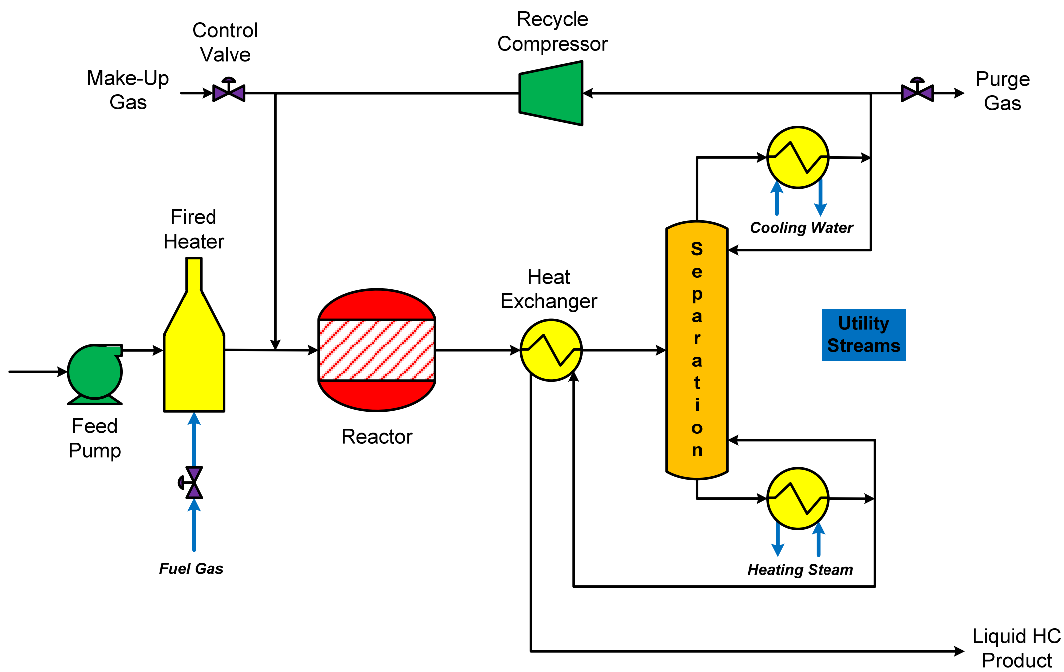


Figure 2 – A Simplified Generic Module for Refinery Unit-Process Flow Diagram

Most refinery unit processes discussed are more complex than the generic process shown above; in some cases, employing multiple reactors, separators and recycle streams. In particular, catalytic cracking, hydrocracking and coking processes are the most complex processes found in a refinery. A few unit processes do not include all of the features described above. For example, the crude distillation unit only involves separations, heat exchange, and fluid handling equipment. No reactions take place in the process.

The core unit operation in most processes is the reactor used for converting the unit's feed stream into desired product or products; followed by separation of the desired products from unconverted feed and fractionation of the individual products. Thermodynamic and chemical kinetic considerations establish pressures and temperatures required to maximize the yield of desirable product(s). Based on these pressure and temperature conditions, and estimated stream physical properties and flow rates, a heat exchanger network (HEN) is designed around the reactor and separation operations to provide required heating or cooling. An energy efficient design will recover heat from hot process streams that require cooling and transfer it to cold process streams that require heating (theory for designing such a system will be discussed briefly later in this section). The process heat exchanger serves this purpose in Figure 2. The operating pressure requirements for the reactor and separations, along with estimates of pressure drops through all equipment (reactors, separators and heat exchangers) and piping establish pumping requirements for liquid streams and compression requirements for vapor streams.

In most cases, the HEN cannot provide all the heating and cooling required by the process, and appropriate hot and cold utilities will need to be supplied at the battery limits of the process. The battery limits of a process is defined as the equipment requirements for the unit process excluding the integration (primarily piping) that connects processing units to each other and the utilities of the refinery. As shown in Figure 2, hot utilities include fuel fired in the heater and steam condensed in the reboiler. Cooling is supplied to the condenser via circulating cooling water. In some situations, a fan-driven air cooler can be used to cool the overhead stream. Energy must also be supplied to any pumps and compressors, as well as to any cooling fans. These are typically driven by electricity, which may be supplied by on-site power generation and/or purchased from a local electric utility. It is also possible to drive pumps and compressors using high-pressure steam or process streams if available, which has implications for energy efficiency improvements.

Almost all refinery processes are designed to operate continuously. Smooth and stable operation of a process requires a robust process control system. The control system monitors key process parameters, such as stream pressures, temperatures, compositions, and flow rates, and then adjusts the process and utility flows to keep these parameters within narrow operating margins around the design specifications. The control system is typically designed last after all operating equipment and conditions have been determined. Figure 2 identifies some possible locations for control valves in the process depicted.

The design procedure described above is depicted in the "onion" diagram shown in Figure 3. As described above, traditional process design has been done starting at the onion's core, which is the reactor, and then moving outward layer by layer. The advent of sophisticated process design software is changing this paradigm, allowing a more integrated approach to design.

Unfortunately, when revamping an existing process, a more *ad hoc* procedure is often required (though software is available specifically for this application also), since most of the existing equipment will be maintained in the re-design. This is especially true for energy efficiency projects, which most often only consider the outer layers of the onion: heat exchange, fluid handling and process control. Modifications to reactors and separation operations are normally capital intensive; though in some situations, modest changes to operating pressures and temperatures may be considered. It has been suggested that new plants overall have a 20% lower energy requirement than existing plants do at any given time [White, 2010]. This may be attributed at least partially to the flexibility of grassroots construction projects versus plant revamps.

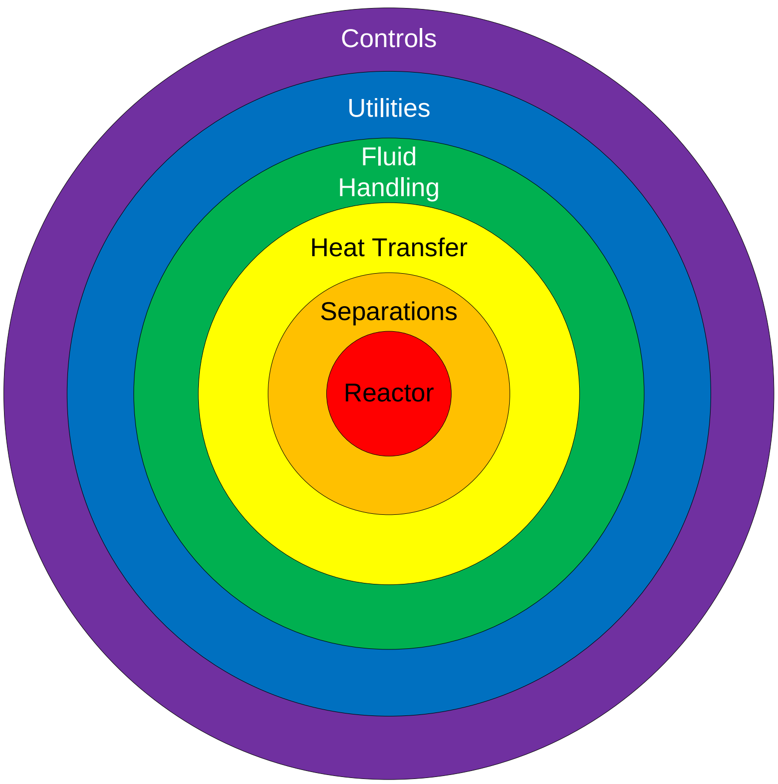


Figure 3 – Onion Diagram of Process Design

In many cases, newer reactor and separation technologies have significantly better efficiency potential than those they are designed to replace. This results from a multiplier effect due to the reduction in feed throughput, which can ripple through the rest of the refinery. However, it is normally modifications to reactors and separations in order to increase plant capacity or improve product quality that enable the consideration of many efficiency improvement projects simultaneously. Therefore, it may be difficult to determine exogenously what the actual costs of energy efficiency related projects.

A heuristical approach to process design is to minimize the number of times a material is heated or cooled, and particularly for gas streams, pressurized or de-pressurized. Repeating these steps multiple times decreases the potential efficiency of a process. Another heuristic of good design is to increase the pressure of a stream while it is in the liquid phase, rather than after it has been vaporized. It is also beneficial to arrange the processing steps such that the pressure and temperature decrease through the process.

Finally, this analysis focuses on fuel savings measures because fuel use is the dominant (75%) energy consumed by the petroleum refining industry. There are measures that effect electricity usage singularly (e.g., higher efficiency motors). Combined heat and power (CHP) is perhaps the largest single electricity efficiency measure. However, CHP also affects heat utilization throughout the refinery through the production of steam as a by-product of electricity production. CHP opportunities are not addressed in this phase of modeling but are recommended for subsequent analysis.

Efficiency Improvement Hierarchy

It should be kept in mind that the conceptual process of Figure 2 is only one of many within a refinery that may have twenty or more processes of roughly equal complexity, and that these processes are integrated through the flow of process streams (*i.e.* the molecules of interest, such as hydrocarbons, hydrogen, and contaminants) and various utility streams (*i.e.* carriers of energy, such as fuel, steam, cooling water, and electricity). Therefore, when considering efficiency improvements all processes and their interactions must be considered. Further, one can speak of the efficiency of a process, not only in terms energy, but also in terms of mass and information. While these three efficiencies are distinct they are also highly correlated. Improved mass efficiency will improve energy efficiency, and the collection and transmission of data enables process optimization and control to be used to improve both. Therefore, to systematically describe and quantify the efficiency options that might be considered within a refinery, these measures can be categorized based on the level at which they are implemented in the refinery and by whether they directly impact the flow of mass, energy or information through the refinery.

Figure 4 identifies the efficiency categories that are used in this study. Efficiency measures for each category are described and quantitative assessments of their impact on efficiency and cost are provided for the unit processes and refinery systems described in Section 3. The results of this analysis are used to estimate energy-usage abatement curves for the U.S. petroleum refining industry.

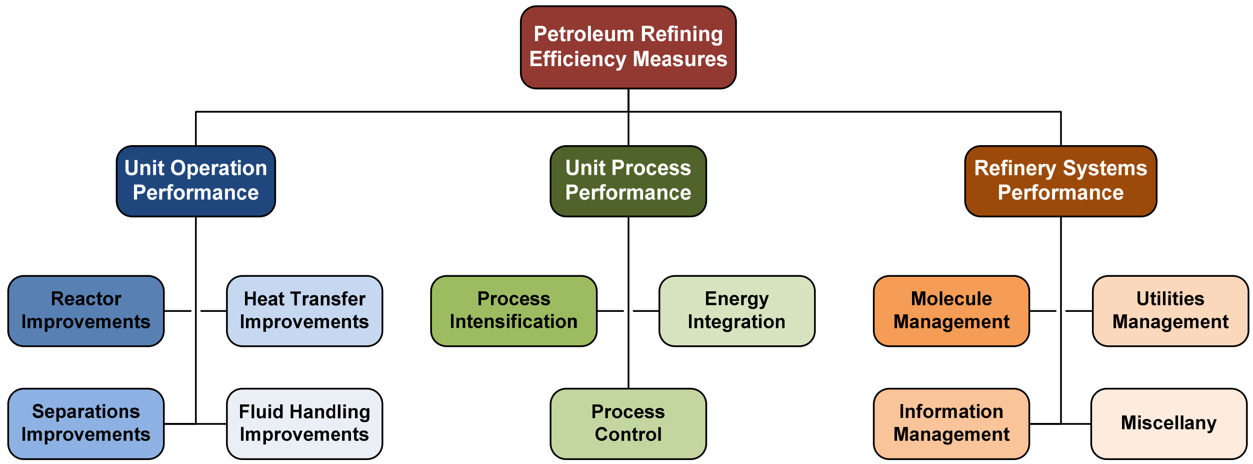


Figure 4 – Efficiency Improvement Hierarchy

2.2 Measure Costing Methodology

The cost of conserved energy for an energy-efficiency measure can be calculated with the following equation:

$$CCE = \frac{I \times q + (M - B)}{ES}$$

where:
CCE - Cost of Conserved Energy, \$/GJ
I - *Added* Capital Cost, \$
q - Capital Recovery Factor, yr^{-1}
M - Non-Energy Annual increases in O&M costs, \$
B - Annual decreases in O&M costs due to non-energy productivity improvements, \$
ES - Annual Energy Savings, GJ/yr

Assigning capital costs to the energy efficiency measures described can be problematic, even when the cost of any new equipment is known, since energy efficiency projects involve modifications to an existing plant. This is especially true when considering major process modifications, such as improved heat integration. Several items must be known in order to make this estimate: the number and character of the new equipment to be added, the added cost of the equipment, and the added cost of installation. The first item may be difficult to estimate if some of the existing equipment is to be re-used. The last item is particularly tricky for projects that involve re-working an existing process. Examples of these types of projects are heat integration and piping network modifications.

The capital recovery factor of 17.1% was assumed for the analysis. The capital recover factor is used to convert unit capital costs to cost per unit energy savings (e.g., \$/GJ) for energy efficiency measures. All costs are in year 2010 dollars.

Any given energy measure applied may result either in increases, decreases or both in annual non-energy operating and maintenance (O&M) costs. Many of the measures considered in Section 3 to reduce fuel requirements, also result in decreases or increases in electricity usage; however, the value of incremental changes in electricity purchases are excluded from the CCE calculation. Other increases in O&M considered result from additional costs associated with improved catalysts and other process consumables.

The algorithm used to order the CCE values of energy measures from lowest to highest begins with a base case representation of a refinery that has not implemented any of the energy measures identified. The algorithm then examines all of these measures separately and selects the measure with the lowest cost of conserved energy. This becomes the basis for the next iteration and the procedure is repeated until all of the measures have been accounted for. This methodology implicitly accounts for changes in the cost of conserved energy for any specific measure due to the implementation of measures selected earlier in the sequence.

3. FUEL-USAGE ABATEMENT

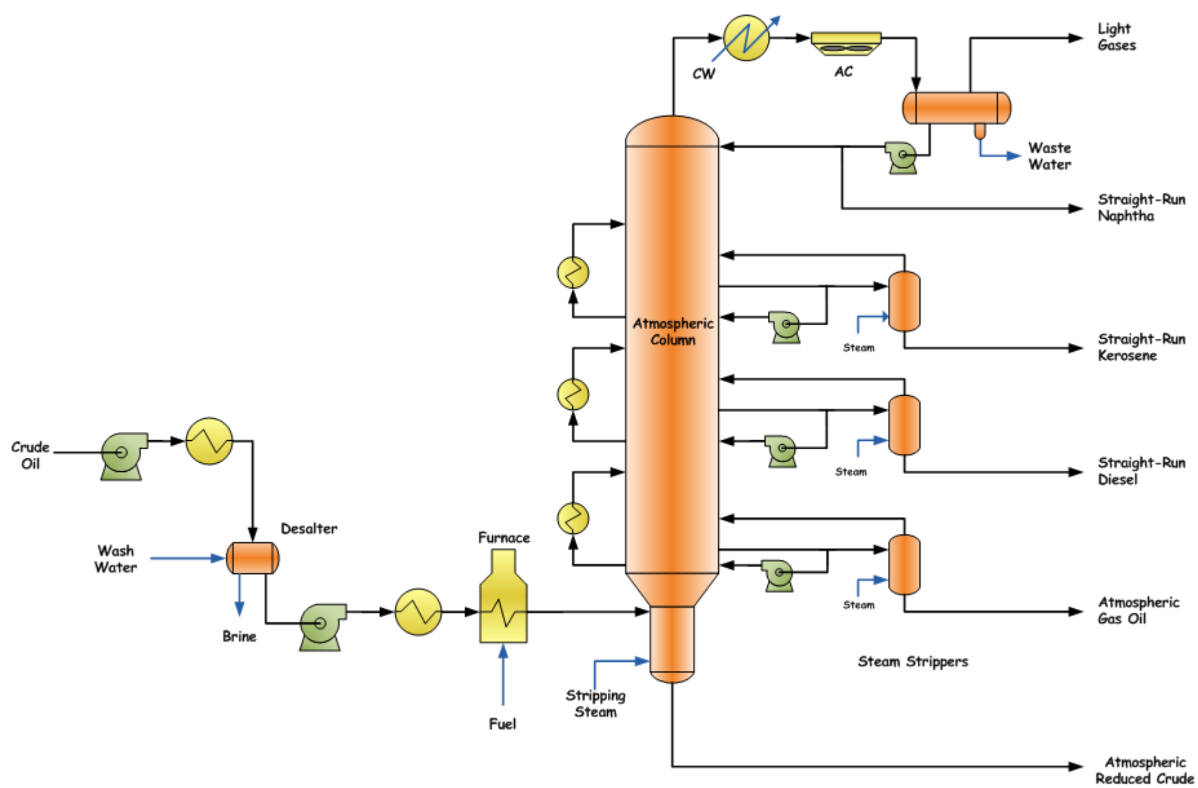
In this section, the individual supply curves for all twelve of the unit processes that make up the notional refinery are presented. Each sub-section below covers an individual unit-process, and includes: a description of the process and its function; a simplified process flow diagram identifying component unit operations that make up the process and impact energy usage; a listing of relevant fuel-usage abatement measures; and a corresponding energy efficiency cost of conserved combined fuel and associated electricity supply curve developed for the unit process based on these measures. Current U.S. penetration rate assumptions, final energy savings (both fuel and associated electricity), and costs per measure are presented in tables following each processing unit supply curve. All data and supply curves are for 2010 representation of the petroleum refinery sector. A cumulative cost of conserved combined fuel and associated electricity for the aggregate refinery sector is presented following the individual process unit sections along with aggregated CO_2 emissions reductions in Section 4.

As discussed in Section 2, each unit process found in the notional representation of the U.S. petroleum refining sector was analyzed separately to qualify and quantify potential energy abatement measures. In addition to measures that bare directly on unit-process fuel and electricity usage, (*e.g.*, furnace efficiency or process pumping efficiency improvements) or indirectly (*e.g.*, steam utilization improvements), measures solely affecting energy usage of major refinery offsites (*e.g.*, boiler efficiency improvements) have been allocated to each unit process based on a weighted distribution of unit consumption of total offsite energy generation. This procedure allows composite fuel and electricity-usage abatement curves to be generated by simply adding together the individual unit-process curves. Measures are selected for their impact of fuel energy conservation but in many cases, they also have an effect (either decreasing or increasing) on electricity usage. Therefore, electricity impacts are included in the fuel conservation supply curves by converting electricity (e.g., kWh) to fuel energy (e.g. joules) using a conversion factor (1kWh = 3.6 MJ). However, this excludes the fuel used to generate electricity and is intended to reflect final energy consumption within the petroleum refining sector. CO_2 emissions are calculated using the IPCC natural gas conversion factor of 0.0561 Mt CO_2/PJ [IPCC 2006]. It is assumed that the marginal electricity consumption within the petroleum refinery sector is grid purchased electricity. A 2010 U.S. average CO_2 emissions factor of 0.572 Mt CO_2/TWh is used to convert electricity saving into grid level CO_2 emissions[1].

3.1 Crude Distillation Unit (CDU)

The crude distillation unit is the first process encountered in a petroleum refinery. It consists of three integrated processes: a desalter removes naturally occurring salts found in produced crude oil by means of a water wash and electrostatic separation; an atmospheric crude-distillation unit (ACU), where heat and steam are employed to separate the crude oil into boiling point-based fractions at near atmospheric pressure; and a vacuum crude-distillation unit (VCU), where heat and steam are employed to separate the bottom stream from the atmospheric unit into boiling point-based fractions at vacuum pressures. Steam ejectors are commonly used in refining to pull a vacuum. It should also be noted that not all refineries have vacuum units.

