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Efficiency Improvement and CO_2 Emission Reduction Potentials in the United States Petroleum Refining Industry

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Abstract
The U.S. EPA is in the final stages of promulgating regulations to reduce CO_2 emissions from the electricity generating industry. A major component of EPA's regulatory strategy targets improvements to power plant operating efficiencies. As the EPA expands regulatory requirements to other industries, including petroleum refining, it is likely that plant efficiency improvements will be critical to achieving CO_2 emission reductions. This paper identifies efficiency improvement measures applicable to refining, and quantifies potential cost of conserved energy for these measures. Analysis is at the U.S. petroleum refining sector national-level employing an aggregated notional refinery model (NRM), with the aim of estimating the efficacy of efficiency improvements for reducing emissions. Using this method, roughly 1,500 petajoules per year (PJ/yr) of plant fuel savings and 650 gigawatt-hour per year (GWh/yr) of electricity savings (representing 54% and 2% of U.S. refining industry consumption, respectively) are potentially cost-effective. This equates to a potential 85 Mt-CO_2/yr reduction. An additional 458 PJ/yr fuel reduction and close to 2,750 GWh/yr of electricity reduction (27 Mt-CO_2/yr) are not cost-effective at prevailing natural gas market prices. Results are presented as a supply-curve ordering measures from low to high cost of fuel savings versus cumulative energy reduction.

Keywords
Energy-efficiency
CO_2 Emissions
Petroleum Refining

Acronyms and Abbreviations

Acronym or Abbreviation	Definition
AMO	Advanced Manufacturing Office within EERE
BPCD	Barrels per Calendar Day
BPCD	barrels per calendar day
CHP	Combined heat and power
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Energy within DOE
EIA	Energy Information Administration within DOE
Energy Star	an international standard for energy efficient consumer products originated in the United States
EPA	U.S. Environmental Protection Agency
green-field	a project that lacks any constraints imposed by prior work
GWh	Gigawatt-hour = 10^9 Wh. A measurement of electricity
ITP	Industrial Technologies Program within DOE
LBNL	Lawrence Berkeley National Laboratory
Mt	metric tonne
NRM	Notional Refinery Model
PJ	Peta Joule = 10^15 joules. 1 PJ = 0.947 TBtu
R&D	Research and Development
SOA	state-of-the-art
TBtu	Trillian British Thermal Units. 1 Btu is the amount of energy needed to cool or heat one pound of water by one degree Fahrenheit
U.S.	United States
ACU	Atmospheric Crude Unit
AGS	Acid Gas Removal and Sulfur Recovery Systems
AKU	Alkylation Unit
API gravity	American Petroleum Institute gravity - a measure of how heavy or light a petroleum liquid is compared to water.
atm.	Atmospheric pressure is the pressure exerted by the weight of air in the atmosphere of Earth
B	Annual decreases in O&M costs due to non-energy productivity improvements, $
bbl	barrels = 42 U.S. gallons
bpd	barrels per day
c	consumption factor of utility
C3/C4/C5	Olefins
CCE	Cost of Conserved Energy
CCU	Catalytic Cracking Unit
CD	Calendar-day
CDU	Crude Distillation Unit
CKU	Coking Unit
Coke	A fuel with few impurities and a high carbon content
CRU	Catalytic Reforming Unit
Crude Oil Assays	The chemical evaluation of crude oil feedstocks by petroleum testing laboratories

Acronym or Abbreviation	Definition
CTU	CCU Treating Unit
DTU	HS Distillate Treating Unit
ES	Annual Energy Savings, GJ/yr
FOE	Fuel Oil Equivalent
GTU	Gasoline Treating Unit
H_2	Hydrogen
HCU	Hydrocracking Unit
HYS	Hydrogen Production and Recovery Systems
I	Added Capital Cost, $
ISBL	inside the battery limits
ISU	Isomerization Unit
KTU	LS Distillate Treating Unit
LPG	Liquefied Petroleum Gas
M	Non-Energy Annual increases in O&M costs, $
NTU	Naphtha Treating Unit
O&M	operating and maintenance
OSBL	outside the battery limits
Pet Coke	Petroleum Coke - fuel coke derived from petroleum
q	Capital Recovery Factor, yr^{-1}
Resids	Residuals
RGS	Refinery Gas Processing and Flare Systems
SD	Stream-day
SP.Gr.	Specific gravity - the ratio of the density of a substance to the density (mass of the same unit volume) of a reference substance
SPS	Steam and Power Systems
U	consumption of utility
UP	Unit Process
UPSM	unit-process sub-models
US	Utility Systems
USSM	unit-system sub-models
V	Material Flow
VCU	Vacuum Crude Unit
WTS	Water Treatment and Delivery Systems
x	deposition factor of streams
y	Yield of product

Contents

1. Introduction

Efficient process technologies are an essential component of any comprehensive strategy for improving energy efficiency and reducing CO_2 emissions associated with petroleum refining. In many cases, energy efficiency measures are among the most cost-effective investments that refineries can make to improve productivity, while simultaneously decreasing their 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 refining cost-effectiveness and address global climate change concerns. This paper provide an assessment of energy efficiency improvement potential and their costs for the U.S. petroleum refining sector.

The development and demonstration of a robust methodology for estimating energy-abatement supply curves for the U.S. petroleum refining industry is complicated by a number of issues unique to refining [Gary, 2007; Worrell, 2005]. The refining industry 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 major green-field refinery constructed in the U.S. was commissioned in 1979[1], 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.