Figure 5 and Figure 6 are schematic depictions of the desalter/ACU and the VCU, respectively. Individual liquid products from distillation are steam-stripped of lower-boiling components in side strippers associated with the ACU. Since crudes from around the world vary in character, the amounts of the various products produced off the CDU are different for different crude oils. In addition, the overall configuration of a petroleum refinery and product slate variation will be reflected in which products are produced from the CDU.



[1] This is calculated from 2,270 Mt CO_2 of electricity sector emissions associated with 3,971 TWh of electricity production reported in EIA AEO 2012 [EIA, 2012]

Figure 5 – Deslater & Atmospheric Crude Unite Process Flow Diagram

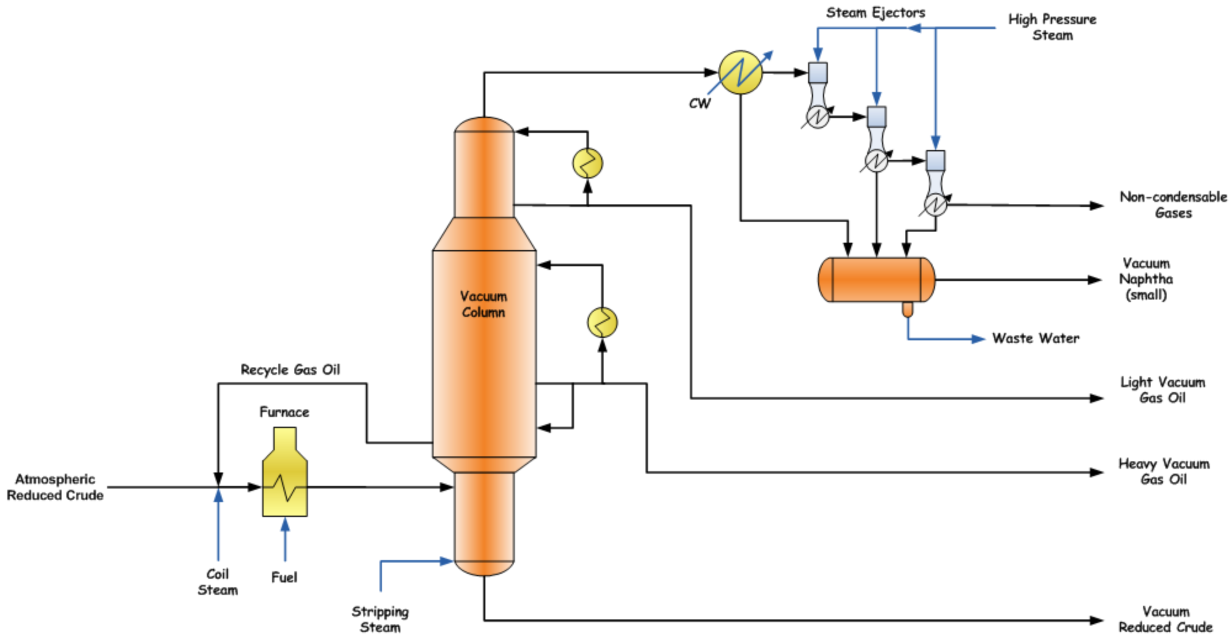


Figure 6 – Vacuum Crude Unite Process Flow Diagram

Table 2 categorizes efficiency improvement measures related to fuel, steam, and cooling water uses and many of the measures have an impact on electricity usage.

Table 2 – CDU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration (low cost)
	Revamp of heat integration (high cost)
	Install overhead chillers to reduce heat duty
	Install new higher-efficiency atmospheric column internals
	Install new higher-efficiency vacuum column internals
	Reduce hot rundown/storage between atm and vacuum columns
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce Process Steam Requirements	Replace naphtha stripping with naphtha splitter
	Add steam recycle with steam ejector to vacuum column
	Install vacuum pump to replace overhead steam ejectors

In addition to the above unit-process related measures, measures associated with offsites utilized by the CDU are included in the CDU supply curve. These include overhead gas processing, steam and power supply, and water treatment. The fuel-usage and associated electricity-usage abatement curve is shown in Figure 7, and each measure's fuel and electricity savings as well as the combined fuel and electricity savings and costs are shown in Table 3.

Figure 7 – Desalter, CDU, and VDU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

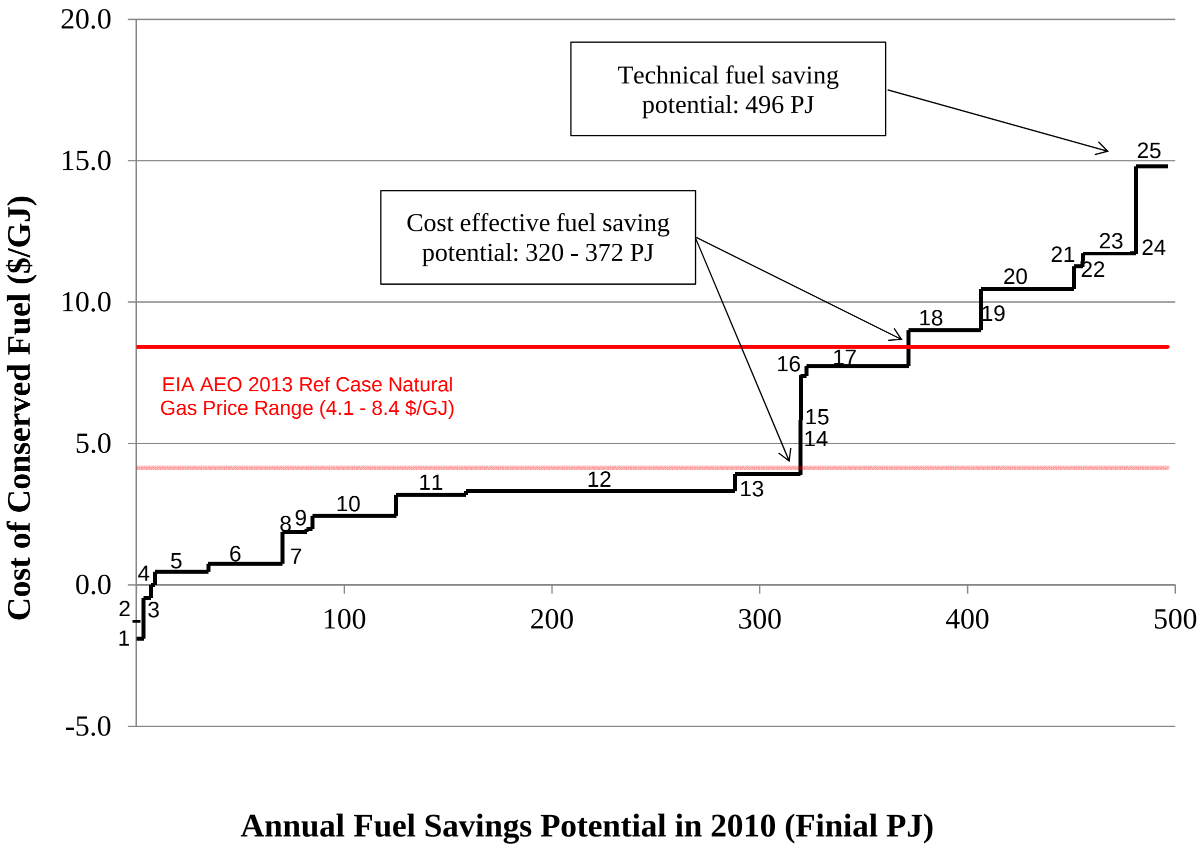


Table 3 – CDU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce stand-by boiler requirements	50%	3.3	0.0	3.3	-$1.90
2	Reduce hot rundown/storage between ACU & VDU	50%	3.6	0.0	3.6	-$0.47
3	Recover blow down steam	90%	0.8	6.6	0.8	$0.00

4	Replace naphtha stripping with naphtha splitter	90%	1.2	0.0	1.2	$0.00
5	Reduce boiler blow down/water treatment	50%	25.7	0.0	25.7	$0.47
6	Add steam recycle with steam ejector to VDU	20%	35.8	0.0	35.8	$0.75
7	Reduce background flaring	20%	0.0	0.0	0.0	$0.82
8	Integrate gas processing unit with ISBL	80%	11.5	33.3	11.6	$1.87
9	Improved maintenance/steam lines & traps	50%	2.7	0.0	2.7	$1.97
10	Reduce fouling of steam and power systems tube surfaces	40%	39.8	171.9	40.4	$2.45
11	Reduce coking of heat transfer surfaces in CDU	60%	33.7	0.0	33.7	$3.19
12	Install vacuum pump to replace overhead steam ejectors	50%	129.3	0.0	129.3	$3.31
13	Efficient burners/control of excess air in CDU	50%	31.6	0.0	31.6	$3.91
14	Install new higher-efficiency atmospheric column internals	0%	0.1	0.0	0.1	$5.66
15	Install overhead chillers to reduce heat duty in CDU	40%	0.0	26.2	0.1	$5.82
16	Revamp GPU heat integration	0%	2.8	0.0	2.8	$7.40
17	Install new GPU internals	0%	49.1	0.0	49.1	$7.73
18	Install flare gas recovery system	0%	34.1	161.3	34.7	$9.01
19	Install furnace air pre-heater in CDU	0%	0.0	43.7	0.2	$9.84
20	Increase steam line insulation	0%	44.2	143.3	44.7	$10.47
21	Increase insulation & reduce air infiltration in steam and power systems	0%	4.0	60.9	4.2	$11.26
22	Revamp of heat integration (high cost) in CDU	0%	0.0	43.7	0.2	$11.44
23	Install new higher-efficiency VDU internals	0%	22.1	153.0	22.7	$11.71
24	Increase insulation & reduce air infiltration in CDU	0%	2.8	0.0	2.8	$11.72
25	Increase insulation & reduce air infiltration in GPU	0%	15.2	0.0	15.2	$14.80

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.2 Coking Unit (CKU)

The coking unit processes the bottom-of-the-barrel, vacuum reduced crude or other petroleum residuals. Not all refineries have coking units, but those that do can produce additional incremental volumes of liquids boiling in the gasoline or diesel range. These liquids, however, are of low quality and must be upgraded prior to blending into finished fuel products. Figure 8 depicts a delayed coking operation; by far the most common coking technology being practiced industrially; however, fluid coking is employed in a small number of refineries in the U.S. In addition to coking, visbreaking, solvent deasphalting and residual oil hydrocracking technologies can also be used to upgrade the bottom of the barrel, but are also uncommon in the U.S.

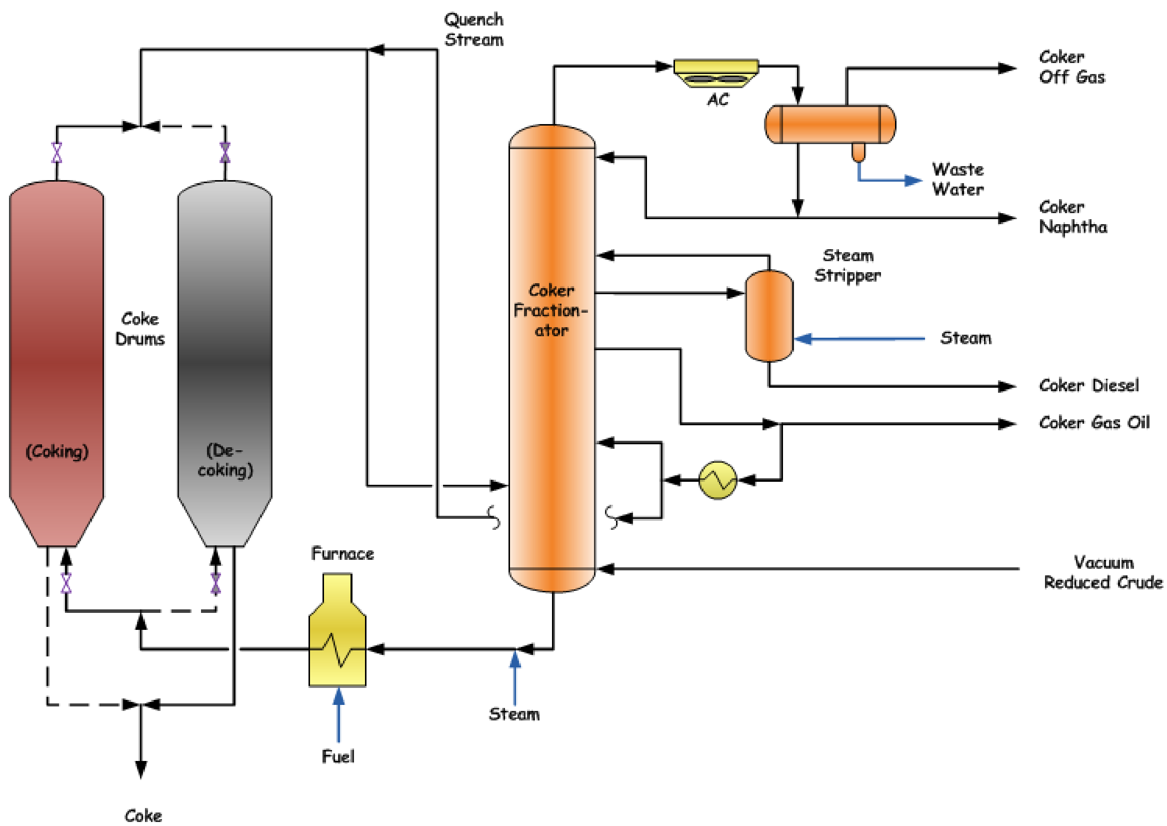


Figure 8 – Delayed Coking Unite (CKU) Process Flow Diagram

The CKU consists of a reaction section (coke drums) and a fractionation section. Within the coke drums, the feed is thermally decomposed (cracked) into a high carbon-content solid (petroleum coke), and lighter liquid and gaseous hydrocarbons. The coke is periodically removed from the drums using hydraulic drills. At least two drums are used, and cycled to achieve a continuous operation. The overhead hydrocarbons are fractionated in a distillation column, which is similar to the ACU, but much less complex. Table 4 categorizes efficiency improvement measures related to fuel, steam, and cooling water uses and many of the measures have an impact on electricity usage.

Table 4 – CKU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration (low cost)
	Revamp of heat integration (high cost)

	Install overhead chiller to lower condenser temperature
	Install new higher-efficiency column internals
	Reduce hot rundown/storage between vacuum column and coker
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce Process Steam Requirements	None identified

In addition to the above unit-process related measures, measures associated with offsites utilized by the CKU are included in the CKU supply curves. These include overhead gas processing, acid gas removal, steam and power supply, and water treatment. The fuel-usage abatement curve is shown in Figure 9.

Figure 9 –CKU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

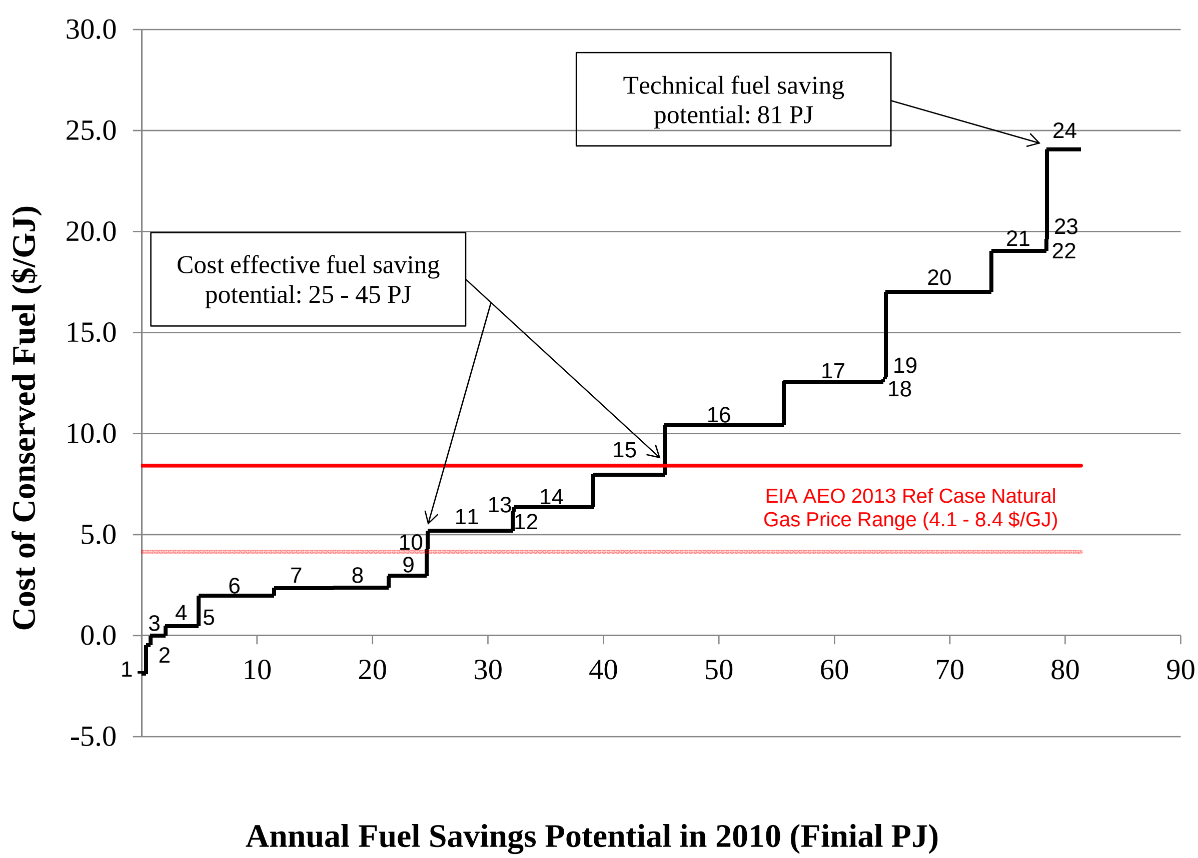


Table 5 – CKU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.4	0.0	0.4	-$1.90
2	Recover Blowdown Steam	50%	0.4	0.0	0.4	-$0.47
3	Install SRU Waste Heat Boiler	90%	1.3	0.0	1.3	$0.00
4	Reduce Boiler Blowdown/Water Treatment	50%	2.9	0.0	2.9	$0.47
5	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
6	Integrate GPU w/ISBL Units	80%	6.5	15.8	6.5	$1.97
7	Integrate AGR w/ISBL Units	80%	5.1	10.3	5.1	$2.36
8	Increase AGR Solvent Concentration	50%	4.8	10.6	4.8	$2.37
9	Integrate SWS w/ISBL Units	80%	3.3	6.7	3.3	$2.95
10	Improved Maintenance/Steam Lines & Traps	50%	0.1	0.0	0.1	$4.28
11	Reduce Coking of CKU Tube Surfaces	60%	7.4	0.0	7.4	$5.18
12	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
13	Revamp GPU Heat Integration	40%	0.0	12.4	0.0	$6.15
14	Efficient CKU Burners/Control X Air	50%	6.9	0.0	6.9	$6.35
15	Revamp CKU Heat Integration (low-cost)	40%	5.8	100.0	6.2	$7.97
16	Install New CKU Internals	0%	9.7	172.8	10.3	$10.41
17	Install CKU Furnace Air Pre-Heat	0%	8.6	0.0	8.6	$12.57
18	Increase Steam Line Insulation	0%	0.1	0.0	0.1	$12.70
19	Install New GPU Internals	0%	0.0	20.7	0.1	$12.79
20	Install CKU Overhead Chillers	0%	8.6	149.4	9.1	$17.02
21	Revamp CKU Heat Integration (high-cost)	0%	4.3	84.6	4.6	$19.03
22	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$19.05
23	Install GPU Overhead Chillers	0%	0.0	20.7	0.1	$19.63
24	Insulation/Reduce CKU Air Infiltration	0%	2.9	0.0	2.9	$24.06

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.3 Catalytic Cracking Unit (CCU)

The catalytic cracking unit processes primarily atmospheric, vacuum and coker gas oils, though some units in the U.S. have been modified to process heavier residual oils. Approximately, half of the gas oils processed in the U.S. are hydro-processed before cracking, to improve unit yields and product quality. In the cat cracker, the feed oil is catalytically cracked to produce products boiling in the gasoline and diesel range, along with refinery gas liquids (three and four carbon hydrocarbons). Cat crackers can be operated in a number of different modes to either maximize gasoline, diesel or gas liquids used for petrochemicals manufacture. In the U.S., most units have traditionally operated to maximize gasoline production; however, in light of mandates to blend ethanol with petroleum-derived gasoline, refiners have revamped many units to increase yield of diesel. Gasoline produced from the cat cracker has a high octane rating, but must be de-sulfurized prior to blending. The diesel must also be de-sulfurized and has a low cetane rating, which can be improved by hydrotreatment. The most common catalytic cracking technology employed today is based on advanced fluid-bed reactors. Figure 10 is a depiction of the catalytic cracking process.