The U.S. Department of Energy's (DOE) Energy Efficiency and Renewable Energy Program's (EERE) Advanced Manufacturing Office (AMO previously the Industrial Technologies Program (ITP)) has sponsored a series of industry-specific energy efficiency-potential bandwidth reports. The initial U.S. petroleum refinery bandwidth report focused on five of the most energy intensive refinery unit operations (crude distillation, fluid catalytic cracking, catalytic hydrotreating, catalytic reforming, and alkylation) concluding that 27% of refinery energy consumption could be reduced through adoption of best practices and state-of-the-art (SOA) technologies [Energetics, 2006]. The petroleum bandwidth report was recently updated and covers the whole refinery industry concluding that 13% of total refining energy consumption could be reduced by implementing best practices and SOA technologies and then an additional 25% reduction is conceivably possible through the adoption of R&D technologies currently under development [Energetics, 2013]. Neither of the bandwidth reports estimated any costs for adopting these measures.

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, 2005]. A subsequent Lawrence Berkeley National Laboratory (LBNL) analysis helps address this need for the U.S. petroleum refining industry through three primary objectives: 1) develop a robust method for estimating process performance, energy requirements, CO_2 emissions, and costs of abatement measures applicable to petroleum refining

[1] Though, a number of small refineries are under construction in North Dakota to supply demand for diesel fuel used in development and operation of the Bakken shale-oil field.

in the U.S.; 2) establish representative baseline data for production, energy, CO_2 emissions and costs; and 3) 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 generate cost-of-conserved energy supply curves to estimate cost effective energy efficiency potential [Morrow, 2013].

Individual refinery configurations are designed to produce a product slate consisting of various transportation and other fuels, petrochemicals, and specialty products, which match the specific markets served by the refinery; based on the available slate of crude oils to which the refiner has access. Refineries are revamped when needed to adjust to changes as feed and product slates evolve over time. Therefore, an engineering model of any one of the roughly 140 refineries in the U.S. is insufficient to represent the refining sector as a whole. In the analysis, the whole U.S. refinery industry is analyzed in aggregate as a notional refinery model to reduce the complexity of attempting to estimate each refinery separately. This notional model of a generic U.S. refinery captures the thermodynamic and reaction chemistry required to transform crude oil into refinery products using petroleum and chemical engineering best practices. It utilizes performance efficiencies within the major processing units of most U.S. petroleum refineries to estimate the energy required to produce refinery products (e.g., jet, diesel, and gasoline fuels). Performance efficiencies were "tuned" to reflect U.S. petroleum refining aggregate yield and energy consumption data, based on date from the literature and other sources spanning the period from 1975 to the present. It presented cost-of-conserved energy (CCE) supply curves specific to each of the processing units. However, only included a brief description of the model structure.

This paper presents a condensed version of that analysis and only presents a single cost-of-conserved energy supply curve aggregated from all of the modeled processing units and their supporting utilities. This paper also provides cost-effectiveness ranges based on U.S. DOE, Energy Information Administration (EIA) natural gas price forecasts. In addition, this paper presents a more detailed documentation of the notional refinery model through descriptions of the model architecture, modeling assumptions, mathematical formulation and solution algorithm, and key parameters and input data required to execute the model.

2. Materials and Methods

Historically, petroleum refineries have evolved independently to handle changing crude oil inputs and product outputs, and therefore no two refineries are exactly the same. Detailed information on the performance of individual refineries is generally not available publically 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. However, simulations can still be constructed, since all refineries rely on a small set of standard unit processes, which can be linked together in a variety of ways to establish the overall refinery configuration.

Based on experience gained over decades, the refinery modeling community has developed a suite of methods to solve these types of problems and to simplify the analysis of the refining sector on a regional, national or global basis (e.g., see [Kaes, 2000]). This paper presents a notional refinery model (NRM) of the U.S. petroleum refining sector that focuses on twelve core unit processes that dictate the operation of a refinery and dominate energy consumption for the refining industry. Input data to the NRM are 2010 operating rates for all unit processes. The model also includes five utility systems that support these twelve processes. Refinery utility systems are major contributors to total refinery fuel and electricity consumption.

2.1 Notional Refinery Model

U.S. refining data collected by EIA and available through their website [EIA 2015b, EIA 2015c] are used to initialize the model. The EIA identifies on an annual basis major unit processes found in each refinery operating in the U.S. By combining unit processes that perform similar functions in the refinery and eliminating the more uncommon ones, it is possible to reduce the total number to twelve critical operations shown in Figure 1 and described in Table 1.

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Figure 1 – Overall Process Block Flow Diagram for U.S. Notional Refinery Model