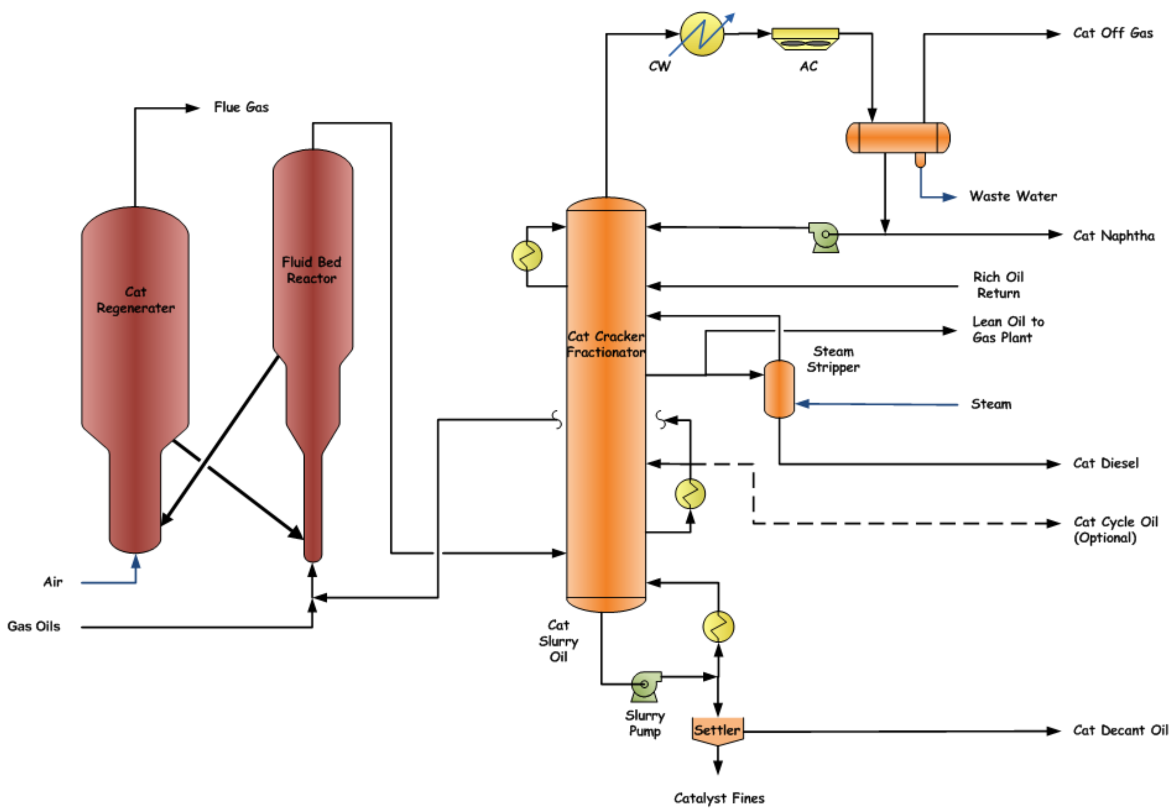


Figure 10 – Gail-Oil Catalytic Cracking Unit (CCU) Process Flow Diagram

The CCU consists of reaction, catalyst regeneration, and fractionation sections. Within the fluid-bed reactor, the feed is catalytically cracked producing lighter liquid and gaseous hydrocarbons. As part of this process, the fine catalyst particles become coated with a high carbon-content solid (catalyst coke) and lose their catalytic activity. Therefore to maintain activity, the catalyst is continuously cycled to a fluid-bed regenerator, where this coke is burned off, and returned to the reactor. The overhead hydrocarbons are fractionated in a distillation column, which is similar to the ACU, but less complex. Table 6 categorizes efficiency improvement measures related to fuel, steam, and cooling water uses and many of the measures have an impact on electricity usage.

Table 6 – CCU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage

Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chiller to lower condenser temperature
	Install new higher-efficiency column internals
	Reduce hot rundown/storage between upstream units and cracker
Reduce Regenerator Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient combustion/Control of excess air
	Increase insulation on regenerator and reactor
Reduce Process Steam Requirements	Replace steam drive on air compressor with electric drive
	Install HRSG downstream of regenerator
	Install CO-burning HRSG downstream of regenerator

In addition to the above unit-process related measures, measures associated with offsites utilized by the CCU are included in the CCU supply curves. These include overhead gas processing, acid gas removal, steam and power supply, and water treatment. The fuel-usage abatement curve is shown in Figure 11.

Figure 11 – CCU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

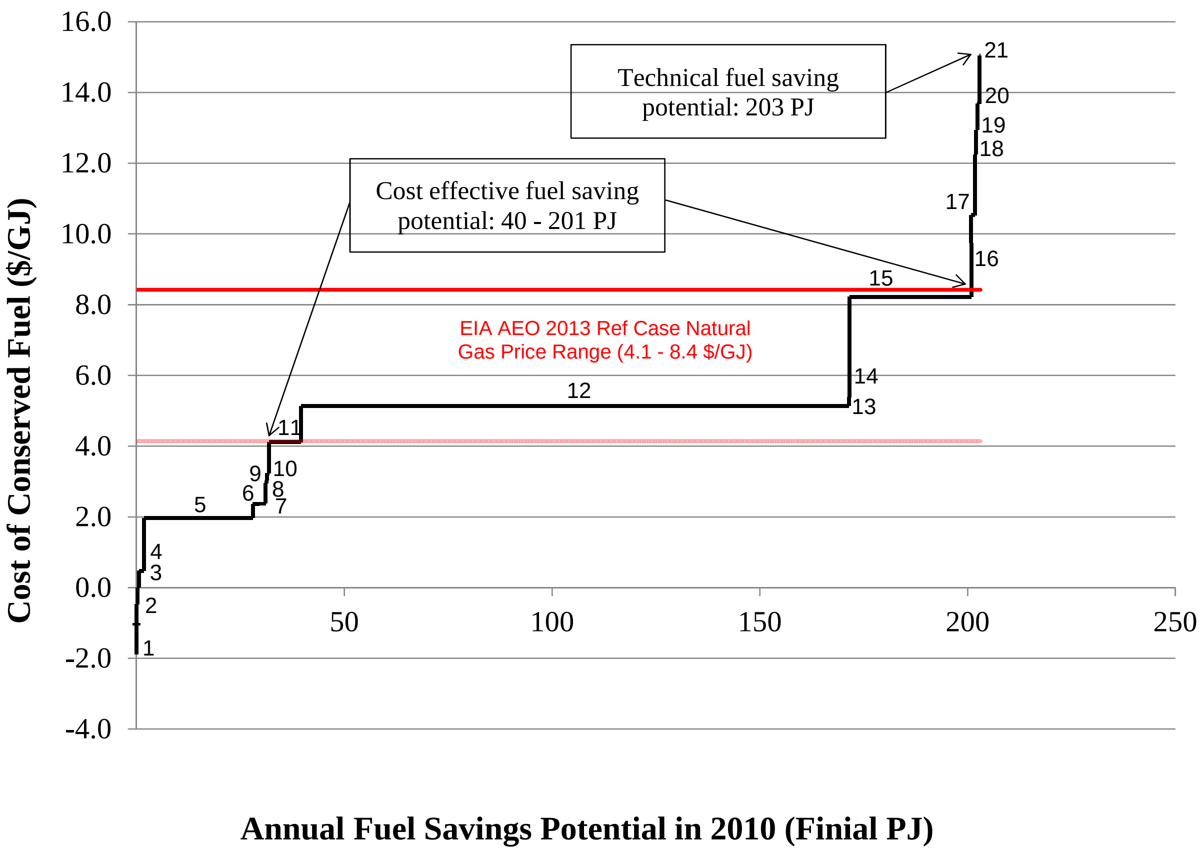


Table 7 – CCU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Recover Blowdown Steam	50%	0.2	0.0	0.2	-$0.47
2	Install SRU Waste Heat Boiler	90%	0.4	0.0	0.4	$0.00
3	Reduce Boiler Blowdown/Water Treatment	50%	1.2	0.0	1.2	$0.47
4	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
5	Integrate GPU w/ISBL Units	80%	26.0	56.6	26.2	$1.97
6	Integrate AGR w/ISBL Units	80%	1.6	3.2	1.6	$2.36
7	Increase AGR Solvent Concentration	50%	1.5	3.3	1.5	$2.37
8	Integrate SWS w/ISBL Units	80%	0.3	0.5	0.3	$2.95
9	Improved Maintenance/Steam Lines & Traps	50%	0.1	0.0	0.1	$3.03
10	Revamp CCU Heat Integation (low-cost)	40%	0.0	143.2	0.5	$3.22
11	Replace Steam Drives w/Elec on Air Compressors	50%	8.0	-87.0	7.7	$4.11
12	Install HRSG Post Regenerator	70%	131.8	0.0	131.8	$5.14
13	Revamp GPU Heat Integation	40%	0.0	44.6	0.2	$5.38
14	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
15	Install CO-burning HRSG Post Regenerator	40%	29.3	0.0	29.3	$8.22
16	Increase Steam Line Insulation	0%	0.0	0.0	0.0	$9.73
17	Install New CCU Internals	0%	0.0	242.2	0.9	$10.53
18	Install CCU Overhead Chillers	0%	0.0	90.3	0.3	$12.24
19	Install New GPU Internals	0%	0.0	74.3	0.3	$12.94
20	Revamp CCU Heat Integation (high-cost)	0%	0.0	129.9	0.5	$13.68
21	Install GPU Overhead Chillers	0%	0.0	74.3	0.3	$15.05

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.4 Hydrocracking Unit (HCU)

Hydrocrackers can be designed and operated to process a variety of streams found in the petroleum refinery, ranging from naphthas to vacuum residuals. Not all U.S. refineries include a hydrocracker, but in those that do, the feedstock is most typically medium to heavy gas oil. A few refineries also process residual oils in specially designed hydrocracking units. Like a cat cracker, a hydrocracker can be operated in a number of different modes to either maximize gasoline, jet or diesel fuel production. However, operation of a hydrocracker is more flexible, and yields can be more easily changed to match prevailing market conditions for gasoline, jet and diesel. Recently, U.S. refiners have been adding hydrocracking capacity to adjust to structural changes in the U.S. transportation-fuels mix.

Naphtha, jet and diesel produced from the hydrocracker are of very good quality and are low in sulfur. To improve octane rating, light naphtha may be processed in an isomerization unit; whereas, the heavy naphtha must be catalytically reformed. Most hydrocracking technology relies on fixed-bed reactors; however, units may be designed to have either one or two catalyst beds and may or may not include a recycle stream to improve conversion. Figure 12 is a depiction of a two-bed hydrocracking process with no gas oil recycling.

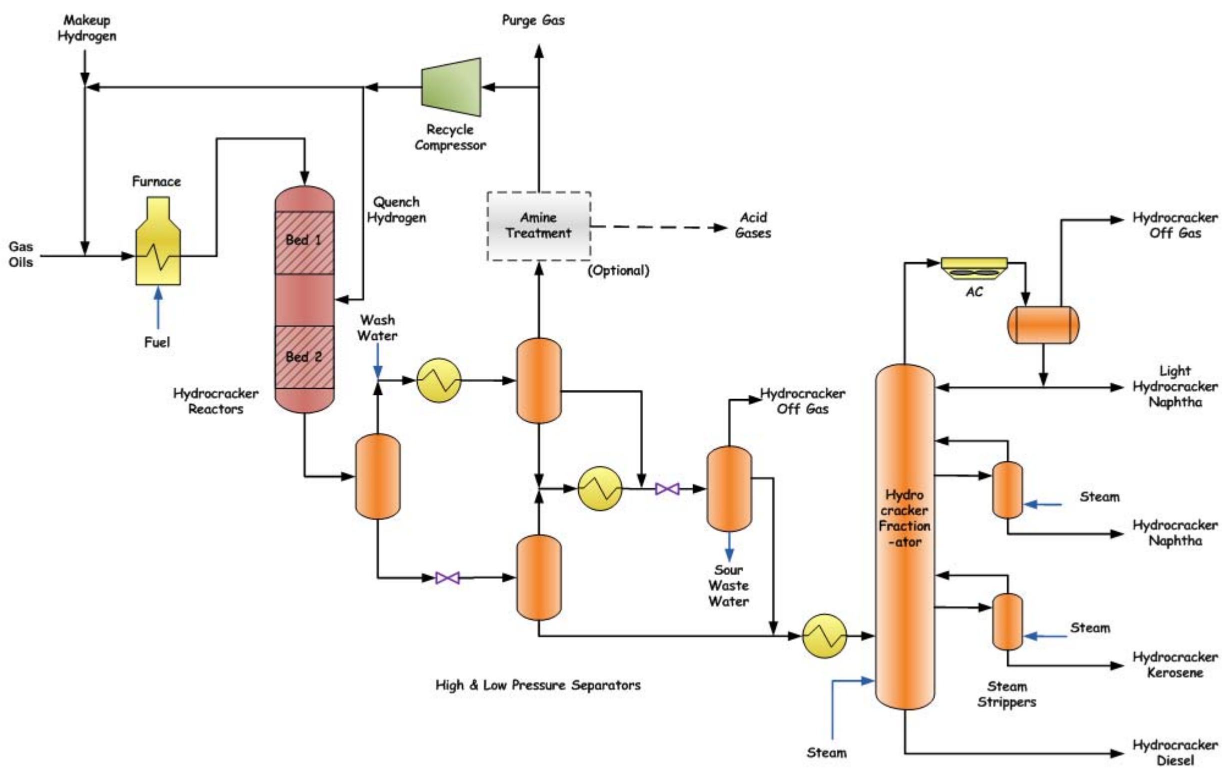


Figure 12 – Gas-Oil Hydrocracking Unit (HCU) Process Flow Diagram

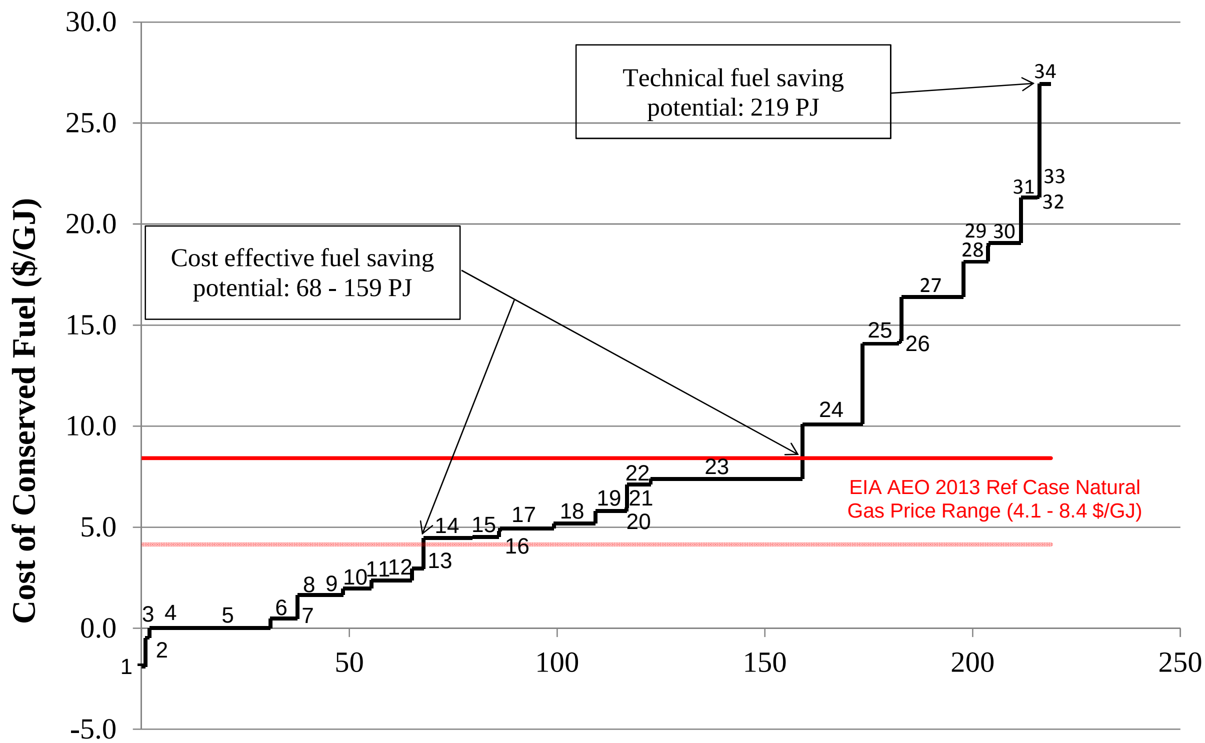
The HCU consists of reaction, gas-liquid separation, and fractionation sections. Hydrogen gas is contacted with the fresh gas-oil feed and flows through two fixed-bed reactors arranged in series. Hydrogen reacts with the feed at elevated pressures and temperatures in the presence of a catalyst to crack the gas oil and produce naphtha and light distillates, along with some LPG. The vapor/liquid leaving the reactor section is cooled and de-pressurized in order to separate methane, ethane, and unreacted hydrogen from the heavier hydrocarbon liquid. This gas may then be treated to remove hydrogen sulfide and ammonia. A portion of the gas is recycled to the reactors to reduce overall hydrogen consumption. The liquids from separation are fractionated in a distillation column, which is similar to the ACU. Table 8 categorizes efficiency improvement measures related to fuel, steam, cooling water, and hydrogen usage with many of the measures having an impact on electricity usage.