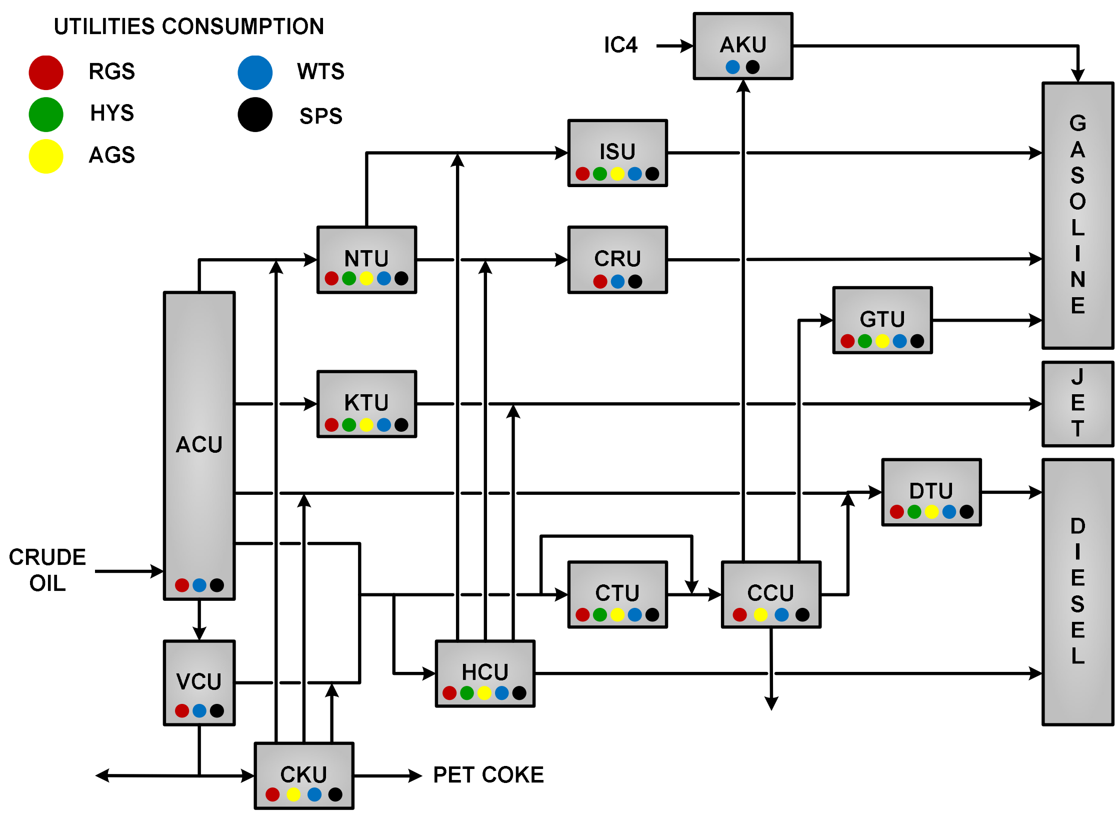


Table 1 – Unit Processes and Utility Systems Represented in the NRM

Unit Process	Abbreviation	Function
Crude Distillation Unit	CDU	Crude oil fractionation into intermediate streams using atmospheric and vacuum distillation (ACU and VCU, respectively)
Coking Unit	CKU	Thermal conversion of VCU residual cut into lighter intermediate streams and solid petroleum coke
CC Treating Unit	CTU	Hydrocatalytic treating of intermediate streams heavier than diesel upstream of the CCU
Catalytic Cracking Unit	CCU	Thermal catalytic conversion of streams heavier than diesel into lighter intermediate streams
Hydrocracking Unit	HCU	Hydrocatalytic conversion of streams heavier than diesel into lighter intermediate streams
HS Distillate Treating Unit	DTU	High-severity hydrocatalytic treating of streams heavier than kerosene but lighter CCU and HCU feeds to remove sulfur
LS Distillate Treating Unit	KTU	Low-severity hydrocatalytic treating of streams heavier than naphtha but lighter CCU and HCU feeds to remove sulfur
Naphtha Treating Unit	NTU	Hydrocatalytic treating of naphthas to remove sulfur upstream of the CRU and ISU
Catalytic Reforming Unit	CRU	Catalytic transformation of paraffinic of medium and heavy naphthas into aromatic gasoline blending component
Isomerization Unit	ISU	Catalytic isomerization of light streams containing n-paraffins into isoparaffins
Gasoline Treating Unit	GTU	Hydrocatalytic treating of CCU product gasoline to selectively saturate olefinic compounds
Alkylation Unit	AKU	Synthesis of gasoline from isobutane and C3/C4/C5 olefins
Utility System		
Refinery Gas Processing and Flare Systems	RGS	Collection of refinery off-gas, fractionation to recovery fuel and liquid products, an refinery flares
Hydrogen Production and Recovery Systems	HYS	Recovery of hydrogen from process off-gas and production of make-up hydrogen via steam methane reforming
Acid Gas Removal and Sulfur Recovery Systems	AGS	Removal of H_2S from process off-gas, production of sulfur, and treating of tail-gas from sulfur recovery unit
Steam and Power Systems	SPS	Boilers and waste heat recovery to produce steam for steam stripping, process heat and power generation
Water Treatment and Delivery Systems	WTS	Sour water strippers, waste water treatment, raw water and cooling water supply

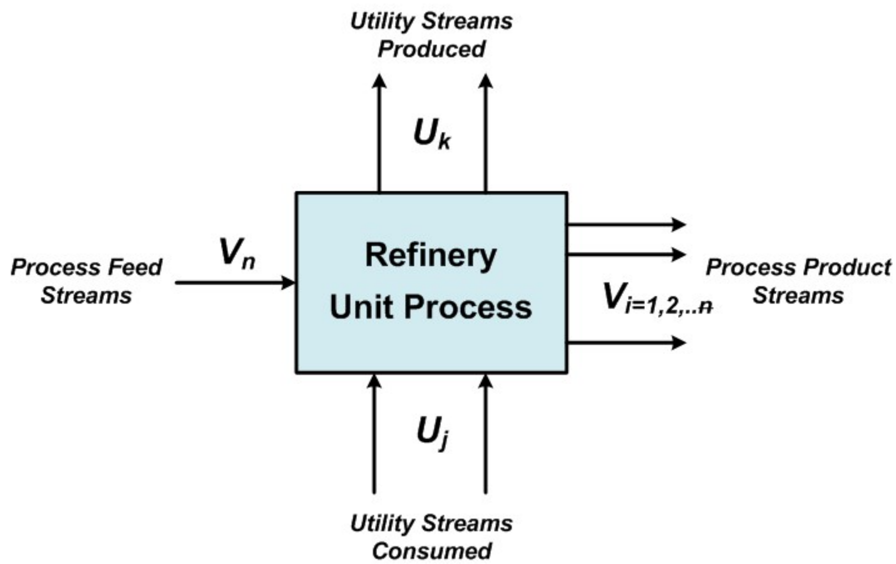
Unit processes (UP) are represented in the NRM as a column vector. The vector contains information on all flows of materials and energy in and out of a process. Process output streams and utility consumptions are calculated directly or indirectly from the input stream flows; therefore, iterative calculations are not required. The set of parameters and formulas used to predict the performance of the various unit processes are referred to as unit-process sub-models (UPSM).

Utility systems (US) are described in a fashion similar to the unit processes; that is all utilities consumed in a specific utility system are calculated directly from the total utility flow supplied to the rest of the refinery, unit processes and other utility systems. Parameters and formulas used for the various utility systems are referred to as the utility-system sub-models (USSM). In general, utility systems aggregate the multiple demands for utilities required by the unit processes. In this analysis however, utility systems fuel and electricity requirements are allocated to the unit processes consuming the utility, and the USSM are incorporated directly into each of the UPSM. This enables efficiency supply curves to be generated independently for each of the separate unit processes (as reported in [Morrow, 2013]), which can then be added together to generate a supply curve for 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, water-usage, and hydrogen) which is designated "outside the battery limits" (OSBL).

All of the UPSMs contained in the NRM possess the same generic form, which is depicted in Figure 2.

Figure 2 – Material and Utility Flows Into and Out of UP Sub Models



Based on this form, the partitioning (i.e. conversion and/or separation) of unit-process feed streams into product streams can be represented mathematically by the following equation:

$$V_{im}^{(out)} = y_{ijm} V_{jm}^{(in)} \tag{1}$$

where: $V_{im}^{(out)}$ - material flow of product *i* leaving unit process m, on a volume basis[2]

y_{inm} - yield of product *i* relative to feed *j* to unit process m

$V_{jm}^{(in)}$ - material flow of a feed *j* entering unit process m

(*i.e.* stream *j* is the basis for yield data for unit process m)

On a volume basis, the summation $\sum_i y_{ijm}$ does not necessarily equal one. However, the yield vectors $\bar{y}_{inm}$ for the various unit processes in the NRM have been developed in a consistent manner to ensure mass balances around all individual processes.

[2] Standard practice in refinery modeling is to report all material flows as volumes. For liquid streams within a refinery, standard liquid volumes are employed with the basis being 60°F in the U.S. and volume units of barrels (bbl). For condensable gases such as propane, the liquid volume at the saturation temperature and 1 atm is used and for incondensable gases, the heating value of the gas relative to the standard heating value and density of fuel oil is used to calculate an "equivalent" liquid volume for the gas (i.e. FOE – Fuel Oil Equivalent volume).

Just as yield vectors are used to distribute UP feed streams to various UP product streams, deposition vectors are used to distribute specific UP product streams to various downstream unit processes or refinery finished products:

$$V_{jn}^{(in)} = x_{hjnm} V_{jm}^{(out)} \quad (2)$$

where: $V_{jn}^{(in)}$ - material flow of stream *j* entering unit process or product pool *n*

x_{jnm} - deposition factor of stream *j* to unit process or pool *n* relative to process *m*

$V_{jm}^{(out)}$ - material flow of a product stream *j* from unit process *m*

To ensure material balance for the refinery, the summation $\sum_n x_{jnm}$ must always equal one, since no chemical changes occur to a stream when it is being transferred to downstream processes.

Utility consumption by a unit process is represented mathematically by the following equation:

$$U_{km}^{(in)} = c_{hkjm} V_{jm}^{(base)} \quad (3)$$

where: $U_{km}^{(in)}$ - consumption of utility *k* associated with unit process *m*

c_{kjm} - consumption factor of utility *k* relative to stream *j* associated with unit process *m*

$V_{jm}^{(base)}$ - material flow of a feed *j* entering unit process *m*

(*i.e.* stream *j* is the basis for utility data for unit process *m*)

Total consumption of a utility in the refinery is the summation of all consumption of the utility in the refinery, including all unit processes and other utility systems. The total utility consumption $\sum_n U_{kn}$ must equal the total utility production within the refinery utility system, plus any utility purchased or minus any utility sold by the refinery.

Utility consumption by a utility system is represented mathematically by the following equation:

$$U_{km}^{(in)} = c_{hkjm} U_{jm}^{(base)} \quad (4)$$

where: $U_{km}^{(in)}$ - consumption of utility *k* within utility system *m*

c_{kjm} - consumption of utility *k* relative to utility production *j* associated with utility system *m*

$U_{jm}^{(base)}$ - utility *j* produced by utility system *m*

(*i.e.* utility *j* is the basis for utility data for utility system *m*)

Calculation of product yields and utilities consumption for all twelve unit processes and five utility systems requires values for the parameters $\bar{y}_{inm}$ and $\bar{c}_{kjm}$. These values were compiled from many sources in the open literature (primary sources include [Gary, 1975, 1994, 2007], [Maples, 1993]) and from previous studies conducted by one of the co-authors (Marano) for various government and industry clients.