Table 8 – HCU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration (low cost)
	Revamp of heat integration (high cost)
	Install overhead chiller to lower condenser temperature
	Install new higher-efficiency column internals
	Reduce hot rundown/storage between upstream units and cracker
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce Process Steam Requirements	Replace recycle compressor steam-drive with electric
Reduce H_2 Make-Up Requirements	Improve reactors/catalysts to reduce hydrogen consumption
	Install membrane/PSA to recover high-purity hydrogen

In addition to the above unit-process related measures, measures associated with offsites utilized by the HCU are included in the HCU supply curves. These include hydrogen production, overhead gas processing, acid gas removal, steam and power supply, and water treatment. The fuel-usage abatement supply curve is shown in Figure 13.

Figure 13 – HCU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve



Annual Fuel Savings Potential in 2010 (Finial PJ)

Table 9 – HCU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.9	0.0	0.9	-$1.90
2	Recover Blowdown Steam	50%	1.0	0.0	1.0	-$0.47
3	Install SRU Waste Heat Boiler	90%	1.3	0.0	1.3	$0.00
4	Install SMR Waste Heat Boiler	90%	7.7	0.0	7.7	$0.00
5	Install PSA to recover high-purity H2	80%	20.0	14.1	20.1	$0.00
6	Reduce Boiler Blowdown/Water Treatment	50%	6.5	0.0	6.5	$0.47
7	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
8	Improve SMR catalysts to reduce steam consumption	30%	5.5	0.0	5.5	$1.65
9	Improve WGS catalysts to reduce steam consumption	30%	5.5	0.0	5.5	$1.65
10	Integrate GPU w/ISBL Units	80%	6.7	19.6	6.8	$1.97
11	Integrate AGR w/ISBL Units	80%	5.0	10.2	5.1	$2.36

12	Increase AGR Solvent Concentration	50%	4.7	10.5	4.7	$2.37
13	Integrate SWS w/ISBL Units	80%	2.7	5.5	2.7	$2.95
14	Revamp HCU Heat Integration (low-cost)	40%	11.8	12.3	11.8	$4.46
15	Replace Steam Drives w/Elec on Rec Compressors	40%	6.3	-11.0	6.3	$4.52
16	Improved Maintenance/Steam Lines & Traps	50%	0.3	0.0	0.3	$4.79
17	Reduce Coking of SMR Tube Surfaces	50%	12.9	0.0	12.9	$4.94
18	Efficient SMR Burners/Control X Air	50%	10.0	0.0	10.0	$5.18
19	Reduce Coking of HCU Tube Surfaces	50%	7.6	0.0	7.6	$5.80
20	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
21	Revamp GPU Heat Integation	40%	0.0	15.4	0.1	$6.15
22	Efficient HCU Burners/Control X Air	50%	5.7	0.0	5.7	$7.11
23	Improve catalysts to reduce H2 consumption	0%	36.5	31.1	36.6	$7.39
24	Install SMR Boiler Feed Water pre-Heat	0%	14.4	0.0	14.4	$10.10
25	Install HCU Furnace Air Pre-Heat	0%	8.8	0.0	8.8	$14.07
26	Increase Steam Line Insulation	0%	0.6	0.0	0.6	$14.22
27	Install New HCU Internals	0%	14.8	20.8	14.8	$16.39
28	Insulation/Reduce SMR Air Infiltration	0%	6.0	0.0	6.0	$18.14
29	Install New GPU Internals	0%	0.0	25.7	0.1	$18.90
30	Install HCU Overhead Chillers	0%	7.8	-33.5	7.7	$19.06
31	Revamp HCU Heat Integration (high-cost)	0%	3.9	14.1	4.0	$21.30
32	Revamp Steam Distribution/Reduce P Drop	0%	0.5	0.0	0.5	$21.33
33	Install GPU Overhead Chillers	0%	0.0	25.7	0.1	$21.98
34	Insulation/Reduce HCU Air Infiltration	0%	2.7	0.0	2.7	$26.94

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.5 Hydrotreating Units (HTU)

Hydrotreating units can be designed and operated to process a variety of streams found in the petroleum refinery, ranging from naphthas to residual oils. In fact, most refineries employ multiple hydrotreaters to pretreat streams prior to further processing or product blending. Hydrotreaters are used to remove contaminants in the oil, such as sulfur and nitrogen. The notional U.S. refinery modeled for this analysis contains five separate units:

1) **Cat Feed Hydroteating Unit (**CTU) which processes cat cracker gas-oil feedstocks to remove sulfur and nitrogen, and to lower conradsen carbon content, which is an indicator of the coking tendency of a feedstock. Operating conditions can range from mild to severe with some hydrocracking occurring at the more severe conditions. Potential

feedstocks include atmospheric and vacuum gas oils from the ACU and VCU, respectively, and coker gas oil;

2) **Diesel Hydrotreating Unit** (DTU) which processes oils boiling in the kerosene-diesel range to remove sulfur and nitrogen, and to saturate olefinic and aromatic compounds. Normally, aromatics are only partially saturated. Operating conditions are severe, and some cracking occurs. The products are suitable for blending into specification diesel fuel. Potential feedstocks include straight-run diesel from the ACU, coker diesel, and cat diesel streams;
3) **Kerosene Hydrotreating Unit** (KTU) which processes oils boiling in the kerosene-diesel range to remove sulfur and nitrogen, and to saturate olefinic and aromatic compounds. Operating conditions are less severe and de-sulfurization is less than complete; very little cracking occurs. The products are suitable for blending into specification jet fuel and distillate fuel oil. Potential feedstocks are primarily straight-run kerosene and diesel from the ACU;
4) **Naphtha Hydrotreating** (NTU) which processes straight-run and coker naphtha to remove sulfur and nitrogen, and to saturate any olefins present in the coker naphtha. Normally, aromatics are only partially saturated. Operating conditions are not severe, and little cracking occurs. Light naphtha from the NTU may be sent to an isomerization unit or directly to gasoline blending. Heavy naphtha is sent to the catalytic reforming unit to boost octane prior to gasoline blending.
5) **Gasoline Hyrotreating Unit** (GTU) which processes heavy cat naphtha to selectively remove sulfur while minimizing saturation of olefinic and aromatic compounds. The product is suitable for blending into gasoline and little or no loss of octane occurs. Operating conditions are not severe, and essentially no cracking occurs.

Most hydrotreating technology relies on fixed-bed reactors, and most units have a single catalyst bed. No product recycle is required. Figure 14 is a depiction of typical fixed-bed hydrotreating operation. Note that the process flow is essentially identical for all of the applications described above and is quite similar to the hydrocracking process described above.

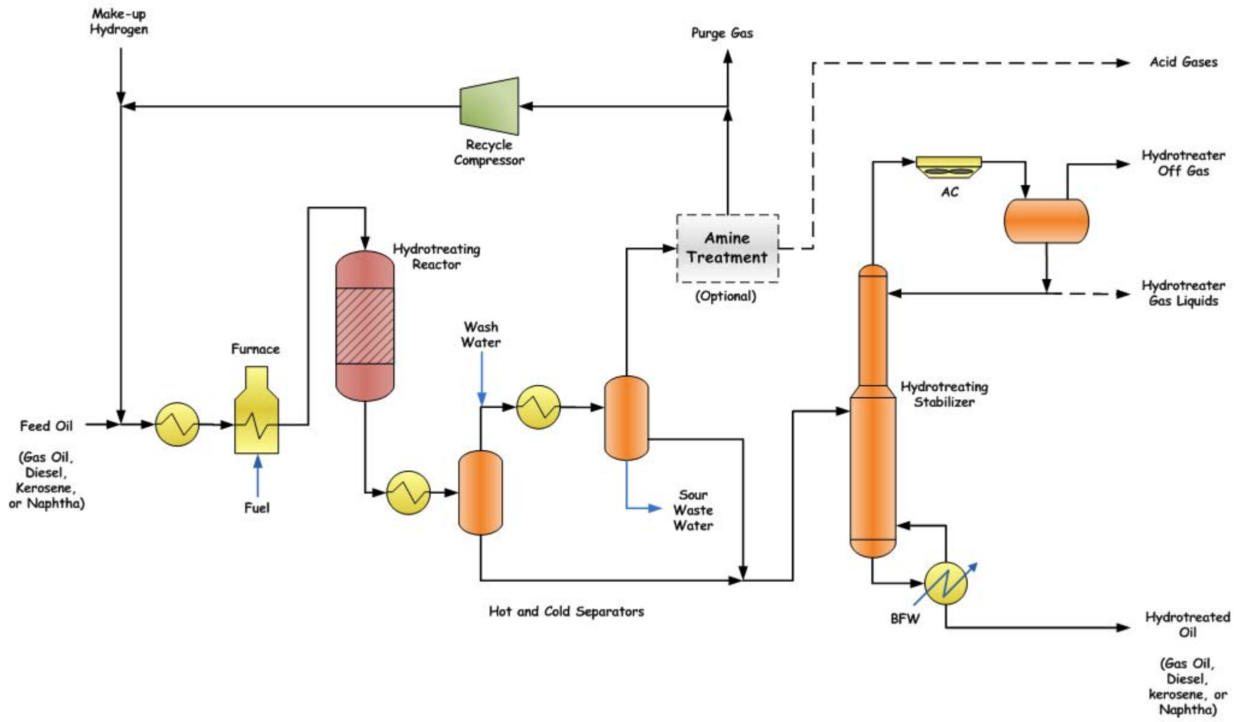


Figure 14 – Hydrotreating Unit (HTU) Process Flow Diagram

The HTU consists of reaction, gas-liquid separation, and fractionation sections. Hydrogen gas is contacted with the fresh feed and flows through a single fixed-bed reactor. Hydrogen reacts with the feed at slightly elevated pressures and moderate temperatures in the presence of a suitable catalyst. In the separation section, the vapors/liquid leaving the reactor is cooled to remove methane, ethane, and unreacted hydrogen. This gas may also be treated to remove hydrogen sulfide and ammonia when operating the reactor at higher severity. A portion of the gas is recycled to the reactors to reduce overall hydrogen consumption. The liquids from separation are stabilized in a distillation column to remove any remaining light hydrocarbons and hydrogen. Table 10 categorizes efficiency improvement measures related to fuel, steam, cooling water, and hydrogen usage with many of the measures having an impact on electricity usage.

Table 10 – HTU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chillers to lower condenser temperature
	Install new higher-efficiency column internals
	Reduce hot rundown/storage between upstream units and treater
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater

	Increase insulation/Reduce air infiltration
Reduce Process Steam Requirements	Replace recycle compressor steam-drive with electric
Reduce H_2 Make-Up Requirements	Improve reactors/catalysts to reduce hydrogen consumption
	Re-use medium-purity hydrogen purge for other application
	Install membrane/PSA to recover high-purity hydrogen

In addition to the above unit-process related measures, measures associated with offsites utilized by the HTU are included in the HTU supply curves. These include hydrogen production, overhead gas processing, acid gas removal, steam and power supply, and water treatment. Fuel-usage abatement supply curves are shown in

Figure 15 through

Table 14 – NTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.2	0.0	0.2	-$1.90
2	Recover Blowdown Steam	50%	0.3	0.0	0.3	-$0.47
3	Install SRU Waste Heat Boiler	90%	0.2	0.0	0.2	$0.00
4	Install SMR Waste Heat Boiler	90%	1.1	0.0	1.1	$0.00
5	Reduce Boiler Blowdown/Water Treatment	50%	1.9	0.0	1.9	$0.47
6	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
7	Improve SMR catalysts to reduce steam consumption	30%	1.0	0.0	1.0	$1.65
8	Improve WGS catalysts to reduce steam consumption	30%	1.0	0.0	1.0	$1.65
9	Integrate GPU w/ISBL Units	80%	0.6	1.8	0.6	$1.97
10	Integrate AGR w/ISBL Units	80%	0.6	1.2	0.6	$2.36
11	Increase AGR Solvent Concentration	50%	0.6	1.3	0.6	$2.37
12	Revamp NTU Heat Integration (low-cost)	0%	14.2	8.6	14.2	$3.53
13	Improved Maintenance/Steam Lines & Traps	50%	0.2	0.0	0.2	$3.79
14	Replace Steam Drives w/Elec on Rec Compressors	40%	16.0	-28.1	15.9	$4.52
15	Reduce Coking of NTU Tube Surfaces	50%	8.2	0.0	8.2	$4.59
16	Reduce Coking of SMR Tube Surfaces	50%	2.3	0.0	2.3	$4.94
17	Efficient SMR Burners/Control X Air	50%	1.7	0.0	1.7	$5.18
18	Efficient NTU Burners/Control X Air	50%	6.2	0.0	6.2	$5.62
19	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
20	Revamp GPU Heat Integration	40%	0.0	1.4	0.0	$6.15
21	Improve catalysts to reduce H2 consumption	0%	6.4	5.4	6.4	$7.39
22	Install SMR Boiler Feed Water pre-Heat	0%	2.5	0.0	2.5	$10.10
23	Increase Steam Line Insulation	0%	0.1	0.0	0.1	$10.65
24	Install NTU Furnace Air Pre-Heat	0%	9.6	0.0	9.6	$11.13
25	Install New NTU Internals	0%	9.7	9.0	9.8	$12.96
26	Install New GPU Internals	0%	0.0	2.4	0.0	$14.16
27	Install NTU Overhead Chillers	0%	8.5	-23.1	8.4	$15.07
28	Install GPU Overhead Chillers	0%	0.0	2.4	0.0	$16.47
29	Revamp NTU Heat Integration (high-cost)	0%	4.3	4.3	4.3	$16.85
30	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$16.87
31	Insulation/Reduce SMR Air Infiltration	0%	1.0	0.0	1.0	$18.14

32	Insulation/Reduce NTU Air Infiltration	0%	2.9	0.0	2.9	$21.30
33	Install PSA to recover high-purity H2	0%	2.7	2.5	2.7	$32.55

Notes:

Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.

* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

Figure 19 for CTU, DTU, KTU, NTU, and GTU, respectively.

Figure 15 – CTU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

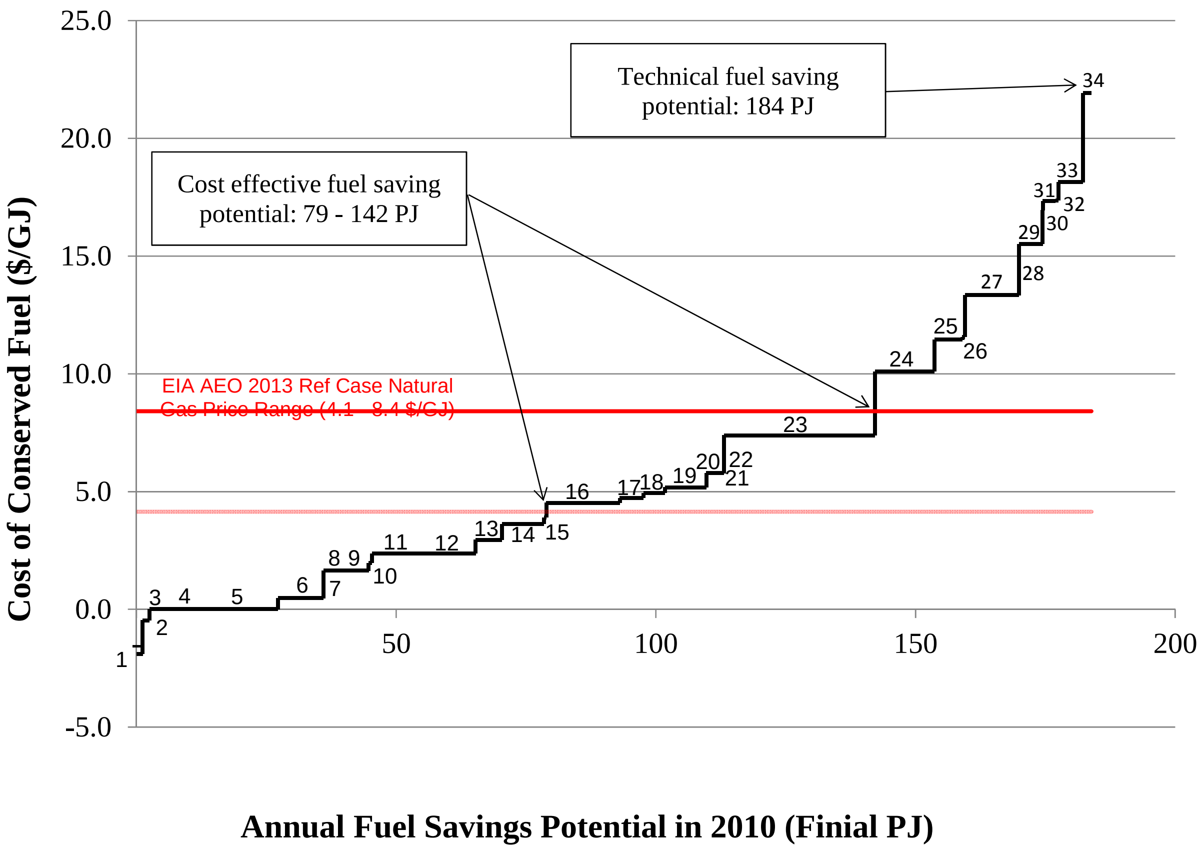


Table 11 – CTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	1.2	0.0	1.2	-$1.90
2	Recover Blowdown Steam	50%	1.3	0.0	1.3	-$0.47
3	Install SRU Waste Heat Boiler	90%	2.7	0.0	2.7	$0.00
4	Install SMR Waste Heat Boiler	90%	6.1	0.0	6.1	$0.00
5	Install PSA to recover high-purity H2	80%	15.9	11.2	15.9	$0.00
6	Reduce Boiler Blowdown/Water Treatment	50%	8.8	0.0	8.8	$0.47
7	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
8	Improve SMR catalysts to reduce steam consumption	30%	4.4	0.0	4.4	$1.65
9	Improve WGS catalysts to reduce steam consumption	30%	4.4	0.0	4.4	$1.65
10	Integrate GPU w/ISBL Units	80%	0.6	1.7	0.6	$1.97
11	Integrate AGR w/ISBL Units	80%	10.2	20.8	10.3	$2.36
12	Increase AGR Solvent Concentration	50%	9.6	21.4	9.7	$2.37
13	Integrate SWS w/ISBL Units	80%	5.0	10.2	5.1	$2.95
14	Revamp HTU Heat Integration (low-cost)	40%	8.0	21.7	8.1	$3.63
15	Improved Maintenance/Steam Lines & Traps	50%	0.4	0.0	0.4	$3.90
16	Replace Steam Drives w/Elec on Rec Compressors	40%	14.3	-25.0	14.2	$4.52
17	Reduce Coking of HTU Tube Surfaces	50%	4.6	0.0	4.6	$4.72
18	Reduce Coking of SMR Tube Surfaces	80%	4.1	0.0	4.1	$4.94
19	Efficient SMR Burners/Control X Air	50%	7.9	0.0	7.9	$5.18
20	Efficient HTU Burners/Control X Air	50%	3.4	0.0	3.4	$5.79
21	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
22	Revamp GPU Heat Integration	40%	0.0	1.4	0.0	$6.15
23	Improve catalysts to reduce H2 consumption	0%	28.9	24.7	29.0	$7.39
24	Install SMR Boiler Feed Water pre-Heat	0%	11.5	0.0	11.5	$10.10
25	Install HTU Furnace Air Pre-Heat	0%	5.3	0.0	5.3	$11.45
26	Increase Steam Line Insulation	0%	0.6	0.0	0.6	$11.57
27	Install New HTU Internals	0%	10.3	36.8	10.4	$13.34
28	Install New GPU Internals	0%	0.0	2.3	0.0	$14.57
29	Install HTU Overhead Chillers	0%	4.8	-54.9	4.6	$15.51
30	Install GPU Overhead Chillers	0%	0.0	2.3	0.0	$16.95
31	Revamp HTU Heat Integration (high-cost)	0%	2.4	24.6	2.5	$17.34
32	Revamp Steam Distribution/Reduce P Drop	0%	0.5	0.0	0.5	$17.36