2.2 Data inputs to the Notional Refinery Model

2.2.1 Refinery Unit Process Capacities

Capacities of various unit processes contained in the NRM are based on EIA collected data for the year 2010 [EIA 2015b]. Two types of capacities are used in this study, name-plate capacities on a stream-day (SD) basis and actual capacity in operation on a calendar-day (CD) basis. The analysis conducted with the NRM is based on capacity in operation in 2010; however, stream-day capacities are required in order to calculate capital costs associated with efficiency-improvement measures applied to the NRM. Capacity data derived from EIA refining surveys are presented in Table 2. It was necessary to estimate the operating capacity for some unit processes in order to establish an overall material balance for the NRM.

Table 2 – Unit Processes Baseline Capacities

Feed Capacity (million barrels per day (BPD))					
	name-plate SD	operating CD		name-plate SD	operating CD
CDU	18.581	15.177	**DTU**	3.647	2.850
ACU	18.581	15.177	**KTU**	2.029	1.585
VCU	8.543	6.978	**NTU**	4.281	3.045
CKU	2.632	2.016	**CRU**	3.700	2.632
CTU	3.816	3.003	**ISU**	0.494	0.399
CCU	6.140	4.873	**GTU**	2.395	1.901
HCU	1.675	1.309	**AKU**	1.581	1.236

2.2.2 Refinery Feed

Petroleum refineries typical run a variety, or slate, of crude oils optimized for their unique configuration, with the slate varying due to changes in crude pricing and product market conditions over time. In the NRM, a single aggregated crude oil with average properties reported for crude runs in the U.S. in 2010 is employed. The composition of this crude oil is estimated by blending three crude oils with known crude assays, to derive a single crude feed with the average density (API gravity) and sulfur content reported. EIA reported the API gravity and sulfur content in 2010 as 30.71^{o} and 1.39 wt%, respectively. The resulting NRM crude assay is given in Table 3.

Table 3 – Aggregate Crude Oil Properties input to the NRM

Crude Cut	Crude Cut Distribution volume%	weight%	SP.Gr. $60^{o}/60^{o}$	Sulfur weight %
Methane	0.00%	0.00%	0.3000	0.0000%
Ethane	0.03%	0.01%	0.3562	0.0000%
Propane	0.34%	0.20%	0.5070	0.0000%
Isobutane	0.33%	0.22%	0.5629	0.0000%
n-Butane	1.00%	0.67%	0.5840	0.0000%
Light Naphtha	6.82%	5.21%	0.6664	0.0062%
Medium Naphtha	1.98%	1.64%	0.7201	0.0223%
Heavy Naphtha	11.81%	10.33%	0.7626	0.0272%
Kerosene	9.03%	8.34%	0.8058	0.1463%
Diesel	19.02%	18.53%	0.8497	0.7467%

Crude Cut	Crude Cut Distribution volume%	weight%	SP.Gr. 60°/60°	Sulfur weight %
Light Gas Oil	25.85%	27.22%	0.9187	1.5672%
Heavy Gas Oil	3.66%	4.04%	0.9622	2.6918%
Resid	20.14%	23.61%	1.0226	3.0031%
Total	100.00%	100.00%	0.8723[a]	1.3984%

[a] A specific gravity of 0.8723 corresponds to an API gravity of 30.72°

2.2.3 Refinery Product Slates

The NRM does not attempt to quantify the more than fifty individual products produced from the refining of petroleum; but rather, establishes different classes of products based on the actual or estimated unit-process capacities in operation in Table 2. The NRM is constrained to satisfy a U.S. aggregated 2010 product demand slate (e.g., quantity of gasoline, diesel, jet fuel, etc.) [EIA 2015c] based on the composite crude oil assay presented in Table 3. Table 4 shows the 2010 refinery finished product demand slate input to the NRM along with a description. The table also includes basic modeling basis assumptions for each product classes that indicates how the NRM.

Table 4 – Refinery finished product slate input to the NRM

Product Class	Source	Description	Model Basis
Refinery Fuel Gas	All Unit Processes	Fuel for process heating, steam and power generation	Refinery fuel requirement less reported refinery fuel purchases
Refinery Gas Liquids	All Unit Processes	LPG and C3-C4 petrochemical feedstocks	C3-C4 not used to produce alkylate or consumed as refinery fuel
Gasolines	AKU, ISU, CRU, CCU, GTU	Various Grades of automotive gasoline and gasoline blendstocks	Refinery production of alkylate, isomerate, reformate, and cat gasoline
Other Naphthas	NTU, CCU	Petrochemical feedstocks, aromatics, solvents, other	Intermediate naphtha streams not consumed in producing gasolines
Kerosenes	KTU, HCU	Turbine and other fuels	All kerosene cuts produced in the refinery
Diesel Fuels	DTU	Low-sulfur diesel fuels of all types	All product from high-severity distillate hydrotreating
Other Distillates	KYU	Home heating oil, lube oils, petrochemical feedstocks	All diesel cuts produced in the refinery less low-sulfur diesel fuel produced
Catalyst Coke	CCU	Coke consumed as fuel in the catalytic cracking unit	All coke produced by the catalytic cracking unit
Petroleum Cokes	CKU	Fuel and metallurgical grades of coke	All coke produced by coking unit
Other Residuals	ACU, VCU, CCU	Residual fuel oils, asphalts, carbon black feedstocks	Resids not consumed by coking or catalytic cracking unit

2.3 Representing efficiency measures applicable to the U.S. petroleum refining sector

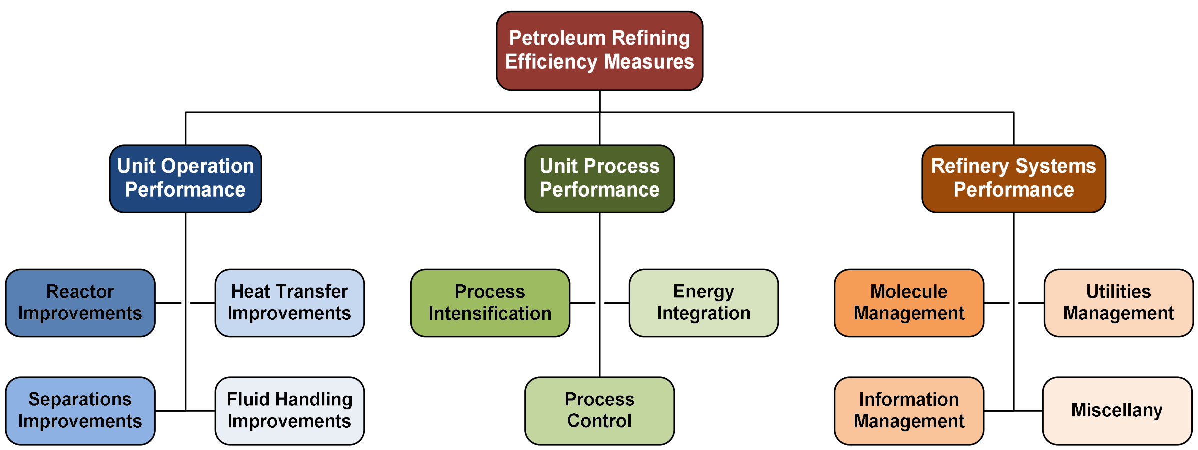
The NRM is employed in the analysis to construct a supply curve ordering of refinery efficiency-improvement measures. This requires that the NRM be coupled with an efficiency-measures cost model.

2.3.1 Efficiency Improvement Hierarchy

Refineries are unique relative to most industrial facilities 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. Due to the highly integrated nature of petroleum refining, energy abatement measures are generally not additive. A hierarchy of improvements exists, such that initial improvements limit the effectiveness of later improvements. When considering efficiency improvements all processes and their interactions are considered.

Figure 3 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 the LBNL report [Morrow, 2013].

Figure 3 – Efficiency Improvement Hierarchy



2.3.2 Measure Costing Methodology

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

$$CCE = \frac{I \times q + (M - B)}{ES} \tag{5}$$

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

This equation states that the cost of conserved energy is equal to the costs incurred for the capital investment and the incremental effects of operating costs divided by the quantity of energy saved.

Estimating energy efficiency measure capital costs is uncertain. Even when the cost of any new equipment is known, energy efficiency projects typically involve modifications to an existing plant; especially when considering major process modifications. 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.

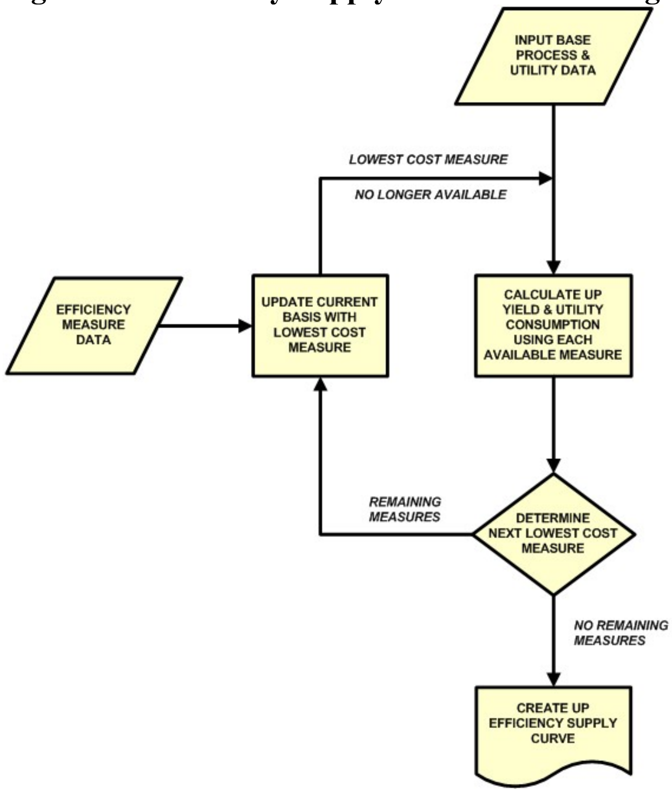
Any given energy measure applied may result either in annual non-energy operating and maintenance (O&M) cost increases, decreases or both. Many of the measures to reduce fuel requirements also result in decreases or increases in electricity usage; however, the value of incremental changes in electricity 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 Cost of Conserved Energy for each of the measures modeling in this analysis are provided in Supplemental Materials. Each measure's capital and incremental O&M costs are estimated by the type of measure in general, and then tailored for each processing or utility units. Numerous sources were consulted to derive the performance and cost parameters used in Equation 5 (some of the most useful are [Parkash, 2003], [Meyers, 2004]). A 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.

2.3.3 Solution Algorithm for the Cost of Conserved Energy (CCE) Supply Curve

Efficiency measures are applied to the input parameters specified for a unit process, creating a new representation of the unit process in the NRM. However, the order in which the measures are applied is not arbitrary. This is because the supply curve is based on implementing measures starting with the lowest cost option and proceeding through to the highest cost option, and the cost of a given measure can be different if implemented earlier or later in the sequence. For example, process heat integration, lowers the actual amount of heating required in a process; whereas, furnace efficiency improvements impact the amount of fuel required for a given heating requirement. If the process is poorly integrated and furnace efficiency measures are implemented first, the energy savings can be extremely large; however, if integration is done prior to furnace improvements, energy savings associated with furnace efficiency measures can be much smaller. Therefore, an optimization procedure is required in order to establish correct sequence for measures used to generate the efficiency supply curve. This algorithm is shown in Figure 3.