33	Insulation/Reduce SMR Air Infiltration	0%	4.8	0.0	4.8	$18.14
34	Insulation/Reduce HTU Air Infiltration	0%	1.6	0.0	1.6	$21.93

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

Figure 16 – DTU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

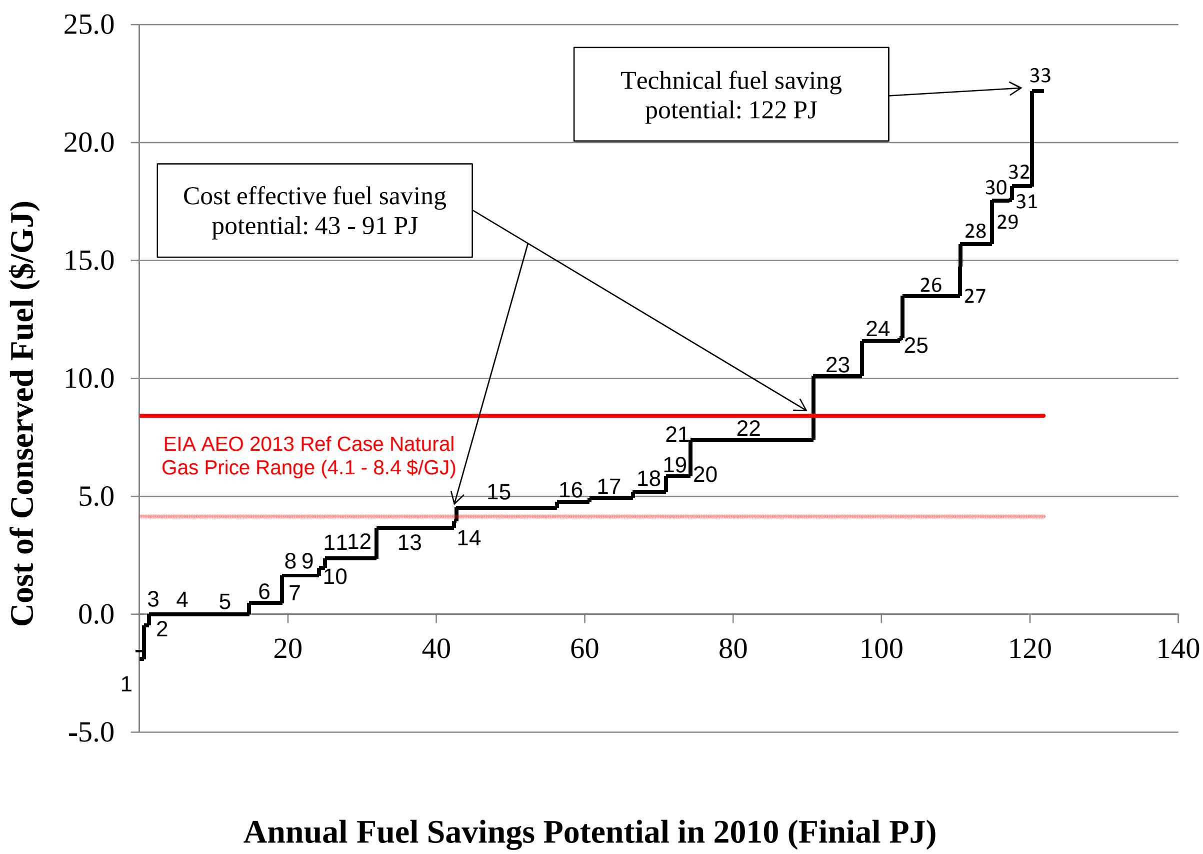


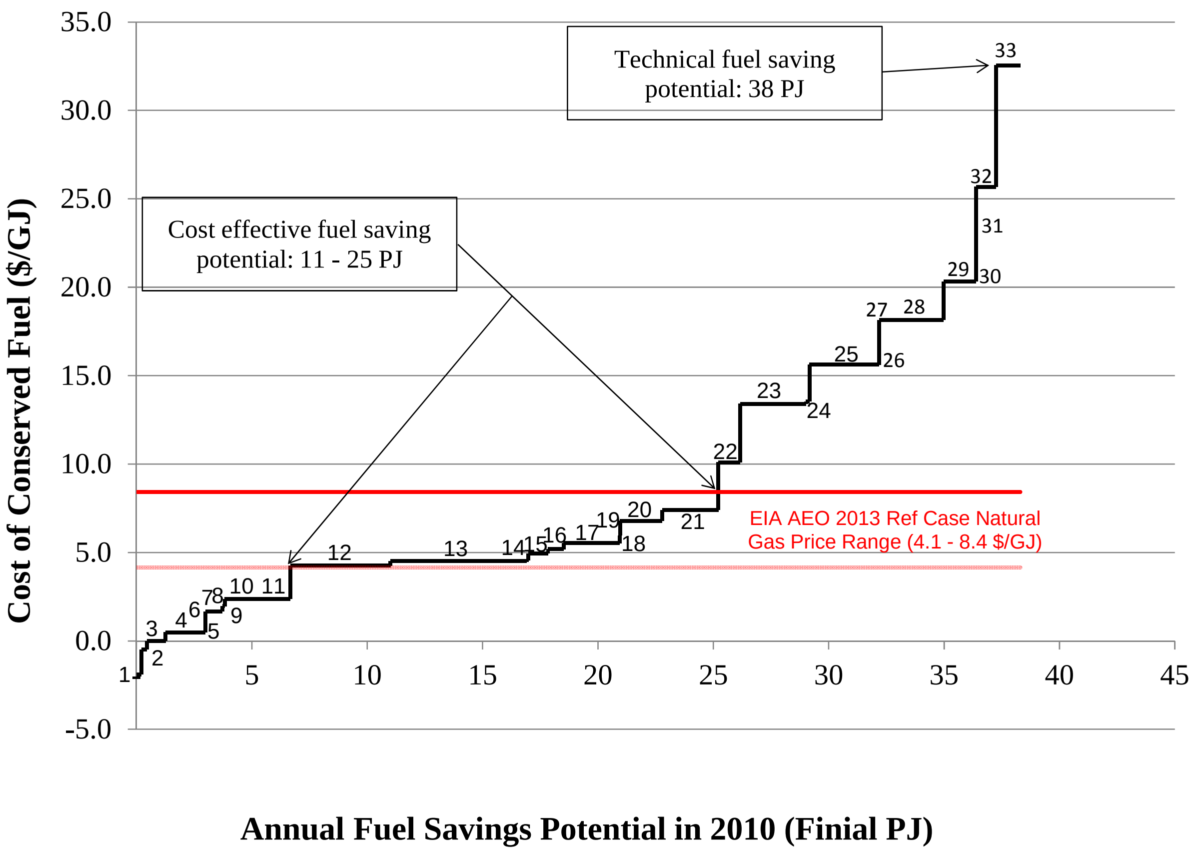
Table 12 – DTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.6	0.0	0.6	-$1.90
2	Recover Blowdown Steam	50%	0.7	0.0	0.7	-$0.47
3	Install SRU Waste Heat Boiler	90%	0.9	0.0	0.9	$0.00
4	Install SMR Waste Heat Boiler	90%	3.5	0.0	3.5	$0.00
5	Install PSA to recover high-purity H2	80%	9.0	6.4	9.1	$0.00
6	Reduce Boiler Blowdown/Water	50%	4.5	0.0	4.5	$0.47

	Treatment					
7	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
8	Improve SMR catalysts to reduce steam consumption	30%	2.5	0.0	2.5	$1.65
9	Improve WGS catalysts to reduce steam consumption	30%	2.5	0.0	2.5	$1.65
10	Integrate GPU w/ISBL Units	80%	0.8	2.3	0.8	$1.97
11	Integrate AGR w/ISBL Units	80%	3.6	7.2	3.6	$2.36
12	Increase AGR Solvent Concentration	50%	3.3	7.4	3.4	$2.37
13	Revamp DTU Heat Integration (low-cost)	0%	10.4	16.7	10.4	$3.67
14	Improved Maintenance/Steam Lines & Traps	50%	0.3	0.0	0.3	$3.94
15	Replace Steam Drives w/Elec on Rec Compressors	40%	13.6	-23.9	13.5	$4.52
16	Reduce Coking of DTU Tube Surfaces	50%	4.4	0.0	4.4	$4.78
17	Reduce Coking of SMR Tube Surfaces	50%	5.8	0.0	5.8	$4.94
18	Efficient SMR Burners/Control X Air	50%	4.5	0.0	4.5	$5.18
19	Efficient DTU Burners/Control X Air	50%	3.3	0.0	3.3	$5.85
20	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
21	Revamp GPU Heat Integration	40%	0.0	1.8	0.0	$6.15
22	Improve catalysts to reduce H2 consumption	0%	16.5	14.1	16.5	$7.39
23	Install SMR Boiler Feed Water pre-Heat	0%	6.5	0.0	6.5	$10.10
24	Install DTU Furnace Air Pre-Heat	0%	5.1	0.0	5.1	$11.58
25	Increase Steam Line Insulation	0%	0.4	0.0	0.4	$11.70
26	Install New DTU Internals	0%	7.7	17.1	7.7	$13.49
27	Install New GPU Internals	0%	0.0	3.0	0.0	$14.74
28	Install DTU Overhead Chillers	0%	4.5	-71.4	4.3	$15.69
29	Install GPU Overhead Chillers	0%	0.0	3.0	0.0	$17.14
30	Revamp DTU Heat Integation (high-cost)	0%	2.3	9.1	2.3	$17.54
31	Revamp Steam Distribution/Reduce P Drop	0%	0.4	0.0	0.4	$17.56
32	Insulation/Reduce SMR Air Infiltration	0%	2.7	0.0	2.7	$18.14
33	Insulation/Reduce DTU Air Infiltration	0%	1.6	0.0	1.6	$22.18

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

Figure 17 – KTU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve


Technical fuel saving potential: 38 PJ
Cost effective fuel saving potential: 11 - 25 PJ
EIA AEO 2013 Ref Case Natural Gas Price Range (4.1 - 8.4 $/GJ)
Cost of Conserved Fuel ($/GJ)
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
5
10
15
20
25
30
35
40
45
1
2
3
4
5
6
7
8
9
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14
15
16
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Annual Fuel Savings Potential in 2010 (Finial PJ)

Table 13 – KTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.2	0.0	0.2	-$1.90
2	Recover Blowdown Steam	50%	0.2	0.0	0.2	-$0.47
3	Install SRU Waste Heat Boiler	90%	0.4	0.0	0.4	$0.00
4	Install SMR Waste Heat Boiler	90%	0.4	0.0	0.4	$0.00
5	Reduce Boiler Blowdown/Water Treatment	50%	1.7	0.0	1.7	$0.47
6	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
7	Improve SMR catalysts to reduce steam consumption	30%	0.4	0.0	0.4	$1.65
8	Improve WGS catalysts to reduce steam consumption	30%	0.4	0.0	0.4	$1.65
9	Integrate GPU w/ISBL Units	80%	0.1	0.3	0.1	$1.97
10	Integrate AGR w/ISBL Units	80%	1.5	3.0	1.5	$2.36
11	Increase AGR Solvent Concentration	50%	1.4	3.0	1.4	$2.37
12	Revamp KTU Heat Integration (low-cost)	0%	4.3	9.2	4.3	$4.25
13	Replace Steam Drives w/Elec on Rec Compressors	40%	7.7	-489.6	5.9	$4.52
14	Improved Maintenance/Steam Lines & Traps	50%	0.1	0.0	0.1	$4.56
15	Reduce Coking of SMR Tube Surfaces	50%	0.9	0.0	0.9	$4.94
16	Efficient SMR Burners/Control X Air	50%	0.7	0.0	0.7	$5.18
17	Reduce Coking of KTU Tube Surfaces	50%	2.4	0.0	2.4	$5.53
18	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
19	Revamp GPU Heat Integration	40%	0.0	0.2	0.0	$6.15
20	Efficient KTU Burners/Control X Air	50%	1.8	0.0	1.8	$6.78
21	Improve catalysts to reduce H2 consumption	0%	2.4	2.1	2.4	$7.39
22	Install SMR Boiler Feed Water pre-Heat	0%	1.0	0.0	1.0	$10.10
23	Install KTU Furnace Air Pre-Heat	0%	2.8	0.0	2.8	$13.41
24	Increase Steam Line Insulation	0%	0.1	0.0	0.1	$13.55
25	Install New KTU Internals	0%	3.0	9.4	3.0	$15.62
26	Install New GPU Internals	0%	0.0	0.4	0.0	$17.07
27	Insulation/Reduce SMR Air Infiltration	0%	0.4	0.0	0.4	$18.14
28	Install KTU Overhead Chillers	0%	2.5	-39.0	2.4	$18.17
29	Revamp KTU Heat Integration (high-cost)	0%	1.3	5.0	1.3	$20.31
30	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$20.33

31	Install GPU Overhead Chillers	0%	0.0	0.4	0.0	$20.95
32	Insulation/Reduce KTU Air Infiltration	0%	0.9	0.0	0.9	$25.68
33	Install PSA to recover high-purity H2	0%	1.0	1.0	1.0	$32.55

Notes:

Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.

* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

Figure 18 – NTU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

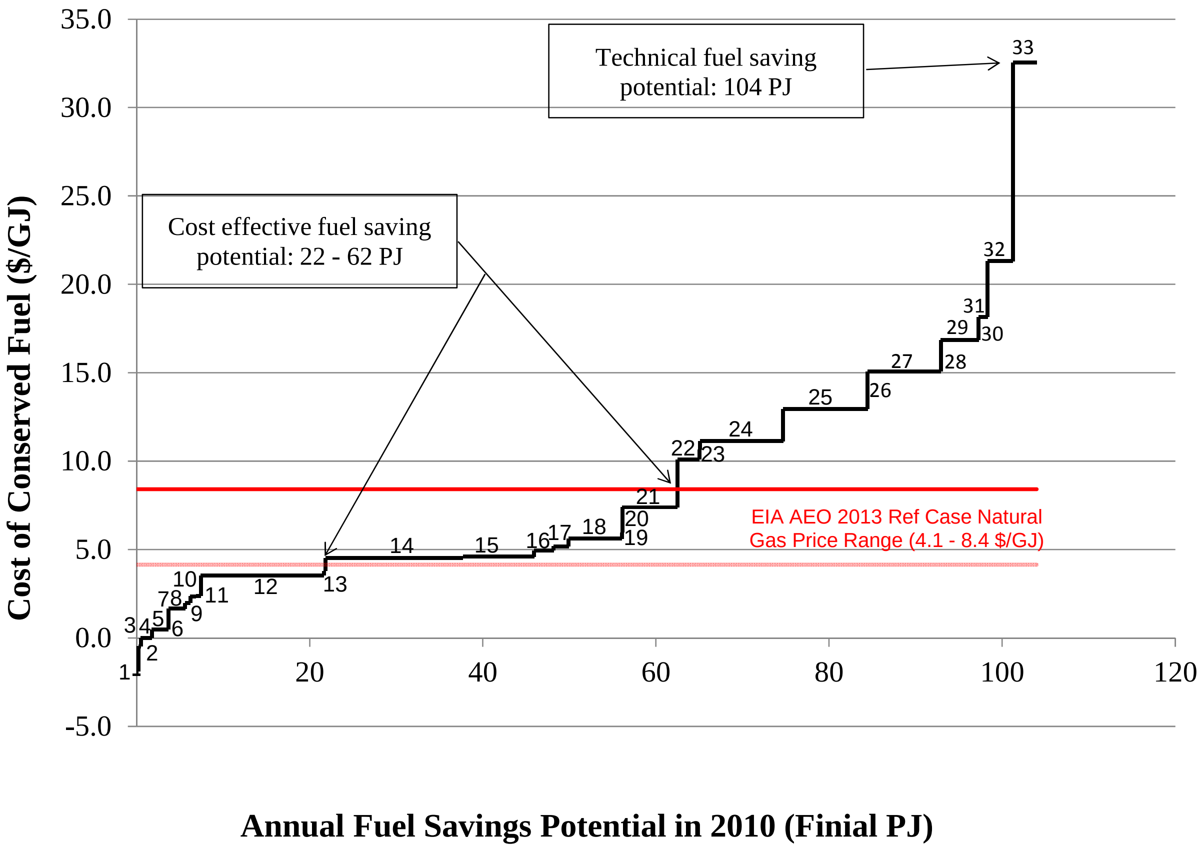


Table 14 – NTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.2	0.0	0.2	-$1.90
2	Recover Blowdown Steam	50%	0.3	0.0	0.3	-$0.47
3	Install SRU Waste Heat Boiler	90%	0.2	0.0	0.2	$0.00
4	Install SMR Waste Heat Boiler	90%	1.1	0.0	1.1	$0.00
5	Reduce Boiler Blowdown/Water Treatment	50%	1.9	0.0	1.9	$0.47
6	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
7	Improve SMR catalysts to reduce steam consumption	30%	1.0	0.0	1.0	$1.65
8	Improve WGS catalysts to reduce steam consumption	30%	1.0	0.0	1.0	$1.65
9	Integrate GPU w/ISBL Units	80%	0.6	1.8	0.6	$1.97
10	Integrate AGR w/ISBL Units	80%	0.6	1.2	0.6	$2.36
11	Increase AGR Solvent Concentration	50%	0.6	1.3	0.6	$2.37
12	Revamp NTU Heat Integration (low-cost)	0%	14.2	8.6	14.2	$3.53
13	Improved Maintenance/Steam Lines & Traps	50%	0.2	0.0	0.2	$3.79
14	Replace Steam Drives w/Elec on Rec Compressors	40%	16.0	-28.1	15.9	$4.52
15	Reduce Coking of NTU Tube Surfaces	50%	8.2	0.0	8.2	$4.59
16	Reduce Coking of SMR Tube Surfaces	50%	2.3	0.0	2.3	$4.94
17	Efficient SMR Burners/Control X Air	50%	1.7	0.0	1.7	$5.18
18	Efficient NTU Burners/Control X Air	50%	6.2	0.0	6.2	$5.62
19	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
20	Revamp GPU Heat Integration	40%	0.0	1.4	0.0	$6.15
21	Improve catalysts to reduce H2 consumption	0%	6.4	5.4	6.4	$7.39
22	Install SMR Boiler Feed Water pre-Heat	0%	2.5	0.0	2.5	$10.10
23	Increase Steam Line Insulation	0%	0.1	0.0	0.1	$10.65
24	Install NTU Furnace Air Pre-Heat	0%	9.6	0.0	9.6	$11.13
25	Install New NTU Internals	0%	9.7	9.0	9.8	$12.96
26	Install New GPU Internals	0%	0.0	2.4	0.0	$14.16
27	Install NTU Overhead Chillers	0%	8.5	-23.1	8.4	$15.07
28	Install GPU Overhead Chillers	0%	0.0	2.4	0.0	$16.47
29	Revamp NTU Heat Integration (high-cost)	0%	4.3	4.3	4.3	$16.85
30	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$16.87

31	Insulation/Reduce SMR Air Infiltration	0%	1.0	0.0	1.0	$18.14
32	Insulation/Reduce NTU Air Infiltration	0%	2.9	0.0	2.9	$21.30
33	Install PSA to recover high-purity H2	0%	2.7	2.5	2.7	$32.55

Notes:

Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.

* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

Figure 19 – GTU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

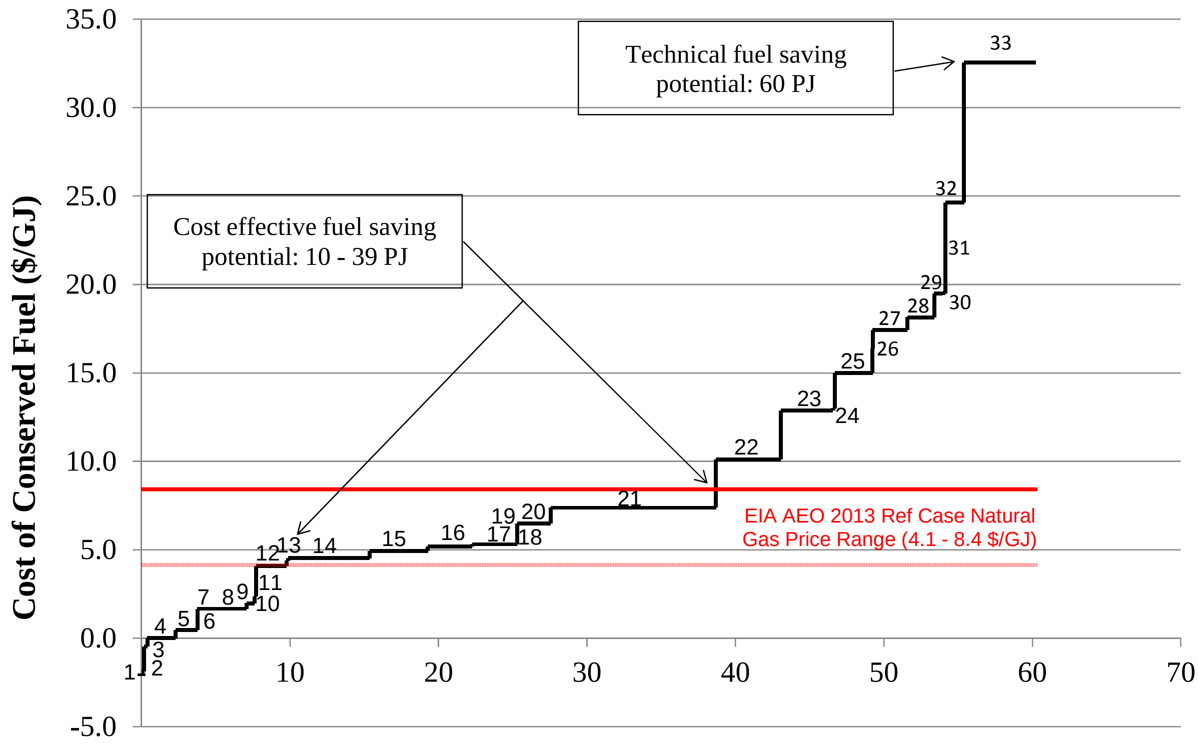


Table 15 – GTU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.2	0.0	0.2	-$1.90
2	Recover Blowdown Steam	50%	0.2	0.0	0.2	-$0.47
3	Install SRU Waste Heat Boiler	90%	0.0	0.0	0.0	$0.00
4	Install SMR Waste Heat Boiler	90%	1.9	0.0	1.9	$0.00

5	Reduce Boiler Blowdown/Water Treatment	50%	1.5	0.0	1.5	$0.47
6	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
7	Improve SMR catalysts to reduce steam consumption	30%	1.7	0.0	1.7	$1.65
8	Improve WGS catalysts to reduce steam consumption	30%	1.7	0.0	1.7	$1.65
9	Integrate GPU w/ISBL Units	80%	0.5	1.5	0.5	$1.97
10	Integrate AGR w/ISBL Units	80%	0.0	0.1	0.0	$2.36
11	Increase AGR Solvent Concentration	50%	0.0	0.1	0.0	$2.37
12	Revamp GTU Heat Integration (low-cost)	40%	2.0	1.8	2.0	$4.08
13	Improved Maintenance/Steam Lines & Traps	50%	0.1	0.0	0.1	$4.38
14	Replace Steam Drives w/Elec on Rec Compressors	40%	5.5	-9.7	5.5	$4.52
15	Reduce Coking of SMR Tube Surfaces	50%	3.9	0.0	3.9	$4.94
16	Efficient SMR Burners/Control X Air	50%	3.0	0.0	3.0	$5.18
17	Reduce Coking of GTU Tube Surfaces	50%	3.0	0.0	3.0	$5.31
18	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
19	Revamp GPU Heat Integation	40%	0.0	1.2	0.0	$6.15
20	Efficient GTU Burners/Control X Air	50%	2.3	0.0	2.3	$6.50
21	Improve catalysts to reduce H2 consumption	0%	11.1	9.4	11.1	$7.39
22	Install SMR Boiler Feed Water pre-Heat	0%	4.3	0.0	4.3	$10.10
23	Install GTU Furnace Air Pre-Heat	0%	3.5	0.0	3.5	$12.87
24	Increase Steam Line Insulation	0%	0.2	0.0	0.2	$13.00
25	Install New GTU Internals	0%	2.5	3.1	2.5	$14.99
26	Install New GPU Internals	0%	0.0	2.0	0.0	$16.37
27	Install GTU Overhead Chillers	0%	2.4	-5.4	2.3	$17.43
28	Insulation/Reduce SMR Air Infiltration	0%	1.8	0.0	1.8	$18.14
29	Revamp GTU Heat Integration (high-cost)	0%	0.6	1.4	0.6	$19.48
30	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$19.50
31	Install GPU Overhead Chillers	0%	0.0	2.0	0.0	$20.10
32	Insulation/Reduce GTU Air Infiltration	0%	1.2	0.0	1.2	$24.63
33	Install PSA to recover high-purity H2	0%	4.8	4.4	4.8	$32.55

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.6 Catalytic Reforming Unit (CRU)

Catalytic reforming is used to convert paraffins and cycloparaffins (*e.g.*, n-hexane and methyl cyclopentane) present in medium to heavy naphtha streams into aromatic compounds (*e.g.*, benzene and toluene), which have higher octane numbers required for blending into gasoline. Reforming reaction conditions also promote catalyst deactivation. To limit deactivation, a portion of the hydrogen produced in the reforming reactions is recycled. However, it is still necessary to continually regenerate the catalyst. A number of different technologies are used in U.S. refineries for regeneration. Older units are based on semi-regenerative or cyclic operation; whereas, newer units employ designs to allow continuous operation. Older units also operate at higher pressures. Newer catalysts have been developed to lower the operating pressure, and this is now the preferred operating mode, since it maintains the aromatics content of reformate within an acceptable range. In addition, the sulfur content of the feed stream must be very low to prevent permanent catalyst deactivation; therefore, the feed is hydrotreated upstream of the unit. Streams suitable for catalytic reforming include hydrotreated medium/heavy naphtha from the CDU, CKU and HCU. Depending on HCU feed sulfur content and operating conditions, HCU-derived naphtha may not require hydrotreatment. Figure 20 depicts a semi-regenerative, fixed-bed catalytic reforming unit. Note that catalytic reformers are a major source of hydrogen used in hydroprocessing operations throughout the refinery.

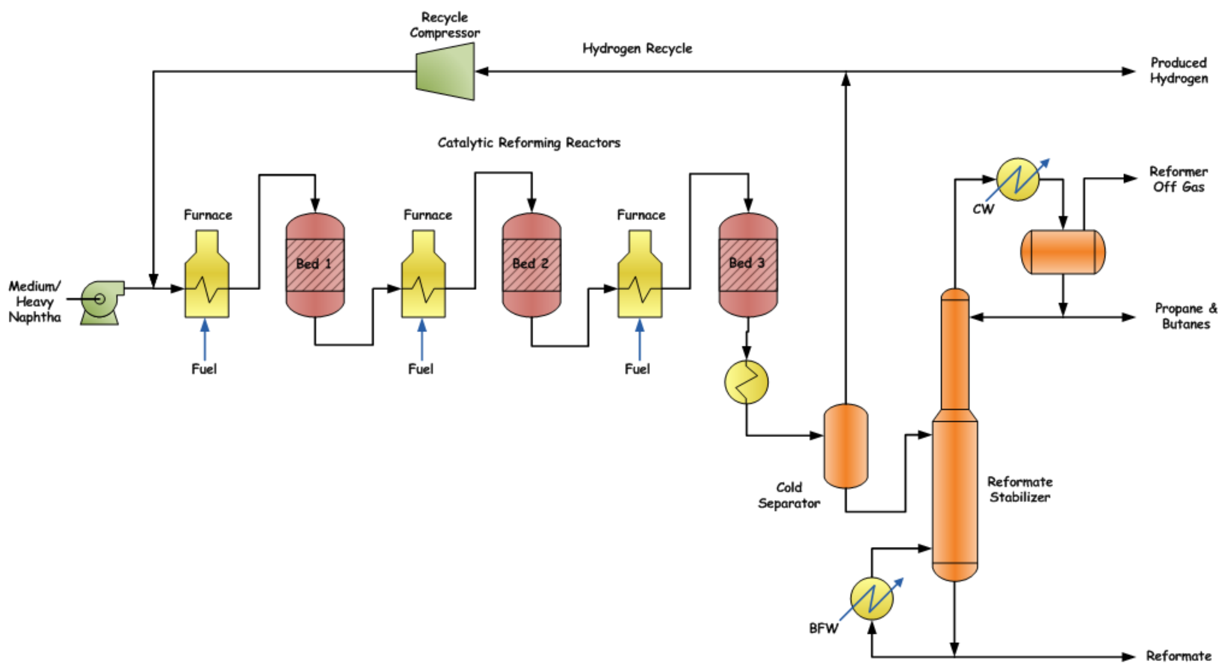


Figure 20 – Semi-Regenerative Catalytic Reforming Unit (CRU) Process Flow Diagram

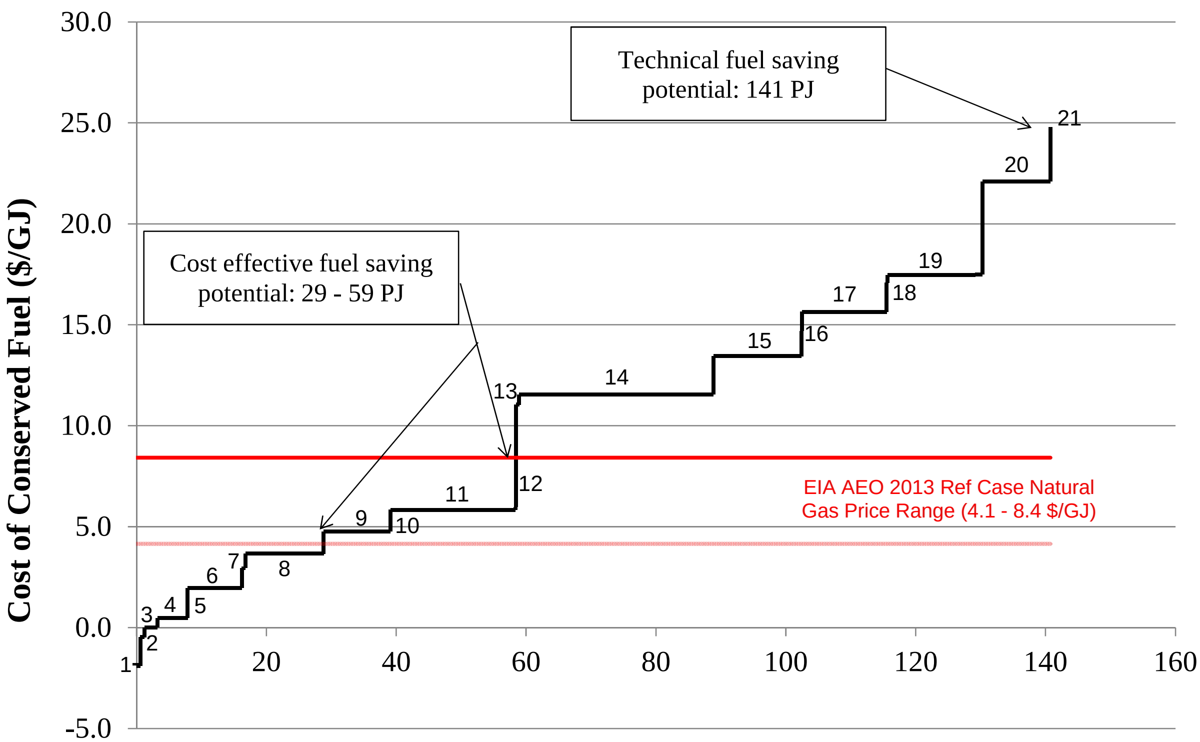
The semi-regenerative CRU consists of a series of reactors with interstage re-heating of the naphtha; followed by a gas-liquid separator and stabilizer column. In the cold separator, gas (primarily H_2 but also containing some methane, ethane and propane) is separated from the refomerate product. This liquid is sent to the reformate stabilizer to remove any remaining butanes and lighter hydrocarbons, and hydrogen.

Table 16 – CRU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chiller to lower condenser temperature
	Install plate-type feed/effluent exchangers
	Install new higher-efficiency column internals
	Reduce hot rundown/storage between upstream units and reformer
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce Process Steam Requirements	Replace recycle compressor steam-drive with electric
Reduce H_2 Make-Up Requirements	Improve reactors/catalysts to reduce hydrogen consumption
	Install membrane/PSA to recover high-purity hydrogen

In addition to the above unit-process related measures, measures associated with offsites utilized by the CRU are included in the CRU supply curve. These include hydrogen purification, overhead gas processing, steam and power supply, and water treatment. The CRU fuel-usage abatement supply curve is shown in Figure 21.

Figure 21 – CRU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve



Annual Fuel Savings Potential in 2010 (Finial PJ)

Table 17 – CRU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.6	0.0	0.6	-$1.90
2	Recover Blowdown Steam	50%	0.6	0.0	0.6	-$0.47
3	Reduce hot rundown	90%	2.0	0.0	2.0	$0.00
4	Reduce Boiler Blowdown/Water Treatment	50%	4.6	0.0	4.6	$0.47
5	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
6	Integrate GPU w/ISBL Units	80%	8.3	24.0	8.3	$1.97
7	Improved Maintenance/Steam Lines & Traps	50%	0.5	0.0	0.5	$2.95
8	Revamp CRU Heat Integation (low-cost)	40%	12.0	33.2	12.1	$3.66
9	Reduce Coking of CRU Tube Surfaces	80%	10.3	0.0	10.3	$4.76
10	Revamp GPU Heat Integation	40%	0.0	18.9	0.1	$5.22
11	Efficient CRU Burners/Control X Air	50%	19.2	0.0	19.2	$5.83
12	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97

13	Increase Steam Line Insulation	50%	0.5	0.0	0.5	$11.05
14	Install CRU Furnace Air Pre-Heat	0%	29.9	0.0	29.9	$11.54
15	Install New CRU Internals	0%	13.3	57.8	13.5	$13.44
16	Install New GPU Internals	0%	0.0	31.5	0.1	$14.69
17	Install CRU Overhead Chillers	0%	13.3	-68.8	13.1	$15.63
18	Install GPU Overhead Chillers	0%	0.0	31.5	0.1	$17.08
19	Revamp CRU Heat Integation (high-cost)	0%	13.3	62.7	13.5	$17.47
20	Revamp Steam Distribution/Reduce P Drop	0%	1.1	0.0	1.1	$17.49
21	Insulation/Reduce CRU Air Infiltration	0%	10.5	0.0	10.5	$22.09

Notes:

Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.

* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.7 Isomerization Unit (ISU)

Isomerization units are used to convert normal-paraffins (*i.e.* n-pentane and n-hexane) found in light naphtha streams into iso-paraffins (*i.e.* isopentane and isohexanes), which have higher octane numbers and are preferred for blending into gasoline. Some U.S. refineries deficient in isobutane for co-feeding alkylation units also isomerize n-butane in a separate unit. Most isomerization technologies require the feed stream to be low in sulfur; therefore, the feed is normally hydrotreated upstream of the unit. Streams suitable for isomerization include hydrotreated light naphtha from the CDU and CKU, or low-sulfur light naphtha from the CDU and HCU. Hydrogen is co-fed to the isomerization unit to suppress catalyst coking reactions. Figure 22 depicts a typical fixed-bed isomerization unit. Note that the process flow is very similar to the naphtha hydrotreating process described above.

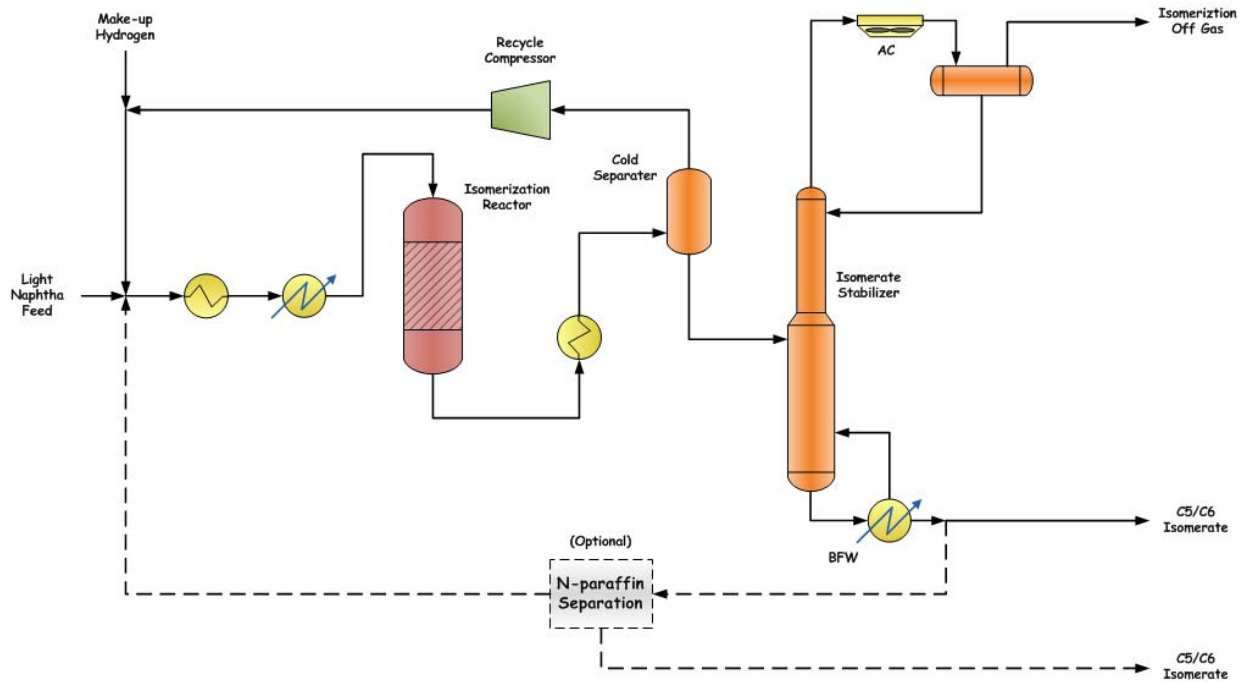


Figure 22 – Isomerization Unit (ISU) Process Flow Diagram

The ISU consists of a reactor, gas-liquid separator, and stabilizer column. Hydrogen gas is contacted with the fresh feed and flows through a single fixed-bed reactor. In the cold separator, gas (primarily H_2 but also containing some methane, ethane and propane) is separated from the C5/C6 isomerate, and recycled. The liquid is sent to a product stabilizer to remove any remaining butanes and lighter hydrocarbons, and hydrogen. It is also possible to separate isoparaffins from n-paraffins, which can be recycled to the reactor to increase conversion. This separation can be achieved through distillation; however, newer, less energy intensive, membrane separation technologies have been developed and are now available. However, n-paraffin recycle is not common in the U.S. Table 18 categorizes efficiency improvement measures related to fuel, steam, cooling water, electricity, and hydrogen usage.