Figure 4 – Efficiency Supply Curve Solution Algorithm



The algorithm used to order the 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.

The NRM and CCE and energy saving potential supply-curve algorithm is implemented in an Excel workbook. Each unit process is set up as a separate worksheet in the workbook, and each column in a worksheet represents the application of an individual efficiency measure to the unit process. Logical functions are employed to ensure the columns are ordered from low to high cost measure and no iteration is required. The efficiency supply curve is then generated using table lookup function available in Excel to extract the x and y coordinates from the table made up of the unit process columns.

3. Results

3.1.1 Refinery Sector 2010 Energy Consumption Results

The U.S. petroleum refinery industry is first modeled without energy efficiency (i.e., vintage 1995) and current energy efficient measure adoption rates are estimated to reflect 2010 aggregate energy consumption. The remaining energy efficiency adoption potential constitutes the energy efficiency potential presented in the results of this paper. Table 5 presents estimated energy consumption for the twelve modeled unit processes for the year 2010 as output from the NRM.

Table 5 – Estimated Energy Consumption for the U.S. Petroleum Refining Model circa.2010

Process	Throughput	Fuel (PJ, Primary)		Electricity (GWh, End-Use)	
	Million bbl/year	ISBL	OSBL	ISBL	OSBL
CDU	5,540	399	636	4,044	1,766
CKU	736	109	26	2,280	881
CTU	1,096	49	398	145	2,079
CCU	1,779	-822	103	5,653	5,103
HCU	478	93	474	61	2,268
DTU	1,040	52	246	151	1,188
KTU	579	29	57	404	424
NTU	1,111	94	92	162	390
CRU	961	303	115	949	1,459
ISU	146	6	28	21	9
GTU	694	56	225	99	701
AKU	205	0	42	5	604
Total Modeled Energy Consumption		368	2,443	13,975	16,873

Inside the battery limits (ISBL) – energy consumption within the processing unit
Outside the battery limits (OSBL) – energy consumption outside the processing unit but necessary to support the processing unit

3.1.2 Cost of Conserved Energy Results

Although an aggregate CCE representation of the U.S. petroleum refining industry is presented below, each unit process was analyzed separately to qualify and quantify potential energy abatement measures. In addition to measures that bear 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 on 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 end-use 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 industry is grid purchased electricity. A 2014 U.S. average CO_2 emissions factor of

0.505 Mt CO_2/TWh is used to convert electricity saving into grid level CO_2 emissions[3]. Thus, the CO_2 reported below reflects the current U.S. average electric grid supplied fuel consumption even though the fuel reported below does not.

Many of the energy efficiency and abatement measures described here 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 (See supporting material for a full list of measures). This results in an accurate representation of costs and impacts.

Figure 4 – Refining cost of conserved energy and energy saving potential (includes fuel & electricity)