Table 18 – ISU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chillers to lower condenser temperature
	Install new higher-efficiency column internals
	Install membrane separator in units with n-paraffin recycle
	Reduce hot rundown/storage between upstream units and isom unit
Reduce Process Steam Requirements	Replace recycle compressor steam-drive with electric

Reduce H_2 Make-Up Requirements	Improve reactors/catalysts to reduce hydrogen consumption

In addition to the above unit-process related measures, measures associated with offsites utilized by the ISU are included in the ISU supply curve. These include hydrogen production, overhead gas processing, steam and power supply, and water treatment. The ISU fuel-usage abatement supply curve is shown in Figure 23.

Figure 23 – ISU Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve

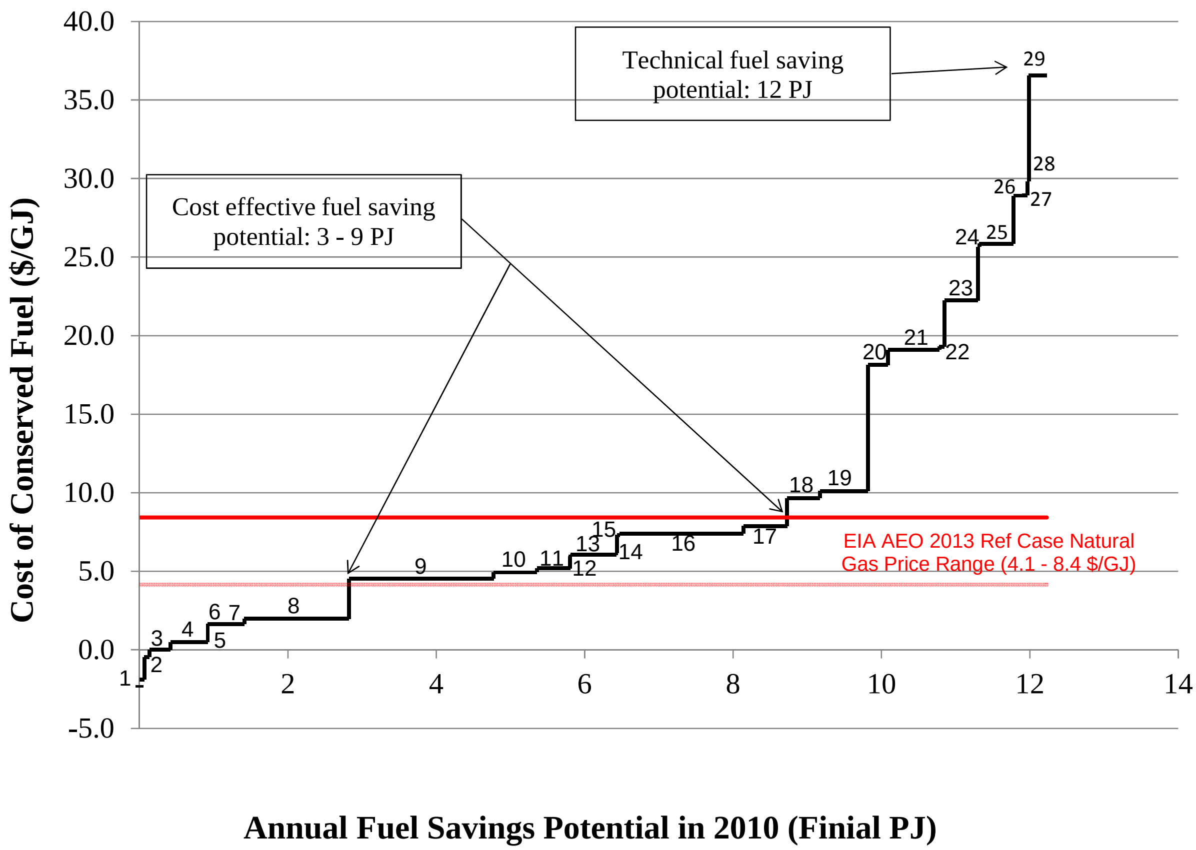


Table 19 – ISU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.1	0.0	0.1	-$1.90
2	Recover Blowdown Steam	50%	0.1	0.0	0.1	-$0.47
3	Install SMR Waste Heat Boiler	90%	0.3	0.0	0.3	$0.00

4	Reduce Boiler Blowdown/Water Treatment	50%	0.5	0.0	0.5	$0.47
5	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
6	Improve SMR catalysts to reduce steam consumption	30%	0.2	0.0	0.2	$1.65
7	Improve WGS catalysts to reduce steam consumption	30%	0.2	0.0	0.2	$1.65
8	Integrate GPU w/ISBL Units	80%	1.4	4.0	1.4	$1.97
9	Replace Steam Drives w/Elec on Rec Compressors	40%	2.0	-3.4	2.0	$4.52
10	Reduce Coking of SMR Tube Surfaces	50%	0.6	0.0	0.6	$4.94
11	Efficient SMR Burners/Control X Air	50%	0.4	0.0	0.4	$5.18
12	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
13	Revamp ISU Heat Integration (low-cost)	0%	0.6	0.9	0.6	$6.06
14	Revamp GPU Heat Integration	40%	0.0	3.2	0.0	$6.15
15	Improved Maintenance/Steam Lines & Traps	50%	0.0	0.0	0.0	$7.31
16	Improve catalysts to reduce H2 consumption	0%	1.7	1.4	1.7	$7.39
17	Reduce Coking of ISU Tube Surfaces	50%	0.6	0.0	0.6	$7.88
18	Efficient ISU Burners/Control X Air	50%	0.4	0.0	0.4	$9.65
19	Install SMR Boiler Feed Water pre-Heat	0%	0.7	0.0	0.7	$10.10
20	Insulation/Reduce SMR Air Infiltration	0%	0.3	0.0	0.3	$18.14
21	Install ISU Furnace Air Pre-Heat	0%	0.7	0.0	0.7	$19.09
22	Increase Steam Line Insulation	0%	0.1	0.0	0.1	$19.29
23	Install New ISU Internals	0%	0.4	0.9	0.4	$22.24
24	Install New GPU Internals	0%	0.0	5.3	0.0	$25.65
25	Install ISU Overhead Chillers	0%	0.5	-1.3	0.5	$25.86
26	Revamp ISU Heat Integration (high-cost)	0%	0.1	0.4	0.1	$28.91
27	Revamp Steam Distribution/Reduce P Drop	0%	0.1	0.0	0.1	$28.94
28	Install GPU Overhead Chillers	0%	0.0	5.3	0.0	$29.83
29	Insulation/Reduce ISU Air Infiltration	0%	0.2	0.0	0.2	$36.55

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.8 Alkylation Unit (AKU)

The major cracking operations within a refinery: coking, catalytic cracking and hydrocracking, inevitably produce light hydrocarbon gases in excess of that required to fuel the refinery. Alkylation units are used to combine isobutane with propylene/butylenes (3 carbon and 4 carbon olefins) produced in the cat cracker (and optionally the coker) to synthesize a high-octane gasoline blending component known as alkylate. Some refiners only process butylenes, while a few also process amylenes (5 carbon olefins) into alkylate. Alkylation capacity in the U.S. is split almost equally between two technologies, one that uses sulfuric acid (SFA) as the reaction catalyst, and the other that uses hydrofluoric acid (HFA). A solid-acid alkylation (SAA) catalyst based fluid-bed reactor process has recently been commercialized, but no units of this type are currently operating in the U.S. The feed gases to the alkylation unit must be desulfurized upstream of the unit. Figure 24 depicts a typical sulfuric acid-based alkylation unit.

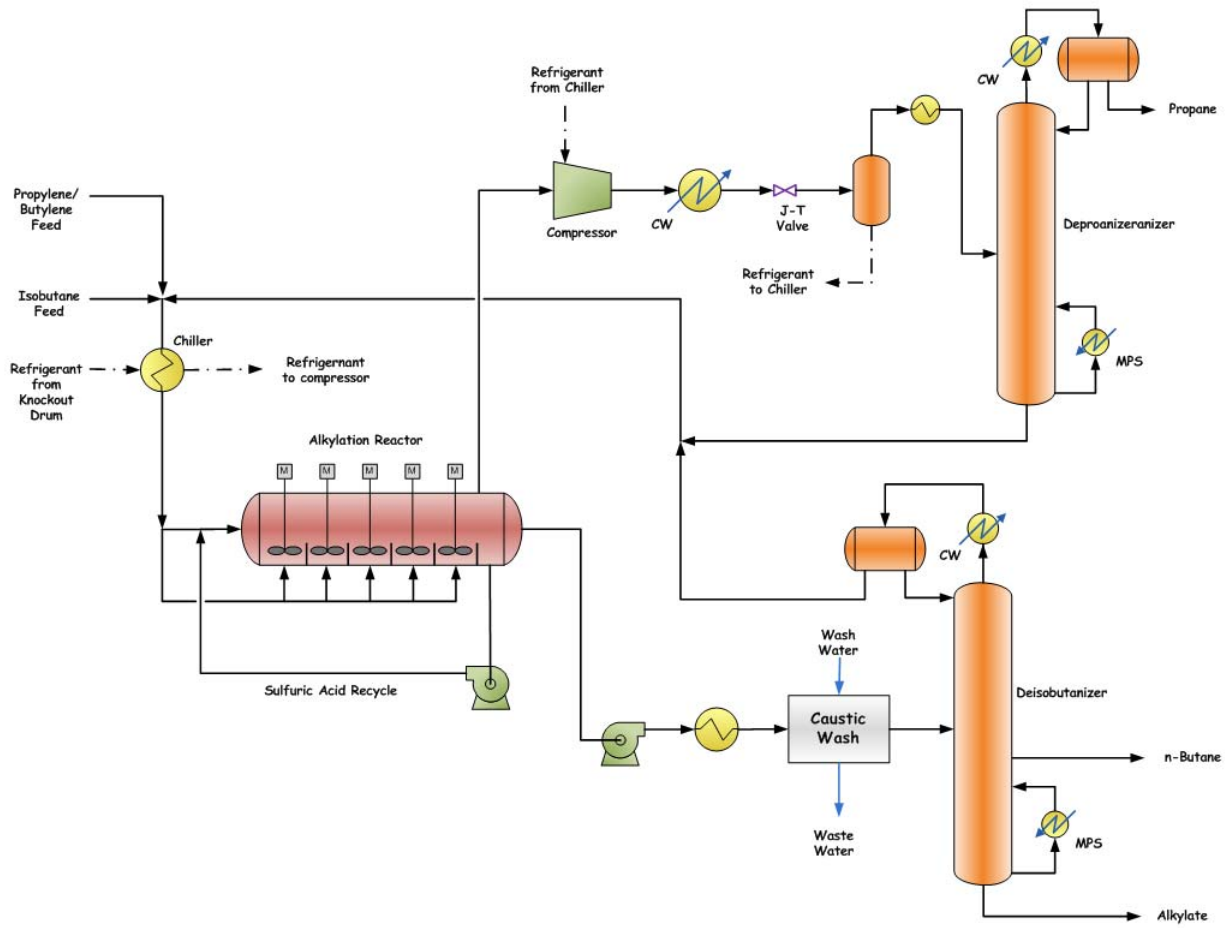


Figure 24 – Sulfuric-Acid Alkylation Unit (AKU) Process Flow Diagram

The SFA AKU consists of a reactor, fractionation and refrigeration sections. The reactor is a single vessel containing a number of reaction zones which are kept well mixed. Nearly complete conversion of propylene/butylenes is achieved in this reactor. Excess isobutane is recovered from the product, separated from alkylate, and purified by distillation in de-propanizer and de-butanizer columns. Temperatures used for alkylation are below ambient; therefore, a means of chilling the feed streams must be provided. In the process shown above, auto-refrigeration is employed. Propane, used as refrigerant, is mixed with the reactor off-gas, compressed, cooled, and then expanded across a Joule-Thomson valve to achieve sub-ambient conditions. The refrigerant exchanges heat with the feed gases in the feed chiller, and is returned. Table 20 categorizes efficiency improvement measures related to fuel, steam, and cooling water with many of the measures having an impact on electricity usage.

Table 20 – AKU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chillers to lower condenser temperature
	Install divided-wall column to improve separation efficiency
	Replace unit with alternative solid-acid alkylation technology
	Reduce hot rundown/storage between upstream units and alky unit
Reduce Process Steam Requirements	Replace steam drive on recycle compressor with electric drive

In addition to the above unit-process related measures, measures associated with offsites utilized by the AKU are included in the AKU supply curve. These include steam and power supply, and water treatment. The AKU fuel-usage abatement supply curve is shown in Figure 25.

Figure 25 – AKU Cost-or-Conserved Combined Fuel and Associated Electricity Supply Curve

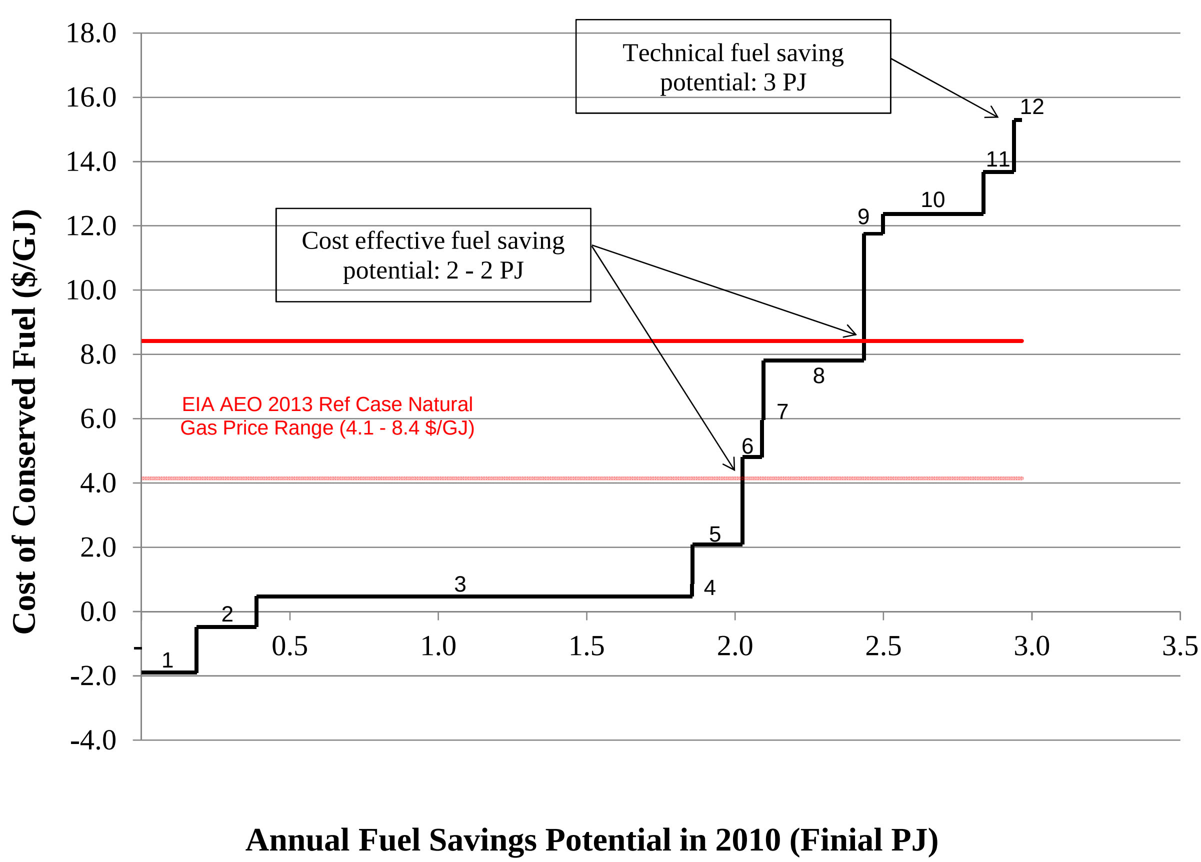


Table 21 – AKU Measure and Cost results

CCE Rank	Energy-Efficiency Measures / Technologies	Assumed Penetration rates	Fuel Savings (PJ)	Electricity Savings (GWh)	Combined Fuel and Electricity Savings (PJ) *	Cost of Conserved Fuel (US$/GJ-saved)
1	Reduce Stand-By Boiler Requirements	50%	0.2	0.0	0.2	-$1.90
2	Recover Blowdown Steam	50%	0.2	0.0	0.2	-$0.47
3	Reduce Boiler Blowdown/Water Treatment	50%	1.5	0.0	1.5	$0.47
4	Reduce Background Flaring	20%	0.0	0.0	0.0	$0.86
5	Improved Maintenance/Steam Lines & Traps	50%	0.2	0.0	0.2	$2.08
6	Revamp AKU Heat Integation (low-cost)	0%	0.0	18.0	0.1	$4.80
7	Install Flare Gas Recovery System	0%	0.0	0.0	0.0	$5.97
8	Increase Steam Line Insulation	0%	0.3	0.0	0.3	$7.81
9	Install New AKU Internals	0%	0.0	18.1	0.1	$11.76
10	Revamp Steam Distribution/Reduce P Drop	0%	0.3	0.0	0.3	$12.37
11	Install AKU Overhead Chillers	0%	0.0	28.9	0.1	$13.67
12	Revamp AKU Heat Integation (high-cost)	0%	0.0	7.2	0.0	$15.28

Notes:
Measures that fall below the low fuel price are not highlighted; measures falling between the low and high fuel prices are highlighted in pink; measures falling above the high fuel price are highlighted in red.
* Combined fuel and electricity savings are finial savings and a conversion factor of 0.0036 PJ/GWh is used to convert electricity to fuel.

3.9 Offsite Systems

In addition to the unit processes described above, refineries incorporate a number of other systems that provide utility and other services to the core processing units. These include fuel, steam, process, cooling and waste water, and electric power. For the purposes of the analysis presented here, it was more convenient to also include refinery hydrogen production, gas processing, acid-gas removal, and sulfur recovery systems as part of offsites, since they supply services to the core units described above, and have components which are distributed throughout the refinery. Off-site energy use is allocated to the major unit processes based on actual consumption of offsite system services by a unit process. Offsite systems having significant impacts on overall energy utilization are described below, along with associated energy abatement measures.

Refinery Gas Processing & Flare Systems (RGS) This system includes the following components:

1) Piping systems that collect refinery off-gas from producers (*i.e.* all of the unit processes described above) and that deliver this gas to acid gas removal, gas processing and refinery flares. Also included is piping used to distribute purchased natural gas and refinery-derived fuel gas to various furnaces in the refinery for process heating, and to utility boilers used to

raise steam for process applications (*i.e.* stripping and heating) and to steam turbines used for on-site electric power generation.