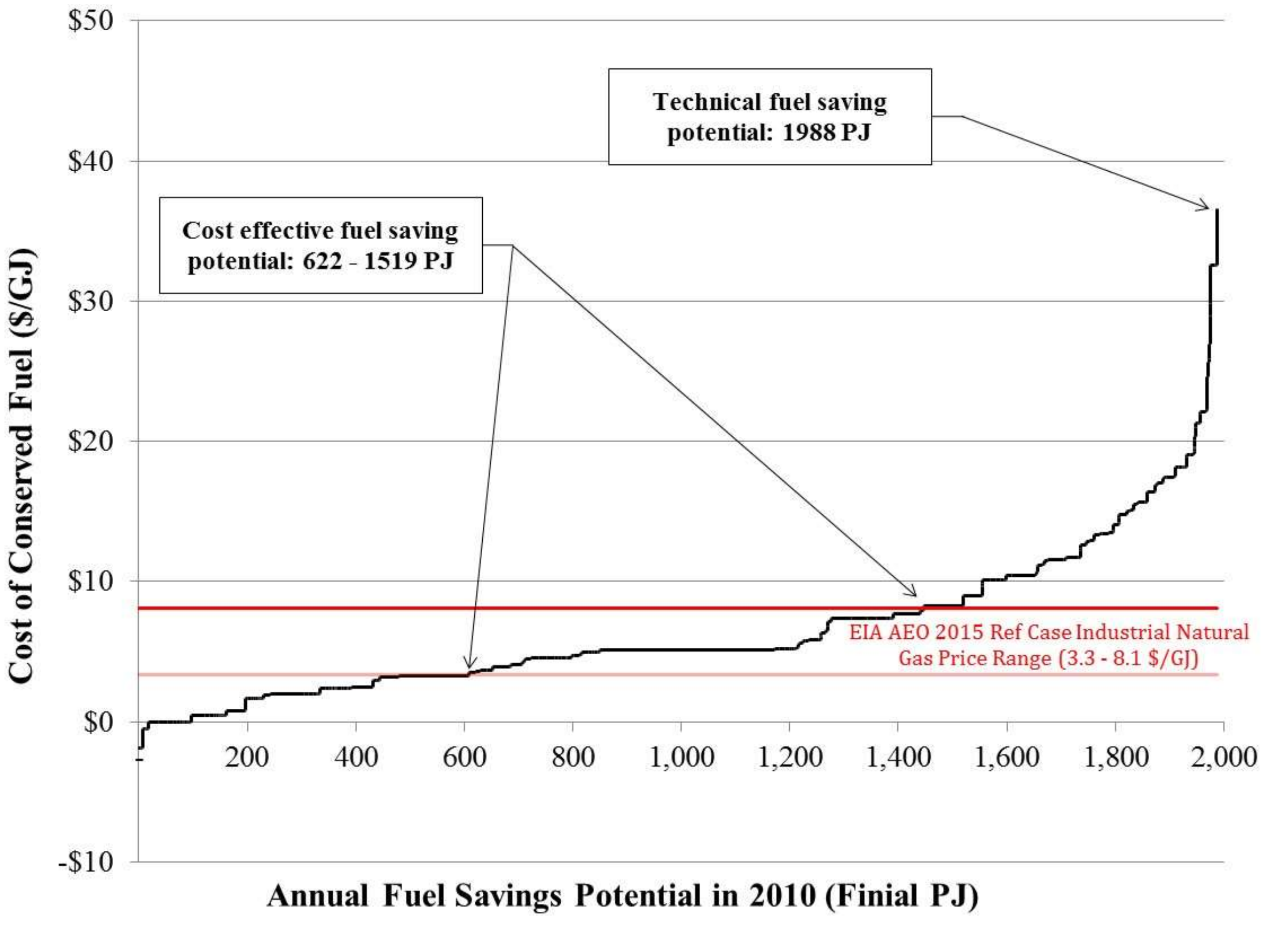


Figure 4 presents all the energy efficiency measures modeled in this analysis ordered from least cost to highest cost, and indicates those that are cost effective given EIA's current forecast for

[3] This is calculated from 2,082 Mt CO_2 of electricity sector emissions associated with 4,119 TWh of electricity production reported in EIA AEO 2012 [EIA, 2015a]

natural gas prices through 2040 (used as an cost-effectiveness evaluation metric [EIA, 2015a]). Total fuel, electricity and CO_2 emission reduction potentials are shown in Table 6. The negative electricity savings within the Potentially Cost Effective category in Table 6 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 therefore 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. Individual efficiency measures are reported in the supplemental material. Table SM1 reports the ranking of each measure, the processing unit where it is applied, the efficiency measure's current penetration estimates, and the measure's relative energy savings and costs.

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 3.3 and 8.1 $/GJ[4]. This energy savings represents 85 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 not possible to quantify this observation directly although estimates of current rates are applied to the individual processing units. Both the individual processing unit and the composite cost of conserved energy curves reflect the current estimates.

Table 6 – Cumulative Refining Composite Results

	Fuel Savings (PJ/yr)	Electricity Savings (GWh/yr)	Combined Savings (PJ/yr)	CO_2 Emissions Reductions (Million t CO2/yr) †
Cost Effective *	618	958	622	35
Potentially Cost Effective **	899	-306	898	50
Technical but not Cost Effective	458	2750	468	27
Total	1976	3403	1988	113

* Costs Effective are the cumulative totals that fall below the lower price line in Figure 4

** Potentially Cost Effective are the cumulative totals that fall in between the lower and higher price lines in Figure 4

† 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, 2015a]

[4] EIA projections for mid to long term natural gas price [EIA, 2015a]

3.1.3 Limitations, uncertainty, and next steps

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 EIA, there were 148 refineries operating in the U.S. in 2010, with an average design capacity of 17,583,790 BPCD [EIA, 2015b]. 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 energy utilization efficiency in the industry, it was necessary to start with a number of simplifying assumptions and then to model the entire industry 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[5].

One more significant challenge is 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 adoption rates to the individual energy abatement measures analyzed[6]. Further work, which might include surveys and/or audits of existing facilities, will be needed to improve these estimates.

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

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[5] A number of excellent case studies based on this approach can be found in the open literature [Glasgow, 2010, Rossiter, 2010, Carbonetto, 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).

[6] Presented in the Supplemental Materials Table SM1 in the column "Assumed Current Unit Adoption Rate (%)

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[7], and an accounting methodology that tracks the inter-dependent nature, as described in the Materials and Methods section, 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 industry affecting energy requirements and efficiency adoptions within the petroleum refinery industry.

4. Conclusions

In this analysis, energy-usage abatement curves have been developed for the U.S. petroleum refining industry. 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, 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 energy savings estimates and cost of conserved energy 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. Individual processing unit cost of conserved energy supply curves are discussed in a previous LBNL report [Morrow, 2013]. The results reflect fuel savings that can be made by the refining industry and have been combined into a composite curve representing the entire refinery industry. This composite curve has been used to identify the potential for reducing refinery CO_2 emissions.

An estimated 622 PJ of saving are below the low fuel price line representing cost-effective efficiency improvements that could lower CO_2 emissions by 35 Mt/yr. Roughly 900 PJ of additional efficiency improvements are potentially cost effective that could lower CO_2 emissions by an additional 50 Mt/yr. 468 PJ of additional efficiency savings are technically available but are not cost-effective to implement given fuel price forecasts.

This analysis primarily 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

[7] 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.

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.

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.

Regional fuel market heterogeneity and crude oil supplies influence the unique configurations of individual refineries across the U.S. Moreover, competitive fuel market create a proprietary nature in the industry resulting in limited publically available data. Thus, the NRM is intended to overcome these significant data gap barriers to estimating the energy efficiency potential available in the U.S. petroleum refinery sector. While the overarching model structure is presented, the NRM leverages several decades of dedicated petroleum engineering modeling expertise.

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