2) Gas Processing Units (GPU) used to recover and fractionate refinery gas liquids and light naphtha from unit process off-gas. Also included are naphtha splitters used to fractionate full-range naphtha into light and heavy naphtha intended for isomerization, catalytic reforming, or direct gasoline blending. Major petroleum refineries have at least two separate gas processing units: one suitable for processing saturated gases produced by the CDU, CRU, and the hydroprocessing-based units, and an unsaturate gas processing unit processing mixed gases containing both saturated (paraffins) and unsaturated (olefins) hydrocarbons produced by the CCU and/or CKU.

   The GPU typically includes feed-gas compression, a lean-oil absorption column for removing methane and ethane/ethylene, a de-propanizer for removing propane'propylene, a de-butanizer column for removing mixed butanes/butylenes, a butane splitter for separating isobutane and n-butane, and a naphtha splitter for separating light and heavy naphtha.

3) Process flares that are used to combust off-gas streams produced from around the refinery before venting to the atmosphere. During process start-ups, shut-downs, and system upsets, gas produced by a unit process is routed to a flare. Under normal operation these flares should only burn a small quantity of fuel gas used to maintain a pilot flame.

Table 22 categorizes efficiency improvement measures associated with the RGS.

Table 22 – RGU Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Process Heating Requirements	Revamp of heat integration
	Install overhead chillers to reduce heat duty
	Install new higher-efficiency column internals
	Substitute waste heat from other unit processes to replace furnace
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce Flaring	Reduce background flaring
	Install flare-gas recovery system

Hydrogen Production & Recovery Systems (HYS) This system includes the following components:

1) Piping systems that collect high and medium-purity hydrogen unit producers (*i.e.* CRU, HCU and HTUs) and that deliver this gas to users (*i.e.* HCU, HTUs and ISU). A significant quantity of medium-purity H_2 is also produced by the catalytic reforming unit of the refinery. The HCU and Some of the higher-severity HTUs produce purge gas with a high enough H_2 content that it can be used in less-severe HTU and ISU operations.

2) Hydrogen production by Steam Methane Reforming (SMR), which involves the reaction of natural gas (*i.e.* methane) with steam to produce hydrogen (H_2) gas, carbon monoxide (CO) and carbon dioxide (CO_2). Older units employ a shift reactor to convert the CO into additional H_2, and then separate the H_2 from the CO_2 using an absorption process (see AGS description below). Newer units eliminate the shift reactor and replace the absorption process with a pressure swing adsorption process that produces a high-purity H_2 stream and a low-purity H_2 reject stream suitable for use as fuel. In addition to natural gas, refineries also use refinery off-gas streams and even naphtha as a feed for steam reforming.

Table 23 categorizes efficiency improvement measures associated with the HYS.

Table 23 – HYS Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce Furnace Fuel Requirements	Reduce coking of heat transfer surfaces
	Efficient burners/Control of excess air
	Install furnace air pre-heater
	Increase insulation/Reduce air infiltration
Reduce System Steam Requirements	Improve SMR reactors/catalyst to reduce steam consumption
	Improve WGS reactors/catalysts to reduce steam consumption
	Install waste heat boiler on SMR furnace

Acid Gas Removal & Sulfur Recovery Systems (AGS) This system includes the following components:

3) Acid Gas Removal (AGR), primarily of hydrogen sulfide (H_2S), is accomplished in a gas absorption/stripping system normally employing an amine solvent that selectively absorbs H_2S from sour refinery gas streams. In some instances, the absorbers are located within the unit process generating the sour gas. Unit processes generating sour gas streams include: CKU, CCU, HCU, CTU, DTU, KTU, NTU and GTU.
4) Sulfur Recovery Unit (SRU), which converts H_2S from the AGR and SWS (sour water stripper, described below) into solid sulfur for sale. This process consists of a burner that converts a portion of the H_2S into SO_2, and downstream reactors that react this SO_2 with the remaining H_2S to elemental sulfur.
5) Tail Gas Treating (TGT), which recovers any unreacted H_2S from the exhaust gas from the SRU before this gas is sent to a flare. Typically, this is also an amine-based solvent process.

Table 24 categorizes efficiency improvement measures associated with the AGS.

Table 24 – AGS Energy Abatement Measures

Measures Primarily Affecting Fuel Usage

Reduce System Steam Requirements	Increase amine concentration to reduce solvent re-circulation rate
	Substitute waste heat from other unit processes in AGR stripper reboiler
	Install waste heat boiler downstream of SRU burner

Steam & Power Systems (SPS) This system includes all boilers and other heat-recovery steam generators/waste heat boilers (HRSG/WHB); as well as, all steam piping used to distribute this steam throughout the refinery for process and utility applications (*e.g.*, stripping and heating steam, respectively), steam traps, and let-down valves. Steam is also used within the refinery to generate electricity. Therefore, all steam turbines along with combustion turbines and associated HRSGs are also included as part of the steam and power systems.

Table 25 categorizes efficiency improvement measures associated with the SPS.

Table 25 – SPS Energy Abatement Measures

Measures Primarily Affecting Fuel Usage	
Reduce System Steam Losses	Reduce boiler blowdown / improved water treatment
	Recover steam from blowdown
	Reduce stand-by boiler requirements
	Revamp steam distribution system to reduce pressure drop
	Increase insulation of steam lines
	Improved maintenance of steam lines & traps
Reduce Boiler Fuel Requirements	Reduce fouling & scaling of heat transfer surfaces
	Efficient burners/Control of excess air
	Install boiler feed water pre-heater
	Increase insulation/Reduce air infiltration

Water Treatment & Delivery Systems (WTS) This system includes the following components:

6) Sour Water Strippers (SWS) used to remove hydrogen sulfide (H_2S), ammonia (NH_3) and any other volatile compounds from waste water streams generated in the following unit operations: CKU, CCU, HCU, CTU, DTU, KTU, NTU and GTU. The off gas from the stripper is routed to acid gas removal, while the recovered water is routed to waste water treatment.
7) Waste Water Treatment (WWT), which include oil separation from free water, and induced/dissolved air flotation for separating any oil/water emulsions. Oily sludge produced from these processes is de-watered further and disposed of in a landfill. Water from desalting operations, storm and other surface water collected within the refinery, and water recovered

from sour water stripping processed in this way may be discharge or with further treatment be re-used within the refinery.

8) Cooling Water (CW) system, which includes all pumps and piping used to circulate cooling water between unit-process and offsite cooling services, and cooling towers. Also included here is any chemical treatment or filtration required to maintain good operating performance of the system.
9) Raw Water (RW) system, which includes refinery water intake systems that may incorporate pumping, screening, filtration, and in some cases desalination equipment depending on the water source. Common sources can be seawater at coastal locations; and rivers, lakes or aquifers at inland locations. In urban locations, municipal water may be purchased. Raw water many be chemically treated to make it suitable for use as process or boiler feed water (PW or BFW, respectively)
10) Steam Condenstate Return (CR), which includes all pumps and piping required to return steam condensate from unit-process and offsite services to the various boilers located within the refinery. Condensate will be chemically treated and filtered as required to maintain all equipment in good working order.

Table 26 categorizes efficiency improvement measures associated with the WTS.

Table 26 – WTS Energy Abatement Measures

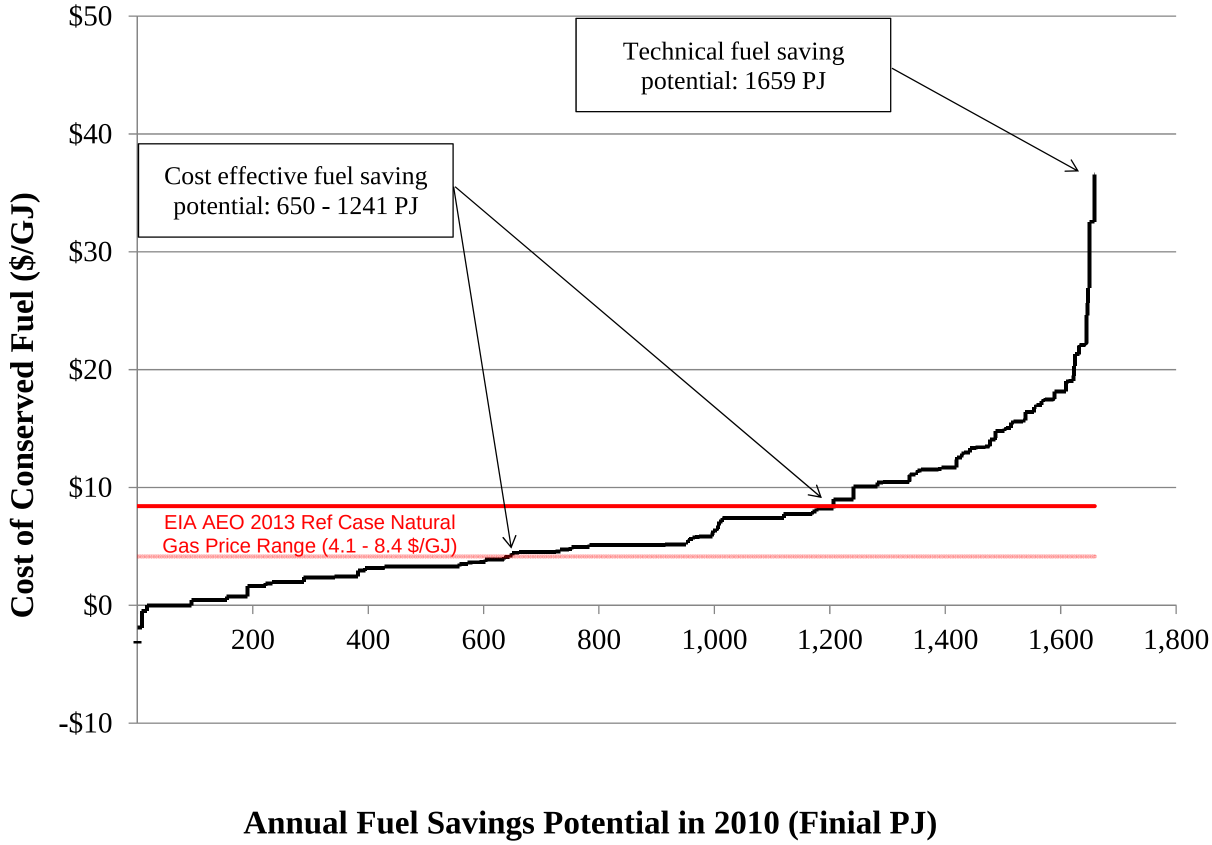
Measures Primarily Affecting Fuel Usage	
Reduce System Steam Requirements	Substitute waste heat from other unit processes in SWS reboiler

[a]CW – Cooling Water, CR – Condensate Return, RW – RW Water, WW – Waste Water

4 COST CURVE FOR THE COMPOSITE PETROLEUM REFINING SECTOR PROCESSES

Many of the energy efficiency and abatement measures described in this report are similar in that they affect common equipment used throughout the processes (e.g., process heaters and boilers, heat exchanges, pumps, steam distribution, etc.) although their application within individual process units varies. However, the application of many of the measures within the processing units has different costs and therefore summing them across the whole notional refinery, and averaging their cost would misrepresent costs by averaging higher and lower cost measures. Instead, measures from each of the processes are presented as individual measures in the composite curve shown in Figure 26. This results in an accurate representation of costs and impacts although there are too many measures to label them individually.

Figure 26 – Refining Composite Cost-of-Conserved Combined Fuel and Associated Electricity Supply Curve



As can be seen in both the composite supply curve and the individual process unit supply curves, there are energy efficiency measures that are cost effective given EIA's current forecast for natural gas prices through 2035 (used as an cost-effectiveness evaluation metric) [EIA, 2012]. Total fuel, electricity and CO_2 emission reduction potentials are shown in Table 27. The negative electricity savings within the Potentially Cost Effective category in Table 27 result when fuels savings measures are replaced with electricity consuming measures. An example of this is replacing recycle compressor steam-drives with electric drives, the largest of which take place in the NTU (Naphtha hydrotreating unit). Replacing steam drives reduces steam loads and therefor fuel consumption for steam generation, but introduces a new electricity load. Because many of these fuel reduction measures are cost effective to implement the cumulative electricity effects result in a net increase in electricity consumption within this category of cost-effective measures.

Table 27 – Cumulative Refining Composite Results

	Fuel	Electricity	CO_2 Emissions

	(PJ/yr)	(GWh/yr)	(Million t CO_2/yr)†
Cost Effective *	647	655	37
Potentially Cost Effective **	591	-83	33
Technical but not Cost Effective	412	1690	24
Total	1651	2262	94

* Costs Effective are the cumulative totals that fall below the lower price line in Figure 26

** Potentially Cost Effective are the cumulative totals that fall in between the lower and higher price lines in Figure 26.

† Fuel CO_2 emissions are based on the IPCC conversion factor of 0.0561 Million t CO_2/PJ [IPCC, 2006], and 0.586 Million t CO_2/TWh for the U.S. electric grid in 2010 [EIA, 2012]

4. CONCLUSSIONS

In this analysis, energy-usage abatement curves have been developed for the U.S. petroleum refining sector. A bottom-up, predictive approach was employed to estimate energy usage on an operation-by-operation basis. This approach builds upon earlier efforts, which focused on energy efficiency technologies [Worrell et. al. 2005], or establishing energy-consumption baselines [Energetics 2006, 2007], by quantifying potential benefits and costs from applying energy efficiency improvement measures.

The results of the analysis are a series of supply curves for each of the twelve primary refining technologies that make-up a composite representation of the U.S. industry. These are crude distillation, petroleum coking, catalytic cracking, hydrocracking, hydrotreating (catalytic cracker feed/diesel/kerosene/naphtha/gasoline), catalytic reforming, isomerization, and alkylation. Saving associated with supporting processes, such as gas processing, hydrogen production, steam and power systems, acid gas removal and water treatment have been allocated based on utilization by the primary processes. The curves reflect fuel savings that can be made by the refining industry and have been combined into a composite curve representing the entire refinery sector. This composite curve has been used to identify the potential for reducing refinery CO_2 emissions.

It has been suggested in the past that in modern petroleum refineries, the “low-hanging fruit” efficiency improvements have been accomplished [CONCAWE 2008]; while others disagree [Laitner, 2012]. The results of this analysis present a more complex picture. Indeed, low-hanging fruit that may be available in other less energy conscious industries (*e.g.* cement or iron and steel) appear to have already have been implemented; however, roughly 1,200 PJ of annual energy savings are still to be achieved within a fuel price of 4.1 and 8.4 \$/GJ[2]. This energy savings represents 33 million metric tons of unrealized annual CO_2 emissions reductions. In addition, it appears from the analysis that there is a broad range of reduction potential across the industry, with in general, the larger refineries and corporations farther along the curve. However, it was

[2] EIA projections for mid to long term natural gas price.

not possible to quantify this observation directly although estimates of current penetration rates are applied to the individual processing units. Both the individual processing unit's and the composite cost of conserved energy curves reflect the current penetration estimates.

4.1 Challenges

The petroleum refining industry is diverse, and while all refineries are similar in that they employ most of the same technologies to process crude oil into finished products, it is also true that no two refineries are identical. According to the U.S. DOE Energy Information Administration (EIA), there were 148 refineries operating in the U.S. in 2010, with an average design capacity of 17,583,790 BPCD [EIA 2013]. These refineries vary by size, complexity, crude quality processed, and product slate, as well as by their age and how well they have been maintained and modernized over the years.

Detailed operational data on individual refineries is confidential. Therefore, in order to assess the past, current and future state of play in the industry in regards energy utilization efficiency, it was necessary to start with a number of simplifying assumptions and then to model the entire sector as a single notional refinery. In addition, a large number of options exist for making energy efficiency improvements. In many cases, these options overlap and will directly impact each other. Therefore, the order in which they are applied matters. For this reason, individual measures have been organized by their direct impact on unit-process operations. Then, a consistent subset of measures was identified for each impact category.

Petroleum refineries in the U.S. are also complex industrial facilities involving multiple processing plants configured both in parallel and series. The component plants are integrated through utility systems, which supply fuel, steam, cooling water, and electricity to the various processes. Individual operations within these plants are also extensively integrated. Due to the high degree of energy integration, both at the refinery and plant level, efficiency improvements to a single operation may have implications throughout the refinery. For this reason, it is essential to examine efficiency improvements in refining at the process level using a bottom-up, predictive approach to estimate energy usage on an operation-by-operation basis[3].

One more significant challenge was establishing a baseline for the existing U.S. refining industry, since individual refineries do not publically report their energy use; though, there are now regulations in place requiring individual refineries to report their CO_2 emissions. A question still to be addressed is: How widely have any given efficiency measures been adopted by refiners? For the current analysis, engineering judgment guided by anecdotal accounts reported in the literature was used to assign market penetration rates to the individual energy abatement measures analyzed. Further work, which might include surveys and/or audits of existing facilities, will be needed to improve these estimates.

4.2 Future Research

[3] A number of excellent case studies based on this approach can be found in the open literature [Glasgow et.al. 2010, Rossiter et.al. 2010, Carbonetto et.al. 2011]; however, these do not systematically address the state-of-play within the industry as a whole, and also require very sophisticated and detailed analyses (e.g., heat exchanger network pinch analysis).

The current analysis does not consider the ramifications of current trends in petroleum refining related to novel technologies, crude oil qualities, fuel specifications, and product slates. These trends will have a significant impact on the future path of the U.S. refining industry. Future challenges that will likely affect the industry include: lower gasoline-to-distillate product ratios due to ethanol blending into gasoline, vehicle hybridization, and projected demand growth for jet and diesel fuel; internationally agreed to marine SOx reductions requiring low-sulfur bunker fuels; refinery crude slate changes due to increased production of domestic shale oils, and increased imports of Canadian synthetic crude oils and dilbit blends; and further implementation of renewable and/or low-carbon fuel standards, which may introduce truly “drop-in” biofuels in the long term. Future sensitivity analyses will be needed to examine impacts of these potential changes, since many of these could have negative ramifications for improving efficiency and lowering emissions, while some may be positive. The role of CO_2 capture and sequestration in petroleum refining will also need to be examined more completely if CO_2 emissions are to be drastically reduced over the next fifty years.

The tools developed for the current analysis include an aggregate, notional petroleum refinery model that is mass and energy balanced[4], and an accounting methodology that tracks the inter-dependent nature, as described in the assessment methodology section (Section 2), of adopting energy-efficiency measures within a highly integrated industry. Importantly, these tools are designed such that they can, with some modifications, be used to analyze other national or regional refining industries; as well as, the petrochemical industry, which is similarly integrated. Scenarios can be examined that specifically look forward in time at a range of market and policy driven changes in the transportation sector affecting energy requirements and efficiency adoptions within the petroleum refinery sector.

In closing, the analysis presented here is unique in that it provides a rigorous framework for evaluating energy consumption and efficiency improvement opportunities within the U.S. petroleum refining industry that previously was not obtainable by looking at reported data alone. The tools developed for this analysis are predictive, meaning that the energy usages are calculated using a bottom-up approach, rather than assumed or derived empirically, and model the individual processing units and ancillary equipment (i.e. hydrogen production, steam, and cooling water) at a level of detail required for quantifying energy efficiency impacts and costs.

[4] The model tracks total mass, carbon, hydrogen, sulfur, nitrogen and energy flows through the individual refinery process units. See Assessment Methodology (Section 2) for description.

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